YUB-YEC-2-29 Attachment 1

TABLE OF CONTENTS

2006 Resource Plan **A-1**

Alexco Power Purchase Agreement **A-259**

2011 Resource Plan Overview **A-304**

2016 Resource Plan Appendices **A-372**

Appendix 3.1 Electricity Values Survey A-372

Appendix 3.2 Public Engagement Methods and Materials A-404

Appendix 4.1 Energy and Peak Demand Forcast Data 2016-2035 ..... A-411

Appendix 4.2 Yukon Macroeconomic Model A-426

Appendix 4.3 Long Term Load and Demand Forecast 2016-2035 ..... A-445

Appendix 4.4 Industrial Energy and Peak Demand Forcast 2016-2035 ..... A-512

Appendix 4.5 Electric Vehicle Investigation A-529

Appendix 4.6 Home Heating Retrofit Business Case A-579

Appendix 4.7 Mirrlees Assessment Report A-599

Appendix 4.8 Generation Adequacy Evaluation A-608

Appendix 5.1 Greenhouse Gas Emmission Life Cycle Assessment of Resource Options (ArcticCan Energy Services A-676

Appendix 5.2 Environmental Social and Economic Attribute Evaluation of Resource Options (InterGroup et al. 2016 ..... A-780

Appendix 5.3 Southern Lakes Concept Project Proposal A-1106

Appendix 5.4 Mayo Lake Enhanced Storage Project A-1140

Appendix 5.5 Aishihik Turbines Uprate Study (KGS 2016) A-1329

Appendix 5.6 Mayo Hydro Future Facility Options Report (KGS 2016) A-1475

Appendix 5.7 Small Hydro Screening Assessment (Knight Piesold 2016) A-1567

Appendix 5.8 Atlin Hydro Expansion Study (Morrison Hershfield 2016) A-1627

Appendix 5.9 Wind Site Inventory (CBER Envint and V3 Energy) A-1829

Appendix 5.10 Geothermal Review and Site Inventory (KGS 2016) A-2009

Appendix 5.11 Solar Site Inventory (Solvest 2016) A-2099

Appendix 5.12 Biomass Fron End Engineering Design Study (Stantec 2016) A-2319

Appendix 5.13 Biogas Feasibility Study (WSP 2016) A-2642

Appendix 5.14 Wast to Energy Design Basis and Business Case Analysis (Morrison Hershfield 2012) A-2799

Appendix 5.15 Thermal Energy Plan Development Study (Stantec 2016) A-2873

Appendix 5.16 Pumped Storage Assessment (Knight Piesold 2016) A-3054

Appendix 5.17 Moon Lake Pumpsed Storage Conceptual Study Report (Midgard 2015) A-3114

Appendix 5.18 Faro Mine Pumped Storage Conceptual Assessment (EMC2 and Picacho and Associates A-3180

Appendix 5.19 Evaluation of Energy Storage Technologies (Transgrid Solutions 2016) . A-3217

Appendix 5.20 Updates to Yukon Electricity Conservation and Demand Management Potential Review
(ICF 2016) A-3282

Appendix 5.21 Transmission Options Evaluation (Midgard 2016) A-3328

Appendix 6.1 Fuel Price Forecast A-3446

Appendix 6.2 Social Cost of Carbon A-3455

Appendix 8.1 Portfolio Analysis Data A-3465

2006 Resource Plan

YUKON ENERGY CORPORATION

20-YEAR RESOURCE PLAN: 2006-2025

January, 2006

and

SUPPLEMENTAL MATERIALS

May, 2006

YUKON ENERGY CORPORATION SUBMISSION
20 YEAR RESOURCE PLAN

SUMMARY OF PROPOSED ACTIONS

INTRODUCTION

Yukon Energy's 20 Year Resource Plan Submission addresses major electrical generation and transmission requirements in Yukon during the 2006 to 2025 period, with emphasis on:

a) near term projects that will require Yukon Energy commitments before the year 2009 with costs of $3 million or more, and
b) planning activities that Yukon Energy may be required to carry out in order to start construction on other projects before 2016 to meet the needs of potential major industrial customers or other major potential developments in Yukon.

In response to past commitments, the 20-Year Resource Plan Submission is expected to provide the Yukon Utilities Board (YUB) with the opportunity to review near term generation or transmission projects that Yukon Energy proposes to commit before 2009 with costs of $3 million or more, including projects based on revised planning criteria now adopted by Yukon Energy. The last Resource Plan, which was submitted for review by the YUB in 1992, covered 1992-2001 and was prepared by Yukon Energy and Yukon Electrical Company Limited (YECL).

The Submission also proposes Yukon Energy planning activities to protect Yukon Energy's ability to start construction on other major generation and transmission projects before 2016 to meet the needs of potential major industrial development opportunities.

This summary reviews the following:

- Resource Planning for Yukon Power Systems (to provide context for this Submission).
- New Capacity Criteria (reviews a key factor affecting proposed actions in this Submission).
- Proposed Near Term Actions (summary of actions proposed for commitment before 2009).
- Proposed Actions Relating to Industrial Development Scenarios and Opportunities (summary of proposed planning activities to protect possible commitments beyond 2009 and before 2016).

RESOURCE PLANNING FOR YUKON POWER SYSTEMS

The distinct and independent power systems in the Yukon are each served by separate source(s) of generation, and include: the Whitehorse Aishihik Faro (WAF) grid; the Mayo Dawson (MD) grid; the diesel community of Watson Lake; and a number of smaller isolated diesel communities (Beaver Creek, Destruction Bay, Pelly Crossing, Swift River and Old Crow).

Yukon Energy's generation on the WAF and MD systems accounts for 112.4 MW of the 127.4 MW of installed and currently rated capacity in Yukon. The YECL generation accounts for the balance, or for 15.0 MW of installed and rated capacity.

Yukon Energy's extensive hydro generation, as well as most of its related transmission facilities, were previously developed in response to major industrial mine developments. Today, these hydro systems are the key factor causing Yukon power costs to be lower than those found in Alaska or the Northwest Territories. Without such hydro facilities, Yukon utilities probably would have relied almost entirely on diesel generation with its associated higher costs.

The Yukon economy, and Yukon's electrical loads and systems have changed substantially since the 1992 Resource Plan review by the YUB. Highlights relevant to the current Resource Plan include:

- Due to closure of the Faro mine, no reopening of the UKHM mine, and no new mines yet having emerged on the WAF and MD systems, there is today a substantial surplus of hydro energy on these grids.
- Yukon Energy's response to these conditions has included greatly increased secondary sales and development of the Mayo Dawson Transmission Line.
- Yukon Energy's three water licences have been renewed.

As the major generator and transmitter of electrical power in the Yukon region, Yukon Energy plans for the capacity and energy requirements of Yukoners, particularly those supplied on the WAF and MD grids.

- **Capacity requirement** planning focuses on the highest or peak megawatt (MW) generation capability (capacity) required on each system during each year, including sufficient generation reserve capability (based on the system's capacity planning criteria) to address unplanned outages.
- **Energy requirement** planning focuses on the number of kilowatt hours (kW.h) of electricity that are required to be generated on each system.

The Resource Plan reviews WAF and MD system capability to supply loads today and into the future under various time horizons, industrial load development scenarios, and resource supply options.

- **Immediate need for new WAF generation capacity:** Forecast load growth, pending retirement (absent substantial Life Extension investment) of three Mirrlees diesel units (11.4 MW) located in YEC's Whitehorse diesel plant, and new capacity criteria adopted by Yukon Energy together create an immediate need for new WAF generation capacity to serve peak winter load requirements in the near term through to 2012.
- **Potential new mines prior to 2009:** Potential new industrial developments prior to 2009 at the Minto and Carmacks Copper mines may also absorb the WAF hydro energy surplus, support transmission extension of the WAF grid from Carmacks to at least Pelly Crossing, and create opportunity to interconnect the WAF and MD grids.
- **Diverse range of other possible industrial development scenarios and opportunities**: Planning activities to proceed with other energy-focused generation projects beyond 2009 and before 2016 are being driven by the potential needs of a diverse range of possible industrial development scenarios and opportunities, including various possible mines and the Alaska Highway Natural Gas Pipeline project.
- **Potential supply resource options for a construction start within the next 10 years**: Supply resource options potentially relevant for a construction start within the next 10 years vary widely depending on the potential industrial developments considered, and include a range of different hydro and diesel generation possibilities as well as transmission, and possibly coal and/or natural gas-fired generation.
- **Balance required**: Readiness and timing to supply new major industrial loads needs to be balanced with understanding of the long predevelopment timelines and considerable costs, uncertainties and risks associated with planning specific power resource options.

Varying levels of technical and costing assessments have been carried out to screen options, including in some instances investigations advanced to the project feasibility stage. The Resource Plan process identifies preferred projects for which YEC can then commit when appropriate to proceed with more detailed project-specific pre-decision planning.

This Submission includes near term projects at different stages of pre-decision planning. No final decision has yet been made to implement these projects. In some instances, environmental approvals have already been secured - in other instances, however, the necessary applications for such approvals have yet to be made. Final design, costing and tendering tend to be a final stage to be carried out prior to final Yukon Energy decisions to proceed with construction/implementation.

NEW CAPACITY CRITERIA

After an extensive review of its system capacity planning criteria, Yukon Energy has adopted new capacity planning criteria. System capacity planning criteria are the sets of rules used to determine how much generation is required on the various Yukon systems and when additions to generation capacity are required.[1]

Background on Evolution of Capacity Planning

Planning of a utility system must provide both for system growth and for operation after a component failure. Utility systems across North America vary greatly in size and complexity but the ability of each system to maintain service is compared by using established and recognized criteria.

The criteria used by the Northern Canada Power Commission (NCPC) prior to 1987 were developed to indicate the amount of firm generating capacity required to cover relatively small isolated systems, and were consistent with utility planning standards of that era. NCPC had started with a multiple of small isolated systems, some of which continued, but others had grown to the point where multiple sources were interconnected.

Yukon Energy (and its then manager, YECL), as the operator succeeding NCPC for the Yukon, initially followed the practice of NCPC. It was quickly found that the continuing small isolated installations were reasonably covered by the NCPC criteria but that the larger systems with multiple sources needed more detailed analysis to be secure:

- The small systems were considered to be adequately protected if the generating capacity with the largest single unit out of service was at least 110% of the anticipated peak load.
- For the larger "grid" systems, it became necessary to consider not only the possible loss of a single generator (in the case of WAF, a single "wheel" at Aishihik), but also the likelihood that at least one of the major WAF diesels would be unavailable at the same time. Consequently, the Resource Plan in 1992 introduced recognition of the diesel-related effect on Yukon Energy's ability to serve any particular WAF load by adding a "10% of installed diesel" reserve on top of the Aishihik hydro reserve.

Under the original NCPC capacity planning criteria and the capacity planning criteria reviewed in the 1992 Resource Plan, the transmission system availability was not taken into consideration.

[1] For the purposes of system planning, all "firm" customer load requirements at the time of system maximum load or peak (e.g., winter peak on WAF) are considered when assessing each system's capacity planning requirements. Yukon Energy's policy requires that secondary energy service be interrupted when surplus hydro resources are not available, and therefore no bulk electrical supply capabilities are planned to supply secondary energy service.

In contrast to these earlier Yukon capacity planning criteria, integrated utilities today typically use a statistical approach to evaluate the potential interruption of service for any customer. This is often evaluated as the Loss of Load Expectation (LOLE) and it is measured in hours per year[2]. Most Canadian utilities apply an LOLE range from one to two hours per year as their capacity planning criteria standard. Further, where relevant, certain utilities today have incorporated transmission into this probability assessment when generation reliability is directly and materially affected by transmission.

Certain utilities have also adopted additional tests along with the LOLE criteria. For example, recently the Northwest Territories Power Corporation (NWT Power Corporation) has incorporated into its system capacity planning criteria a second test which is applied in parallel with LOLE criteria to ensure that customers are protected against failure of any single system component.

In summary, throughout various integrated utilities it is apparent that capacity planning criteria have evolved gradually into more defined ratios as systems have grown larger and more complicated. Furthermore, where relevant, transmission reliability is also being addressed today where it directly affects generation reliability.

Recent Yukon Energy Review of Capacity Planning Criteria

Yukon Energy recently completed an extensive review of its capacity planning criteria and, amongst other things, has examined the LOLE approach, testing it against the operating history of its WAF system. This review was undertaken in consultation with reliability experts from the University of Saskatchewan (under the direction of Dr. Roy Billinton[3]). Dr Billinton and his colleague were retained in late 2004 to review Yukon Energy's then established capacity planning criteria (i.e., the criteria as reviewed in the 1992 Resource Plan), including studying and determining the probabilities inherent in that criteria.

In contrast with statistical approaches such as LOLE, Yukon Energy's capacity criteria reviewed in the 1992 Resource Plan are "deterministic" in that a specific test was adopted for each system as a proxy intended to ensure adequate capacity. Yukon's criteria dealt with the concept of a "reserve" rather than actually assessing the likelihood (or probability) that the generation available will be insufficient to supply the load at any given point in time. Without reference to a specific probability of interruption, the adequacy of Yukon Energy's capacity criteria as reviewed in the 1992 Resource Plan cannot be readily compared today with criteria adopted in other jurisdictions for integrated systems.

[2] Other terms are also used to describe the probabilistic measures, such as the BC Hydro criteria of Loss of Load Probability (LOLP) or Newfoundland and Labrador Hydro's Loss of Load Hours (LOLH).

[3] The same experts advised NWT Power Corporation in the development of the Snare-Yellowknife system planning criteria which criteria received approval from NWT Power Corporation and its regulator in 2004.

The recent work by Dr. Billinton addressed this issue with regard to WAF. It indicated that Yukon Energy's capacity criteria as reviewed in the 1992 Resource Plan provided excellent capacity reliability, based on LOLE, for residential and commercial WAF customers in 1996/97 when the Faro mine was operating. Today, however, in terms of the maximum peak load that can be supported, Dr. Billinton's work indicated that WAF generation is not adequate to supply the peak allowed under that same criteria within any reasonable LOLE reliability standard adopted elsewhere in Canada. The primary reasons for this conclusion are that the WAF system has substantial hydro generation availability that is directly affected by certain transmission, and further that the WAF system also has been trending to an increasing probability of longer outages as it expands (particularly with expansion of residential and commercial loads and major reductions in industrial load).

As a result of this recent review, Yukon Energy has now incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages.

At the same time, Yukon Energy has recognized that the LOLE function is an average that does not indicate how long any particular outage will last, and that any extended outage on WAF or the Mayo Dawson grid during the winter peak could be extremely serious for affected residential and commercial customers. Yukon Energy has addressed this concern by incorporating a second test as part of its capacity planning criteria, known as the N-1 standard[4] which ensures sufficient system capability to continue to serve firm residential and commercial customers when a failure occurs to the single largest system component. As an example, the biggest loss of generation on WAF today at winter peak would be 30 MW following a failure of the Aishihik transmission line; this loss would be far greater than the loss during winter peak of the biggest generator (which currently is a 15 MW generator at Aishihik).[5]

New Capacity Planning Criteria

The following new capacity planning criteria have been adopted by Yukon Energy:

1. **WAF and MD System-wide capacity planning criteria:** Each grid system (WAF and MD) will be planned not to exceed a Loss of Load Expectation (or LOLE) of 2 hours/year.
2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each grid system

[4] A test described as "surviving the first failure" or "operating in the N-1 condition where "N" is the normal system complement.

[5] The largest single unit on the WAF system today is WH 4, one of the hydro units at Whitehorse. However, as Whitehorse has 4 hydro units (WH1 at 5.8 MW, WH2 at 5.8 MW, WH3 at 8.4 MW and WH4 at 20 MW), but only 24 MW of firm flows in winter in drought conditions, a loss of WH4 would only effectively reduce the available capacity by 4 MW (as the other 3 units would still be available); this loss at winter peak would therefore be smaller than the loss of 15 MW via one of the units at Aishihik.

(WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source.

3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

For isolated diesel communities no change has been made for the capacity planning criteria (Yukon Energy will maintain the past criteria of being able to meet 110% of the community peak with the largest unit out of service).

PROPOSED NEAR TERM ACTIONS

Four separate major investments are proposed for Yukon Energy generation and transmission commitment before 2009, three with anticipated costs of $3 million or more. These proposed major projects will address near term requirements and opportunities to 2012 and together will provide over 21 MW of new WAF firm winter capacity by 2012 (i.e., enough new firm capacity to meet WAF capacity shortfalls that would otherwise be expected by 2012 of 18.7 MW under the Base Case forecast and 21.5 MW under the Base Case forecasts plus the Minto and Carmacks Copper mine loads). The four major proposed projects are reviewed below, along with contingency provisions and other proposed actions before 2012:

1. **Aishihik 3rd Turbine Project:** This project, which was initially reviewed in the 1992 YUB Resource Plan hearing, will provide 7 MW of added peaking capability[6] and about 5.4 GW.h/yr of long-term average hydro energy supply at the existing Aishihik generation station at a capital cost of about $7 million (2005$). Under Base Case loads without any new industrial developments, this project is expected to be economic within the planning period to 2025 based solely on its diesel operating cost saving benefits for the WAF grid, including displacement of peaking and then baseload diesel as WAF loads increase. Yukon Territorial Water Board and environmental approvals for the project were received in the new Aishihik Water Licence.
    a) Accordingly, this project will proceed with final planning activities to enable a final decision during 2007 to start construction for in-service by October 2009.

[6] Without twinning of the Aishihik Transmission Line, none of this added Aishihik capacity is recognized under the N-1 WAF capacity planning criteria, and only 0.6 MW is recognized under the LOLE WAF capacity planning criteria.

b) If Marsh Lake Fall/Winter Storage is developed without any additional non-industrial load growth or new industrial loads emerging, the final decision to start construction is proposed to be deferred until late 2009 for in-service in 2011 or 2012.

2. **Marsh Lake Fall / Winter Storage licence revision:** This project, which was not reviewed in the 1992 Resource Plan hearing, will increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and increase long-term average hydro energy from this facility by about 7.7 GW.h/year at a capital cost of no more than $1 million.[7] Yukon Energy will undertake the project planning activities, including consultation and environmental licensing, as required to seek amendment of the Whitehorse Rapids water licence to enable modified operation of Marsh Lake within its current lake levels to enhance fall/winter storage. Basically no new physical works are expected to be required for this project. Project approval is forecast by August 2007 (although provision is made in the event that the new Yukon environmental licencing regime requirements delays completion of the licence amendment to 2008). The effects of the proposed licence amendment are summarized as follows:
   a) **Remain within current lake level limits:** In all cases, the water levels with the amended licence will remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake).
   b) **Licence amendment changes the "controlled maximum" level:** The proposed amendment would change the licenced "controlled maximum" level that YEC can maintain upwards by about 1 foot; however, during uncontrolled periods of summer and fall (when YEC currently has no control over the lake and it is operating under an entirely natural regime), Marsh Lake has been known to peak at 2 feet above the YEC "controlled maximum" level. The effects of the proposed change are as follows depending on water conditions:
      i. **Non flood year operation other than a drought:** This project would allow Yukon Energy to reduce the amount of water it releases in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period. No effect is to occur under these conditions in any year prior to August 15, other than under drought conditions (see below).
      ii. **Flood year operation:** During flood years, there would be no change in the flood levels experienced on Marsh Lake, and no change to operations would be made during August and September until after flood levels subside.
      iii. **During drought years:** Current licence provisions to help alleviate summer drought levels on Marsh Lake through "early closures" of the Lewes Dam would

7 This estimated capital cost is made up of the costs for licencing, any required mitigation works and any potential facility modifications.

remain, and would likely be adapted to alleviate further summer drought conditions to ensure the lake reached the full supply capacity level in each year.

3. **Carmacks-Stewart Transmission Line Project:** This project will fully interconnect the MD and WAF grids as well as facilitate WAF transmission access to potential new mine loads at Minto and Carmacks Copper, providing 5.6 MW of additional firm near term capacity and 15 GW.h/year of additional near term energy for WAF[8]. Development of this project, which is estimated to cost about $35 million (2005$), is subject to provision of Yukon Government funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy. Based on external funding to assure no adverse impact on ratepayers from project development, planning activities will proceed with the Carmacks-Stewart project to enable a decision to proceed with construction early in 2007 for an in-service date in approximately late 2008.

4. **Mirrlees Life Extension Project**: Subject to confirmation of technical feasibility that is expected to be determined within the first quarter of 2006, the Mirrlees Life Extension Project will conclude final planning activities in 2006 in order to provide in-service during 2007 through to 2009 to provide an additional 14 MW of firm WAF winter capacity at a cost of up to $4.5 million (2005$).
    a) **First Mirrlees unit in service by October 2007:** By the summer of 2006 planning work and commitments for construction/implementation will begin on the first Mirrlees unit (5 MW) at a cost of up to $2.5 million (2005$)[9] in order that in-service will occur before October 2007.
    b) **Other two Mirrlees units by October 2008 and 2009**: Life Extension for the other two Mirrlees units will proceed thereafter for expected in-service in 2008 and 2009, subject to review of the experience gained from Life Extension of the first unit and the possible Yukon Energy consideration of replacing the third Mirrlees unit (4 MW) with a larger capacity new diesel unit (e.g., 8 MW or 11 MW unit).[10]

[8] Added capacity and energy supplied to WAF by this interconnection are subject to MD loads, and will decline as MD loads increase. Reopening of the UKHM mine or other new industrial developments on MD, for example, would reduce MD surplus capacity and hydro energy available to WAF. In contrast, potential additional enhancements at the existing Mayo hydro facility or other new generation opportunities in the MD area could enhance overall WAF/MD power supply in the event of Carmacks-Stewart Transmission line development.

[9] This cost includes a "teardown" level of overhaul and the common diesel plant upgrade work necessary to undertake the Mirrrlees Life Extension Project.

[10] In the event that Mirrlees Life Extension proceeds but the Carmacks-Stewart Transmission Line is not developed in the near term, replacing the third Mirrlees unit with an 11 MW new diesel would more than replace the capacity that otherwise would have been provided by the Carmacks-Stewart Transmission Project.

5. **If Mirrlees Life Extension is not technically feasible, implement diesel replacement/expansion and/or other project options as appropriate:** Without the Mirrlees Life Extension option providing 14 MW of firm capacity, the key near term choice is between the option involving Whitehorse Diesel Replacement/Expansion (capability for three units with combined capacity of up to at least 33 MW) versus the Aishihik 2nd Transmission Line (providing 22 MW under N-1 criteria and about 14.4 MW with LOLE criteria).[11]

   Although the expected capacity shortfall can technically be met with the Aishihik-related option, this is not expected to be the lowest cost option to 2012 under Base Case loads and also this is not the lowest cost long-term option under higher loads including mines. The Aishihik-related option also exposes the WAF grid to near term and growing capacity shortfalls until it is completed.

   Accordingly, the Diesel Replacement/Expansion option will be implemented as follows in the event that Mirrlees Life Extension is not technically feasible[12]:

   a) **Base Case Loads**: **First Diesel Unit (8 to 11 MW) needs to be installed by October 2007:** Yukon Energy will need under these circumstances to proceed with final planning work on this project by summer 2006, including orders for the necessary engine unit (with cancellation provisions) in order that the unit can be installed by October 2007 at a capital cost (2005$) of up to about $7.2 million (8 MW) or $8.8 million (11 MW). This will include updating any common diesel plant systems necessary for connection of a new unit.
   b) **Other Diesel Units**: Once the first unit is committed, it is expected that up to two additional diesel units (depending on the unit size selected) will be implemented thereafter as required for in-service before 2012.

6. **Ongoing monitoring of existing customer load forecasts and new industrial development opportunities:** In order to facilitate ongoing assessment of generation and transmission options and requirements, Yukon Energy monitoring of annual customer class load trends (peak capacity and seasonal energy) on each grid is required. In addition, Yukon Energy will continue to monitor directly with developers and government specific new industrial

[11] In this context, the Aishihik-related option has been examined for possible implementation assuming that it is feasible to commit development of the Aishihik 2nd Transmission Line by 2009 at the latest; under this option, material near term capacity shortfalls would still occur until the Aishihik 2nd Transmission Line was in service.

[12] Diesel Replacement/Enhancement will also be the option pursued as required in the event that other major projects do not proceed as proposed, e.g., the Carmacks-Stewart Transmission Line Project (which is assumed to provide 5.6 MW by late 2008) and/or the Marsh Lake Fall/Winter Storage (which is assumed to provide 1.6 MW by fall 2007 or 2008). In the event that mine loads are connected to WAF without completion of the Carmacks-Stewart Transmission, Yukon Energy will review the feasibility of the Aishihik 2nd Transmission Line project.

development opportunities for grid power service, including assessment of any mine site power contribution to the supply of reliable grid peak capacity.

7. **Other Small Enhancement Projects:** Continued routine utility investment is recommended in assessing and proceeding with projects to enhance existing facilities at a cost less than $3 million. This includes:

    - study of the hydrology of the Southern Lakes, and potentially pursuing small water control structures in this region (new generating stations to manage water plus generate hydro power would, if proposed in the future, exceed $3 million);
    - continued pursuit of opportunities to cost-effectively rewind or re-runner existing hydro generating units at Whitehorse and Aishihik; and,
    - assessing need and timing for a potential 1 MW diesel unit installation at Carcross/Tagish (likely by YECL).

PROPOSED ACTIONS RELATING TO INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Yukon Energy proposes planning activities as set out below to address a wide range of potential industrial development scenarios beyond the near term, and to protect future opportunities to commit development of additional generation and transmission projects before 2016 in a timely and cost-effective way in the event that one or more of these industrial development scenarios materialize.

Planning activities are organized by industrial development load scenario, identifying proposals as to how to approach each load scenario should it arise. “Pre-commitment” activities are also addressed which encompass planning activities Yukon Energy proposes to carry out prior to any certainty or commitment on the part of potential new industrial loads.

Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario

This industrial development scenario (which provides for near term development and operation between 2007 and 2018 of the Minto and Carmacks Copper mines) supports commitment of modest existing hydro enhancements, but does not support commitment of any new hydro site development before 2016 unless mine loads of at least 10 MW are sustained well beyond 2016. Consideration of the smallest hydro site options (1-4 MW) could potentially be supported in the event that 10 MW mine load development extends through to at least 2020. In this context, the following planning activities are recommended in the event these mine loads are seriously being considered for development prior to 2016:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should then proceed to commit the Aishihik 3rd Turbine, the

Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments.

  - If not already committed, Aishihik Diversions and Atlin Storage should then be advanced to Level 2 studies, including system-wide water and load dispatch modeling, to quantify the energy benefits under this scenario.
  - Ongoing assessment of the Southern Lakes should be completed to identify additional water control or small hydro opportunities to enhance Whitehorse Rapids output.

- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission line is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility, including enhanced peaking capability.
- **New WAF hydro site development:** If industrial and overall load development commitment is such that both new capacity and baseload diesel generation energy are required through to at least 2020 (and there is no clear indication of more major industrial development scenarios emerging during the 20 year planning period), planning activities should be carried out to enable commitment of a very small hydro site development (1-4 MW, 5-30 GW.h/year) [13] able to provide new capacity and displace diesel energy.
  - Based on current information, this would indicate that the hydro site at Drury should at that time be advanced to full Level 3 studies that include consideration of variations that maximize capacity.
  - Possible consideration might also be given to Level 2 studies for Squanga as a utility project or IPP, and/or for Morley, as potential alternatives for comparison to Drury.
  - Consideration must include means to mitigate downside risks should industrial loads close prematurely.
  - Actual development in each or these cases will involve investments greater than $3 million, or long-term contract commitments in excess of $3 million present value to IPPs, and therefore YUB review will be sought prior to project commitment.
- **Other activities re: DSM:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused primarily on reduction of system peak demand.

Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 for development of more than 10 MW (70 GW.h/year) but less than about 20-25 MW (comparable to the Faro mine) for a period through to at least 2025, planning activities should be carried out to enable commitment before 2016 to develop new hydro site resources to provide approximately 50 GW.h per year to WAF.

[13] Present estimates of the costs are $12-$47 million generation capital cost (2005$) with potential generation planning costs of $1.2-$4.7 million prior to a decision to proceed with construction.

For potential hydro projects, key options to be considered at such time as greater load certainty develops regarding this level and duration of industrial load are as follows:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should proceed to commit the Aishihik 3rd Turbine, the Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments (see proposals for Scenario 1).
- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility (including any feasible enhanced peaking capability).
- **New hydro site development:** If industrial and overall load development commitment on WAF before 2016 is such that WAF baseload diesel generation energy of more than 10 MW (70 GW.h/year) is then required through to at least 2025, and there is no clear indication of more major industrial development scenarios establishing new WAF industrial loads in excess of about 20 MW (about 125 GW.h/year) emerging during the 20 year planning period and extending beyond 2025, planning activities should then be carried out to enable commitment of a small hydro site development (7-10 MW, about 50 GW.h/year[14]) able to provide diesel displacing energy to WAF.
  - New hydro options focused on Yukon-based projects, if available, would be the preference.
  - However, given limited attractive projects in this size range identified in Yukon to date, further Level 1 and 2 activity should be undertaken if timing permits in areas within 50 km of existing 138 kV WAF transmission focused initially on scans of the various inventory studies completed by NCPC or others.
  - Sites in BC, including Moon Lake and Tutshi[15], should have Level 2 studies updated in preparation for this possible load scenario, particularly focusing on the costs and risks associated with interprovincial licencing requirements and water rentals. Level 3 studies should then proceed if warranted.
- **Coal supply possibilities:** In the event that the loads of this scale develop and coal also becomes available from developed Yukon sources, coal generation technology should be reviewed in the event that timing permits to determine the potential for an economic and environmentally sound coal development at sizes below 20 MW, sized as appropriate to fit the industrial loads being developed at that time.

[14] Present estimates of the costs are $50-$100 million generation capital cost (2005$) with potential generation planning costs of $5-$10 million prior to a decision to proceed with construction.

[15] No further work should proceed on Surprise Lake so long as the community continues its plans to develop micro-hydro at the site.

- **Other activities re: DSM and wind:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused on both the reduction of system peak demand and energy conservation, and development of new wind generation (if attractive sites near established utility grids can be identified).

Actual development of new hydro sites (or any other new generation site) in each case will involve investments greater than $3 million, so YUB review will be sought prior to project commitment. In addition, for larger scale developments, planning and feasibility work may exceed the $3 million level, so there is the potential for YUB review at this earlier stage as well.

Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 of more than about 20-25 MW (150 or more GW.h/year) for a period through to at least 2030, resulting in forecast baseload WAF diesel generation energy of more than about 150 GW.h/year to be required until at least 2030, then planning activities can reasonably proceed to consider commitments before 2016 to develop new hydro site or coal generation resources of 20-30 MW to provide 130-150 GW.h per year of long-term energy (20 or more years) to WAF.

- **Load uncertainties and low probabilities today:** The industrial loads required to reach the above levels at this time involve significant uncertainties and low probabilities.
- **New medium scale hydro site development (20-30 MW, 130-150 GW.h/year):** The development of generation and transmission to serve these loads, based on currently identified potential hydro sites (Primrose and Finlayson), would involve substantial generation capital costs ($179-$191 million (2005$)), excluding transmission, as well as very large planning costs (about $20 million) prior to a decision to proceed with construction. Such costs are likely at or beyond the limits of YEC's current financial capabilities and involve material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line.
- **Coal supply thermal generation possibilities:** Coal resource options of this scale could involve far less capital than comparable new hydro sites, provided that coal supply as such was otherwise available from developed Yukon sources. The scale at 20 MW (144 GW.h/year[16]), however, is still very small for coal thermal technology and would require careful Level 2 and 3 screening and feasibility assessments to confirm its potential feasibility.

For potential generation projects related to the above scales, it is not apparent today that there is sufficient likelihood of this major development scenario arising to justify major investment at this time in planning and

[16] The present estimate of the costs are $ 61 million thermal plant capital cost (2005$), excluding transmission or coal resource development costs, with potential generation planning costs of $6 million or more prior to a decision to proceed with construction.

feasibility studies for medium new hydro or small coal plants. Accordingly, no specific planning activities are recommended at this time.

Coal options for thermal generation must be environmentally sound to be considered. The feasibility of coal generation will depend in part on the cost of employing state of the art technologies to reduce emissions, as well as on the availability of coal supply from developed Yukon sources and the occurrence of very large industrial mine developments that can be connected economically to the grids.

Future decisions with respect to the level of effort and expense in this area will reflect YEC's ongoing assessment of the probabilities of the required loads developing. For projects of this scale, even early planning and feasibility work (at least on hydro sites) will exceed the $3 million level, in which case YUB review will be sought before proceeding with specific planning commitments of $3 million or more.

Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario

The Scenario 4 pipeline loads at this time involves significant uncertainties as regards timing and magnitudes. However, given the implications of this industrial development for all aspects of Yukon power utility activities, and its clear possibility to come into service within the 20-year period for the current Resource Plan, one key activity recommended for the near-term regarding Scenario 4 involves continued active monitoring of this development as well as active planning to identify and assess all potential related material impacts, options and opportunities, including:

- Power supply options for the pipeline for compression (focusing initially on short listing and assessing at Level 1 knowledge large scale hydro site options and related transmission requirements).
- More modest power supply opportunities focused on compressor station "station service" loads.
- Options to use natural gas for power generation to serve cost effectively other incremental industrial loads.

The development of generation and transmission to serve these pipeline loads is likely well beyond the limits of YEC's current financial capabilities, as well as involving material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line. Accordingly, prior to carrying out any planning activities beyond Level 1 assessment of any specific site or technology specific studies, it is proposed that Yukon Energy identify and assess options that would address this constraint, e.g., joint venturing with others, and/or options to secure external government or other financing.

Proposed "Pre-commitment" activities

Prior to any certainty developing regarding any specific industrial scenario that may arise, it is proposed that Yukon Energy remain focused on certain key planning activities to ensure protection of the options to address new load requirements. Yukon Energy proposes the following activities in this regard:

- **Monitoring of Industrial load developments:** Yukon Energy will continue to monitor closely potential load development and related spin-off residential and commercial impacts, including necessary discussions with mineral exploration companies active in Yukon, key officials in Yukon government working with mines and other industrial developments and relevant industry associations. Separately, YEC will maintain ongoing monitoring of potential Alaska Highway pipeline developments and factors that may impact electrical loads in Yukon (including potential for electrical compression).
- **Southern Lakes hydrology assessments:** Continued assessment and studies of the hydrology of the southern lakes area, including identification of potential for water control structures to enhance output of Whitehorse Rapids, as well as potential hydro generation sites.
- **Other existing hydro facility enhancements:** Continued focus on projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases, Mayo. This includes full Level 3 and 4 studies on the Aishihik 3rd turbine and updating Level 2 studies on Aishihik diversions. Where suitable, activities should be carried out in conjunction with other normal Supply Side Enhancement planning by Yukon Energy, such as re-runnering.
- **Level 1 and 2 assessments to identify preferred 5-30 MW scale Yukon hydro sites**: There is an option to invest in further surveying the potential of other Yukon based hydro generation sites to try to identify good sites in the 5-10 MW range (within about 50 km of existing high voltage transmission) and to advance credible candidates in the 5-30 MW range through Level 2 assessments (including ongoing monitoring of hydrology) in order to identify more clearly preferred sites to develop for possible loads within this range. However, this activity is costly and may require assessment of a number of sites. No activities in this regard are recommended today; however, in the event that at least one large industrial load (such as Red Mountain or Division Mountain) proceeds to advanced licencing and likely commitment stages, it is proposed that this initial work should proceed quickly to determine if the sites identified to date are indeed the best candidates or if there are other Yukon-based sites that should be seriously considered, and to identify specific projects for Level 3 feasibility assessments.
- **Ongoing monitoring of hydrology**: Active hydrology monitoring will proceed where feasible for all hydro sites likely to be serious candidates for future development within the 20 year planning period. The monitoring may be periodic (seasonal flow information, current cost of $1,000 per year per site) up to a full-time recording station (at a current cost of $30,000 (initial costs) plus ongoing costs of between $10,000 to $15,000 per year).

TABLE OF CONTENTS

CHAPTER 1 - INTRODUCTION

1.0 INTRODUCTION 1-1
1.1 PURPOSE OF THE SUBMISSION 1-1
1.2 SCOPE OF SUBMISSION 1-2
1.3 RESOURCE PLANNING FRAMEWORK 1-3
1.3.1 Power Capacity and Energy in Yukon 1-4
1.3.2 Basic Planning Process 1-6
1.3.3 Resource Plan and Specific Capital Project Decisions 1-8
1.4 CURRENT YUKON SITUATION COMPARED WITH 1992 1-9
1.5 SUBMISSION OVERVIEW 1-13

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

2.0 BACKGROUND ON YUKON POWER SYSTEMS 2-1
2.1 OVERVIEW OF GENERATION FACILITIES AND TRANSMISSION IN YUKON 2-1
2.1.1 Generation in Yukon 2-3
2.1.2 Transmission in Yukon 2-7
2.2 OUTCOMES FROM THE 1992 REVIEW 2-8
2.3 MAJOR EVENTS AFFECTING POWER SYSTEMS SINCE 1992 2-13
2.3.1 Closure of the Faro Mine 2-13
2.3.2 The Growth of Secondary Sales 2-14
2.3.3 Shift to Direct Management 2-14
2.3.4 Whitehorse Rapids Generating Station Fire Rebuilding Project 2-15
2.3.5 Renewal of Water Licences at Whitehorse, Mayo and Aishihik 2-15
2.3.6 Mayo-Dawson Transmission Line 2-16
2.3.7 System Upgrades and Changes 2-17
2.4 BULK ELECTRICAL SUPPLY PLANNING SINCE 1992 2-17
2.4.1 Ongoing Yukon Energy Infrastructure Planning Process 2-18
2.4.2 BC Hydro Inventory of Potential Future Hydro Supply Options 2-18
2.4.3 Bulk Electrical Supply Infrastructure Condition Assessment Work 2-18
2.4.4 Generation Capacity Planning Criteria Review 2-18
2.4.5 Demand Side Management and the Energy Solutions Centre 2-19

CHAPTER 3 – SYSTEM CAPABILITY

3.0 SYSTEM CAPABILITY 3-1
3.1 CURRENT FACILITIES CONDITION ASSESSMENT 3-1
3.1.1 Yukon Energy's Response to Condition Assessments 3-2
3.1.2 Condition Assessment Findings Relevant to Resource Planning 3-5

3.2 CAPACITY AND ENERGY OUTPUT OF EXISTING FACILITIES 3-6
3.2.1 Whitehorse Rapids Hydro Firm Capacity 3-7
3.2.2 Aishihik Hydro Capacity and Energy 3-9
3.2.3 Mayo Hydro Capacity 3-10
3.2.4 Whitehorse Diesel Capacity 3-10
3.2.5 Fish Lake Hydro (YECL) Capacity 3-11
3.3 CAPACITY PLANNING CRITERIA REVIEW 3-11
3.3.1 Background and Overview on the Evolution of Capacity Planning 3-12
3.3.2 Yukon Energy's Previous Capacity Planning Criteria (prior to late 2005) 3-14
3.3.3 Previous Yukon Criteria Compared with Criteria for Other Jurisdictions 3-17
3.3.4 New Criteria Adopted by Yukon Energy 3-20
3.3.5 Rationale for Adopting a Two-Part Criteria on WAF and MD 3-21
3.3.6 Implications of the Adopted Criteria 3-23
3.4 SUMMARY: REVISED CAPACITY PLANNING CRITERIA 3-25

CHAPTER 4 – NEAR TERM REQUIREMENTS

4.0 NEAR TERM REQUIREMENTS 4-1
4.1 PLANNING APPROACH AND TIMELINE 4-1
4.2 REQUIREMENTS 4-3
4.2.1 Basis for Non-Industrial Load Forecasts 4-4
4.2.2 Basis for Near Term Industrial Load Forecasts 4-7
4.2.3 Near Term WAF Load –
Cases Analyzed Based on Non-Industrial and Industrial Requirements 4-7
4.2.4 Base Case Requirements 4-8
4.2.5 Low Sensitivity Case 4-10
4.2.6 Base Case with Mine Loads 4-12
4.2.7 High Sensitivity Case Including Mines 4-14
4.3 OPTIONS 4-16
4.3.1 Overview of "Opportunity" Project Options 4-17
4.3.2 Aishihik 3rd Turbine 4-19
4.3.3 Marsh Lake Fall/Winter Storage 4-20
4.3.4 Carmacks to Stewart Transmission Line Project 4-22
4.3.5 Overview of Major Capacity-Related Project Options 4-26
4.3.6 Mirrlees Life Extension Project 4-28
4.3.7 Whitehorse Diesel Replacement/Expansion Project 4-32
4.3.8 Aishihik 2nd Transmission Line Project 4-34
4.3.9 Supplemental Project Options 4-38
4.4 ASSESSMENT 4-39
4.4.1 Assessment of Opportunity Projects 4-40
4.4.2 Assessment of Capacity-Related Projects 4-46

4.4.3 Schedule and Sequencing of Alternatives 4-53
4.4.4 Rate related Impacts of Near Term Options 4-53
4.5 PROPOSED ACTIONS 4-57

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

5.0 INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES 5-1
5.1 PLANNING APPROACH AND TIMELINE 5-1
5.1.1 Need to Consider and Balance Several Key Factors 5-3
5.1.2 Regulatory and Policy Framework 5-7
5.1.3 Planning Framework 5-9
5.2 REQUIREMENTS 5-12
5.2.1 Scenario 1: A 10 MW WAF Industrial Scenario 5-18
5.2.2 Scenario 2: A 25 MW WAF Industrial Scenario 5-22
5.2.3 Scenario 3: A 40 MW WAF Industrial Scenario 5-24
5.2.4 Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline 5-26
5.3 OPTIONS 5-27
5.3.1 Overview of Resource Supply Options 5-28
5.3.2 Options for Scenario 1: A 10 MW WAF Industrial Scenario 5-38
5.3.3 Options for Scenario 2: A 25 MW WAF Industrial Scenario 5-38
5.3.4 Options for Scenario 3: A 40 MW WAF Industrial Scenario 5-40
5.3.5 Options for Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario 5-42
5.4 PRE-ASSESSMENT AND SCREENING 5-43
5.4.1 Technical Pre-Assessment and Load Fit 5-45
5.4.2 Economic Pre-Assessment 5-49
5.5 PROPOSED ACTIONS 5-51
5.5.1 Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario 5-52
5.5.2 Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario 5-53
5.5.3 Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario 5-54
5.5.4 Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario 5-55
5.5.5 Proposed “Pre-commitment” activities 5-56

APPENDICES

APPENDIX A: POWER RESOURCE TECHNOLOGY OPTIONS

A.1 POWER RESOURCE TECHNOLOGY OPTIONS A-1
A.1.1 DIESEL A-1
A.1.2 HYDRO A-2
A.1.3 WIND A-2

A.1.4 BIOMASS A-4
A.1.5 COAL A-5
A.1.6 COAL-BED METHANE A-6
A.1.7 NATURAL GAS A-6
A.1.8 GEOTHERMAL A-7
A.1.9 HYDROGEN A-7
A.1.10 SOLAR A-8
A.1.11 NUCLEAR A-8
A.1.12 DEMAND SIDE MANAGEMENT A-9
A.2 LITERATURE REVIEWED A-10
A.2.1 HYDRO A-10
A.2.2 WIND A-10
A.2.3 BIOMASS A-11
A.2.4 COAL A-11
A.2.5 LITERATURE REVIEWED ASSESSING MULTIPLE GENERATION TECHNOLOGIES A-11

APPENDIX B: HYDRO PROJECT OPTIONS

B.1 HYDRO PROJECT OPTIONS B-1
B.1.1 LEVELIZED COST OF ENERGY (LCOE) B-4
B.2 EXISTING HYDRO ENHANCEMENTS B-5
B.2.1 AISHIHIK DIVERSIONS B-5
B.2.2 ATLIN STORAGE B-5
B.3 VERY SMALL PROJECTS (1-4 MW) B-6
B.3.1 DRURY B-6
B.3.2 SQUANGA B-6
B.3.3 MORLEY, LAPIE AND ORCHAY B-7
B.4 SMALL PROJECTS (5-10 MW) B-7
B.4.1 MOON HYDRO SITE B-8
B.4.2 SURPRISE LAKE HYDRO SITE B-9
B.4.3 TUTSHI AND OTHER HYDRO SITES IN THE SOUTHERN LAKES B-10
B.4.4 MAYO B B-10
B.4.5 LACK OF OTHER YUKON-BASED HYDRO PROJECTS B-11
B.5 MEDIUM PROJECTS (10-30 MW) B-11
B.5.1 PRIMROSE/KUSAWA/TAKHINI HYDRO SITE B-11
B.5.2 FINLAYSON HYDRO SITE B-13
B.6 LARGE PROJECTS (30-60 MW) B-14
B.6.1 HOOLE B-14
B.6.2 SLATE B-14
B.6.3 HESS B-14

B.7 VERY LARGE PROJECTS (60 MW+) B-14
B.7.1 GRANITE CANYON B-14
B.7.2 FRASER FALLS B-15
B.7.3 VARIOUS OTHER LARGE YUKON RIVER SITES B-15

APPENDIX C: AISHIHIK 3RD TURBINE ASSESSMENT

C.1 AISHIHIK 3RD TURBINE ASSESSMENT C-1
C.2 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE LOAD C-4
C.3 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE WITH 10 MW MINE LOADS C-6
C.4 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS C-8
C.5 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE WITH 10 MW MINE LOADS C-10
C.6 AISHIHIK 3RD TURBINE AT 2011 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS C-12
C.7 SECTION C-7: AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE AND (2008) OF CARMACKS-STEWART (CS) UNDER BASE CASE WITH 10 MW MINE LOADS C-14

GLOSSARY OF TERMS

LIST OF TABLES

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

Table 2.1: Generation Capacity in Yukon – YEC and YECL in 2005 2-4

CHAPTER 3 – SYSTEM CAPABILITY

Table 3.1: BC Hydro Generation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s) 3-4

Table 3.2: BC Hydro Substation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s) 3-5

Table 3.3: Yukon Energy Generation Inventory 3-7

Table 3.4: Current WAF Generating Complement and Maximum Allowable Peak Load (MAPL) under Previous Planning Criteria 3-17

Table 3.5: WAF Peak and Capacity Surplus (Shortfall) as Whitehorse Diesels are Retired (MW) 3-24

CHAPTER 4 – NEAR TERM REQUIREMENTS

Table 4.1: Near Term Non-Industrial Load Forecasts 4-5

Table 4.2: Summary of Near Term Opportunity Projects to 2012 (2005$ millions) 4-41

Table 4.3: Comparison of Near Term Capacity-focused Options to 2012 4-47

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Table 5.1 Industrial Development Opportunities 5-14

Table 5.2 Potential Hydro Resource Options 5-30

APPENDIX B: HYDRO PROJECT OPTIONS

Table B-1: Potential Hydro Sites B-2

APPENDIX C: AISHIHIK 3RD TURBINE ASSESSMENT

Table C-1: Summary of Aishihik 3rd Turbine Assessment Cases (2005$, $000s) C-3

Table C-2A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) – IRR based on cash flows C-4

Table C-2B: Aishihik 3rd Turbine Economics (65 years) – NPV based on annual impacts on ratepayers C-5

Table C-3A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) – IRR based on cash flows C-6

Table C-3B: Aishihik 3rd Turbine Economics (65 years) – NPV based on annual impacts on ratepayers C-7

Table C-4A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage IRR based on cash flows C-8

Table C-4B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers C-9
Table C-5A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage IRR based on cash flows C-10
Table C-5B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers C-11
Table C-6A: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Fall/Winter Storage – IRR based on cash flows C-12
Table C-6B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers C-13
Table C-7A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & Carmacks-Stewart (CS) S- IRR based on cash flows C-14
Table C-7B: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & (CS) S- NPV impacts on ratepayers C-15

LIST OF FIGURES

CHAPTER 1 – INTRODUCTION

Figure 1.1: 20-Year Resource Plan and Decisions on Specific Projects 1-9
Figure 1.2: Load Situation, Resource Needs and Supply Options 2006-2025..... 1-12
Figure 1.3: Submission Overview 1-13

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

Figure 2.1 Map of Yukon Territory Power Infrastructure 2-2
Figure 2.2 Yukon Total Power Generation 1967-1997 2-5
Figure 2.3 YEC WAF Generation 1976-2004..... 2-6
Figure 2.4 Generation on MD 1980–2004 2-7

CHAPTER 3 – SYSTEM CAPABILITY

Figure 3.1: WAF System – Comparison of Capacity Criteria 3-25

CHAPTER 4 – NEAR TERM REQUIREMENTS

Figure 4.1: WAF Base Case Capacity Requirements 4-9
Figure 4.2: WAF Base Case System Energy Requirements..... 4-10
Figure 4.3: WAF Low Sensitivity Case Capacity Requirements 4-11
Figure 4.4: WAF Low Sensitivity Energy Requirements..... 4-11
Figure 4.5: WAF Base Case with Mine Capacity Requirements 4-12
Figure 4.6: WAF Base Case with Mine Energy Requirements 4-13
Figure 4.7: WAF High Sensitivity Case with Mines Capacity Requirements 4-14
Figure 4.8: WAF High Sensitivity Case with Mines Energy Requirements 4-15
Figure 4.9: Carmacks to Stewart Transmission Line in 2008 4-25
Figure 4.10: Carmacks to Stewart Transmission Line in 2008 4-26
Figure 4.11: Mirrlees Life Extension 4-31
Figure 4.12: Whitehorse Diesel Replacement and Expansion..... 4-33
Figure 4.13: Aishihik Second Transmission Line 2009 4-36
Figure 4.14: Aishihik Second Transmission Line in 2009 (with Aishihik 3rd Turbine in 2009) 4-37
Figure 4.15: Timing and Sequencing of Opportunity and Capacity-Related Projects..... 4-54

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Figure 5.1: Map of Industrial Development Opportunities and Power Infrastructure 5-13
Figure 5.2: Earliest In-Service Dates and Power Loads for Potential Mine Developments..... 5-16
Figure 5.3: Scenario 1: WAF Capacity Requirements 5-20
Figure 5.4: Scenario 1: WAF Energy Requirements..... 5-21
Figure 5.5: Scenario 2: WAF Capacity Requirements 5-23
Figure 5.6: Scenario 2: WAF Energy Requirements..... 5-24

Figure 5.7: Scenario 3: WAF Capacity Requirements 5-25
Figure 5.8: Scenario 3: WAF Energy Requirements..... 5-26
Figure 5.9: Map of Potential Supply Option Sites..... 5-29

APPENDIX B: HYDRO PROJECT OPTIONS

Figure B-1: Map of Potential Supply Options B-3
Figure B-2: WAF Energy Requirements under 25 MW Scenario with Moon Lake Hydro..... B-9
Figure B-3: WAF Energy Requirements under 40 MW Scenario with Primrose Hydro..... B-12
Figure B-4: WAF Energy Requirements under 25 MW Scenario with Primrose Hydro..... B-13

1.0 INTRODUCTION

Yukon Energy Corporation's ("YEC" or "Yukon Energy") 20-Year Resource Plan Submission addresses major generation and transmission requirements in Yukon during the period 2006 to 2025. The last Resource Plan, which was submitted for review by the Yukon Utilities Board ("YUB") in 1992, covered 1992-2001 and was prepared by YEC and Yukon Electrical Company Limited ("YECL").

This chapter sets out the purpose, scope, framework, and approach and outline of the 20-Year Resource Plan Submission. The sections for this chapter are as follows:

- Section 1.1: Purpose of the Submission
- Section 1.2: Scope of the Submission
- Section 1.3: Resource Planning Framework
- Section 1.4: Current Yukon Situation Compared with 1992
- Section 1.5: Submission Overview

1.1 PURPOSE OF THE SUBMISSION

The Resource Plan Submission provides Yukon Energy's 20-Year Resource Plan with respect to major electrical generation and transmission requirements during the 2006 to 2025 period, with emphasis on:

a) near term projects that will require YEC commitments before the year 2009 with costs of $3 million or more, and
b) planning activities that YEC may be required to carry out in order to start construction on other projects before 2016 to meet the needs of potential major industrial customers or other major potential developments in Yukon.

Yukon Energy is committed to seek YUB review, prior to construction, of any new capital project costing $3 million or more. Yukon Energy's December 2004 Application to the YUB regarding 2005 Required Revenues and Related Matters also committed Yukon Energy to bring forward to the YUB new or revised capacity planning criteria in advance of capital investment in new generation for capacity reasons. Accordingly, the 20-Year Resource Plan Submission is expected to provide the YUB with the opportunity to review near term generation or transmission projects costing $3 million or more, including projects that are required based on revised capacity planning criteria now adopted by Yukon Energy.

The Submission also proposes Yukon Energy planning activities within the next 10 years to protect YEC's ability to start construction on other major generation and transmission projects before 2016 to meet the

needs of potential major industrial development opportunities. In some circumstances, to identify and protect power resource options related to industrial development opportunities, some of these planning commitments will need to be made on some form of contingent basis in advance of resolving various major uncertainties.

1.2 SCOPE OF SUBMISSION

The planning and development of new transmission and generation projects requires a forward looking perspective regarding major objectives, options, policies and planning activities. The Resource Plan Submission identifies generation and transmission issues and options facing Yukon Energy in both the near term (i.e., prior to 2009), and within the next 10 to 20 years. The Submission also provides an overview of the development and composition of Yukon's power systems; an update on Yukon Energy's capital planning process since the last Resource Plan submitted in 1992; and the context today for bulk electrical supply ("BES") planning by Yukon Energy.

With regard to near term generation and transmission projects of $3 million or more included in the Plan for construction start within the next three years (i.e., by 2009), Yukon Energy has examined:

- the necessity of the proposed spending commitments, their expected effects on overall utility costs and electricity rates, and (to the extent currently known) their physical and engineering characteristics and their economic consequences;
- the capability and condition of existing generation and transmission facilities, taking into account appropriate capacity planning criteria;
- forecast load requirements for electricity and the need for spending commitments to meet these forecast requirements;
- all reasonable alternative near term options and developed proposals based on reasonable grounds; and
- the potential risks of each option.

During the planning process, Yukon Energy reviewed the studies and activities that have taken place before and after 1992. Major initiatives carried out in the past few years include a review the condition of existing assets, and an examination of the adequacy of the current capacity planning criteria. Additional technical project-specific feasibility or planning studies have generally not been carried out since 1992, beyond developments actually undertaken such as the Mayo Dawson Transmission Line Project. Yukon Energy also completed an initial review of a potential Carmacks-Stewart Transmission

Line in 2002; a review of a potential Atlin Transmission Line in 2003; and a Small Hydro Assessment in 2004.

Major near term projects addressed in the Submission for construction start prior to 2009 are the result of the adoption in late 2005 of revised capacity planning criteria. Studies are ongoing with regard to leading near term major project options. The Submission proceeds on the basis of current information regarding these near term options, setting out the conditions relevant to proceeding with any specific option. Updates will be provided during the review of the Submission to the extent that relevant new information is forthcoming from ongoing studies on these projects.

Longer term opportunities addressed in the Submission are contingent on the extent to which new industrial developments do in fact move forward during the next 10 to 20 years. The Submission identifies representative scenarios related to possible future industrial development, and the planning activities appropriate for Yukon Energy to identify and protect relevant generation and transmission options that may need to be developed with respect to these scenarios.

1.3 RESOURCE PLANNING FRAMEWORK

In Yukon, electric power resource planning focuses separately on each electric power system. The Whitehorse-Aishihik-Faro ("WAF") grid, and the Mayo-Dawson ("MD") grid are typically planned as separate systems, as are each of the isolated diesel-served communities.

The basic electric power resource planning model addresses separately each system's generation **capacity** (MW [megawatts], particularly at the time of system winter peak) and its **energy** generation kW.h or MW.h [kilowatt hours or megawatt hours] over the full year). An overview of power capacity and energy in Yukon is provided below (Section 1.3.1).

The basic resource planning process in the Submission is then reviewed (Section 1.3.2), including the following elements (in the following sequence) which the Submission examines separately as required for capacity and energy on both the WAF and MD systems:

1. **System Capability** – existing system capability over the next 20 years, based on the condition of existing facilities, firm capability of these facilities at the time of winter peak, and capacity planning criteria for each system that define generation capacity (MW) adequacy and load carrying capability;

2. **System Requirements** – capacity and energy requirements forecast over the next 20 years (and beyond) for each system in order to assess the loads that may need to be met under different industrial development scenarios;

3. **New Facility Requirements** – the capability of installed plant on each system over the next 20 years compared to forecast system requirements (to establish forecast requirements for new facilities under each load scenario);

4. **Options** – resource options to meet new facility requirements for each load scenario on each system;

5. **Assessment of Options** – resource options are assessed and/or screened, to the extent feasible today, based on consideration of technical feasibility (including timing), cost efficiency, reliability and risk.

1.3.1 Power Capacity and Energy in Yukon

As the main generator and transmitter of electrical power in the Yukon region, Yukon Energy focuses on serving and planning for the capacity and energy requirements of Yukoners, particularly those supplied on the WAF and MD grids. An overview of power capacity and energy in Yukon is provided below.

Capacity: The capacity requirement on a power system in any year is the highest or peak generation capability (MW) required during the year. This required capability reflects both the operating generation capability needed to serve the peak loads on the system (including provision for system losses over and above customer loads) plus the provision of sufficient generation reserve capability to address unplanned generation outages (based on the system's capacity planning criteria).

Capacity requirements on Yukon systems typically drive the need to develop a specific MW amount of new generation facilities within a certain time period. The type of generation selected, however, may depend on forecast energy requirements[1].

[1] Diesel generating units have low capital costs, and very high operating costs; accordingly, diesel units are typically well-suited to meeting capacity needs during system peaks and as reserve capacity, rather than being run to provide sustained energy on a regular basis throughout the year. Conversely, hydro generating plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units.

In Yukon, the peak power requirement is typically in the winter. For example, during the winter of 2004/05, the WAF system peak occurred on Wednesday January 12th, 2005, when the temperature reached -44.5 degrees Celsius. The WAF system integrated hourly peak for generation on that day was 56.4 MW.

The capacity capability of generation facilities can vary depending on the time of year. For example, the winter peak in Yukon occurs on the WAF grid when the capability of the Whitehorse Hydro Plant is reduced due to lower water flows. For a hydro asset, the amount of electricity that the asset can generate is determined in part by the volume of water moving through the plant. The amount of water flowing through the Whitehorse Plant in the winter months under normal or low flow water regimes is typically lower than in the summer months. Accordingly, given that there is very little reservoir storage to retain water for the winter, the Whitehorse Plant firm capacity in the four coldest winter months (about 24 MW) is well below its peak capacity in the summer months (40 MW).

The capacity planning criteria applied on each Yukon system in the past, as reviewed and recommended by the YUB in 1992, in effect provide a requirement for "reserve generation capacity" equal to the capacity needed to meet forecast winter peak load with the loss of the single largest winter generation unit (on WAF, this is one 15 MW hydro unit at Aishihik) plus the loss of 10% of the installed diesel capacity[2]. In light of changes since 1992, it became timely to review the adequacy of the current capacity planning criteria for the WAF and MD systems.

Energy: The annual energy requirement on a power system is the number of kilowatt hours of electricity that are required to be generated.

Generation requirements are higher than the sales to customers as a result of system losses between the generation plant and the customers as well as generation station service power requirements. Yukon Energy must generate enough electricity to serve its load, and to account for the associated line and other system losses. Between 2000 and 2004, Yukon Energy's energy losses overall required generation averaging 8% more than YEC's sales to its customers.

Yukon's existing diesel generation facilities on each system typically are sufficient to provide a reliable supply of firm energy to meet system loads, even under low flow conditions for the hydro generation

[2] On isolated systems, this is worded so as to require the diesel plant installed, less the largest unit, to be 110% of the forecast peak.

facilities. The prime energy-related issue when assessing new facilities in Yukon therefore relates to the opportunity to displace diesel generation with less costly energy supply alternatives.

Energy requirements in Yukon may establish the economic opportunity for certain types of new generation or even transmission facilities. If sufficient energy is required on a sustained basis, past Yukon experience has shown that opportunities may emerge to develop new hydro or transmission facilities (with access to surplus or cost competitive hydro generation) to displace what would otherwise be served by diesel generation. These opportunities arise because hydro plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units[3].

Current surplus hydro generation capability on both the WAF and MD systems limit opportunities today for developing new lower cost generation on these systems. The Resource Plan identifies the future growth conditions required before the current surplus hydro would be fully utilized and new opportunities may emerge to displace diesel generation on these systems.

1.3.2 Basic Planning Process

The basic planning process that Yukon Energy undertook to develop its 20 Year Resource Plan included the following elements:

1. **System Capability:** Existing system capability over the next 20 years was assessed, based on the condition of existing facilities, firm capability of these facilities at the time of winter peak, and capacity planning criteria for each system that define generation capacity (MW) adequacy and load carrying capability.
    a) **Condition assessments of existing facilities:** Yukon Energy commissioned assessments of its existing facilities to determine their condition and their remaining life. The prime focus for the Resource Plan from these assessments is the potential timing for retirement of any generation or transmission facilities during the next 20 years.

[3] Conversely, diesel units have low capital costs and very high operating costs; accordingly, diesel units are typically well-suited to meeting capacity needs during relatively brief system peak periods, rather than being run to provide sustained energy on a regular basis throughout the year. Diesel units, however, can be cost effective for sustained operation in many specific situations, e.g., Yukon experience demonstrates instances involving isolation from a grid and/or viable energy options, small scale of requirements, or short term time periods for requirements.

b) **Firm capability of existing facilities:** The ability of these facilities to provide capacity and energy was reviewed, particularly at system peak periods in winter. This included planned retirements and age-related derates.

c) **Capacity planning criteria review:** Capacity planning criteria were thoroughly reviewed for each system. These criteria establish the "reserve" capacity (MW) capability that must be planned over and above the capacity needed to supply forecast system winter peak load when each facility is operating at its respective capability (e.g., the reserve needed to cover reasonable contingencies regarding potential generation and transmission or BES unit failures). Yukon Energy has adopted revised capacity planning criteria as a result of this review.

2. **System Requirements Forecasts:** Capacity and energy requirements were forecast over the next 20 years (and beyond) for each system in order to assess the loads that may need to be met under different industrial development scenarios. For Yukon, a key historic driver has been opening and closing of major industrial loads (new or existing mines) and planning for each system must therefore address different industrial load scenarios. Generation and transmission are designed, built and operated on each system to provide reliable supply of both capacity and energy to meet forecast non-industrial and industrial requirements:

   a) **Capacity requirement forecasts:** These forecasts address the peak facility power requirements (MW) at the specific time of the system annual peak load in winter, including the provision of sufficient generation reserve capability to meet the capacity planning criteria.

   b) **Energy requirement forecasts:** These forecasts address the energy requirements (kW.h) over the full year; and, where relevant, seasonal energy requirements.

3. **Forecast New Facility Requirements:** The capability of installed plant on each system over the next 20 years was compared to forecast system requirements (to establish forecast requirements for new facilities under each load scenario):

   a) **New capacity requirements:** New capacity requirements reflect the extent to which forecast MW requirements at the time of system peak in winter (including provision to meet capacity planning criteria for reserve capability) exceed the forecast system capability of existing plant (i.e., reliable MW of capacity from what is installed today, less those units that are retired over time). Given the short duration of peak capacity needs in any year, capital cost minimization will typically be a key factor in selecting new facility options required solely to meet new capacity needs.

b) **New energy opportunities:** To the extent that such requirements affect the choice for new facilities, new energy requirements in Yukon typically reflect cost effective opportunities to displace either existing or new diesel fuel energy generation.

4. **Resource Options:** Supply side options to meet new capacity and/or energy requirements on each system include: enhancing existing generation facilities; extending the life of existing generation facilities; developing new generation plants (diesel, hydro, coal, wind, biomass, etc); and/or developing new transmission facilities connecting existing and/or new resources to load centres. Demand side options also exist, including conservation, load management, and customer efficiency improvements.

5. **Assessment of Resource Options:** Available options to meet new capacity and/or energy requirements on each system are assessed and/or screened based on consideration of technical feasibility (including timing), cost efficiency, reliability, and risk.

1.3.3 Resource Plan and Specific Capital Project Decisions

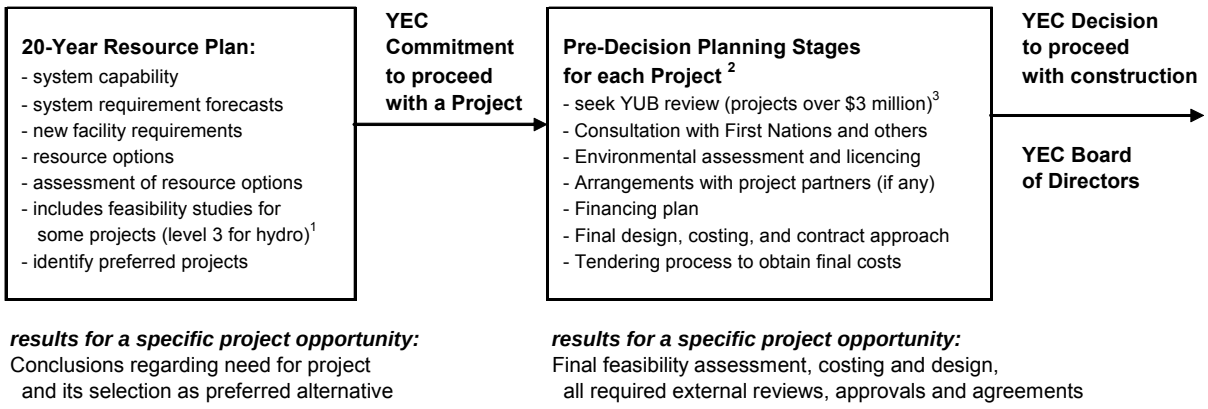
Figure 1.1: 20-Year Resource Plan and Decisions on Specific Projects reviews the relationship between the 20-Year Resource Plan process and activities leading to final Yukon Energy construction decisions on specific project opportunities identified by the Resource Plan.

The structure and framework of the 20-Year Resource Plan reflect overall broad capabilities and requirements for each system, options to fulfill requirements and/or capture opportunities identified for new facilities, and comparisons/assessments between the options. In assessing specific resource options under the Resource Plan, Yukon Energy carries out varying levels of technical and costing assessments to enable screening of options, including in some instances investigations advanced to the project feasibility stage. The Resource Plan process in this manner identifies preferred projects for which YEC can then commit to proceed with more detailed project-specific pre-decision planning.

Figure 1.1 identifies pre-decision planning stages that Yukon Energy carries out, as needed, for each preferred project identified by the Resource Plan process prior to any final decision to proceed with construction or implementation. Pre-decision planning for each project reflects specific requirements for that project, including anticipated regulatory review and/or approval needs, consultation requirements, any arrangements needed with other parties, final design and costing needs, and timing needs for bringing the project into service.

This Submission includes near term projects at different stages of pre-decision planning. No final decision has yet been made to implement these projects. In some instances, environmental approvals have already been secured – in other instances; however, the necessary applications for such approvals have yet to be made. Final design, costing and tendering tend to be a final stage to be carried out prior to final Yukon Energy decisions to proceed with construction/implementation.

Figure 1.1:
20-Year Resource Plan and Decisions on Specific Projects



1 - In large projects (e.g., over $30 million), project feasibility stages can exceed $3 million and YEC would then seek YUB review prior to commitment to these stages.
2 - For individual projects, these planning stages will proceed in different sequences and with different timing. For projects over $3 million,Yukon Energy is committed to seek YUB review prior to a decision by the YEC Board to proceed with construction.
3 - An OIC under the Yukon Utilities Act can direct the YUB to review a YEC submission on need and justification for a project and to report on its findings to the Commissioner in Executive Council. This type of YUB review would be separate and distinct from a normal YUB review of project rate base costs as required for a Yukon Energy revenue requirements and rate application.

1.4 CURRENT YUKON SITUATION COMPARED WITH 1992

The last Resource Plan that was submitted to the YUB in 1992 was filed jointly by Yukon Energy and Yukon Electrical Company Limited, and reflected a situation very different from that facing the Yukon today. At that time, the Faro mine was in operation, the WAF system was consuming significant diesel fuel throughout each year, and there were substantial uncertainties regarding the life of the Faro mine load (about 25 MW and up to 180 GWh/yr). The submission also covered the potential opening of new mines; extensive planning studies previously carried out on Demand Side Management ("DSM"); various hydro supply development options; and possible transmission developments. There were no projects being requested in the near term, and the applicability of nearly all projects hinged on which mine load "scenario" was going to arise, and the risks associated with the load. In the end, due to substantial

downside risk related to existing loads, the 1992 Resource Plan did not propose any near or long term projects for development.

The Yukon economy, and Yukon's electricity loads and systems have changed substantially since the 1992 review. Due to the closure of the Faro mine, no reopening of the United Keno Hill Mine ("UKHM"), and no new mines yet having emerged, there is currently a surplus of hydro energy available on the WAF and MD grids. Potential new industrial developments during the next several years may absorb the WAF hydro energy surplus. However, forecast load growth even without new industrial loads, pending retirement of existing diesel generation and the adoption of new capacity planning criteria indicate an immediate need in any event to provide new WAF generation capacity to serve winter peak load requirements even through the WAF hydro energy surplus could remain for most of the current 20 year planning period.

Beyond near term needs and opportunities, current planning issues must be addressed regarding other potential future major industrial loads and developments during the next 10 to 20 years, including the Alaska Highway Natural Gas Pipeline project. Potential industrial loads need to be considered, and the identification, definition and "protection" of appropriate resource options is required to ensure that Yukon Energy is able to meet new loads when relevant on a timely basis if and when they develop.

Supply side options potentially relevant for a construction start within the next 10 years vary widely depending on the potential industrial developments considered, and include a range of different hydro possibilities as well as coal-fired generation and potentially natural gas-fired generation.

Lead times required to plan, approve and develop major new power supply projects, as well as the material planning costs associated with pre-construction activities required to keep these options available on a timely basis, underline the relevance of the current Resource Plan review.

Yukon Energy has organized generation and transmission project options by different load situations and resource needs. As shown in *Figure 1.2 Load Situation, Resource Needs and Project Options*, the resource needs (capacity or energy) are the primary driver in evaluating the appropriateness of an option for a given scenario. New industrial loads of less than 10 MW typically give rise to capacity-focused options, while new industrial loads above 10 MW may create opportunities for energy-focused options,

driven in part by specific opportunities to enhance existing hydro systems and in part by Yukon Energy's revised capacity planning criteria. Changes in Yukon power systems, significant load growth in the Whitehorse area and the potential retirement of three diesel units at Whitehorse prompted a re-examination of these planning criteria. Yukon Energy believes that its revised criteria better reflect the Yukon electrical grids' reliability requirements today.

- **Potential near term major project options** include opportunities, projects and major capacity shortfall projects as noted in Figure 1.1. These near term project opportunities and options are examined in the context of a range of possible load situations (see Figure 1.2).
- **Opportunities projects** include enhancements to existing hydro facilities at Whitehorse and Aishihik as well as possible access to government infrastructure funding to develop a Transmission Line from Carmacks to Stewart Crossing connecting the WAF and MD systems.
- **Major capacity shortfall project options** address major new WAF system capacity needs in the context of current surplus hydro energy on both the WAF and MD systems.

As outlined in Figure 1.2, planning activities to proceed with other generation or transmission projects beyond 2009 and before 2016 are being driven by the potential needs of a diverse range of possible major industrial customers (such as various possible major new mines) or other major potential industrial developments (i.e., Alaska Highway Pipeline project), and the energy requirements and/or opportunities related to such industrial developments. The Submission examines these opportunities in the context of the different possible load situations outlined in Figure 1.2, the significant uncertainties associated with such load possibilities, and the lead times and other needs associated with Yukon Energy protecting appropriate resource options related to these different loads.

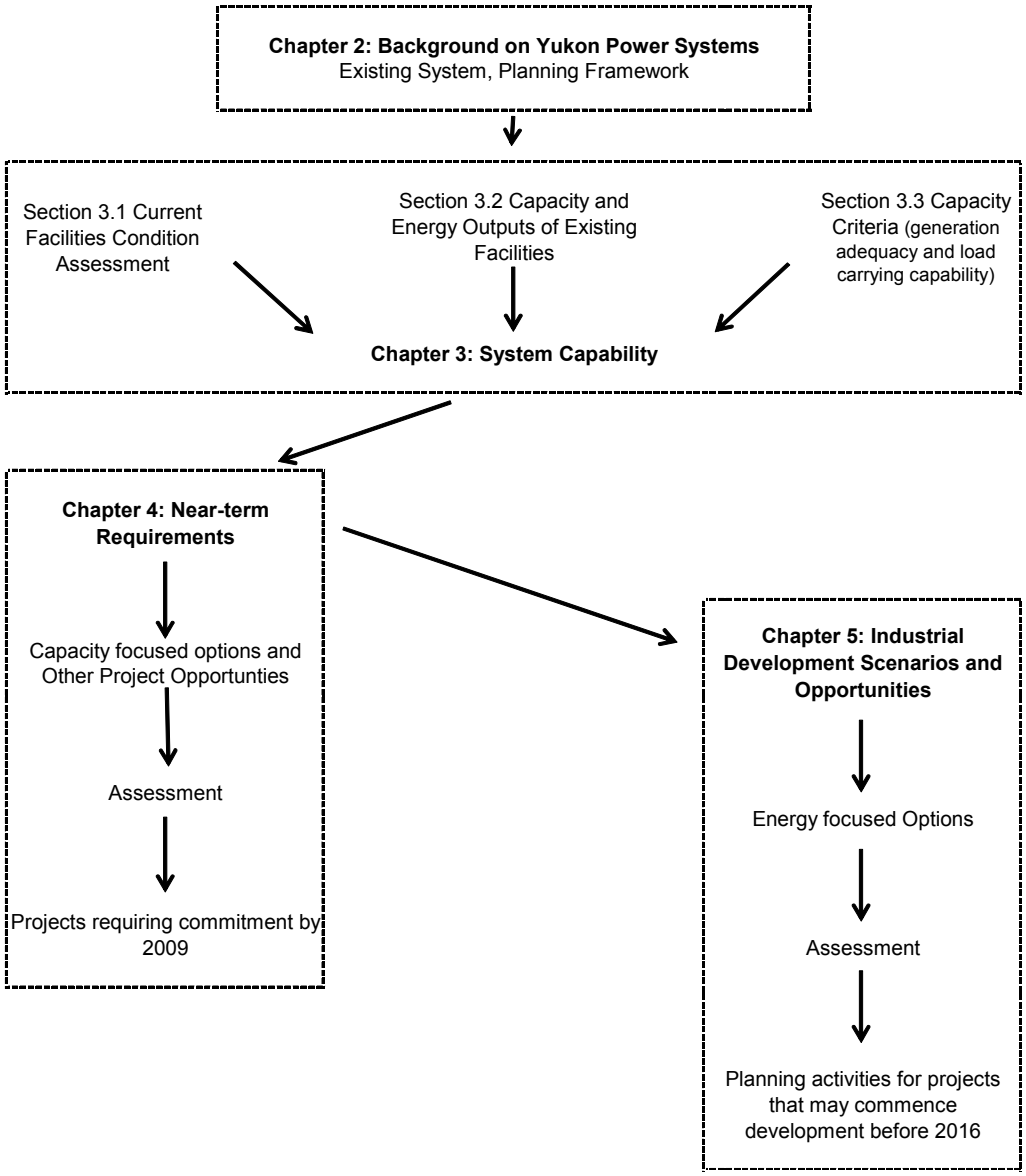
Figure 1.2:
Load Situation, Resource Needs and Supply Options 2006-2025

Load Situation (WAF Scenarios)	Resource Needs	Well Defined Project Options	Relatively Undefined Project Options
Scenario 4: **A 120 to 360 MW Alaska Highway Natural Gas Pipeline Scenario**	Large Energy (223 to 894 GW.h/yr, starting at earliest in 2012-2015 time period)		• Granite (80 MW, 660 GW.h/yr up to perhaps 254 MW) • Hoole (40 MW, 275 GW.h/yr) • Fraser Falls (100 MW, 613 GW.h/yr up to perhaps 450 MW) • Yukon River (multiple sites including Rink Rapid, Eagles Nest and Five Fingers, 75-240 MW) • Two Mile Canyon on Hess (53 MW, 280 GW.h/yr), Slate (42 MW, 266 GW.h/yr) • Natural Gas (to be determined)
Scenario 3: **A 40 MW WAF Industrial Scenario: Substantial Mining Industry Development in Excess of the Faro Mine** (more intense mine development than Scenario 2)	More Energy (max about 250 to 300 GW.h/yr during life of mine projects) Following mine closures, energy requirements at 56 GW.h or less		• Primrose (28 MW, 141 GW.h/yr) • Finlayson (17 MW, 129 GW.h/yr) • Coal (previously studied at 20 MW, about 144 GW.h/yr, up to 50 MW or larger, no credible smaller concept developed to date)
Scenario 2: **A 25 MW WAF Industrial Scenario: Multiple Major Developments Comparable to Faro Mine** (similar to Faro Mine, could comprise multiple mines, such as Minto, Carmacks Copper plus Red Mountain or Division Mountain coal)	Smaller Energy (max about 100 GW.h/yr for life of mine projects) Following mine closures, energy requirements at 35 GW.h or less	• Drury (2.6 MW up to perhaps 5.2 MW, 23 GW.h/yr)	• Moon (8.5 MW, 50 GW.h/yr) • Mayo B (10 MW, 48 GW.h/yr) • Aishihik Diversions (maximum 24 GW.h) • Tutshi (7.5 MW, 51 GW.h) • various other hydro (Orchay, Morley, Lapie,Squanga) • Surprise (8.5 MW, 50 GW.h/yr; removed by other proposals)
Scenario 1: **A 10 MW WAF Industrial Scenario: Combined Industrial load up to about 10 MW** (focus on Minto and Carmacks Copper mines [9-11 MW, about 60 GW.h/yr], 8-12 years)	Capacity focus - absorb current WAF surplus hydro while both mines operate (21 to 27 MW shortfall by 2012, base case and high load sensitivity)	Minor added capacity over and above base case (diesel or other options noted below)	
Base Case: **Existing Non-Industrial Loads** (new capacity planning critieria, retirement of 11.4 MW of Whitehorse diesel capability (3 Mirlees units))	Capacity shortfall focus - WAF surplus hydro likely until near end of 20 (Base Case shortfall by 2012 at 19 MW; range 15 to 24 MW)	**Major Capacity Shortfall Projects** • WH Diesel Replacement/Expansion Project (15-24 MW by 2012 wihout new industrial loads) • Mirrlees Life Extension Project (14 MW) • Aishihik 2nd Trans. Line (up to 22 MW, 0 GW.h/yr) **Opportunity Projects** • Aishihik 3rd Turbine (7 MW, 5.4 GW.h/yr) • Marsh Lake Fall/Winter Storage (1.6 MW, 7.7 GW.h/yr) • WAF-MD Interconnect (about 6 MW, 15 GW.h/yr, decreasing as MD load grows)	• Atlin Lake Top Storage (2.0 MW, 9 GW.h/yr) • Aishihik Supply Side Enhancements (about 6 MW potential) • Other Southern Lakes (to be determined)

1.5 SUBMISSION OVERVIEW

Figure 1.3: Submission Overview provides an overview of the organization and the interconnections that are present in the document.

Figure 1.3:
Submission Overview



The document is composed of five chapters:

Chapter One: Introduction provides the framework for the Submission.

Chapter Two: Background on Yukon Power Systems provides background information. The chapter includes an overview of the Yukon power system; the outcomes from the 1992 review; major events affecting power systems since 1992; and bulk power planning since 1992.

Chapter Three: System Capability provides information on the capability of the Yukon systems to meet the electricity needs of Yukoners, and addresses a review of system capacity planning criteria and the revised criteria that Yukon Energy has adopted.

Figure 1.3: Depicts the three sections of Chapter Three. These sections are separate, but each contributes in determining the adequacy of the system.

Section 3.1: Current Facilities Condition Assessment provides information on Yukon Energy's generation, substation and transmission assets. The second section of the chapter,

Section 3.2: Capacity and Energy Outputs of Existing Facilities focuses on implications of changes to major facility output since 1992, either from age, enhancement, or licencing conditions. The third section of the chapter,

Section 3.3: Capacity Planning Criteria Review, provides information on Yukon Energy's previous capacity criteria, the Company's 2005 review of its capacity criteria, and its adoption of revised criteria.

The next two chapters of the Plan reflect differentiation of (a) the near term requirements, and (b) longer term industrial development scenarios and opportunities.

Chapter Four: Near Term Requirements reviews major projects currently in the pre-decision planning stage (Figure 1.1) that Yukon Energy proposes to commit for construction or implementation prior to 2009, focusing on near term opportunities with regard to enhancing existing Yukon Energy facilities as well as near term projects which Yukon Energy is required to address under the revised capacity planning criteria. Proposed actions by Yukon Energy are identified regarding major projects that require final commitment decisions prior to 2009.

Chapter Five: Industrial Development Scenarios and Opportunities identifies and assesses on a preliminary basis major energy focused project possibilities during the 20 year planning period beyond 2009 and before 2016 in response to different industrial development scenarios. Proposed actions by

Yukon Energy are identified regarding planning activities that Yukon Energy may be required to carry out to start construction on such projects before 2016, including actions to ensure that YEC protects its ability to deal with these industrial development loads and opportunities should they arise. No project options examined in Chapter 5 are yet at the pre-decision stage of project planning (as reviewed in Figure 1.1).

2.0 BACKGROUND ON YUKON POWER SYSTEMS

The chapter provides background on current Yukon power systems, primarily encompassing the two integrated grids and generation facilities and transmission owned by Yukon Energy.

The sections for this chapter are as follows:

- Section 2.1: Overview of Generation Facilities and Transmission
- Section 2.2: Outcomes from the 1992 Review
- Section 2.3: Major Events Affecting Power Systems Since 1992
- Section 2.4: Bulk Electrical Supply Planning Since 1992

2.1 OVERVIEW OF GENERATION FACILITIES AND TRANSMISSION IN YUKON

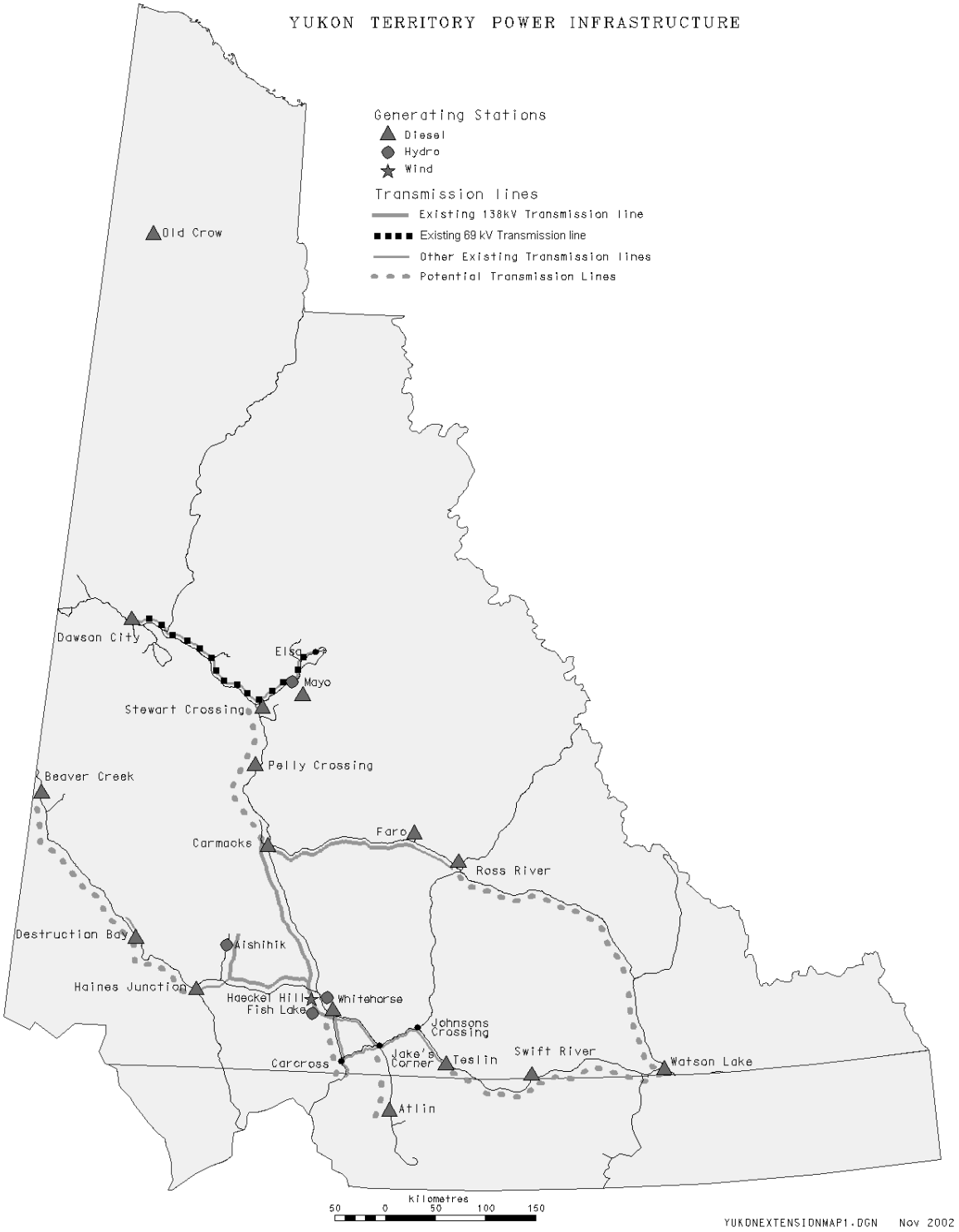
Yukon Energy is the main BES provider, or main generator and transmitter of electrical energy in Yukon. Yukon Energy currently accounts for 90% of annual Yukon power generation, and operates two independent transmission grids – the WAF and the MD.

The power systems identified in this Resource Plan are distinct and independent systems, each being served by its own source(s) of generation. The power systems in the Yukon include: the WAF grid; the MD grid; the diesel community of Watson Lake; and a number of smaller isolated diesel communities (Beaver Creek, Destruction Bay, Pelly Crossing, Swift River and Old Crow). The Yukon power systems are shown in *Figure 2.1: Map of Yukon Territory Power Infrastructure*.

Yukon Energy currently serves approximately 1700 retail customers, or 11%, of Yukon's customers directly. The retail customers that are served directly include residential and commercial classes. The majority of these customers are located in and around Dawson City, Mayo and Faro.

Yukon Energy's wholesale customer, YECL, distributes power to the other 89% of Yukon's retail customers. The bulk of Yukon Energy's sales are composed of firm wholesale sales to YECL on the WAF grid. YECL maintains and operates its distribution lines independent of Yukon Energy.

Figure 2.1:
Map of Yukon Territory Power Infrastructure



Hydro generation from the Aishihik and Whitehorse stations supply the WAF communities of: Carmacks, Carcross, Haines Junction, Teslin, Whitehorse, Ross River, Tagish, Deep Creek, Takhini River Sub and Marsh Lake through wholesale sales to YECL. The WAF communities of Champagne, Faro, Johnsons Crossing and Braeburn are served directly by Yukon Energy.

Hydro generation from the Mayo Generating station is supplied by Yukon Energy to the Town of Mayo, the City of Dawson, as well as to loads along the Mayo-Dawson transmission line route (the North Klondike Highway loads), as well as on a wholesale basis to YECL for service to Stewart Crossing, Elsa, and Keno.

Hydro generation stations on the Yukon grids are supplemented as necessary by a small amount of diesel for peaking or maintenance purposes, and on the WAF grid, by wind generation. The absence of power grid interconnections with other neighbouring jurisdictions prevents export of surplus generation or import of competitive supplies, and is one of the key factors distinguishing Yukon's situation from that prevailing in most southern jurisdictions in Canada.

2.1.1 Generation in Yukon

Yukon Energy's systems account for 112.4 MW of the 127.4 MW of installed capacity in Yukon. The YECL systems account for the balance, or for 15.0 MW of installed capacity.

The generation assets currently owned by both Yukon Energy and YECL are shown in *Table 2.1: Generation Capacity in Yukon – YEC and YECL in 2005*.

Table 2.1:
Generation Capacity in Yukon – YEC and YECL in 2005

Yukon Energy Generation Assets (in MW installed & currently rating)			**YECL Generation Assets** (in MW installed)		
Hydro Facilities			Hydro Facilities		
Whitehorse	WAF	40.0	Fish Lake	WAF	1.3
Aishihik	WAF	30.0	Base Load Diesel Facilities		
Mayo	MD	5.4	Old Crow	Isolated	0.7
Total Hydro		75.4	Pelly Crossing	Isolated	0.7
			Beaver Creek	Isolated	0.9
Wind Facilities			Destruction Bay	Isolated	0.9
Haeckel Hill	WAF	0.8	Swift River	Isolated	0.3
			Watson Lake	Watson Lake	5.0
Diesel Facilities			Back-up Diesel Facilities		
Whitehorse	WAF	22.4	Carmacks	WAF	1.3
Faro	WAF	5.3	Teslin	WAF	1.3
Dawson	MD	5.0	Haines Junction	WAF	1.3
Mayo	MD	2.0	Stewart Crossing	MD	0.3
Mobile Diesel		1.5	Ross River	WAF	1.0
Total Diesel		36.2	Total Diesel		13.7
TOTAL YUKON ENERGY		112.4	TOTAL YECL		15.0
TOTAL YUKON GENERATION		**127.4** **(YEC + YECL)**			

Yukon Energy's extensive hydro generation and transmission facilities and the resulting significant reduction in overall reliance on diesel generation are the key factor causing Yukon power costs to typically be lower than those found in Alaska or the Northwest Territories ("NWT"). Without such hydro facilities, Yukon utilities probably would have relied almost entirely on diesel generation with its associated higher costs[1].

[1] See Cabinet Commission on Energy, Technical Background Paper on Electrical Rates and Relief, 1997. Chart 1 in this paper reviewed Residential power bills in North America in 1996. The paper (pages 6-7) reviewed factors affecting northern power costs (e.g., lower population and customer densities, reliance on diesel generation, and the absence of power grid connections with other jurisdictions), and concluded that the lower power costs in Yukon reflect YEC's extensive hydro generating facilities (e.g., YEC hydro generation provided from 70 to 90% of all Yukon power generation each year from 1987 through to 1997). The paper noted that production or generation costs represented almost 70% of all Yukon power costs forecast for 1997 in the 1996/97 GRA.

Figure 2.2:
Yukon Total Power Generation 1967 – 1997

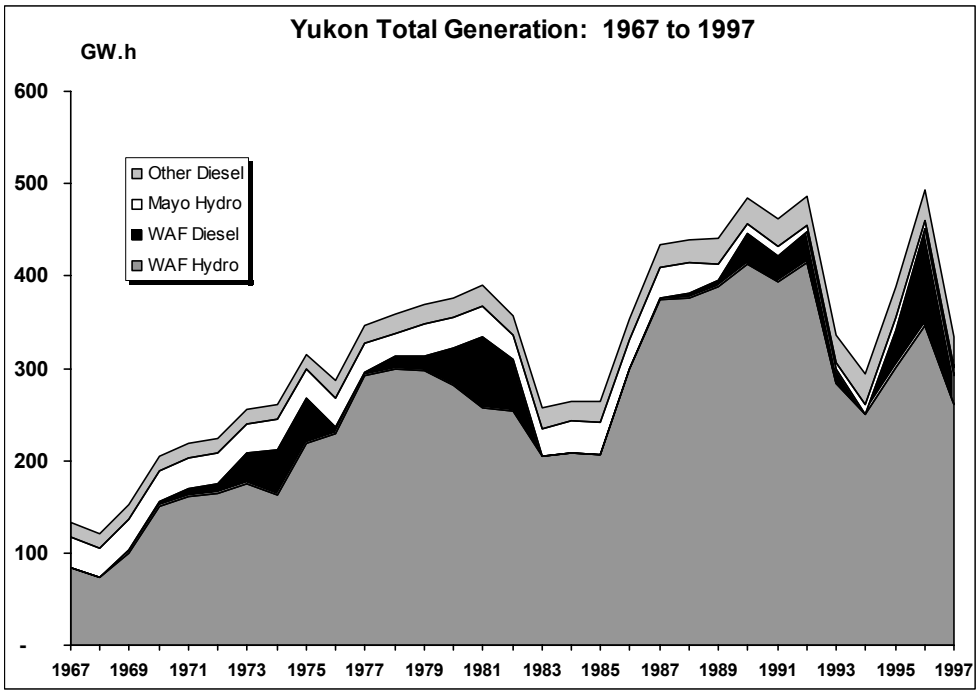


Figure 2.2: Yukon Total Power Generation: 1967-1997 highlights the overall importance of Northern Canada Power Commission ("NCPC")/YEC hydro generation in Yukon and the evolution of this capability from the late 1960's (after the first two hydro units were installed at Whitehorse Rapids) until the mid 1980s. This figure also demonstrates the relatively minor effect overall for Yukon related to diesel generation required outside the WAF and Mayo areas[2].

Hydro generation in Yukon was developed in the past by the NCPC in response to load developments in the Yukon, particularly mine-related loads at Faro, Keno, and Whitehorse. Yukon Energy acquired these hydro assets in 1987 as a result of the NCPC transfer.

- In 1952, NCPC built the Mayo Hydro facility to supply power to Mayo and UKHM in Elsa and Keno.

[2] Completion of the MD transmission line in 2002 materially further reduced diesel generation requirements in Yukon (by displacing diesel generation at Dawson). Figure 2.2 requires access to YECL generation data, which is not available after the years noted in the figure.

- In 1958, NCPC built the first two turbines at Whitehorse Rapids to supply the rapidly growing demand for power in Whitehorse.
- A third turbine was added to the Whitehorse Rapids plant by NCPC in 1969, along with the 138 kV transmission line from Whitehorse to Faro, as a consequence of an agreement between Cyprus Anvil Mining Corporation and Government of Canada to build a mining facility at Faro.
- In response to the Faro mine's power requirements and the opportunity to cost effectively displace diesel generation, the Aishihik hydro plant was developed by NCPC between 1973 and 1975, and the Whitehorse fourth hydro turbine generator was developed between 1982 and 1984.

Figure 2.3: YEC WAF Generation 1967 – 2004 details historic generation on the WAF grid. The majority of WAF generation has been hydro generation. During periods when the Faro mine was in operation there was also ongoing material diesel generation.

Figure 2.3:
YEC WAF Generation 1967 – 2004

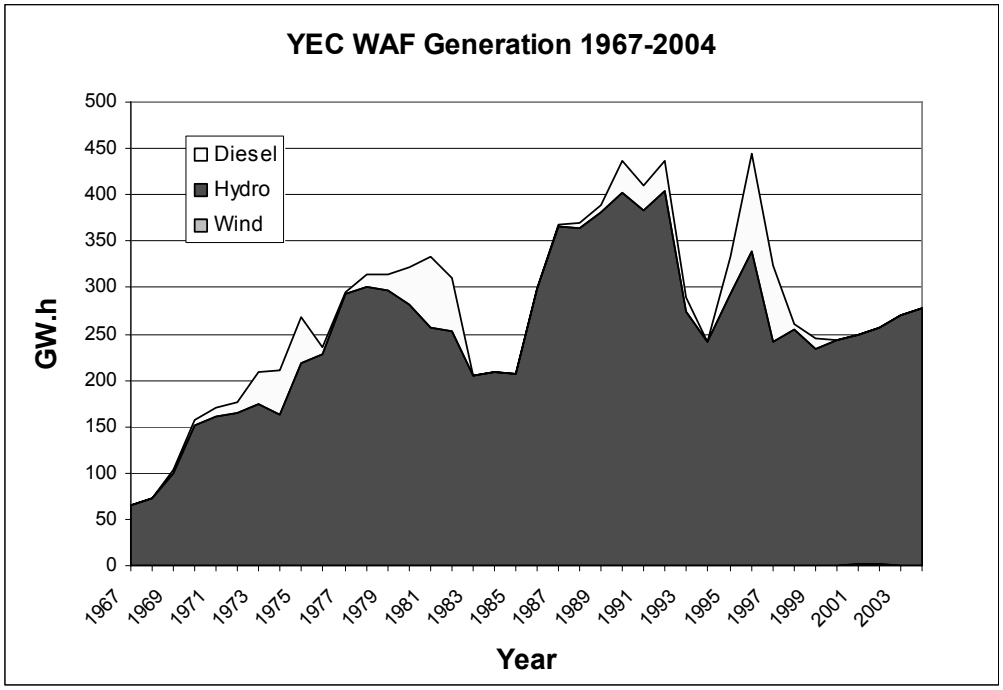
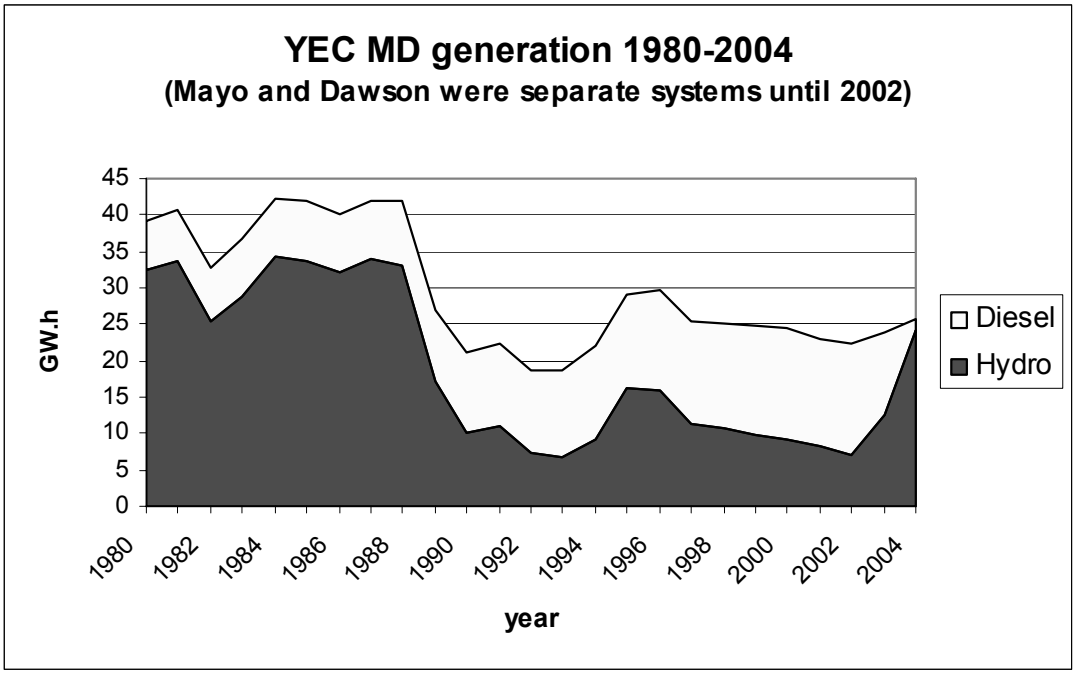


Figure 2.4: YEC Generation on MD 1980 to 2004 details historic generation in the communities that now form the MD grid. Until the UKHM closure in 1989, there was substantial hydro generation being used

(primarily at UKHM). Prior to completion of the Mayo-Dawson Transmission Line project in 2002, Dawson was a diesel served community; with completion of the MD grid, hydro generation has become the main source of generation for all MD grid communities. By 2004, only 6% of MD generation was by diesel.

Figure 2.4:
Generation on MD, 1980 – 2004



2.1.2 Transmission in Yukon

Yukon Energy owns and operates the WAF and MD transmission systems in Yukon of 69 kV or higher, as well as certain lower voltage lines; certain lower voltage lines (25 to 34.5 kV) are also owned and operated by YECL. The WAF and MD grids, and the other lines in Yukon are identified in *Figure 2.1: Map of Yukon Territory Power Infrastructure*.

The WAF and MD transmission lines are characterized as transmission lines because the lines transmit power from one community to another. However, due to the lower voltage, some of these transmission lines would be considered to be sub-transmission or distribution lines on a larger system.

WAF transmission is primarily a 510 kilometre 138 kV line that extends from Aishihik east to Whitehorse, north to Carmacks, and then east to Faro. Separate lower voltage lines connect other communities, comprising a 25 kV line (YEC) to Haines Junction, a 25 kV line (YEC) from Faro to Ross River, and a 34.5 kV system (YECL) southeast from Whitehorse to Teslin, Carcross, Tagish, Marsh Lake, Jakes Corner and Johnsons Crossing.

The MD grid is composed of a 223 kilometer 69 kV transmission line extending from the Town of Mayo to the City of Dawson, and connecting Stewart Crossing. A separate 69 kV transmission line connects to Keno and Elsa, northeast of Mayo.

2.2 OUTCOMES FROM THE 1992 REVIEW

Order-in-Council 1992/092 directed the YUB to review Yukon Energy and YECL (the "Companies") major capital projects and contract commitment proposals required for non-diesel fuel generation, transmission and DSM to 1997. The 1992 Resource Plan submission prepared by the Companies was jointly submitted to the YUB, and provided the first opportunity since the NCPC transfer in 1987 to review long-range major capital planning options for Yukon power systems.

The 1992 Submission Overview provided a snapshot of an ongoing dynamic resource planning process, and proposed a set of ongoing demand and supply work plan elements for the 1992 to 2001 period rather than the development of a single resource option.

The YUB conducted a public hearing in October, 1992 to review the 1992 Resource Plan, and submitted a report (the "Capital Hearing Report") with recommendations to the Commissioner in Executive Council on December 7, 1992 (Review of the Capital Resource Plans of YEC and YECL. Yukon Energy and YECL subsequently provided comments on the YUB's forty-eight recommendations in Section 5.3 of the 1993/94 General Rate Application ("GRA") Submission. Some of the notable recommendations are detailed below, along with responses by the Companies (as filed in the 1993/94 GRA), and updates on each recommendation:

A Framework for Capital Programs to be Pursued: The YUB's Recommendations 1 and 2 stated that the Capital Hearing Report provided a framework for future capital projects, and that the capital resource plan should be reviewed as part of general rate applications, or as directed by the Board. The Companies agreed.

Yukon Energy and YECL provided updates to the YUB on capital planning activities as part of the jointly filed 1993/94 and 1996/97 general rate applications. Yukon Energy provided updated information on capital projects in *Section 5 of the 2005 Required Revenues and Related Matters Application*. The current Resource Plan Submission provides a further and more detailed update for the YUB.

Market Risks: The Companies agreed with Recommendations 3 and 4 that stated the significant market risk associated with the closure of the Faro Mine should be considered in assessing the Companies' Resource Plan and in determining the need for new facilities.

After the closure of the Faro Mine in 1998, there has been a significant WAF hydro surplus. As a result, there has not been a need for new facilities to address mining loads in Yukon. However, there are now new mining opportunities on the horizon for Yukon.

Potential mining loads are discussed in *Chapter Five: Industrial Development Scenarios and Opportunities*. Yukon Energy's assessment of new facilities in the context of mining loads takes into account the related risks.

Load Forecasts and Demand Side Management: The Board recommended that the low and base case scenarios should be considered in assessing the need for DSM (Recommendation 5).

The Companies agreed that DSM initiatives should not be based on the high case scenarios. Since the closure of the Faro Mine, there has been a hydro surplus, and the "high" case that the Board considered in 1992 does not exist at the present time (i.e., there is no industrial customer in Yukon today).

The Board also supported aggressive DSM activities to the extent that it can be demonstrated that the activities result in lower costs to consumers than alternate supply options (Recommendation 22). The Companies agreed that DSM activities should only be pursued where they are more economic than supply-side investments.

There is currently a hydro energy surplus in Yukon. The incremental cost to produce hydro generated electricity is virtually zero, and therefore there has not been a need on the WAF and MD systems to reduce energy use. As a result, both supply-side and demand-side conservation initiatives have not been a key focus for Yukon Energy since 1997.

In terms of managing the demand (customer consumption) on the system, the focus for Yukon Energy since the Faro Mine closure in 1998 has been primarily on developing interruptible energy sales opportunities on the WAF and MD systems (see *Section 2.3.2: The Growth of Secondary Sales*).

Recent DSM activities have been undertaken by the Energy Solutions Centre ("ESC")[3] . DSM options that reduce the load on the WAF system at the very immediate peak times (i.e., reduce the capacity requirement of the Yukon system) have the potential to provide value to Yukoners today. Programs that have been developed and tested by Yukon Energy and ESC since 1992 are explored in greater detail in *Section 2.4: Bulk Power Planning Since 1992*.

Load Factoring: The Board's Recommendation 11 recommended that the Companies perform studies and tests to determine the potential to use load factoring to increase the capacity relied on at the Whitehorse Rapids Hydro Plant.

The Companies continued to experiment with load factoring between 1992 and the 1993/94 GRA. The Companies maintained in the 1993/94 GRA that enhanced load factoring would not result in a firm capacity rating above 24 MW for Whitehorse during non-drought years. This item is further discussed in *Chapter 3*.

Load Forecasts and Use Per Customer: The YUB recommended a more rigorous approach to estimating residential and general service use per customer (Recommendations 7 and 8).

Yukon Energy and YECL did review the historical use per customer during the 1993/94 GRA. The average use per customer was expected to stay relatively constant. Consequently the driver in the load growth forecasts was the number of customers.

In the 1993/94 General Rate Application the Companies agreed to explore opportunities to carry out research pertaining to use per customer with the Yukon Government and others, and to document current electric heating use characteristics on the WAF system.

[3] The Energy Solutions Centre was under the management of the Yukon Development Corporation. On February 5th, 2005, the Yukon Territorial Government ("YTG") announced its plan to transfer management from YDC to YTG. Release #05-23, "New Model for Energy Solutions Centre to Improve Accountability", Online: http://www.gov.uk.ca/news/2005/05-23.html.

Yukon Energy and YECL also examined use per residential customer in the 1996/97 GRA. The Companies identified a trend of declining use per customer, and reflected this trend in the sales forecast. The decline in use per customer was attributed to a reduction in electric heat. The Companies suggested that higher electricity rates in the mid-1990s had encouraged conversions from electric heating.

Yukon Energy has factored a use per customer variable into its current load forecasting methodology for its retail customers. Yukon Energy's current load forecasts have two components: a measure of the increase in the number of customers; and a measure to reflect changes in the average use per customer. Yukon Energy's load forecast methodology is explained in greater detail in *Section 4.2.1: Non-Industrial Load Forecasts*. Due to its limited retail customer load, Yukon Energy does not have the data or analysis to weather normalize its past sales or forecasts for its own retail customers. Yukon Energy is not able to carry out analysis on customer numbers or use per customer on YECL's current retail customers.

Aishihik 3rd Turbine: The Board recommended in Recommendation 37 that the Companies pursue approval for the construction of the third turbine at Aishihik, given that it is economically, technically and environmentally feasible. The Board asked the Companies to "report back to the Board before commencing construction" and indicated that "the Companies should pursue installation of the maximum capacity that is economically, technically and environmentally feasible".

As of the 1993/94 GRA, the Companies were delaying activity on the third Turbine due to the closure of the Faro Mine at that time; similarly, active consideration of developing this project was once again delayed after the Faro Mine closures in 1997 and 1998. The third Turbine, however, remained a component of the Yukon Energy application for Aishihik relicencing throughout the period.

Yukon Energy received its renewed water licence at Aishihik in 2002 (which extends to December 31, 2019), including the environmental approval to install a third Turbine of up to 7 MW. Based on the current Resource Plan, Yukon Energy is now proceeding with the next steps in the Aishihik third Turbine project, including updated costing of the 7 MW installation and confirmation of hydrology.

Supply Options: In Recommendation 36 the Board stated that before pursuing construction of "large projects" (defined as projects with a cost of more than $5 million), preference should be given to DSM, small utility owned projects and Independent Power Producers ("IPP") that are cost effective for consumers.

In the 1993/94 GRA the Companies agreed with this option, providing that these options are cost effective for consumers. Yukon Energy's last internal large-scale Resource Planning exercise took place in 1996. In September, 1996, Yukon Energy requested Expressions of Interest from qualified parties interested in providing technologies, investments and/or partnerships to establish new generation facilities in Yukon to displace diesel generation. During that planning process, IPP projects were considered.

Independent Power Producers: The Companies agreed with the Board's Recommendation 45 that IPP's should be encouraged in Yukon, provided that there are no negative rate impacts on consumers. The Board recommended (Recommendation 47) that the Minister direct the Board to hold a hearing with respect to IPP policy and to develop a firm IPP policy for Yukon.

A hearing was not held. However, as noted above, Yukon Energy did solicit IPP proposals for development in 1996.

Feasibility Studies: Recommendation 39 stated that the Companies should not proceed with any feasibility studies for Drury Creek, Morley River, Lapie River and Orchay River, other than developing long-term hydrological data.

Yukon Energy has collected hydrological data, but has not proceeded with feasibility studies.

Coal: The Companies agreed with the Board's Recommendation 42 that studies of coal-fired generation should be limited to a review of coal technology, particularly with respect with plants under 20 MW.

Yukon Energy has not proceeded with any detailed study of coal technology. However, when Expressions of Interest were requested in 1996, three respondents focused on coal-based thermal generation for the WAF system. As a result of the closure of the Faro mine in 1997 and again in 1998, no projects were developed as a result of the call for Expressions of Interest.

Mayo-Dawson Transmission Line: The Companies agreed with Recommendation 42 that no further studies should be conducted on this transmission line unless demand changed sufficient to warrant a review of the project.

Escalating fuel costs and load growth subsequently led Yukon Energy to update its studies and ultimately commit to proceeding with the MD project in 2001 (including receiving the approval of the Minister). The

Line commenced operation in September of 2003, and has offset diesel generation and reduced fuel costs for Yukon Energy. For more information of the MD Transmission Line, see *Section 2.3.6: Mayo-Dawson Transmission Line*.

Wind: Recommendation 43 stated that research and development work should continue to be pursued with respect to wind generation. The 1993/94 GRA included the purchase and installation of a wind turbine on Haeckel Hill.

Yukon Energy has installed two research and development wind turbines at Haeckel Hill with a combined generating capacity of 800 kW.

2.3 MAJOR EVENTS AFFECTING POWER SYSTEMS SINCE 1992

There have been a number of significant changes to the Yukon system since 1992. The most notable of these changes include: closure of the Faro Mine; the increase in Secondary Energy sales; Yukon Energy's shift to direct management; the Whitehorse Rapids Generating Station fire rebuilding project; renewal of Yukon Energy's three water licences; and the construction of the MD Transmission Line. These events are outlined below.

2.3.1 Closure of the Faro Mine

After decades of operation on the WAF grid, including a number of closures and re-openings, the Faro Mine closed in 1998. This mine closure followed the 1989 closure of the United Keno Hill Mine ("UKHM"), which had been served by the Mayo hydro plant. As a result of the Faro Mine closure, there are currently no major industrial customers being served in Yukon. Major industrial customers are defined by Order-in-Council 1995/90 as, "a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer[4]."

Overall generation and diesel usage declined after the Faro Mine's closures in 1983 and 1993, 1997 and again after its final closure in 1998. When the Faro Mine was in operation, all of Yukon's hydro generation was absorbed by the system, and diesel generation was required on an ongoing basis. Since the final closure of the Faro Mine in 1998, there has been a hydro energy surplus on WAF.

[4] Rate Policy Directive, Order-in-Council 1995/90, May 29, 1995.

2.3.2 The Growth of Secondary Sales

Secondary Energy has been available from time to time to General Service or Industrial customers based on the availability of surplus hydro since before the NCPC transfer. Rate Schedule 32 – Secondary Energy, provides Yukon Energy with an opportunity to sell excess low-cost hydro power when it is available, but can interrupt secondary sales customers when it is likely that the utility will be required to generate electricity with diesel. There are now approximately 25 retail customers who together receive more than 20 GW.h of electricity under Rate Schedule 32. These customers use the electricity to displace fuel oil, and in some cases, propane.

The current Secondary Energy rate was approved in YUB Board Order 2005-12 at 66.7% of the equivalent energy price of fuel oil. The rate is adjusted quarterly to reflect ongoing market price adjustments for fuel oil.

Secondary sales have grown from 3,917 MW.h in 2000, to a forecast 20,613 MW.h for 2005. The recent growth in secondary sales can be attributed to the surplus in hydro energy on the WAF grid since the closure of the Faro Mine in 1998. Surplus hydro generation on the MD grid is also stimulating secondary sales on that system.

At today's rates, Secondary Energy sales are very beneficial, and help to pay for the fixed costs of the system (more than $1 million in revenues annually). However, although Secondary Energy are available from existing system assets, the generation system is not planned to provide service to secondary customers. For the purposes of planning the system for capacity requirements or energy projects, Secondary service is not included as required load to be served (however, in some cases the ability to enhance sales of secondary power can provided added economic benefits from certain projects).

2.3.3 Shift to Direct Management

On January 1st, 1998, Yukon Energy assumed full management and operation of its generation, transmission and distribution infrastructure and services. This includes direct responsibility for activities related to planning the Yukon integrated generation and transmission systems today.

Prior to 1998, Yukon Energy's assets had been managed by Canadian Utilities, a subsidiary of ATCO, which is YECL's parent company. Yukon Energy's billing service is the only service that is still provided by an ATCO company.

Yukon Energy and YECL are both regulated by the YUB. YECL was an active intervenor in the spring 2005 YUB hearing on Yukon Energy's *2005 Required Revenues and Related Matters* application. This was the first comprehensive revenue requirement submission that either had made to the YUB since the shift to direct management.

2.3.4 Whitehorse Rapids Generating Station Fire Rebuilding Project

On October 30, 1997, a fire started in the pump room of the Whitehorse Rapids generating station. The fire destroyed the generating station building, the system control centre, the Yukon Energy Corporate office, the switchgear, and caused superficial damage to hydro generators 1, 2 and 3. Even with the damage sustained by Yukon Energy, electrical service was not interrupted during the fire.

Yukon Energy filed insurance claims under its insurance provisions, and received a favourable settlement. The fire destroyed assets with a rate base of $2,280,000. A total of $11,604,000 of new assets were placed in service to replace the assets destroyed or damaged during the fire. A total of $1,799,000 in betterments were also completed. Yukon Development Corporation ("YDC") paid for $1 million of these costs. The balance of $799,000 was put into rate base.

The insurance claim resulted in a net benefit to ratepayers. Aging assets were replaced at essentially no cost to ratepayers. There was also a resulting insurance gain of $744,000.

2.3.5 Renewal of Water Licences at Whitehorse, Mayo and Aishihik

Yukon Energy is required to have water licences for the hydroelectric facilities that it owns and operates in Whitehorse, Mayo and Aishihik (near Haines Junction, Yukon). Water licences in the Yukon are issued for a period up to, but not exceeding 25 years. All of the water licences for these three facilities expired since the 1992 Resource Plan filing, and renewal of each licence has been obtained.

Whitehorse: The Whitehorse Water Use Licence (HY99-010) expired in 2000, and was renewed for 25 years (expires in 2025). It combines two prior licences, Marsh Lake and Whitehorse Rapids. The renewal of the licence was sought on the basis of no relevant changes being made to its terms and conditions, and included only administrative changes. The licence renewal was granted by the Yukon Territorial Water Board ("YTWB") on this basis. Dam safety monitoring requirements were formalized in the new licence. This was consistent with Yukon Energy practices and current Canadian Dam Safety Guidelines.

Mayo: Mayo Water Use Licence (HY99-012) expired in 2000, and was renewed for 25 years (expires in 2025). Similar to the Whitehorse facility, the renewal of the licence was sought on the basis of no

relevant changes being made to its terms and conditions, and included only administrative changes, and the licence renewal was granted by the YTWB on this basis. Dam safety monitoring requirements were formalized in the new licence, which was consistent with Yukon Energy practices and current Canadian Dam Safety Guidelines.

Aishihik: Relicencing of the Aishihik hydroelectric facility took place over a number of years. It involved four amendments to the 1978 licence. A new licence with a Fisheries Act Authorization was issued in 2002 upon expiry of the 1978 licence. Yukon Energy had sought a new licence, and a 17-year licence was granted. Similar to Whitehorse and Mayo, the dam safety requirements in the licence are normal modern utility standards that would need to be completed whether a requirement of the licence or not. The renewal of the licence called for ongoing heritage payments, the construction of a boat launch at the north end of the lake, and an annual fish monitoring program.

New terms of the 17-year licence provide for a conditional seven-foot operating range subject to the terms of the Department of Fisheries and Oceans ("DFO") Fish Act Authorization, and allow for the installation of a third turbine not exceeding 7 MW (subject to the requirement for YTWB approval of an operating plan when the third turbine is installed). Additional details on the Aishihik Licence renewal were provided in Interrogatory Response YUB-YEC-1-55 in Yukon Energy's 2005 Required Revenues and Related Matters Application.

2.3.6 Mayo-Dawson Transmission Line

The MD Transmission Line Project came into service in September of 2003. The MD project was the first large-scale transmission infrastructure development project undertaken by Yukon Energy since the NCPC transfer in 1987. The 223 kilometre 69 kV transmission line links Mayo, a community with surplus hydro, with Dawson, a community that was previously served solely by diesel generation. The transmission line now supplies almost all of Dawson's energy requirements. The line also provides hydro power to YECL at Stewart Crossing, which was previously served with diesel generation, as well as various locations along the North Klondike Highway that were not previously served by utility power.

The costs of the MD Transmission line were projected to be $35.6 million as of the end of 2005. A total of $5.8 million of this amount was provided by Yukon Development Corporation at no cost to ratepayers. YDC has also provided flexible debt financing to Yukon Energy. This financing ensures that ratepayers

will be protected so that they are not paying, in any year, more than they would have paid had Dawson remained on diesel fuel generation[5].

2.3.7 System Upgrades and Changes

In addition to the completion of the MDTransmission Line project, and relicensing of its three hydro plants, Yukon Energy has undertaken additional system upgrades since the submission of the 1992 Resource Plan. Recent Upgrades include:

- Aishihik Unit #1 Rewind in 2003 (cost $1.2 million)
- Mayo Hydro Unit #1 and Unit #2 Capacity Increase in 2002 (cost $1 million)
- Addition of Wind Turbine #2 in 2000 (cost $2 million)

Yukon Energy has also been able to extend the service life of its three Mirrlees Blackstone base load diesel units located in its Whitehorse diesel plant (diesel units WD1, WD2 and WD3). WD3 is currently scheduled for retirement in 2007; WD2 is currently scheduled for retirement in 2009; and WD1 is currently scheduled for retirement in 2011. The 1992 Resource Plan had scheduled the retirement of WD1, WD2, and WD3 in 1998, 1998, and 2000 respectively. By 1996 the retirement was extended. After the Faro Mine closed, these units provided required reserve capacity for the system.

Since the Faro Mine closure in 1998, a 5 MW diesel unit was retired at Faro. Two diesel units with a combined capacity of 2 MW were moved to Mayo, and a 1.3 MW unit was removed from Faro to act as a mobile unit. The result is a decrease in the Faro diesel plant size from 13.6 MW to 5.3 MW.; in addition, two diesel units with a combined capacity of 1.3 MW were retired from Mayo.

2.4 BULK ELECTRICAL SUPPLY PLANNING SINCE 1992

Yukon Energy has been engaged in a number of power planning activities since the 1992 Resource Plan submission. In addition to the submission of the current plan, Yukon Energy has provided updates to the YUB in its rate and revenue application submissions. Yukon Energy's planning has included: developing an inventory of future supply options with YDC and BC Hydro; condition assessment work of its key generation and transmission assets; a review of the WAF and MD capacity criteria review; and work with ESC on DSM. Yukon Energy's significant power planning activities since 1992 are outlined in the following sub-sections.

[5] YUB Board Order 2005-12 approved $29.046 of the costs of the MD Transmission Line for inclusion into YEC's ratebase, net of the $5.75 million contribution by YDC ($0.05 million of the amount provided by YDC was an interest-free advance, not a contribution) and about $0.8 million being disallowed (amounts YEC cannot charge to ratepayers).

2.4.1 Ongoing Yukon Energy Infrastructure Planning Process

Infrastructure updates were provided as part of Yukon Energy's GRAs to the YUB in 1993/94, 1996/97, and in the *2005 Required Revenues and Related Matters* Application. These updates were in response to the YUB's Recommendation 2 from the 1992 Resource Plan hearing. The YUB recommended that the Companies' capital resource plan should be reviewed on an ongoing basis as part of general rate applications, or as directed by the Board.

2.4.2 BC Hydro Inventory of Potential Future Hydro Supply Options

YDC commissioned BC Hydro to work with YEC to conduct a Small Hydro Resource Study in 2002. The study included a review and assessment on existing information on hydro sites located in Yukon and relevant projects located in northern British Columbia. BC Hydro summarized over 200 sites which has provided Yukon Energy with a consolidated source for information on potential project options. The area studied included the WAF and MD transmission corridors, roughly 50 kilometres from the grids or highways. On WAF the study was extended from the current gird to Watson Lake along the Alaska Highway area.

2.4.3 Bulk Electrical Supply Infrastructure Condition Assessment Work

Yukon Energy commissioned three recent condition assessment studies. Acres International was commissioned to assess Yukon Energy's key transmission assets, while BC Hydro was commissioned to complete two studies: a study of Yukon Energy's key generating assets, and a study of selected substation assets. In May of 2004, BC Hydro completed its *Condition Assessment of Selected Yukon Energy Generating Assets*. BC Hydro's second report, *Condition Assessment of Selected Yukon Energy Corporation Substation Assets* was completed by BC Hydro in June of 2004. The Acres International report, *Assessment of Transmission Lines for Yukon Energy Corporation* was completed in December of 2003. A more thorough review of the findings from the condition assessments can be found in this Plan in *Section 3.1: Current Facilities Condition Assessment*.

Most of the assets examined by Acres International and BC Hydro were found to be in good to relatively good condition, and were expected to have operating lives of 20 additional years or more. The main exception is the Whitehorse Mirrlees diesel engines, which are further discussed in *Chapters 3 and 4*.

2.4.4 Generation Capacity Planning Criteria Review

There have been changes to the Yukon systems since the last detailed Yukon Utilities Board review of bulk system planning in 1992 as well as in the 1993/94 and 1996/97 GRAs including: closure of the Faro

Mine; growth in Whitehorse area loads; the interconnection of Mayo-Dawson; and the need to address the near term retirements of the Whitehorse Mirrlees engines. In combination, the above factors raised concerns regarding the ability of the assets in the Whitehorse area to serve the city in the event that the Aishihik Line was out of service for a substantial period during the winter peak. As a result, Yukon Energy undertook a review of the Capacity Planning Criteria.

For the Whitehorse area capacity, one specific issue was to determine how to approach the pending retirement of 14 MW of nameplate capacity for three Whitehorse Mirrlees diesel (WD) units (WD1, WD2 and WD3). Reviewing the adequacy of capacity planning criteria is a prudent first step prior to making (or rejecting the need to make) any such new capital investments.

NWT Power Corporation recently undertook a similar review of their Yellowknife grid. NWT Power Corporation commissioned a study of their capacity planning criteria by Dr. Billinton from the University of Saskatchewan. The NWT Power Corporation received approval from its regulator for its revised capacity planning criteria in November of 2004.

Yukon Energy retained Drs. Billinton and Karki from the University of Saskatchewan to study the key areas and characteristics of the Yukon systems (focused on WAF) relevant for a review of the required firm capacity planning criteria. As part of the capacity criteria review, Yukon Energy worked with Drs. Billinton and Karki to develop recommendations on capacity planning criteria for the Yukon systems. The conclusions from that work are detailed in *Section 3.3: Capacity Planning Criteria Review*.

2.4.5 Demand Side Management and the Energy Solutions Centre

Section 2.2: Outcomes from the 1992 Review touched on Yukon Energy's approach to DSM. When the Faro Mine was in operation, hydro generation was fully utilized and Yukon Energy actively pursued DSM opportunities in order to save diesel generation costs. The Faro Mine closures shifted Yukon Energy's focus away from DSM due to surplus diesel generation costs. After the final closure of the Faro Mine in 1998, the focus on DSM activities decreased greatly. The key activities from the 1992 to 1998 are outlined below.

DSM From 1992 to 1998

Smart Home on Wheels Community Tour: In 1992 the Companies developed a Smart Home on Wheels Community Tour to educate Yukon residents and retailers outside of Whitehorse of the benefits of Power Smart products. This program was intended to parallel the impact of The Power Smart Idea

Shop which was located in Whitehorse. Between October 26 and December 14, 1992, the Tour visited the communities of: Burwash Landing, Beaver Creek, Carmacks, Pelly Crossing, Teslin, Haines Junction, Mayo, Stewart Crossing, Dawson City, Carcross, Tagish, Watson Lake, Ross River and Faro. Fifteen presentations were made to local schools, and over 500 people visited the trailer. A survey was completed by the majority of visitors to the trailer, and 99% of respondents indicated that they learned something new about energy management. A further 85% identified steps that they planned to take to reduce energy consumption.

Home Smart: In March 1993 Phase one of the Home Smart program was completed. The program provided subsidies on six energy-saving and energy efficient products, including: outdoor timers, water saver kits, water tank wraps and pipe insulation, power cord savers, compact fluorescent light bulbs and compact fluorescent hardware fixtures. The program was retail focused, and 59 Yukon retailers participated by carrying Power Smart products, information displays and information.

Energy Management Working Group: On November 1st, 1996, Yukon Energy and YECL submitted a Final Report to the Yukon Utilities Board on the activities of the Energy Management Working Group. The group was formed as per Item 4 of the 1996/97 GRA Settlement, as approved by the Board in Order 1996-7. The parties who participated in the process included:

- Utilities Consumers' Group
- Yukon Housing Corporation
- Yukon Energy/YECL
- Yukon Chamber of Mines
- Whitehorse Chamber of Commerce
- City of Whitehorse
- The Government of Yukon

The Report identified work in progress that Yukon Energy and YECL set to achieve within the 1996/97 GRA period. The activities noted were:

- Education to the general public via bill stuffers, trade shows, etc.
- Opportunity assessments completed for customers on request
- An Opportunity Assessment was completed for Anvil Range Mining Corporation and paid for by Yukon Energy
- Opportunity Assessments were completed by YECL for the City of Whitehorse and Town of Haines Junction to train their employees

- YECL committed to investigate and study programmable electric hot water controllers to shift the peak load
- Yukon Energy planning a "Opportunities Assessment" of their plants
- Studies on capacity enhancements were scheduled for 1997
- YECL committed to start a more aggressive energy management initiative with its major users
- Rebate programs for residential customers were scheduled for study in 1997

Demand Side Management Since 1998

Since the closure of the Faro Mine in 1998, there has been a hydro energy surplus. Consequently there has been minimal economic justification to pursue DSM initiatives for most Yukon assets. However, DSM programs have not been terminated.

Since 2000, management of DSM programs has been undertaken by the ESC. ESC is a service and program delivery agency for energy efficiency and green power programs for the Federal and Yukon governments. The programs run by ESC include electricity programs, and programs focussed on improving the energy efficiency of other energy sources, such as wood-burning. As reported by ESC, the ESC programs that specifically address electricity conservation include the following:

2002-2003 Fridge Exchange: A Pilot Project of Yukon Development Corporation and Natural Resources Canada: The program encouraged Yukoners to exchange fridges that were 10-years old or more, for new, and more energy efficient ENERGY STAR fridges. Yukoners were responsible for purchasing the new appliances, however incentives were given. The program resulted in the following savings:

- 58 reduced tonnes of CO2 generation
- 72 megawatt hours of savings
- $14,400 in avoided costs

Final Report to Climate Change Action Fund Public Education and Outreach, Completed June 2001: The program targeted 2,000 house call energy audits. A total of 1,457 homes were visited. The program focussed on low flow showers to reduce water heater use; water heater blankets; and higher efficiency bulbs. The program resulted in:

- 2,203 reduced tonnes of CO2 generation
- 2,938 megawatt hours of savings

"Six Pack" Parking Lot Controller Pilot Project: A 2003 study of Intelligent Parking Lot Controllers in six Whitehorse locations: This pilot project evaluated the use of a block heater conservation device that limited the number of hours that block heaters would be in use during the business day. The test year that was used for the analysis was a warmer than average year which reduced the savings realized during the year. The total savings realized were 6,426 KWh. However, the payback period for the equipment was very difficult to forecast.

Penguin Pilot Project: Assessing the acceptability of residential tank timers: Results and Evaluation report, December 2003: The pilot project evaluated timers on residential water heaters. The bulk of the water heaters in the pilot project were 40-gallon capacity, with two 3,000 watt elements. The pilot project included 50 hot water tanks, and had a combined load of 150 KW.

The GreenHog Handbook: The handbook was launched in March 2004 by ESC. The handbook solutions to reduce greenhouse gas emissions in the Yukon. The 50-page handbook includes information on climate change, practical tips and solutions for lowering greenhouse gas emissions, coupons for free and discount items, and a booster card for discounts on locally available products and services. This handbook provides a number of suggestions and detailed information, but it is difficult to calculate the greenhouse gas emissions reduced due to this program.

3.0 SYSTEM CAPABILITY

In order to begin an effective resource planning exercise, it is necessary to assess the capability of the existing system to supply loads today and into the future under various time horizons and scenarios. This includes assessing the condition of Yukon Energy's assets, their capability to provide capacity and energy to the system, and ensuring that an adequate capacity planning criteria for the system is in place. This chapter provides a review of the condition and output of Yukon Energy's assets, and Yukon Energy's new capacity planning criteria.

The sections for this chapter are as follows:

- Section 3.1 Current Facilities Condition Assessment
- Section 3.2 Capacity and Energy Output of Existing Facilities
- Section 3.3 Capacity Planning Criteria Review
- Section 3.4 Summary: Revised Capacity Planning Criteria

The condition assessment section contains a description of three recent condition assessment reports requisitioned by Yukon Energy, and the findings of the assessments.

The capacity and energy output of the existing facilities are reviewed in the second section, which focuses on implications of changes to major asset output since 1992, either from age, enhancement, or licencing conditions.

The capacity planning criteria review section provides an overview of Yukon Energy's past capacity criteria, and the new capacity criteria that was recently adopted. Yukon Energy's past criteria was developed by NCPC, adopted in 1987 when Yukon Energy acquired NCPC's assets, and modified slightly in 1992. Yukon Energy reviewed its capacity criteria in 2004-2005 to determine if the criteria still reflects the needs of the Yukon system, and concluded that changes are required as set out in Section 3.4.

3.1 CURRENT FACILITIES CONDITION ASSESSMENT

Yukon Energy has recently had independent assessments of its key generation, substation and transmission assets.

- In May of 2004, BC Hydro completed its *Condition Assessment of Selected Yukon Energy Generating Assets*. This assessment was focused on Whitehorse Hydro (Units WH1 through

WH4), Whitehorse Diesel (Units WD1 through WD7) and Aishihik Hydro (units AH1 and AH3). The condition assessment did not review the other diesel plants or the Mayo hydro facility.

- A *Condition Assessment of Selected Yukon Energy Corporation Substation Assets* was completed by BC Hydro in June of 2004. The focus of BC Hydro's assessment was on circuit breakers and transformers located at the substations at Aishihik, Takhini, MacIntyre, Whitehorse (all on WAF) plus Mayo.
- Acres International was commissioned to assess Yukon Energy's transmission assets. The Acres International report, *Assessment of Transmission Lines for Yukon Energy Corporation* was completed in December of 2003. The condition assessment by Acres International of Yukon Energy's transmission lines was of a significantly different type than the Generation and Substation assessments. In the Acres assessment, the primary item to be addressed was the expected remaining life of the transmission assets, based on a sampling of the WAF transmission lines.

The three reports were filed in YEC's 2005 Required Revenues and Related Matters Application as Interrogatory Response YUB-YEC-A52. BC Hydro and Acres International found Yukon Energy's assets to be in good to relatively good condition with a few notable exceptions:

- Whitehorse Diesel Units WD1, WD2 and WD3 were assessed to be at their "end of life" and either need to be retired, or require substantial investment;
- Mayo Substation transformer T1 needs to be replaced in the next five years; and
- A number of circuit breakers need to be replaced at various substations.

Other smaller projects for modernization or life extension were also recommended in the various condition assessments.

3.1.1 Yukon Energy's Response to Condition Assessments

As a result of the condition assessment documents, Yukon Energy developed short to medium term capital investment plans to address the bulk of the items identified by BC Hydro and Acres International. This Yukon Energy plan was provided in the 2005 Required Revenues and Related Matters Application and has been reviewed by the Yukon Utilities Board. To summarize:

- **BC Hydro Condition Assessment of Selected Yukon Energy Generation Assets:** As shown in the Table 3.1, the BC Hydro report recommended $2.454 million in work on these units. Yukon Energy's capital plan for these same units over the period 2004-2009 reflects overall approximately the same scope of work (also shown on Table 3.1). Yukon Energy's plan consists of $3.760 million. The reason for the $1.306 million variance is primarily

material costs associated with the WH1 and WH2 trunion bushing capital projects that were not forecast by BC Hydro for $824,000, plus a 2004 project for major capital work on WD5 for $201,000 that was already in progress when BC Hydro prepared their report (and therefore is not addressed in the BC Hydro recommendations).

- **BC Hydro Condition Assessment of Selected Yukon Energy Corporation Substation Assets:** In this report, BC Hydro reviewed a number of Yukon Energy's substations and recommends $921,000 in work over the "medium to long-term" at Appendix I of their report (also see Table 3.2). Yukon Energy's capital plan for 2004-2006 includes $880,000 to complete this work, including further detailed assessment of each of the recommendations. YEC intends to review other options before proceeding with circuit breaker replacements estimated at $210,000.
- **Acres International Assessment of Transmission Lines for Yukon Energy Corporation:** Although some token amounts were identified as being recommended as capital to be spent in the next five years ($43,000 per page 28), the majority of the report was not aimed at determining the appropriate capital investment in transmission line. Yukon Energy has incorporated the amounts identified by Acres International in its five year capital plans for transmission spending.

Table 3.1:
BC Hydro Generation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s)[1]

BC Hydro 5 year Recommendation

	P125	P126	P127	AH0			
Unit Life Extension Mech	$152	$438	$84	$22			$696
Unit Life Extension Elect	$20		$40	$130			$190
Plant Life Extension Mech	$37	$245	$0	$8			$290
Plant Life Extension Elect	$10	$4	$43	$15			$72
Unit Modernize Mech	$92		$55	$181			$328
Unit Modernize Elect	$70		$120	$160			$350
Plant Modernize Mech	$48		$40	$80			$168
Plant Modernize Elect	$50		$10	$300			$360
	$479	$687	$392	$896	$0	$0	**$2,454**

YEC Budget Planning

	2004	2005	2006	2007	2008	2009	
P126 Diesel Life Ext (Mech)	$201						
P126 Diesel Life Ext (Elect)	$19						
Generation Unit Life Mech		$75	$75	$250	$150		
Generation Unit Life Elect		$75		$100			
Plant Life Mech					$250		
Plant Life Elect			$50				
Unit Modernize Mech					$250		
Unit Modernize Elect			$50		$250		
Plant Modernize Mech				$150			
Plant Modernize Elect				$250	$100		
P125 Vibration Monitoring	$120	$60					
P125 Trunions	$504	$400					
P127 Exciter Assessment		$21					
P127 Unit Mech Overhaul				$350			
P127 Ventilation		$10					
	$844	$641	$175	$1,100	$1,000	$0	**$3,760**

Notes:
YEC budget does not align with BC Hydro recommendations due to:
YEC not in full agreement all work is appropriate, and costs estimates are different between BC Hydro and YEC.

[1] P125 is Whitehorse Hydro plant containing units WH1, WH2 and WH3; P126 is the Whitehorse diesel plant; P127 is the hydro plant containing WH4; AH0 is Aishihik.

Table 3.2:
BC Hydro Substation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 ($000s)

BC Hydro Medium and Long Term Recommendations

	S249	S150	S164	S167	S171	General	
Transformer Replace	$150						
Circuit Breaker Replacements		$210					
Vertical Break Switches			$130	$130			
Disconnect Replacements		$30					
Station Service Upgrade			$60		$60		
Insulation Coordination Study						$30	
Circuit Breaker Analyzer						$18	
Infrared Digital Camera						$3	
Stock Inventory						$100	
	$150	$240	$190	$130	$60	$151	**$921**

YEC Budget Planning

	2004	2005	2006	2007	2008	2009	
Transformer Replacement			$200				
Station Service Upgrades				$150			
Breaker Analyzer		$40					
Transformer Leveling		$40					
Substation Follow Up Work		$150	$150	$150			
	$0	$230	$350	$300	$0	$0	**$880**

Notes:
Only YEC plans that correlate to the BC Hydro report are shown here. Other work is planned for substations or components that BC Hydro did not assess.

3.1.2 Condition Assessment Findings Relevant to Resource Planning

The Condition Assessment findings indicate Yukon Energy's system is generally well suited to meeting the future WAF and MD system load requirements over the duration of the Resource Plan within the as-built capabilities of each the various units studied. Aside from new requirements related to load growth, the clear exception is the three Whitehorse Mirrlees diesel units, WD1, WD2, and WD3, located at the Whitehorse diesel plant.

It has been well known to Yukon Energy that the Mirrlees units were approaching retirement, and in fact earlier Yukon resource planning exercises (both 1992 and 1996) were based on these three units being retired prior to 2006. The units have been retained in-service due to the current system load, which has not required material running time for these three units during the 1993-1995 closure, or since the 1998 closure of the Faro mine and into the future until at least the current hydro surplus on the WAF system is consumed by firm load.

The issues and options relating to the requirement to retire the Mirrlees units are further addressed in *Chapter 4.*

3.2 CAPACITY AND ENERGY OUTPUT OF EXISTING FACILITIES

The generating assets in service are required to meet both capacity (instantaneous peak) and energy (annual and sometimes seasonal requirements) of the individual systems (WAF, MD, isolated). An overview of Yukon Energy's generating assets is set out in Table 3.3. On each of the WAF and MD grids, supply is also available from diesel and, in one case, hydro assets owned by YECL.

This section reviews the capability of key Yukon generation assets to meet capacity and energy requirements of the various systems.

The capacity ratings of Yukon Energy's assets reflect design or "nameplate" ratings, as adjusted in certain cases to reflect the real-world conditions with respect to the individual unit, or conditions that exist at the time of year when capacity requirements are highest (e.g., winter). Capacity ratings for resource planning also must reflect what can be relied upon in worst case conditions, in particular drought conditions for hydro units.

Energy ratings could similarly be developed to reflect reliable output in worst case conditions (such as a drought for hydro units). However, given the current surplus energy conditions on the two main Yukon systems, energy output is only addressed in this section with respect to Aishihik, which has been moderately affected by recent changes to the Water Licence under which it operates.

Table 3.3:
Yukon Energy Generation Inventory

Location	*Unit No.*	*Type*	*Manufacturer*	*Mover Model*	*Name Plate Capacity*	*MCR Rating (kW)*	*In-Service Date*	*Planned Retirement Date*
Aishihik						30,000		
	AH1	hydro	Dom Eng.	Francis	15,600	15,000	1975	none
	AH2	hydro	Dom Eng.	Francis	15,600	15,000	1975	none
Faro						5,300		
	FD3	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	FD5	diesel	Caterpillar	3516	1,400	1,300	1990	2020
	FD7	diesel	Caterpillar	3612	3,000	3,000	1992	2027
Dawson						5,000		
	DD1	diesel	Caterpillar	3512	800	800	1988	2018
	DD2	diesel	Caterpillar	3516	1,000	1,000	1987	2017
	DD3	diesel	Caterpillar	3516 TA	1,000	1,000	1990	2020
	DD4	diesel	Caterpillar	D399	700	700	1975	2005
	DD5	diesel	Caterpillar	3606	1,500	1,500	1996	2031
Mayo						7,400		
	MD1	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	MD2	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	MH1	hydro	Dom Eng.	Francis	2,620	2,600	1957	none
	MH2	hydro	Dom Eng.	Francis	2,840	2,800	1951	none
Whitehorse						62,400		
	WH1	hydro	K.M.W.	Kaplan	5,800	5,800	1958	none
	WH2	hydro	K.M.W.	Kaplan	5,800	5,800	1958	none
	WH3	hydro	C.A.C.	Propeller	8,400	8,400	1969	none
	WH4	hydro	Dom Eng.	Propeller	20,000	20,000	1984	none
	WD1	diesel	Mirrlees	KV12	3,920	3,000	1968	2011
	WD2	diesel	Mirrlees	KV16	5,150	4,200	1968	2009
	WD3	diesel	Mirrlees	KV16	5,150	4,200	1970	2007
	WD4	diesel	EMD	20C	2,500	2,500	1975	2025
	WD5	diesel	EMD	20C	2,500	2,500	1975	2025
	WD6	diesel	EMD	20C	2,700	2,700	1990	2025
	WD7	diesel	Caterpillar	3612	3,300	3,300	1991	2026
Haeckel Hill						810		
	WW1	wind	Bonus	MARK III		150	1993	2013
	WW2	wind	Vestas			660	2000	2020
Mobile Diesels						1,450		
	YM1	diesel	Caterpillar	3516	1,400	1,300	1990	2015
	YM2	diesel	J Deere		150	150	1999	2024
Total Capacity						**112,360**		

3.2.1 Whitehorse Rapids Hydro Firm Capacity

The largest generating station in Yukon is the Whitehorse Rapids hydro plant. The output of the plant at full river flow conditions in summer is 40 MW, or slightly above. However, during low flow (i.e., drought) winter periods, the plant's firm output that can be relied upon is well below this level.

Whitehorse hydro is supplied by the flows of the Yukon River. The plant is largely "run-of-the-river", but there is some modest flow control via a control structure at the outlet of Marsh Lake (the Lewes Dam). By managing the flow out of Marsh Lake in accordance with licence conditions, Yukon Energy can help sustain Yukon River flows into the winter periods when system load requirements are highest. Absent this control, the plant would have very low firm winter output. Although YEC has a modest level of flow control on the river, there is very limited ability during winter to use the Whitehorse Rapids plant for "load factoring" where the plant output might be materially varied on (say) a daily basis. In summary, "load factoring" types of fluctuation in downstream flows at this plant during winter conditions can cause ice break-up and ice jamming, and consequently flood low-lying areas of Whitehorse, as was reviewed in detail by the YUB at the 1992 Resource Plan hearing.

The Whitehorse Rapids reliable firm capacity rating during low winter flows was reviewed in 1992 and in follow-up at the 1993/94 GRA (as set out in Chapter 2). In short, at that time Yukon Energy and YECL provided evidence that during drought years, a managed drawdown of Marsh Lake over six months can provide 19 MW of consistent firm capacity under the lowest flows on record. However, Yukon Energy also indicated that in 80% of the years (i.e., non-drought years), the plant could reliably provide 24 MW or more during winter. In 1992, the Companies indicated that in drought years, if 24 MW of plant capacity was required, up to 5 MW of diesel may be able to be temporarily leased for the winter to maintain a 24 MW reliable level of capability at this plant (over and above the capability provided by the plant's existing diesel units). As a result, since that time the hydro units at this plant have been assigned a winter reliable capacity rating of 24 MW.

Yukon Energy has continued to refine its operation of the Whitehorse Rapids hydro plant, particularly in the period since the closure of the Faro mine. Based on these more recent reviews, Yukon Energy can now confirm that the drought-year capability of the Whitehorse Rapids plant is 24 MW under current load conditions. This is achieved largely by being able to maximize Marsh Lake outflows, starting November, at a stable level for the four coldest winter months, and at licenced minimum flows for the remaining two winter months (when capacity is less of a concern on the WAF system). In addition, Yukon Energy can manage Schwatka Lake levels to a small degree on a daily basis, drawing down the lake by about six inches during the day and allowing it to refill at night.

Consequently, Yukon Energy continues to use 24 MW as the firm capacity of the Whitehorse Rapids plant. Moreover, this full level is now achieved without the earlier concept of resorting to short-term leased diesel units during drought conditions.

3.2.2 Aishihik Hydro Capacity and Energy

Unlike Whitehorse Rapids, Aishihik hydro capacity output is not limited by water storage or droughts. This is because the multi-year Aishihik reservoir is large and quite flexible (with a seven foot restricted operating range under the renewed licence), and can be dispatched largely as needed by Yukon Energy to meet peak loads. For this reason, Aishihik's output can vary substantially during the day in winter as loads change (compared to Whitehorse hydro, which is a very stable daily output). Aishihik's output also varies materially on a seasonal basis, as summer use is minimized to allow the lake to re-fill for the coming winter.

The maximum capacity output of Aishihik hydro is 30 MW today, based on 2 – 15 MW units. For the reasons noted, this capability is available on a firm basis during winter low flow conditions.

Recent rewinds performed on AH1 indicate a potential to increase the rating on the units to 15.4 MW. However, rewind work has not yet been performed on AH2 (scheduled for 2006) and until this is completed and consequent coordinated testing done on the units, YEC will not be able to confirm the slight increase in capacity ratings. Future potential also exists to re-runner the Aishihik units to theoretically increase the mechanical capacity output by as much as 20%; however this initial indication requires significant further work to confirm that the electrical system and various physical components (such as wicket gates and turbine bearings) can handle the increase in output. This preliminary assessment work is ongoing.

In terms of annual energy capability, due to the multi-year characteristics of the Aishihik plant and how it is used, the long-term annual energy output of Aishihik is dependent upon a combination of (a) long term average flow conditions, (b) load requirements on WAF, and (c) the constraints relating to the facility's capacity and its water licence terms and conditions. For the purposes of this Resource Plan, Yukon Energy has retained the Aishihik long-term average output at 105 GW.h/year consistent with previous plans. As noted below, this capability is expected to increase slightly should sufficient major new industrial loads be placed on the system; however, under such increased load conditions, Aishihik's energy long term average capability is currently estimated to be about 3 GW.h/year lower than it would have been had the previous licence conditions (nine foot unrestricted operating range) been maintained.

- **Current WAF Load Conditions:** At present, given surplus hydro energy on WAF due to current load conditions, Aishihik Lake is being maintained in a substantially full condition near the top end of its licence limits, so any major increase in need to drawdown the lake (such as for major new loads) will allow high output for some time before the stored energy is

consumed (similarly, drought conditions at Aishihik today can be addressed by a period of drawdown to maintain long-term average generation levels despite low inflows). Under these conditions, the earlier long-term average energy capability does not appear to be materially affected by the new Water Licence terms and conditions.

- **Major Industrial Load Additions:** At such time as sufficient large new industrial load develops on WAF, similar to the Faro Mine loads in the past (or greater), it is to be expected that Aishihik Lake would tend over a few years to be drawn-down to within the mid-range of its licenced operating range. After such drawdown, Aishihik's long-term average annual energy output is expected to increase slightly above 105 GW.h/year and to reflect licence conditions. In the event that sufficiently higher WAF industrial loads occur, this long-term average energy capability is expected to be somewhat further increased, but also to be as much as 3 GW.h per year lower under the current seven foot restricted operating range than would be expected under the nine foot unrestricted operating range of the reservoir with the previous Water Licence.

3.2.3 Mayo Hydro Capacity

The capacity of the Mayo hydro plant has traditionally been listed as 5 MW based on 2-2.5 MW turbines. However, there has not been sufficient load on this system for many years to make use of this full capacity.

Due to the age of the units, in the last few years Yukon Energy has re-runnered and rewound the units which has enabled an increase in individual unit performance (now rated at 2.6 and 2.8 MW respectively). For planning purposes, Yukon Energy has assumed the combined 5.4 MW can be generated at the plant. It is important to note, however, that there is not sufficient load today to bring both units simultaneously up to full load to determine whether the full 5.4 MW can be achieved. This testing cannot occur until further load growth occurs on the Mayo-Dawson system. The increase in capacity is also forecast to increase the long-term average energy from 40 to 42 GW.h/yr.

3.2.4 Whitehorse Diesel Capacity

As noted in Section 3.1, there are immediate issues with respect to determining the future of the Whitehorse diesel plant in light of requirements to either retire or invest substantially in the Mirrlees diesel units WD1, WD2, and WD3.

In the interim, the three units are not in a condition that can sustain a Maximum Continuous Rating ("MCR") for planning purposes to the full nameplate ratings of these units. As a result, Yukon Energy has based its near-term planning on a "de-rated" MCR for these units of 4.2 MW (WD 2 and WD3, nameplate ratings of 5.15 MW) and 3.0 MW (WD1, nameplate rating of 3.92 MW).

Should some form of life extension project be undertaken on these units, that project would need to re-assess the ability to bring these units back up to the full nameplate MCR.

3.2.5 Fish Lake Hydro (YECL) Capacity

YECL maintains a small two unit hydro facility on the WAF system called Fish Lake, rated at 1.3 MW. Fish Lake hydro is neither dispatched nor monitored by Yukon Energy, and cannot be readily adjusted to match load conditions on a daily basis.

Fish Lake has traditionally been included in the Yukon planning process as firm capacity on the WAF system, at 1 MW. However, recent reports on the output of Fish Lake indicate winter flows cannot be relied upon to sustain outputs higher than about 400 kW, as was the case through the monthly averages during the winter of 2003/04 (December of that year dropped to a monthly average output of 389 kW), with many recent winters not recording average monthly outputs above about 600-700 kW.

Consistent with normal system planning practice of recognizing winter constraints, as is done for Yukon Energy's assets, the YECL Fish Lake facility are considered in this Resource Plan to be reliable firm winter capacity at a maximum of 400 kW.

3.3 CAPACITY PLANNING CRITERIA REVIEW

The Yukon system capacity planning criteria are the sets of rules used by YEC to determine how much firm generation capacity is required on the various Yukon systems and when additions to generation capacity are required. Criteria are applied separately for each power system in Yukon, e.g., the WAF system versus each isolated diesel system.

Changes to the Yukon systems since 1992, as well as the pending retirement of the three Mirrlees diesel units at Whitehorse, prompted a re-examination of the capacity planning criteria, focused particularly on WAF. As a result of this re-examination, Yukon Energy has adopted new capacity planning criteria.

Adequate firm generation capacity is one component of providing reliable power. Overall reliability of each BES system (generation and transmission) requires:

a) that there is adequate firm generation (and transmission) capacity installed on the system;
b) that the installed system be properly protected;
c) that the installed system be properly maintained (including brushing of transmission lines); and,
d) that the installed system is operated and dispatched in accordance with sound operating criteria.

In addition, the reliability of service to customers served on the distribution system will also include various factors relating to the reliability of that lower voltage system as well.

Standard utility reliability tests are intended to cover all of the recognized factors affecting system generation supply reliability including load factor growth both on a system and on each feeder, maintenance of equipment, regular and routine servicing and repair, assessing remaining life, planning for end of life replacement, removal of danger tress, and a range of other specific factors that affect reliability.

Capacity criteria in regards to long-term BES resource planning deals only with the first item in the above list of factors affecting BES system reliability; namely, that there be adequate firm generation and transmission capacity installed on each system.

In assessing capacity planning, it is recognized that Yukon Energy policy first interrupts secondary energy service that is to be supplied by surplus hydro resources, and that no BES capability is planned to supply secondary energy service. All remaining “firm” customer load requirements at the time of system maximum load or peak (e.g., winter peak on WAF) are considered when assessing each system’s capacity planning requirements.

3.3.1 Background and Overview on the Evolution of Capacity Planning

Planning of a utility system must provide both for system growth and for operation after a component failure. Systems vary greatly in size and complexity but the ability of each system to maintain service is compared by using established and recognized criteria.

In general, throughout various systems these planning criteria have evolved gradually into more defined ratios as systems have grown bigger and more complicated. Where relevant, transmission reliability has also been addressed where it directly affects generation reliability.

The criteria used by NCPC were developed to indicate the required amount of firm generating capacity to cover relatively small isolated systems, and were consistent with utility planning standards of that era. NCPC had started with a multiple of small isolated systems, some of which continue, but others had grown to the point where multiple sources were interconnected.

Yukon Energy (and its then manager, YECL), as the operator succeeding NCPC for the Yukon, initially followed the practice of NCPC. It was quickly found that the continuing small isolated installations were reasonably covered by the NCPC criteria but that the larger systems with multiple sources needed more detailed analysis to be secure:

- The small systems were considered to be adequately protected if the generating capacity with the largest single unit out of service was at least 110% of the anticipated peak load. This approach is continued today.
- For the larger "grid" systems, it becomes necessary to consider not only the possible loss of a single generator (in the case of WAF, a single "wheel" at Aishihik), but also the likelihood that at least one of the major WAF diesels would be unavailable at the same time. Consequently, the Resource Plan in 1992 introduced recognition of the diesel-related effect on Yukon Energy's ability to serve any particular WAF load by adding a "10% of installed diesel" reserve on top of the Aishihik hydro reserve.

Under the NCPC capacity planning criteria and the 1992 Resource Plan criteria, the transmission system availability was not considered at all.

In the meantime, other integrated utilities developed a statistical approach to the potential interruption of service for any customer. This is often evaluated as the Loss of Load Expectation ("LOLE") and it is measured in hours per year[2]. Most of the various Canadian utilities have come to apply an LOLE range from one to two hours per year as their capacity planning standards. Where relevant, certain utilities have incorporated transmission into this assessment where generation reliability is directly and materially affected by transmission. Specific recent experience with Northwest Territories Power Corporation has

[2] Other terms are also used to describe the probabilistic measures, such as the BC Hydro criteria of Loss of Load Probability ("LOLP") or Newfoundland and Labrador Hydro's Loss of Load Hours ("LOLH").

also applied, in parallel with LOLE criteria a second test to ensure that customers are protected against failure of any single system component.

Yukon Energy has recently examined the LOLE approach and tested it against the operating history of its WAF system. This review has shown that the WAF system has substantial hydro generation availability that is directly affected by certain transmission, and that the WAF system also has been trending to an increasing probability of longer outages as it expands (particularly with expansion of residential and commercial loads and major reductions in industrial load). Yukon Energy has therefore now incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages.

At the same time, Yukon Energy has recognized that the LOLE function is an average that does not indicate how long any particular outage will last, and that any extended outage on its grid systems during the winter peak could be very adverse and serious, particularly for affected residential and commercial customers. Yukon Energy has addressed this concern by considering in parallel with LOLE a second test as part of its planning criteria, namely the effect of the failure of any individual bulk electrical system component and the ability of the system to continue to serve its firm residential and commercial customers without the failed component (i.e., a test described as "surviving the first failure" or "operating in the N-1 condition where "N" is the normal system complement). As an example, the biggest loss of generation on WAF today at winter peak would be 30 MW following a failure of the Aishihik transmission line; this loss would be far greater than the loss during winter peak of the biggest generator (which currently is a 15 MW generator at Aishihik)[3].

The previous criteria, the recent review and the revised criteria now adopted by Yukon Energy are each reviewed in more detail below.

3.3.2 Yukon Energy's Previous Capacity Planning Criteria (prior to late 2005)

The Yukon systems were previously planned with criteria (as reviewed in 1992) using a single formula for specifying its required firm generation capacity on each type of system. This deterministic criteria was outlined in the 1992 Resource Plan.

[3] The largest single unit on the WAF system is WH4, one of the hydro units at Whitehorse. However, as Whitehorse has four hydro units (WH1 at 5.8 MW, WH2 at 5.8 MW, WH3 at 8.4 MW and WH4 at 20 MW), but only 24 MW of firm flows in winter in drought conditions, a loss of WH4 would only effectively reduce the available capacity by 4 MW (as the other three units would still be available), which is smaller than the loss of 15 MW via one of the units at Aishihik.

- For **Isolated Diesel Communities**, the criteria required each system to have installed generation capacity sufficient to meet 110% of the forecast peak load with the largest generation unit out of service.
- For the **WAF grid**, the required system generation capacity was determined as follows:
  1. The installed generation system, less a "Generation Reserve Requirement", must be able to meet the forecast WAF winter peak loads. For simplicity, this approach was used to define the Maximum Allowable Peak Load ("MAPL") for the WAF system at any time, i.e., the installed capacity at that time less the applicable Generation Reserve Requirement.

  2. The Generation Reserve Requirement was the reserve needed to meet forecast winter peak load with the loss of the single largest winter unit (one of the Aishihik units at 15 MW) plus the loss of 10% of the installed diesel capacity.

- For **individual communities on the WAF grid**, there was no generation capacity planning criteria in place. In practice, communities over about 300 people other than Faro and Whitehorse typically have local diesel generation installed to serve a dual purpose: overall grid support similar to major diesel installations at Whitehorse or Faro, as well as local supply during transmission outages. This applied at Ross River, Carmacks, Haines Junction, and Teslin, but has not been traditionally applied at Carcross. It was also not applied at smaller centres below 300 people.

  With respect to Faro, there has traditionally been a major diesel plant well in excess of the town requirements, but below the requirements of the Faro mine. Today, Faro maintains a diesel plant of 5.3 MW, which serves as a major diesel anchor point for the grid as well as for local supply in the case of transmission outages.

  For Whitehorse, there were no criteria regarding generation capacity requirements. In practice, however, Whitehorse has traditionally had sufficient generation (hydro plus diesel) installed in the local area to supply the community in the case of major transmission outages. This condition has now changed with recent growth in Whitehorse and the pending retirement of the Mirrlees units.

- For the **MD grid**, there was previously no approved capacity planning criteria. Previously, the Mayo system criteria had been based on supplying 110% of the peak load with the hydro

units out of service. The separate Dawson system had been planned as an isolated diesel community (prior to the Mayo Dawson transmission development).

For both of the grid systems, the generation assets were included in the past capacity planning criteria calculation, but transmission assets were not considered. As a result, the possibility of transmission failure was not accounted for.

The MD Transmission Line was brought into service in 2002 to use surplus hydro at Mayo to offset diesel generation in Dawson City. The Dawson diesel plant is still in service in Dawson as back-up capacity well in excess of the community's peak loads (it had been installed to meet the Isolated system standard). There are also two diesel units in Mayo that together approximate the local Mayo firm peak loads. Consequently, the WAF grid was the focus during the examination of the capacity planning criteria.

Table 3.4 depicts the generating complement and Maximum Peak Load under the previous planning criteria for WAF. The result is that a WAF load of 68.7 MW can be allowed under these criteria without exceeding the calculated capability of the current generating units in service.

Table 3.4:
Current WAF Generating Complement and
Maximum Allowable Peak Load (MAPL)
under Previous Planning Criteria

Unit	Rating (MW)
Whitehorse Hydro (winter - for all units)	24.0
Whitehorse diesel #1	3.0
Whitehorse diesel #2	4.2
Whitehorse diesel #3	4.2
Whitehorse diesel #4	2.5
Whitehorse diesel #5	2.5
Whitehorse diesel #6	2.7
Whitehorse diesel #7	3.3
Faro diesel #3	1.0
Faro diesel #5	1.3
Faro diesel #7	3.0
Aishihik #1	15.0
Aishihik #2	15.0
Carmacks diesel (YECL)	1.3
Haines Junction diesel (YECL)	1.3
Teslin diesel (YECL)	1.3
Ross River diesel (YECL)	1.0
Fish Lake hydro (2 units - YECL)	0.4
Total	87.0
Less: 15 MW hydro Reserve	-15.0
Less: 10% Diesel Reserve	-3.3
Maximum Allowable Peak Load (MAPL)	68.7

3.3.3 Previous Yukon Criteria Compared with Criteria for Other Jurisdictions

Yukon Energy's previous capacity criteria do not identify any specific BES system capacity requirement that can be readily compared with criteria adopted in other jurisdictions for integrated systems. This was because the previous Yukon criteria only dealt with the concept of a "reserve" rather than actually assessing the likelihood (or probability) that the generation available will be insufficient to supply the load at any given point in time, which has been adopted by the majority of Canadian utilities. The previous Yukon criteria are described as "deterministic" in that a set test is adopted for each system as a proxy

intended to ensure adequate capacity – however, to assess the adequacy of this proxy, it was necessary to compare Yukon's situation with criteria adopted in other jurisdictions.

Reliability experts were hired from the University of Saskatchewan in 2004 (under the direction of Dr. Roy Billinton) to study and determine the probabilities inherent in the existing Yukon capacity planning criteria. NWT Power Corporation has used Dr. Billinton as an advisor in the development of their Snare-Yellowknife system planning criteria, and received approval from its regulator for their revised criteria in November of 2004.

The review confirmed that a comparison of Yukon's previous criteria with criteria typically adopted by major Canadian utilities cannot be readily undertaken. However, in terms of the maximum peak load that can be supported, the review indicated that WAF generation was not adequate to supply the 68.7 MW peak (as would be allowed under the existing criteria (see Table 3.4)) within any reasonable reliability standard adopted elsewhere in Canada[4].

Generation Adequacy (capacity) criteria in Canada today are typically derived by looking at the probability of an outage occurring due to having inadequate generation installed. This "probabilistic" approach looks at the likelihood of different load levels over the year and the likelihood of this load not being met due to unplanned outages of generation units or (in some limited cases) transmission facilities. The resulting criteria are expressed for a system as LOLE (stated as average number of hours or days per year that the BES system would be inadequate due to unplanned events) and Loss of Energy Expectation (LOEE, stated in MWh/yr of energy desired by customers that would go unserved). The review indicated that criteria commonly used in the NWT and southern Canada are LOLE between about one and two hours per year. If applied to the Yukon system (including consideration of constraints posed by the reliability of the Aishihik transmission line), the review indicated that such standards would only allow a maximum peak on the current WAF system of about 60.1 MW to 62.9 MW (compared to 68.7 MW under the previous criteria).

The review also indicated several key findings with regard to the previous WAF criteria, as follows:

[4] The work by Drs. Billinton and Karki reflects an evaluation of the WAF system with some minor overall differences from the capacity values indicated in Table 3.4. For example, Drs. Billinton and Karki did not consider Fish Lake as a reliable supply resource (the load data available was net of Fish Lake outputs, so the resource was effectively already accounted for in the loads) and used a higher assumed Haines Junction diesel output of 1.7 MW. Subsequent investigations indicate this assumed capacity for Haines Junction was too high. The net result, however, of these variations is minimal on the overall conclusions of the report.

1. **The WAF Deterministic Criteria was adequate in 1996/97** – The previous WAF capacity criteria provided excellent capacity reliability for residential and commercial customers in 1996/97 when the Faro Mine was in operation, with an LOLE of 0.008 hrs/year (based on the Faro Mine being the first customer to be interrupted). The reliability for industrial customers was considerably less at that time at about 9.4 hours per year. However, even in the event of a major shortage of WAF generation, the mine would still have typically received substantial supply from the Faro diesel plant (13.6 MW at that time).

2. **The WAF Deterministic Criteria is not adequate today based on LOLE** – The previous WAF capacity criteria provide poor capacity reliability today with an LOLE of about 5.9 hrs/yr at the peak load level allowed by the past criteria. The LOLE is considerably higher than it was in 1996, and also well above the normal range of one to two hours per year adopted by other Canadian utilities. Since there are currently no major industrial customers on WAF, this assessment in effect addresses the current capacity reliability for residential and commercial customers on WAF.

3. **Aishihik transmission line is key capacity constraint** – The transmission line from Takhini to Aishihik (L171 line) accounts for about 80% of the total LOLE today for WAF, and is thus the key WAF capacity constraint. This transmission line connects 31.3 MW of capacity to the Whitehorse area (as well as loads at Haines Junction). Were it not for this exposure to transmission outages, the LOLE would drop from 5.9 to 1.2 hours per year. The effect of considering the transmission line reliability is a reduction of 8.0 MW of load carrying capability at the two hours per year LOLE level.

4. **Previous criteria not adequate to track impacts of WD retirements** – The previous capacity criteria did not keep pace from a reliability standpoint with the planned retirement of Whitehorse capacity (WD1, WD2 and WD3). This is because retirement of 4.2 MW of diesel units at Whitehorse only reduced the MAPL by 3.8 MW (due to the 10% diesel reserve). The recent review however indicated that load carrying capability at an LOLE of two hours per year reduced by at least 4.2 MW upon a retirement of a unit of this type (in some cases slightly more than 4.2 MW).

In addition to LOLE generation criteria, some utilities (including NWT Power Corporation for its Yellowknife grid) also adopt a further emergency standard to ensure each major BES system can meet its peak winter loads with loss of its largest single transmission component (called “N-1” criteria). The

previous Yukon criteria do not address the N-1 emergency criteria for systems such as WAF because the transmission facility loss was not considered in the capacity planning criteria. The overall result was to potentially expose Whitehorse area customers in particular to loss of adequate generation if the Aishihik line suffers a sustained failure at the time of system peak. In practice, this risk exposure was not material so long as there was adequate generation (including diesel units) in the Whitehorse area to reliably supply this area's loads; however, this situation is changing through growth in Whitehorse area loads and pending retirement of diesel units at the Whitehorse Rapids Diesel plant.

3.3.4 New Criteria Adopted by Yukon Energy

The new capacity planning criteria now adopted by Yukon Energy are as follows:

1. **WAF and MD System-wide capacity planning criteria:** Each system (WAF and MD) should not exceed a LOLE of two hours per year. The two hour measure is the same as that adopted in NWT and is comparable to the lower end of standards commonly used in southern Canada (which are typically from one to two hours per year LOLE).

   Although determining the LOLE requires sophisticated computer modelling, in practice the LOLE approach can generally be applied on WAF by benchmarking the two hours per year LOLE to a WAF overall "load carrying capability" of 62.9 MW. In rough terms, this load carrying capability changes by about 1 MW for every MW of non-Aishihik line generation that is added or retired (e.g., a retirement of 4 MW from the Whitehorse diesel plant will reduce this load carrying capability by about 4 MW, vice versa for additions). The benchmarking is also based on a rough assumption that the load carrying capability would be increased by about 8.0 MW if the current Aishihik transmission line constraint was removed. This could be done by twinning the line (i.e., creating a second line to allow access to Aishihik generation resources in the event of failure of the existing line).

   For MD, this criteria is well exceeded today. MD is well below two hours/year LOLE and also satisfies an N-1 condition in all locations.

2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Yukon's grids are small and isolated from major power grids, with single transmission lines connecting generation to load centres. Consequently, it was also determined to be appropriate to incorporate a standard to address the potential for sustained emergency conditions. In order to be able to address major emergencies, each system (WAF and MD) should be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single

contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source. For the case of the WAF system, the largest possible loss would currently be the Aishihik line, which connects 31.3 MW of capacity (30 MW from Aishihik, and 1.3 MW of Haines Junction diesel).

This N-1 criteria on WAF equates to a current load carrying capability (non-industrial) of 55.7 MW (excluding Haines Junction load, as it would not need to be served from the Whitehorse end of the Aishihik transmission line in the event that transmission line is out of service).

3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more should be considered as a preferred location for new diesel units if that community does not already have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

For isolated diesel communities no change has been adopted for the capacity planning criteria. Accordingly, the previous criteria is maintained for isolated diesel systems of being able to meet 110% of the community peak with the largest unit out of service.

3.3.5 Rationale for Adopting a Two-Part Criteria on WAF and MD

The two-part capacity planning criteria adopted by Yukon Energy for the WAF and MD systems is essentially the same as the capacity criteria approved by the regulator for the Yellowknife system[5]. This approach ensures that two different concerns are addressed on an ongoing basis.

The LOLE criteria provide an overall system measure that assesses the normal balance of the system including industrial loads, and the probabilities of experiencing outages due to having inadequate generation (and transmission) installed on the system. For Yukon, a standard approximately comparable to that used in Yellowknife (at about the lower end of planning standards used in southern jurisdictions in Canada), was viewed as reasonable. The LOLE standard in effect indicates the probability that the installed BES resources will be inadequate to supply the load for the total load on the system (including

[5] The only exception is that the Yellowknife N-1 criteria (called "minimum diesel") is slightly more stringent, in that 105% of the forecast winter peak loads must be carried under the N-1 condition, not simply 100% of the forecast peak as adopted by Yukon Energy.

industrial). In effect, it measures the balance between generation and loads (under normal probabilities of each system generating and key transmission units failing) and indicates how likely or unlikely it is that the balance will be unable to be maintained. This part of the criteria ensures that system capacity is planned on an ongoing basis to meet standards adopted and approved for other similar utilities in Canada.

However, the severity of a potential outage for non-industrial customers is not accounted for in the LOLE model. For example, despite an LOLE of two hours per year, it is entirely possible to have sustained outages (due to generation and transmission inadequacy, primarily related to the Aishihik line which is the largest single system constraint) for much longer than this under extreme winter conditions.

An emergency criteria was determined to be a necessary complement, given the potential seriousness of a sustained outage of the critical component of the system in winter (e.g., the Yukon system peak occurs in the coldest months of winter, when there is the least amount of sunlight to effect repairs such as to transmission facilities). This is to address the "surviving the first failure" consideration noted above (the N-1 test). YEC is incorporating this second level of testing into its capacity planning along with the LOLE criteria already described. As an example, the current biggest single winter generator on the WAF system is a single Aishihik wheel at 15 MW but the current biggest single potential loss of supply would be 30 MW following a failure on the Aishihik transmission line[6].

The N-1 criteria will not be extended to major industrial customer loads who typically maintain sufficient on-site diesel for their own emergency purposes (these customers would be informed that they would not receive full supply should the Aishihik line be out-of-service during the coldest days of winter).

Yukon Energy considered the NWT approach of requiring the system to meet the N-1 condition to a full 105% of forecast peak loads (slightly more stringent than a strict N-1) as a "safety factor for load forecast error"[7]. Given a WAF peak in 2005 of about 55.4 MW (excluding Haines Junction, which is not part of the N-1 criteria as it is on the western end of the Aishihik transmission line), such a "reserve" on WAF would equate to 2.8 MW. As the load today on WAF is only forecast to grow by about 1 MW per year (about 1.85%) and diesel capacity can be added relatively quickly if new capacity is seen to be required from unusual load growth, such a reserve for load forecast error was not considered necessary.

[6] The WAF system would also lose access to the 1.3 MW of generation installed at Haines Junction, but would similarly lose the need to supply the Haines Junction load from remaining WAF capacity (Haines Junction would be supplied by its own diesels) so there would be no impact on WAF of this additional loss.
[7] NWT Public Utilities Board Decision 14-2004, page 25.

The N-1 criteria will effectively govern the need for WAF system capacity requirements in the near term. However, this may not always be the case. As an example, if the Aishihik line was to be twinned, the N-1 condition would then only exclude 15 MW (the second largest single contingency on the WAF system is a loss of one Aishihik turbine) and it is likely that the LOLE condition would then govern the need for WAF system capacity. In addition, the LOLE condition may drive the need for new generation in the event of large new industrial loads, although these loads will have no impact on the N-1 criteria. It is important to ensure that ongoing capacity planning therefore addresses both concerns identified in the adopted two-part criteria approach.

3.3.6 Implications of the Adopted Criteria

The net effect of the new criteria adopted by Yukon Energy is a 2005 WAF system condition that is basically at the limits for all retail/wholesale loads (with approximately 300 kW of surplus in 2005). In short, any further wholesale or retail growth on WAF will be required to be met with new generation, as well as all future WAF system diesel unit retirements (see *Table 3.5, WAF Peak and Capacity Surplus (Shortfall) as Whitehorse Diesels are Retired (MW)*).

New capacity requirements of 18.7 MW are forecast for WAF for 2012 based on the adopted N-1 criteria as compared with only 12.5 MW based on the adopted LOLE criteria of two hours per year. Consequently the N-1 criteria has governed assessment today of new WAF capacity requirements. In contrast, the previous WAF criteria would indicate that no new WAF capacity would be required until 2010, and by 2012 only 5.5 MW of new capacity would be needed. These forecasts are based on current estimates of system load growth, excluding new industrial loads.

In contrast, MD generation under the new criteria adopted by Yukon Energy is well in excess of required levels in the absence of new major industrial loads. The same criteria can be applied to the MD system as capacity constraints arise on that system. However, at this point in time it is clear that MD is well below two hours per year LOLE and satisfies an N-1 condition in all locations.

Table 3.5:
WAF Peak and Capacity Surplus (Shortfall)
as Whitehorse Diesels are Retired (MW)

		Previous Criteria			LOLE Criteria			N- 1 Criteria		
Year	**Retirements**	**Peak (WAF wide, including loads served by Fish Lake)**	**Load Carrying Capability**	***Surplus / (shortfall)***	**Peak (WAF wide, including loads served by Fish Lake)**	**Load Carrying Capability 2 hours / year LOLE**	***Surplus / (shortfall)***	**Peak excluding Haines Junction (assumed to be 1 MW)**	**N – 1 criteria load carrying capability**	***Surplus / (shortfall)***
2005		56.4	68.7	*12.3*	56.4	62.9	*6.5*	55.4	55.7	*0.3*
2006		57.4	68.7	*11.3*	57.4	62.9	*5.5*	56.4	55.7	*(0.7)*
2007	WD3	58.5	64.9	*6.4*	58.5	58.7	*0.2*	57.5	51.5	*(6.0)*
2008		59.6	64.9	*5.4*	59.6	58.7	*(0.9)*	58.6	51.5	*(7.1)*
2009	WD2	60.6	61.1	*0.5*	60.6	54.5	*(6.1)*	59.6	47.3	*(12.3)*
2010		61.7	61.1	*(0.6)*	61.7	54.5	*(7.2)*	60.7	47.3	*(13.4)*
2011	WD1	62.9	58.4	*(4.4)*	62.9	51.5	*(11.4)*	61.9	44.3	*(17.6)*
2012		64.0	58.4	*(5.5)*	64.0	51.5	*(12.5)*	63.0	44.3	*(18.7)*

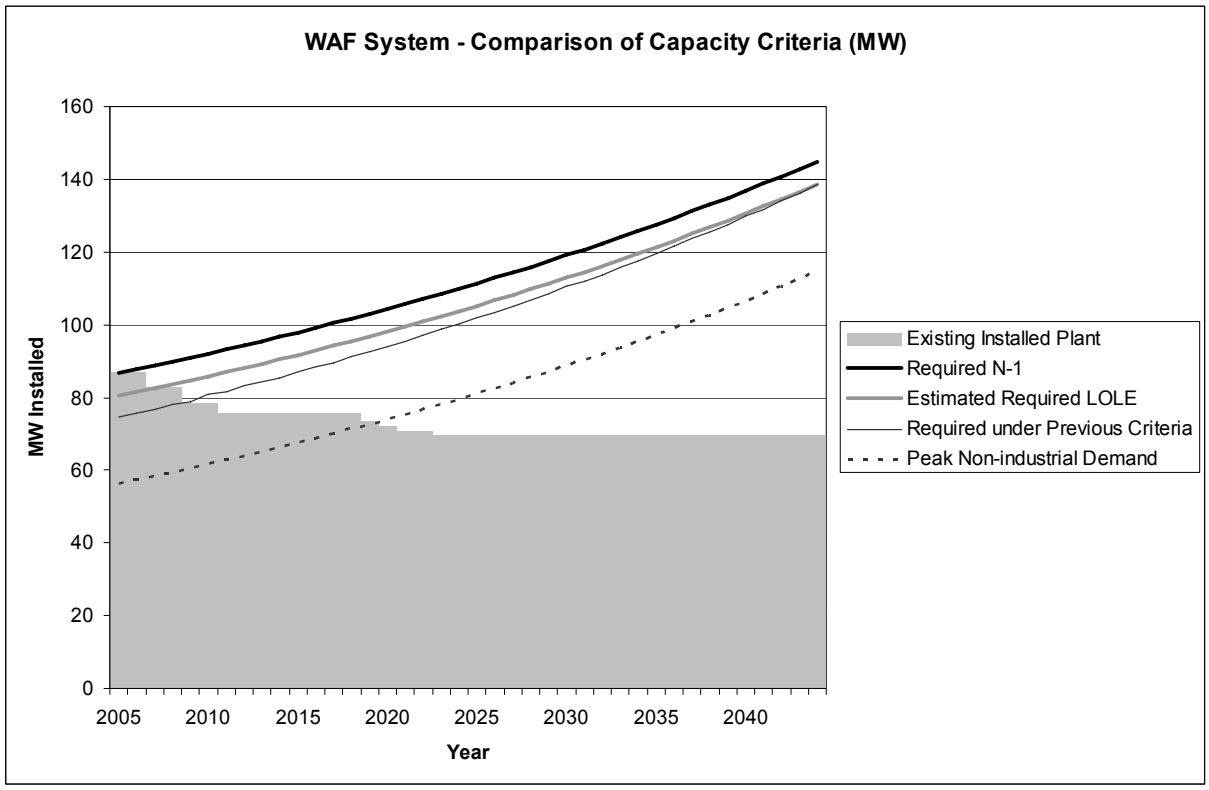
As long as the WAF system with the current Aishihik line (i.e., no twinning of this line) can meet the wholesale/retail peak under the N-1 criteria, up to 6-7 MW of major industrial loads can be served without driving new generation investment for capacity reasons.

Adoption of the revised planning criteria was required to plan and develop infrastructure in Yukon. The new criteria indicate a need to have WAF generation additions occurring in the next 12-24 months. This may drive a requirement for capital investment in excess of $3 million in the near-term.

Figure 3.1 WAF System – Comparison of Capacity Criteria depicts Yukon Energy's need for new capacity through to 2045 under the N-1, LOLE, and previous criteria. Forecast WAF peak load (non-industrial) is depicted by the dashed line. Required capacity is shown based on the forecast peak load and the three different capacity planning criteria examined in Table 3.5 – this analysis assumes continuation of the current WAF systems without any new investment (such as twinning of the Aishihik line) to remove of the current Aishihik transmission line constraint. Forecast existing installed plant reflects retirement assumptions as noted in Figure 3.1. In effect, the analysis assumes that all new capacity requirements are met with diesel installed at Whitehorse.

Of note is that even under the existing capacity planning criteria, the planned retirement of the Mirrlees combined with expected load growth over the next five to six years will require new capacity to be installed on the WAF system. However, with adoption of the new criteria noted above, this requirement will lead to the need for new capacity to address all planned Mirrlees retirements plus basically all load growth from 2005 forward.

Figure 3.1:
WAF System – Comparison of Capacity Criteria



3.4 SUMMARY: REVISED CAPACITY PLANNING CRITERIA

The following revised capacity planning criteria have been adopted by Yukon Energy:

1. **WAF and MD System-wide capacity planning criteria:** Each system (WAF and MD) will be planned not to exceed a Loss of Load Expectation (or LOLE) of two hours per year.

2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each grid system (WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source.

3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already

have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

For isolated diesel communities no change has been adopted for the capacity planning criteria (which requires being able to meet 110% of the community peak with the largest unit out of service).

4.0 NEAR TERM REQUIREMENTS

"Near term" requirements address Yukon Energy generation and transmission commitments required before 2009 for major investments with anticipated costs of $3 million or more. Given the time needed for possible construction, the assessment examines possible in-service needs to meet loads out to 2012.

This chapter focuses on opportunities for enhancements to existing hydro stations as well as cost-effective resource supply alternatives capable of meeting the 15 to 27 MW of new capacity required within the defined near term period. The sections for this chapter are as follows:

- Section 4.1: Planning Approach and Timeline
- Section 4.2: Requirements
- Section 4.3: Options
- Section 4.4: Assessment
- Section 4.5: Proposed Actions

4.1 PLANNING APPROACH AND TIMELINE

Potential major investments in the near term for new generation or transmission relate to opportunities to enhance existing system assets, and to address WAF system capacity shortfalls. As reviewed in Section 4.2, the WAF shortfalls are forecast to be between 15 and 27 MW within the next five to six years. In contrast, with material surplus hydro generation on both the WAF and MD systems, there is no apparent near term requirement or opportunity for major new energy-related investments. There is a near term opportunity to extend the WAF grid to supply two possible new mines in the Carmacks to Pelly Crossing region using available surplus hydro generation (see *Section 4.2: Requirements*).

Near term opportunities in respect of existing hydro assets focus on both the Whitehorse and Aishihik generating stations. In each case, the projects have been reviewed over many years in different variations. These projects fit with similar initiatives in other jurisdictions such as BC Hydro's "Resource Smart" program focusing on means to provide additional energy or capacity "through physical or operational modifications to existing facilities", and similar Supply Side Enhancement programs at Manitoba Hydro.

In respect of capacity requirements, as reviewed below capacity shortfalls on WAF under the new capacity planning criteria begin to arise as soon as 2006, even before any Whitehorse diesel units are retired, and become sufficiently material in 2007 to require overall spending commitments exceeding the

$3 million level. Consequently, planning activities for the near term focus on supply options that are sufficiently well-defined to make commitments and begin the necessary licencing or construction activities by, at the latest, late 2006 to early 2007.

The planning approach for near term requirements follows the general planning approach set out in Chapter 1:

1. **System capability** (part of Section 4.2: Requirements) over the intended "near term" horizon (in this case, as explained above, to about 2012) is reviewed, particularly noting planned retirement of generating capacity.
2. **System capacity requirements** (part of Section 4.2: Requirements) are reviewed over the near term based on the new capacity planning criteria, focused on non-industrial load forecasts plus potential loads from reasonably well-defined industrial load options that might emerge in the near term; sensitivities are examined with regard to different possible load forecasts.
3. **Forecast New Facilities Requirements** (part of Section 4.2: Requirements) are reviewed over the near term based on system capacity requirements, opportunities to enhance existing hydro generation facilities and, in the event loads are sufficiently high, opportunities to displace diesel-based energy production.
4. **Resource Options** (Section 4.3: Options) are reviewed over the near term, focused on potential resources of sufficient definition, size and timing for in-service to meet the near term requirements for new facilities.
5. **Assessment of Resource Options** (Section 4.4: Assessment) are reviewed over the near term, focused on technical feasibility (including timing), cost efficiency, reliability, and risk (in particular, risks related to "markets" or future loads developing differently than indicated by forecasts today).

Key considerations with respect to system capability are reviewed in Chapter 3. Over the focused near term to about 2012, one key system capability issue relates in large part to the planned retirement of the three Mirrlees engines:

- **WD1:** A Mirrlees KV12, installed in 1968, currently rated at 3.0 MW MCR (nameplate 3.92 MW) with a planned retirement in 2011;
- **WD2:** A Mirrlees KV16 from 1968, currently rated at 4.2 MW MCR (nameplate 5.15 MW), with a planned retirement in 2009; and,
- **WD3:** A similar Mirrlees KV16 dating from 1970, currently rated at 4.2 MW MCR (nameplate 5.15 MW) with a planned retirement in 2007.

The three Mirrlees engines have been planned for retirement for many years, including as far back as the 1992 Resource Plan hearing (when they were planned to be retired in 1998, 1998 and 2000 respectively). By 1996, the planned retirement of these units had been extended by four years to reflect in part lower running hours during the 1993-1995 closure of the Faro mine, as well as maintaining their running hours at a very low level by maintaining the units at the bottom of the stacking order.

With the 1998 closure of the Faro mine, Yukon Energy was able to further extend the planned retirements to the current schedule (WD1 by 9 years, WD2 by 5 years and WD3 by 3 years) based on updated assessment of the relative condition of each unit, and continued minimal operation.

However, at the present time, it is clear that further delay of retirement of these units is not possible without material investment in major tear-down overhaul work. This is further confirmed by the BC Hydro Condition Assessment (see Section 2.1) which concluded that these units were at “end-of-life”. In addition, the Mirrlees are low-speed base load units (514 RPM) which are poorly suited to the current operating regime of stop-and-start operation. Finally, Yukon Energy and others who maintain Mirrlees engines of this vintage (including Northwest Territories Power Corporation) have substantial concern with the ongoing ability of the current owner of Mirrlees to provide ongoing parts and technical support.

Any further delay in planning for an orderly retirement or, if possible, major refurbishment of the Mirrlees units will in all likelihood substantially increase the risks of a major failure or inability of these units to supply reliable utility standard service when required.

4.2 REQUIREMENTS

Yukon requirements for new capacity or energy resources in the near term result from the combined effects of three factors within each system:

- forecast non-industrial load growth, particularly on WAF related most notably to growth in the Whitehorse area;
- potential opportunities to connect new major industrial mine loads, including via new transmission to supply potential mines in the Carmacks to Stewart Crossing area; and,
- changes in the capability of existing generation or transmission resources, including changes related to new capacity planning criteria and planned retirements.

As set out in detail in Section 4.3, there are only two material new near term resource supply opportunities and/or requirements on Yukon systems:

1. New firm WAF capacity required, due to WAF winter peak capacity exceeding the maximum loads allowed on the system under new capacity criteria (however, this system has no need for new firm energy capability due to ongoing surplus hydro energy generation of over 90 GW.h/yr, with about 21 GW.h/yr of this surplus being currently used to supply interruptible secondary sales).
2. Opportunities to enhance existing WAF hydro generating assets to increase energy and/or capacity outputs.

The MD system has surplus hydro energy generation of about 17 GW.h per year, and surplus winter peak capacity with existing hydro and diesel generation. Consequently, as reviewed in Section 3.3, the LOLE for the MD system is not likely to exceed 2.0 hrs per year for many years into the future, absent major new industrial loads on this system. The MD system also satisfies the N-1 capacity criteria at each end of the MD transmission line as well as at the community of Stewart Crossing.

With respect to WAF requirements, four near term load cases have been identified, and are set out in the following sections. Each section includes graphs depicting the capacity and energy requirements under each scenario as follows:

- **Forecast WAF generation capacity:** The MW capacity requirement at winter peak is indicated, showing separately the capacity to meet N-1 Requirement and the LOLE Requirement, as well as the projected winter peak generation load. The graphs also illustrate the capability to meet this requirement from existing capacity, net of scheduled retirements, and the forecast need for new required capacity. For the purposes of illustrating requirements, the new capacity is portrayed in these “requirements” graphs based on a consistent assumption that requirements will be met by new 4 MW diesel units.
- **Forecast WAF generation energy:** The MW.h per year from existing hydro and from diesel are indicated separately. The energy graphs also show any surplus supplied as Secondary interruptible energy up to the forecast maximum Secondary Load expected (maximum of 30 GW.h per year). The forecasts show the generation expected to occur, and therefore these graphs do not show the full surplus hydro energy generation capability (which in many cases materially exceeds forecast Secondary sales).

4.2.1 Basis for Non-Industrial Load Forecasts

Yukon Energy’s near term non-industrial load forecasts for WAF are shown in Table 4.1, and are reviewed in more detail below.

Table 4.1:
Near Term Non-Industrial Load Forecasts

Load Forecasts				
Population Increase	**Source**	**Increase in Use/Customer**	**Combined Percentage Increase**	**Sensitivity**
0.4%	Yukon Bureau of Statistics: Medium Growth Projection	0.5%	0.9%	Low
1.0%	City of Whitehorse Population Increase (4 year average)	0.5%	1.5%	Medium-Low
	Mid-point		1.85%	Medium
	Yukon Energy's 3-Year Average Recorded Increase in Consumption		2.2%	Medium-High
	Yukon Energy's Highest Annual Recorded Increase in Consumption		3.0%	High

Yukon Energy's long-term non-industrial load forecast is based on a review of sales over past periods (as far back as 1992 in some cases, but focused on the period since 1998 when the Faro mine last closed), readily available information on the Yukon economy and other relevant statistics, and in some cases review of load forecasting variables used by other Canadian utilities.

The Yukon landscape is such that forecasting long-term non-industrial loads with precision is considerably more difficult than in southern jurisdictions. Although electricity consumption in many cases follows trends typical of other places in Canada, the Yukon economy can be substantively impacted by single events that, in most cases, cannot be foreseen with any accuracy more than a very short period in advance of the event (this short period can be one to two years or less). Examples include the opening and closing of large resource projects, such as mines, and major changes to Government of Canada funding to the Yukon Government.

Since the 1992 Resource Plan, the most material change in the Yukon electricity load forecast landscape has been the closure of the Faro mine (previously 40% of Yukon's load). Not only did the closure reduce industrial loads by nearly 200 GW.h a year, but it also dramatically reduced the loads in communities local to the mine (such as Faro, which reduced from an average residential customer count of 478 in 1996 to an average of 189 in 2001) and also major centers such as Whitehorse (Yukon Energy wholesales to YECL declined from 232 GW.h in 1996 to 217 GW.h in 2001).

The 1998 Faro mine closure impacts appear to have been largely incorporated into the Yukon economy and population by 2001. During this 1998-2001 period, out-migration of about 10% of the Yukon's population occurred (over 3,000 people).

Since 2001, the Yukon's economy and electricity loads have begun to develop a more normalized pattern. This is most evident in YECL's native load (Yukon Energy's wholesales to YECL plus YECL's own WAF Fish Lake generation added back) which has been characterized by growth of about 2.2% per year (three year average from 2001-2004) with one year growth as high as 3% in 2004. As a normal level of growth in the major load centers in Yukon, this three year average growth rate is likely within a reasonable range of forecasts for the near term period in question. This reflects three factors:

1. **Population growth:** Population in the major load center of Whitehorse has been recently increasing by approximately 1% per year reflecting fertility and mortality rates, net in-migration to Yukon and net in-migration to Whitehorse from other places in Yukon (both of these net in-migration trends have been positive since 2001). From 2001 to 2004 the resulting Whitehorse growth rate was in excess of 1% per year. Growth in customer numbers is expected to be at about this same level if not slightly higher due to reduced average number of persons per household, reflecting normal Canadian trends.
2. **Use per residential customer:** Use per customer for residential customers is assumed to be increasing at about 0.5% per year. Changes in use per customer are typically small over time, with Canadian utilities typically forecasting similar uptrends over the next 20 years for non-heating loads. This uptrend reflects in part increased use of certain appliances (such as internet connected computers and other electronic devices) offset by modest efficiency improvements in certain appliance sectors (for example, fridges are now far more efficient than in past years, but the stock of fridges typically changes quite slowly so is only a modest incremental change each year).
3. **Use per commercial customer:** Use per customer for commercial customers is not expected to vary materially from trends seen for residential customers, although growth may be slightly higher reflecting the trend towards larger stores and facilities (such as the Argus properties).

Based on the above assessment, Yukon Energy has based long-term load forecasts on a **base case** of 1.5% (medium-low) to 2.2% (medium-high) growth per year with 1.85% growth per year as the mid-point. In order to ensure the impacts of potential extreme outcomes with respect to non-industrial loads are considered, load forecast uncertainty to a range of 3.0% annual growth (High Sensitivity) and 0.9%

annual growth (Low Sensitivity) have been considered where these extremes have the potential to materially change the recommendations for major new investments in power resources.

- The **high sensitivity** of 3.0% per year is based on the highest one year wholesale sales growth rate experienced by YEC (2004). This was a period of very high growth, but given that it is the very recent experience, it is necessary to consider the potential that this rate is representative of a major new evolution with respect to Yukon electrical load.
- The **low sensitivity** of 0.9% per year based on a very nominal growth which is the combination of strictly the growth in use per customer plus the Yukon Bureau of Statistics population forecast growth assuming no in-migration (0.4%). This is consistent with the Yukon experience of not having had any periods of sustained zero to negative growth in the non-industrial system (and reflecting the fact that today's loads are not predicated on any downside risks related to underlying industrial projects, as no major industrial customers are currently receiving service in Yukon).

4.2.2 Basis for Near Term Industrial Load Forecasts

In order to address the current expectation that two new industrial loads may proceed in the area north of Carmacks, two industrial load cases have been included in the near term analysis (a range of other still more optimistic industrial development scenarios are examined separately in Chapter 5):

1. **No new industrial load**, and
2. **Industrial loads consistent with Minto and Carmacks Copper both being developed in the near term,** or about 9-11 MW of new load (2-4 MW for Minto plus 7 MW for Carmacks Copper) and 64 GW.h of annual energy. These mine projects are not expected to be long-lived, at 12 years for Minto starting 2007 and 8.5 years for Carmacks Copper starting 2008 (although these starting dates may be delayed by other processes and development timelines).

4.2.3 Near Term WAF Load – Cases Analyzed Based on Non-Industrial and Industrial Requirements

Based on the above near term non-industrial and industrial load forecasts, four near term WAF load cases have been considered:

1. **Base Case:** The Base Case near term assumptions are based on non-industrial loads at the mid-point base case level (1.85% per year) and no new industrial loads.
2. **Low Sensitivity Case:** This case maintains non-industrial loads at the low sensitivity level (0.9% growth) and no new industrial loads.

3. **Base Case including Mines:** This case combines the Base Case assumption for non-industrial (1.85% growth) plus near term development of the Minto and Carmacks Copper loads at a combined 9 MW.
4. **High Sensitivity Case, including Mines:** As the largest near term growth scenario, this case combines the high sensitivity non-industrial load growth (3.0%) with near term development of the Minto and Carmacks Copper loads.

4.2.4 Base Case Requirements

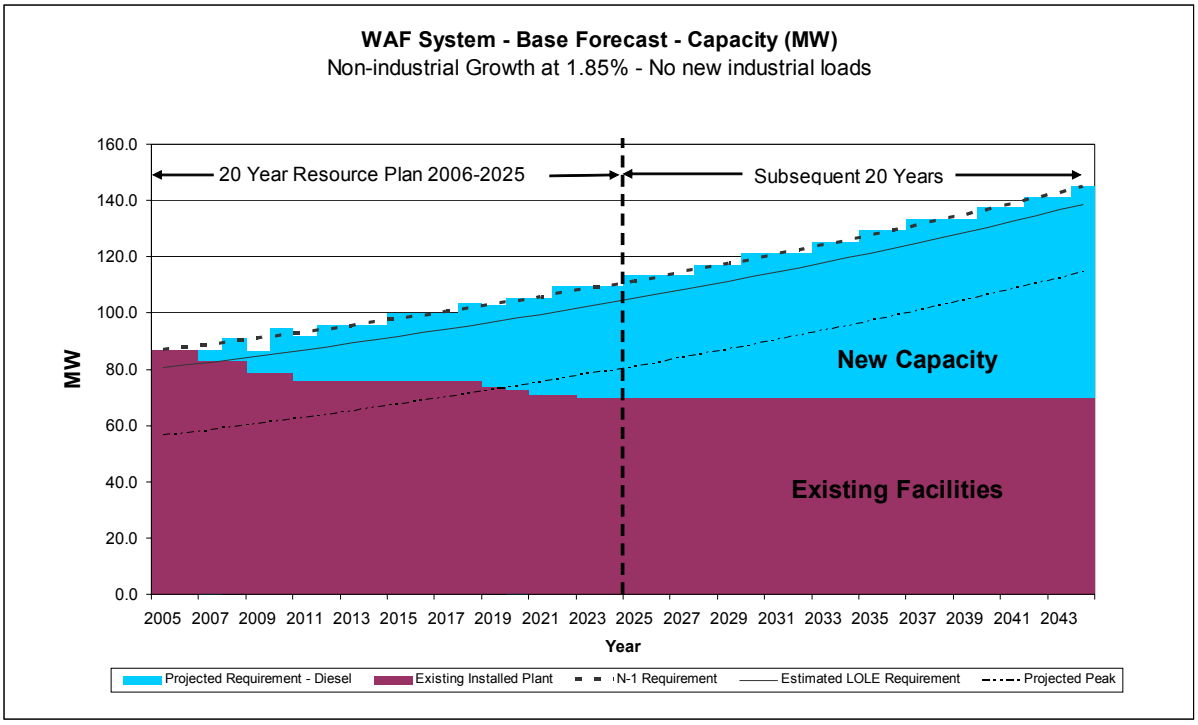
Under the Base Case, forecast loads exclude any major industrial customers. Non-industrial load growth is projected at 1.85% per year.

Capacity: Under the Base Case, there is a 0.7 MW capacity shortfall forecast for 2006, increasing to 18.7 MW by 2012 assuming that all three Mirrlees units (11.4 MW) have been retired by that time[1].

Figure 4.1 provides a 40 year horizon (20 years of Resource Plan plus the 20 subsequent years) and indicates the capability of the existing facilities with planned retirements as well as the requirement for new facilities to meet the proposed new planning criteria (LOLE and N-1, indicated by solid and dotted lines respectively). In this figure, five new 4 MW diesel generation units (or equivalent 20 MW) are assumed to be installed to meet the capacity shortfalls to 2012.

[1] Note that under the previous capacity criteria, the capacity shortfall in 2012 is 5.5 MW as noted in Section 3.3, and is entirely driven by the retirement of the 11.4 MW of current Mirrlees capacity.

Figure 4.1:
WAF Base Case Capacity Requirements

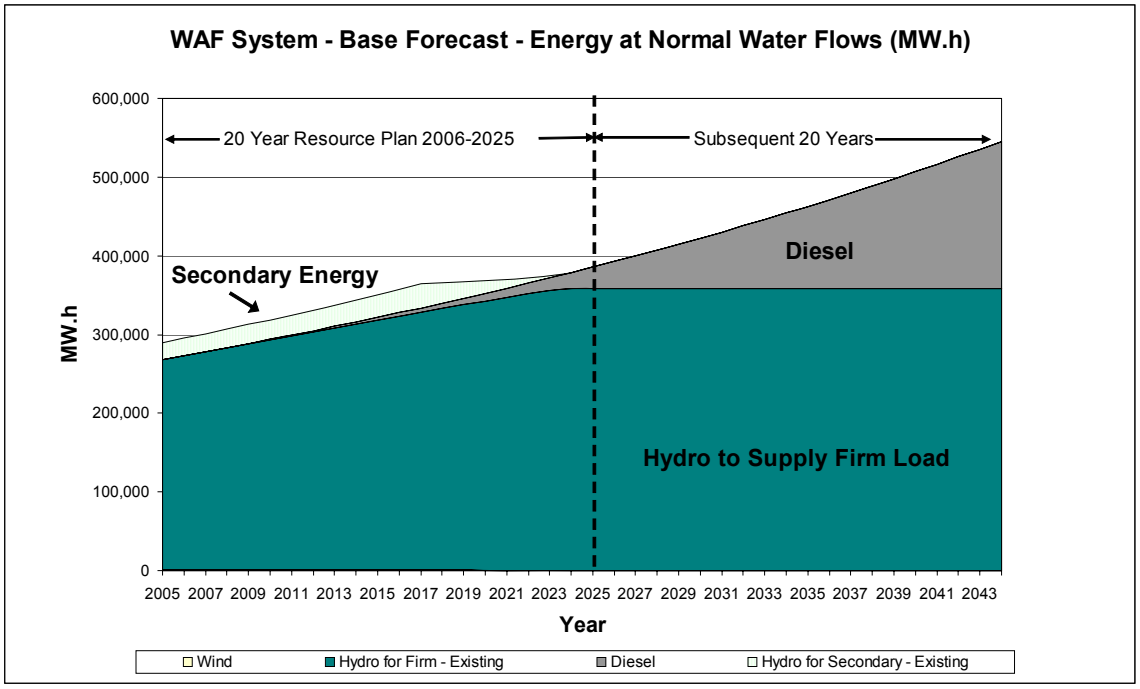


Energy: The Base Case analysis as reviewed in Figure 4.2 indicates that diesel generation is not required to supply sustained loads (e.g., loads in excess of average annual hydro energy generation) until at earliest the end of the 20 year forecast planning period. Some diesel generation is required for peaking purposes (i.e., brief time periods during the winter peak months), but these peaking diesel generation requirements remain below 10 GW.h per year until after 2020 (i.e., near the end of the 20-year planning period), increasing to about 28 GW.h/year in 2025. Figure 4.2 also indicates the potential energy available for supplying secondary power up to the expected maximum annual program subscription of 30 GW.h/year[2].

In summary, there is no opportunity under the Base Case near term forecast to develop new non-diesel generation to displace diesel fuel until near the end of the 20 year planning horizon.

[2] The analysis does not attempt to determine the secondary energy demanded that would go unserved due to short-term winter interruptions during periods of peaking diesel, i.e., the analysis determines only the annual impacts on energy available to service secondary loads. In reality, actual secondary sales would experience greater short term interruption as load growth increases the periods of peaking diesel operation during each year.

Figure 4.2:
WAF Base Case System Energy Requirements

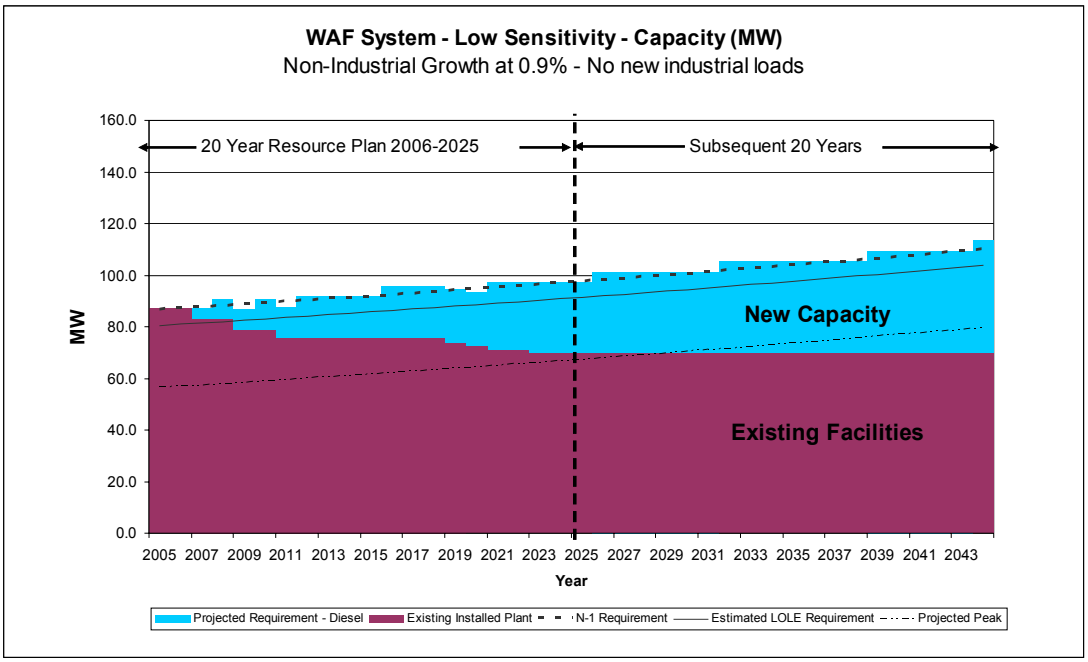


4.2.5 Low Sensitivity Case

The Low Sensitivity Case is based on non-industrial load growing at 0.9%/year and no new industrial loads.

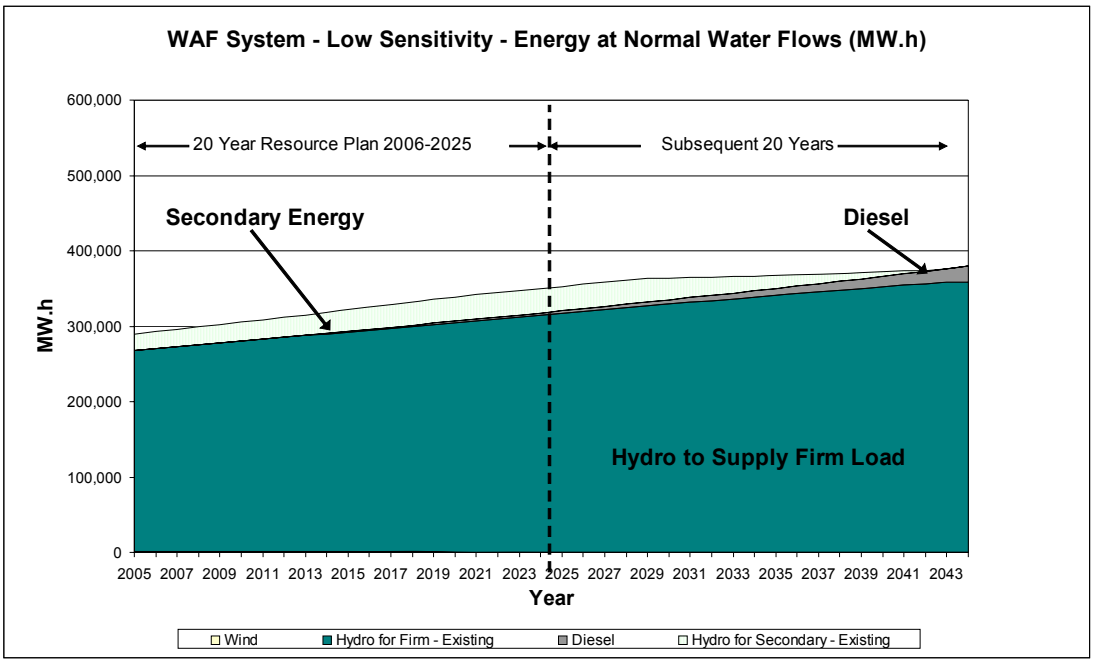
Capacity: Under this case, as reviewed in Figure 4.3, capacity shortfalls occur in 2006 of 0.2 MW with growing requirements thereafter driven primarily by retirement of diesel units (11.4 MW of retirements by 2011). The Low Sensitivity Case forecast indicates 14.7 MW of capacity shortfall by 2012. Figure 4.3 identifies a requirement by 2012 of four new 4 MW diesel units (16 MW).

Figure 4.3:
WAF Low Sensitivity Case Capacity Requirements



Energy: Under the Low Sensitivity Case (see Figure 4.4), as with the Base Case, there is no requirement for material diesel generation in the 20 year planning horizon.

Figure 4.4:
WAF Low Sensitivity Energy Requirements

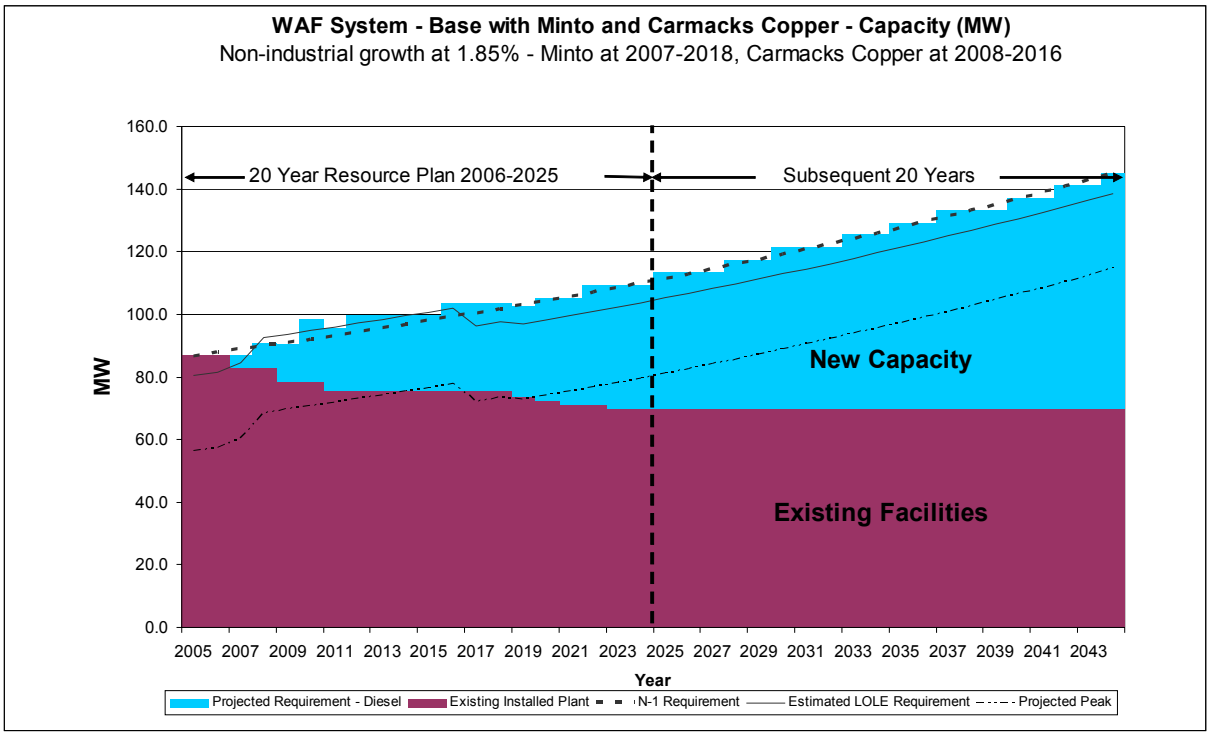


4.2.6 Base Case with Mine Loads

The Base Case with Minto and Carmacks Copper Mine loads includes the same non-industrial load growth of 1.85% from the Base Case, plus an assumed near term connection of the Minto and Carmacks Copper new mine loads to the WAF grid. This case presumes near term development of new transmission from Carmacks to at least about Pelly Crossing with spurs to connect these two new mines.

Capacity: Under this case, capacity shortfalls of 0.7 MW arise in 2006, growing to 21.5 MW by 2012 (in this case driven by the LOLE criteria instead of the N-1 criteria which drove capacity shortfalls for the Base and Low sensitivity cases)[3]. The capacity shortfall is illustrated in Figure 4.5 below as six new 4 MW diesel units (24 MW) assumed by 2012.

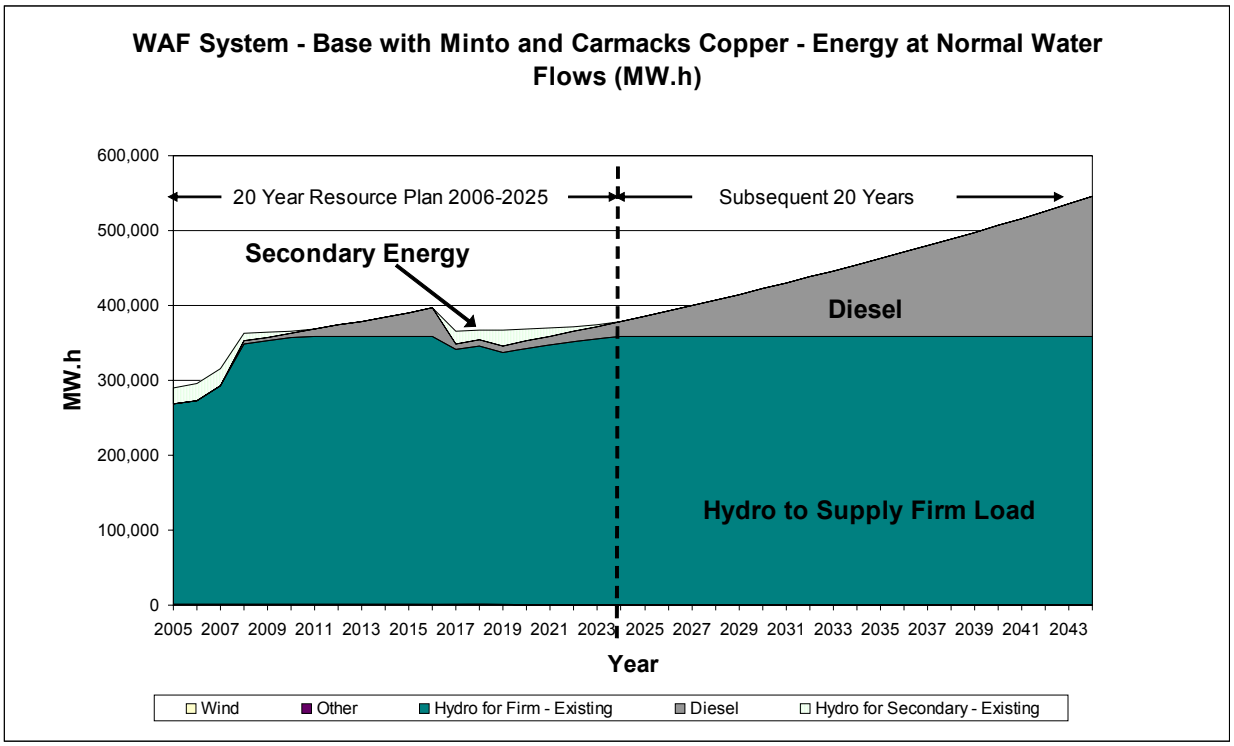
Figure 4.5:
WAF Base Case with Mine Capacity Requirements



[3] The combined mine loads in this scenario total 9 MW. Mine loads do not contribute towards peak loads for N-1 calculations but do contribute for LOLE (see Section 3.3). Under Base Case load scenarios, N-1 is requiring additions of capacity approximately 6.2 MW ahead of LOLE requirements. For this reason, the first 6.2 MW of industrial load do not drive any additional capacity requirements over and above the basic base load requirements. The result in this case with the added 9 MW of industrial load is an increase in capacity required compared to the Base Case (in order to serve the two mines) of only 2.8 MW (9 MW total load less 6.2 MW that can be served without additional capacity).

Energy: Under this scenario, as reviewed in Figure 4.6, the incremental mine load consumes largely hydro energy that would otherwise be surplus under the Base Case. However, with ongoing non-industrial load growth during the life of the mines, the WAF system begins to utilize diesel of up to about 40 GW.h per year for modest base load generation (reflects WAF system hydro capability of about 358 GW.h in a normal water year, with system energy requirements approaching 400 GW.h in about 2016 at the highest levels before mine closure). After the mine closures as assumed in this case, however, there would be a period of about seven years when excess hydro would return to the WAF system (along with the opportunity to make secondary sales) before normal non-industrial load growth would eliminate the hydro surplus (in 2024) and begin to drive new base load diesel requirements (beyond the current 20 year Resource Planning horizon). Although this load pattern may give rise to the opportunity to consider very small hydro or other low variable cost generation within the 20 year horizon (perhaps up to a 2-3 MW), the scale of any such generation would not materially affect the large capacity requirements (21.5 MW) beginning in the very near term.

Figure 4.6:
WAF Base Case with Mine Energy Requirements

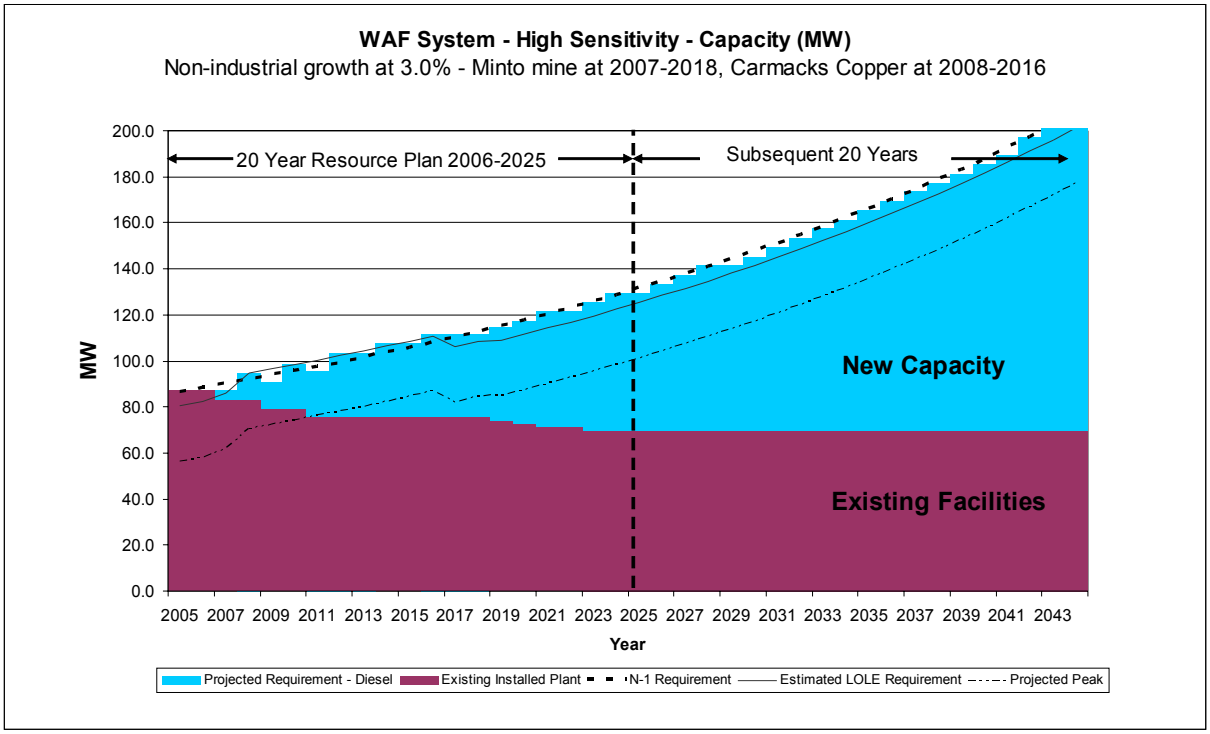


4.2.7 High Sensitivity Case Including Mines

In the High Sensitivity Case, the non-industrial load growth is forecast at 3.0% per year plus near term addition of the Minto and Carmacks Copper mine loads (which presumes near term development of new transmission from Carmacks to at least about Pelly Crossing with spurs to connect these two mines).

Capacity: Under this case, as reviewed in Figure 4.7, there would be material increases in the required installed capacity to meet the loads, assuming that the new capacity criteria are adopted. Capacity shortfalls in 2006 are at 1.4 MW, and by 2012 are at 26.7 MW (indicating the need in Figure 4.7 for an assumed seven new 4 MW diesel units, or 28 MW)[4].

Figure 4.7:
WAF High Sensitivity Case with Mines Capacity Requirements

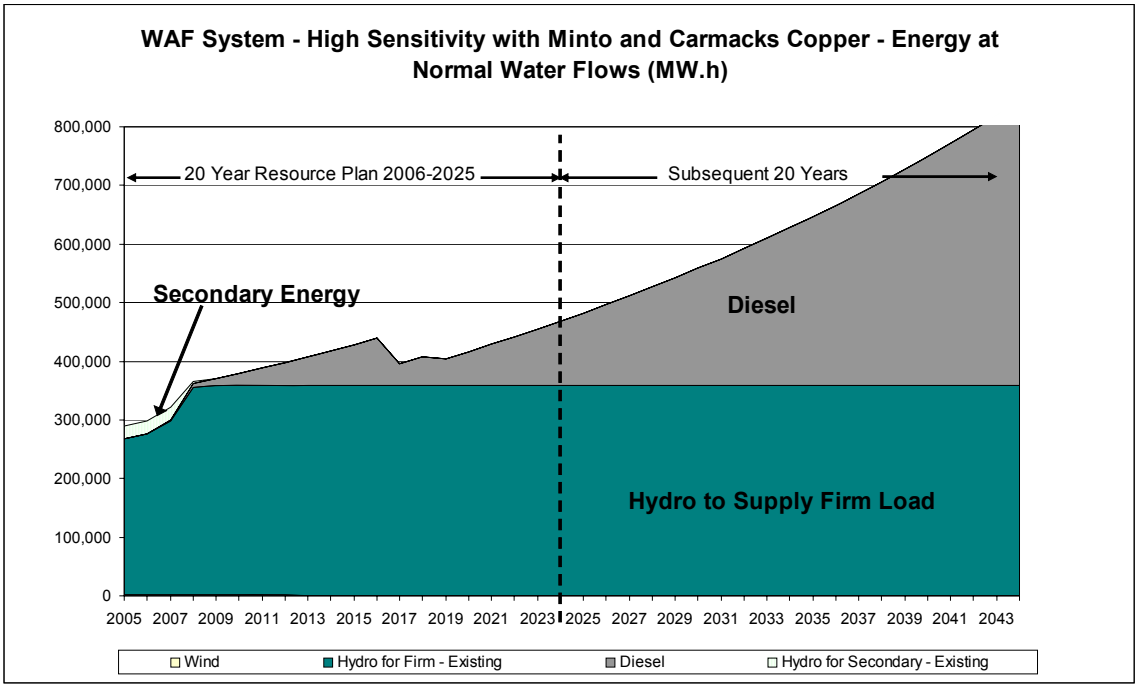


Energy: If the WAF system were to experience material sustained ongoing growth at the 3% level year over year, as well as the near term opening of both the Minto and Carmacks Copper mines as assumed in this high sensitivity case, the system will begin to experience base load diesel generation needs beginning

[4] Without the two mines, the High Sensitivity Case capacity shortfall in 2012 is 24.1 MW.

in 2009[5]. This may present near term opportunities to examine new non-diesel (e.g., hydro) generation. However, on a sustained long-term basis as reviewed in Figure 4.8, the requirement for new generation such as hydro after the mines close as assumed in this case is only in the range of about 50 GW.h per year (due largely to load reductions upon the closure of the mines)[6]. This scale of generation is consistent with hydro sites of about 8 MW. Consequently, even if new baseload energy projects are enabled by this major load growth, they will not be of sufficient size to address the very material (27 MW) new capacity requirements indicated under this scenario by 2012.

Figure 4.8:
WAF High Sensitivity Case with Mines Energy Requirements



Yukon Energy will also not likely be able to provide commitments to develop such capital intensive energy projects within the near term timeframes where capacity shortfalls begin to arise on the WAF system. This is because it would take a number of years to see loads develop at this high annual growth rate, as well as greater certainty with respect to mine loads, before capital intensive projects of this type would be suitable to consider. In addition, following appropriate commitments, hydro projects also typically require several years to plan, licence, design and construct.

[5] Without the two mines, the High Sensitivity Case will begin to experience base load diesel generation only in 2017 (when no surplus hydro for secondary sales).

[6] If 3% per year growth in non-industrial loads is sustained, as assumed in this case, diesel energy requirements grow to 124 GW.h by 2025.

4.3 OPTIONS

Based on the above requirements, three broad categories of project resource options are noted for the period prior to 2012:

1. **Opportunities projects to enhance existing facility energy and/or capacity output** or to allow better use of existing capabilities to ensure Yukon Energy has maximized the potential from past investments in major generating facilities. There are three well-defined near term project options in this regard:
   a) **Aishihik 3rd Turbine project:** Facility enhancements at Aishihik via a third turbine of 7 MW costing over $3 million to allow better ability to use the existing plant to meet peak loads, as well as more efficient use of water when operating at low outputs.
   b) **Marsh Lake Fall/Winter Storage project**: Improved water management at Whitehorse via changes to the water licence for upstream storage not costing over $3 million, in order to allow reduced discharge of water during the fall months to enhance the ability to store water for winter.
   c) **Carmacks to Stewart Transmission project**: The opportunity to use Government of Yukon infrastructure funding to develop new transmission costing over $3 million to interconnect the WAF and MD systems, including opportunities to connect to the WAF two potential new mines north of Carmacks.

2. **Major capacity-related replacement and/or expansion projects** costing $3 million or more to address substantial impending and unavoidable capacity shortfalls on WAF (approaching 15 MW to 27 MW by 2012) requiring new generation and/or transmission to ensure sufficient firm capacity to supply forecast peak loads. As noted in Section 3.3, this shortfall is driven in large part by exposure to Aishihik transmission line outages. Two main concepts are explored in this regard:
   a) **Maintain/Replace/Expand Whitehorse Diesel projects:** One concept seeks to reduce exposure to the transmission line weaknesses through reducing the potential *impact* of transmission line outages, focused on maintaining existing diesel (a major Life Extension project on the Mirrlees units), or installing new diesel generation on the WAF grid not dependent on the Aishihik transmission line (a major Whitehorse Diesel Replacement and Expansion project).
   b) **Aishihik 2nd Transmission Line project**: Alternatively, the Aishihik 2nd Transmission Line Project concept seeks to reduce exposure to weaknesses through reducing the potential *incidence and duration* of transmission line outages through developing redundancy in the Aishihik transmission connection.

3. **Smaller supplemental projects** that may contribute towards meeting WAF supply requirements, but are either not currently defined or not currently expected to cost at least $3 million, and do not independently offer sufficient capacity to play a major role in satisfying the near term capacity shortfall requirements. Yukon Energy continues to evaluate supplemental projects in the near term and on an ongoing basis, but the main near term focus is on system enhancement opportunities and major replacement and/or expansion projects that will be required based on the new capacity planning criteria.

Studies are ongoing with regard to each of the above major near term options. The Submission provides a screening of projects based on current information (as summarized below), setting out the conditions and requirements relevant to proceeding with each specific option as well as initial cost estimates currently available for each option (which, aside from opportunity projects, remain preliminary and subject to ongoing adjustment and refinement). Updates will be provided during the review of the Submission to the extent that relevant new information is forthcoming for the ongoing studies of these projects.

4.3.1 Overview of "Opportunity" Project Options

The implementation of supply side enhancement or Resource Smart projects reflects a sensible and prudent approach to maximizing the value of existing resources. Such projects are routine in other jurisdictions in Canada, and often offer the lowest cost sources of supply available (although the scale can be modest in some cases).

Opportunities to put in place enhanced system assets can also be enabled by new loads or external funding to offset capital costs so as to put no burden on ratepayers.

Yukon Energy has focused on three major opportunity projects in the near term:

- **Aishihik 3rd Turbine Project (7 MW; 5.4 GW.h/year):** Up to 7 MW of capacity could be added to the existing Aishihik hydro plant through addition of a third turbine. This potential project was reviewed in the 1992 Resource Plan hearing as a potential 5 MW unit, and pursuant to YUB recommendations from that proceeding[7], Yukon Energy pursued and received environmental approvals for the unit in the new Aishihik Water Licence of up to 7 MW. The third turbine would yield an increase in long-term average hydro energy supply from Aishihik of up to 5.4 GW.h/yr (if load conditions on the system are sufficiently high) but

[7] The YUB recommended that Yukon Energy pursue a licence for "the maximum capacity that is economically, technically and environmentally feasible".

in certain conditions prior to high WAF load conditions can allow displacement of diesel generation in excess of this level due to the ability to allow added Aishihik generation at the time of system winter peak (see Section 4.3.8). The 3rd turbine by itself is of no reliable peak capacity value whatsoever under the N-1 criteria as it is subject to the same Aishihik transmission line constraints as the existing units (unless an Aishihik 2nd Transmission Line project is in-service) and is similarly of limited reliable peak capacity value (0.6 MW) under LOLE criteria. Current investigations are updating capital costs and planning for this project.

- **Marsh Lake Fall/Winter Storage Project (about 1.6 MW; 7.7 GW.h/year):** There is the potential with a Marsh Lake Fall/Winter Storage project to increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and to increase its long-term average hydro energy by about 7.7 GW.h/yr (actual enhancement depends on load conditions assumed). The project involves seeking changes to the Whitehorse Rapids water licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period (during flood years, no change would be made during August and September, until after flood levels subside). In all cases, the water levels would remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake). Basically no new physical works are expected to be required for this project[8].

- **Carmacks-Stewart Transmission Line Project (about 6 MW; 15 GW.h/year, decreasing with time as MD load grows, plus opportunity to connect up to 2 new mines):** Yukon Energy is currently using Yukon Government Infrastructure Funding to carry out initial planning and permitting for this project; development of this project at this time is contingent on commitment of the necessary Yukon Government Infrastructure Funding as needed to ensure no adverse impacts on Yukon ratepayers. The development from Carmacks to at least Pelly Crossing would provide the basis to supply potential mine loads at Minto and Carmacks Copper with WAF surplus hydro energy. Development beyond Pelly Crossing to Stewart Crossing would interconnect the WAF and MD grids, thereby accessing surplus MD capacity for WAF in the near term. The full project with interconnection of the two grids would provide about 6 MW and 15 GW.h/yr of hydro energy to WAF, with this contribution decreasing as the MD load grows.

[8] This project concept would increase the licensed full supply level by 0.3 meters. The lake would not experience water levels higher than are currently experienced. No environmental studies on this specific project concept have been completed to date.

4.3.2 Aishihik 3rd Turbine

The Aishihik 3rd turbine project (current capital cost forecast of $7 million for 7 MW[9]) has long been considered as a relatively cost-effective means to add material new capacity to the WAF system, as well as a modest amount of new hydro energy.

Review of the system capacity constraints as part of the Capacity Planning Criteria review indicates that the capacity value of Aishihik 3rd turbine is extremely modest (about 600 kW under an LOLE of 2 hours/year, 0 MW under N-1) in the absence of a second Aishihik transmission line. This is because there is already a disproportionate amount of WAF generation at risk of an Aishihik transmission line outage, and the firm load carrying capability of WAF (under a probability-based assessment approach such as LOLE, or an N-1 approach) is not aided by further capacity development at Aishihik.

However, there remain two other enhancement aspects of the Aishihik 3rd turbine that cannot be ignored:

- First, there are certain circumstances where an Aishihik 3rd turbine could be valuable capacity to WAF (most notably if an Aishihik 2nd transmission line were developed, but also with major future generation development elsewhere on WAF which would reduce the relative weighting of Aishihik in the generation mix).
- Second, and likely of greater near term value, the long-term energy value of the Aishihik 3rd turbine (estimated at 5.4 GW.h per year under high load scenarios and new Water Licence terms) can be of value to WAF and can potentially yield diesel unit cost savings to offset the Aishihik 3rd turbine capital cost[10].

The Aishihik third turbine also provides material added near term enhancement benefits in displacing peaking diesel energy generation on the WAF system (as well as enhancing the ability to maintain maximum secondary sales revenues) while WAF surplus hydro is still available. This is because the presently installed firm winter hydro capability is only 54.4 MW (30 MW at Aishihik and 24 MW at Whitehorse plus 0.4 MW for Fish Lake) with normal winter hydro capacities in the range of 56-58 MW (i.e., in non-drought years). Consequently at the present time the maximum WAF load that can be allowed before diesel units must be started (and secondary sales interrupted) is a maximum of about 54 MW or less. With the addition of 7 MW of new hydro capacity at Aishihik, the operation of peaking diesel

[9] The $7 million cost estimate is currently under active review and refinement to reflect current pricing.

[10] The potential energy of 5.4 GW.h/yr represents an annual capacity factor of only 8.8% for the 7 MW unit; however, offset cost savings of about $1 million or more per year will occur if this displaces diesel fuel generation at 65 cents/litre cost. Base Case loads are not sufficient to yield any material diesel fuel displacement in the near term, but this starts to occur before 2025. Peaking diesel savings, which are discussed separately, are also material during this period under Base Case assumptions.

(and interruption of secondary sales) will not occur until closer to 61 MW. This can lead to material savings in WAF diesel generation starting when the unit comes into service (ranging under Base Case conditions from 0.4 GW.h a year in 2009 to as high as about 6 GW.h per year over the period of the Resource Plan). This effect also is expected to result in an increased number of hours of secondary sales availability and consequently secondary sales revenues[11] (this benefit has not been quantified).

The Aishihik 3rd Turbine is already authorized in the renewed water licence. Approximately 20-24 months are estimated to be needed from commitment until it comes into service (i.e., time needed for remaining pre-decision final design and costing and tendering as well as for subsequent construction). It is assumed that the project, if committed, would at the earliest come into service in 2009.

4.3.3 Marsh Lake Fall/Winter Storage

Although the Whitehorse Rapids hydro generating station is a largely run of river plant, there is some modest storage available at Marsh Lake, controlled via the Lewes Dam (a control structure upstream of Miles Canyon).

Various options have been reviewed over many years to enhance the output of Whitehorse Rapids by increasing the ability to control Marsh Lake.

One option that was previously studied and not adopted in 1992 was a project called the "Marsh Lake Top Storage Project" which YEC investigated in 1991-92 at the request of the YUB, to raise the licenced maximum storage on Marsh Lake by five feet (as well as associated lake level impacts on Tagish and Bennett Lakes). A study produced at that time for YEC estimated a requirement for only $760,000 (1992$) of physical works to the Lewes Dam control structure, but likely well over $25 million (1992$) in mitigation costs related to significant adverse impacts on many properties and developments affected by the higher water levels (YEC noted to the YUB that the company considered the study's estimates to be low). Consequently, YEC recommended in the 1992 Resource Plan that it not proceed with the project, and the YUB agreed with this recommendation in its 1992 Report.

The Marsh Lake Fall/Winter Storage project under consideration today is a fundamentally different project than that considered in 1992. In this case, the project involves seeking changes to the Whitehorse Rapids water licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake under

[11] The impact on secondary sales quantities from hydro peaking resources such as the Aishihik Third Turbine has not been assessed. At certain loads, the Third Turbine may also reduce somewhat the availability of surplus power for secondary energy, as the water would be used to avoid baseload diesel and consequently no longer be "surplus hydro". However, this is not expected to occur until the system is near the full utilization of hydro capability and only for a limited number of years.

certain conditions in the fall and early winter, in order to enhance Yukon River flows during the coldest months of winter[12]. The effect of the revised water licence would be as follows:

- **In non-flood years:** The licence revision would allow Yukon Energy to reduce Marsh Lake outflows from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period.
- **During flood years:** In years where Marsh Lake levels are at flood stages, no change would be made during August and September until after flood levels subside. Similar to existing rules, once the floods have subsided, water levels would be controlled to reduce further spillage in fall and early winter months (at a level about one foot higher than presently allowed), to allow the water to be used instead during the peak winter generation period. In all cases, the water levels would remain within the lake level limits currently experienced (i.e., the peak level that YEC is allowed to maintain by use of Lewes Dam would be below the natural high water levels experienced in the lake during uncontrolled summer periods). There would be no effect on the flood levels experienced on Marsh Lake.
- **During drought years:** Yukon Energy is currently permitted to help alleviate summer drought levels on Marsh Lake through "early closures" of the Lewes Dam (as early as July 7 in extreme droughts). These provisions would remain, and would likely be adapted somewhat to further alleviate summer drought conditions to ensure the lake reached the full controlled supply level (as revised) in each year.

Environmental licencing activities for the project have not been initiated. Studies will need to confirm the extent (if at all) to which the project may affect water levels in lakes that extend into BC.

The Marsh Lake Fall/Winter Storage project has the potential to enhance the output of the Whitehorse Rapids hydro facility by about 1.6 MW and 7.7 GW.h/yr long-term average hydro energy (actual enhancement will depend on load conditions assumed and revised maximum licence level allowed, which is assumed here to be one foot). Basically no new physical works are expected to be required for this project.

[12] During uncontrolled periods of summer and fall (when YEC has no control over the lake and it is operating under an entirely natural regime), Marsh Lake has been known to peak at two feet above the Yukon Energy "controlled maximum" level currently provided for in the water licence, and to typically peak at least one foot above the "controlled maximum" level. The specific revision sought to the water licence would be to change the licenced "controlled maximum" level that YEC can maintain at Marsh Lake upwards by likely in the range of one foot, i.e., the proposed licence revision will still be well within the normal natural levels experienced on the lake.

Costs of the project relate almost entirely to environmental licencing and mitigation, which are very difficult to predict. Given the relatively limited potential for physical or environmental effects (but recognizing the potential for notable public interest in ensuring full review of all potential effects) the costs of the project are not expected to exceed $1 million. Licensing and other pre-decision activities are assumed to require a year such that the project could potentially come into service in 2007 (in time to be of value in addressing the 2007/2008 winter peak).

4.3.4 Carmacks to Stewart Transmission Line Project

The proposed 138 kV Carmacks to Stewart Transmission Line would extend the WAF system north from Carmacks generally along the Klondike Highway to at least Pelly Crossing, and potentially as far as Stewart-Crossing in order to provide full interconnection with the MD system. Interconnection of the WAF and MD grids would provide near term capacity and energy benefits to the WAF system.

If the project is developed from Carmacks to at least Pelly Crossing, potential new mine developments in close proximity to the new transmission line could have access to service with WAF surplus hydro energy. In particular, the Minto mine and the Carmacks Copper mine, located between Carmacks and Pelly Crossing, are both located in areas that could be serviced with the proposed line. Development only to Pelly Crossing, however, would not result in interconnection of the MD and WAF grids.

Costs to develop this project from Carmacks for full interconnection to Stewart-Crossing have been estimated at about $35 million (2005$). It is not currently economic for Yukon Energy, as a regulated utility, to develop this project since both the WAF and MD systems today have surplus hydro power and the line would not at this time displace the level of diesel fuel or other high cost generation needed to justify its costs. Accordingly, this project is being examined as a key Yukon territorial infrastructure initiative to meet a specific window of opportunity related to two potential new mines (Minto and Western Silver at Carmacks Copper) and current Yukon Government Infrastructure Funding.

The project is currently being advanced using Yukon Government funding for permitting and approvals activities, including licencing under the new *Yukon Environmental and Socio-Economic Assessment Act (YESAA)*, as well as for finalizing project final design and costing. If critical planning does not proceed in a timely way through 2006 using Yukon Government Infrastructure Funding, permits and other preparatory work will not likely be done in time to enable the project to help in the development of these two mines (based on the current planned development schedules for Minto in particular). Current planning is seeking to protect a potential in-service date for this project between mid-2008 and mid-2009.

The extent to which the ultimate project concept is developed in the near term will be determined based on available Yukon Government Infrastructure Funding as well as the mine development that will actually occur. The project's capital costs will not impact regulated utility rates to the extent that its costs are funded through Yukon Government grant funding or through customer contributions from mines connecting to the WAF grid. Rates charged to such mines for use of WAF power would need to be approved by the YUB in accordance with OIC 1995/90 (which requires that such rates at least cover utility costs of service evaluated on a Yukon wide basis).

Development of this project from Carmacks to Pelly Crossing is estimated to cost in the range of about $20 million (2005$). This extent of development, in combination with the two proposed mines being developed and connected (costs for "radial" lines to service Minto and Carmacks Copper sites will be addressed via normal utility and customer investment policies), would fully utilize WAF surplus hydro in the near term.

Extending the project fully from Carmacks to Stewart Crossing (a further likely capital cost (2005$) of about $15 million over and above the cost for the project from Carmacks to Pelly Crossing) would provide near term capacity and energy benefits for the WAF system related to interconnection of the WAF and MD systems. It is estimated that such interconnection would provide in the near term about 6 MW of net capacity benefit to WAF[13] as well as another 15 GW.h/yr of net long-term average hydro energy; these benefits would decrease in future as MD load grows (or if new industrial developments, such as reopening of the UKHM mine, connect to the MD system). The surplus hydro made available can yield

WAF economic benefits during the planning period through both diesel unit cost savings and extended maintenance of secondary sales revenues[14].

In assessing various alternatives related to the Carmacks to Stewart Transmission Line project, Yukon Energy is examining the net cost that could be funded through rates in order to make interconnection cost competitive with other options. This is based on the assumption that if the project was to be developed in the near term, the project's capital cost will be provided for through Yukon Government Infrastructure Funding as required to ensure no impact on regulated utility rates.

[13] This reflects 12 MW of installed MD firm capacity and MD peak load forecast (2008) of 5.9 MW.

[14] The present value (2005$) of these diesel cost savings and extended secondary sales revenues approximates only $1.2 million over the 20 year planning period under Base Case conditions; under Base Case including Mines conditions (which are likely to be required, at least in part, if the interconnection is to be developed at this time), and excluding consideration of any other opportunity projects, this present value increases to $4.7 million. (These present values assume a discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre for peaking and 3.9 kW.h/litre for baseload, diesel fuel prices at $0.65/litres (2005$), diesel O&M at $0.016/kW.h (2005$) and inflation at 2%/yr. No firm capacity benefit is included in these present values.)

Long term benefits from the Carmacks Stewart Transmission project connecting the two grids include: encouraging economic development along the corridor of the new line and its extended environment; enhancing overall power system reliability on these systems; and providing greater flexibility to accommodate future load and generation interchange between the WAF and MD systems as they are currently known. Potential benefits, for example, include the ability under certain load development scenarios to move surplus WAF power to serve major new mine developments in the MD grid region should they arise; or to move surplus MD power to the WAF grid region from potential new hydro developments in the MD grid or Pelly Crossing regions, as well as from potential future Mayo hydro plant enhancements.

The Carmacks to Stewart Transmission Line project (full interconnection) impact on WAF firm winter capacity, plus other new diesels as required to meet capacity requirements, is illustrated in Figure 4.9 (at Base Case loads and excluding consideration of any other non-diesel capacity enhancements).

- The Base Case capacity shortfall in 2012 with interconnection of the MD and WAF grids is approximately 13.1 MW, and is assumed in Figure 4.9 to be met through 16 MW of added diesel units (4 MW in 2009, 4 MW in 2010, and 8 MW in 2012).
- Under other forecast conditions examined, the capacity shortfall in 2012 with the Carmacks to Stewart Transmission Line project (full interconnection) is 8.7 MW (Low Sensitivity case), about 15.8 MW (Base Case including Mines), and about 21.5 MW (High Sensitivity including Mines).

Figure 4.9:
Carmacks to Stewart Transmission Line in 2008

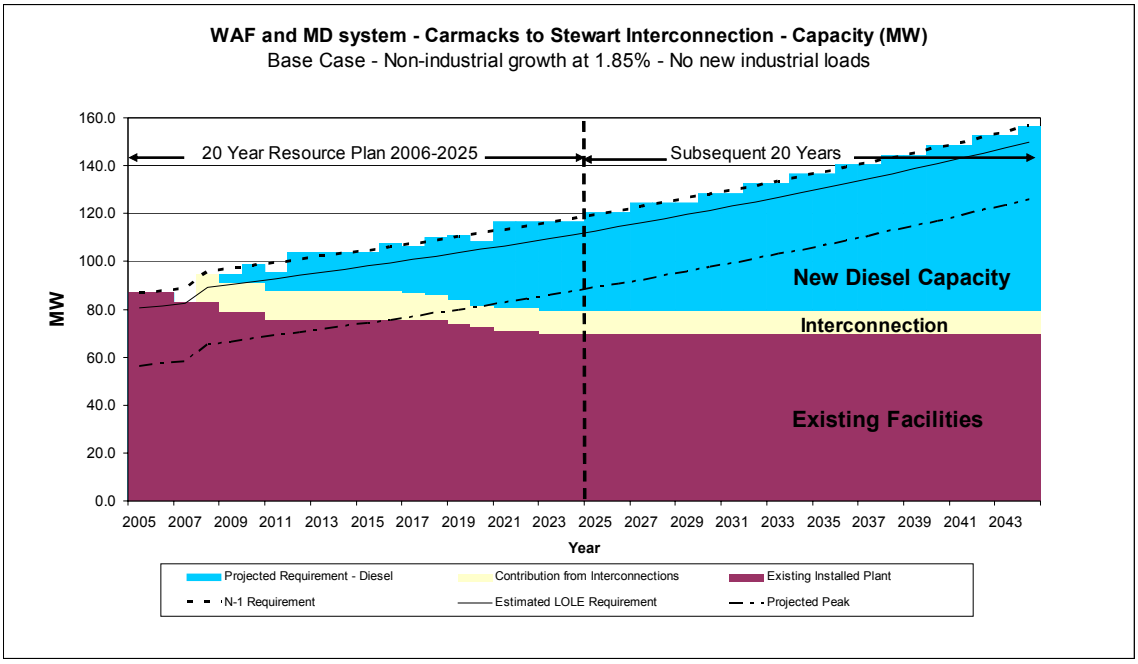
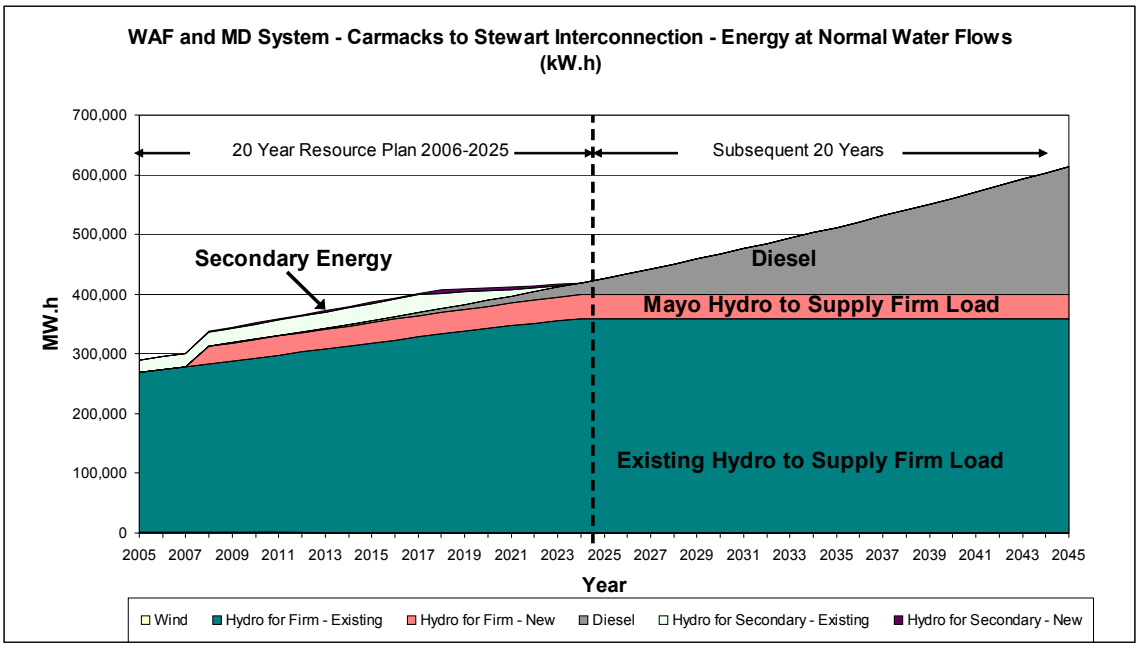


Figure 4.10 reviews the hydro and diesel energy loads under the Base Case forecast with interconnection of the MD and WAF grids, indicating surplus hydro remaining throughout the 20-year planning period.

- Under Base Case forecast conditions including the Minto and Carmacks Copper Mines, the full interconnection project has the same surplus hydro after the mines close in 2016 and 2018.
- Under the High Sensitivity case including these mines, the full interconnection project has no surplus hydro available after the mines close.

Figure 4.10:
Carmacks to Stewart Transmission Line in 2008



4.3.5 Overview of Major Capacity-Related Project Options

Under the new capacity planning criteria, the WAF system is facing a capacity shortfall in the very near term. As reviewed in Section 4.2, the magnitude of the capacity shortfall depends in part on the load growth that occurs over the next few years (including the extent to which new mine loads, if developed, are connected to WAF through new transmission facilities). However, even under the lowest load growth scenarios, the shortfall approaches 15 MW by 2012, which is a very material scale for the WAF system (which peaks at about 56 MW today).

Facing this requirement, Yukon Energy has identified three major replacement and expansion project options (beyond the "opportunity" project options already noted) that have the potential to largely or entirely address major capacity shortfalls by 2012 on the WAF system:

- **Mirrlees Life Extension Project (14 MW):** One option that requires consideration is a major refurbishment of the three existing Mirrlees units at Whitehorse to reclaim the full 14 MW nameplate ratings and extend the life of the units for 10 years or more. The project would require a full "tear down" overhaul of the three units as well as upgrading to various shared systems in the Whitehorse diesel plant. As the project would only provide 14 MW of capability, it would need to be combined with other projects to meet the full 2012 shortfall

assumed based on retirement of these Mirrlees units (i.e., to achieve the full 15 MW to 27 MW under the various scenarios in Section 4.2). This option is reviewed in more detail below (see Section 4.3.6).

- **Whitehorse Diesel Replacement/Expansion Project (unlimited MW):** This flexible option is available to meet the full range of possible new capacity requirements in near term (up to the full high load scenario requirements of 27 MW by 2012). New units of any type or combination could be added to the system incrementally as required. In all likelihood the units would be installed as replacements for the retired Mirrlees (in the bays vacated by the retirements) and, if undertaken with large units such as modern 8 MW Wartsila gensets (or larger, such as 11 MW units), could largely or entirely be accomplished within the confines of the existing site. In addition, other major resource options that are not sufficiently large to address the entire 2012 shortfalls may be combined with a smaller scale of new diesel installation. This option is reviewed in more detail below (see Section 4.3.7).

- **Aishihik 2nd Transmission Line Project (15 MW under N-1 criteria, 8.0 MW under LOLE criteria):** As discussed in detail in Section 3.3, the largest single factor influencing the reliability and risk profile of the WAF system today is the non-redundant nature of the Aishihik transmission line. A major rationale for maintaining substantial "stand-by" diesel in Whitehorse is to address the risks of an Aishihik line failure. One project option that consequently merits consideration is a "twinning" of the Aishihik transmission line to provide required redundancy. Were such a facility to be put into service to provide complete redundancy, the N-1 criteria would be revised to indicate 15 MW as the largest single contingency (based on one of the hydro units at Aishihik, which are the largest single units on the system) rather than 30 MW currently arising from a potential loss of the line. Under the N-1 criteria, this would currently be a 15 MW benefit to the load carrying capability of the system. Under the LOLE criteria, also as noted in Section 3.3, the benefit from a redundant Aishihik transmission line would currently be about 8.0 MW. In addition, this option enables the opportunity for additional firm capacity benefits related to other potential enhancements at the Aishihik generating station such as the Aishihik 3rd Turbine, as well as the potential for re-runnering (as discussed below). As the Aishihik 2nd Transmission line project would currently only provide 15 MW of new load carrying capability, it would currently need to be combined with other projects to meet the full 2012 shortfall (to achieve the full 15 MW to 27 MW under the various scenarios in Section 4.2). This option is reviewed in more detail below (see Section 4.3.8).

Aside from relying only on diesel expansion/replacement, none of the above major options on its own is likely to address the full WAF capacity shortfall expected in the near term (to 2012). For initial review below, it is assumed that additional diesel engines are the default option to be used as required with each of the other options in order to meet the full near term capacity shortfall. Later, in section 4.4, optimum combination of these options is examined under a range of planning assumptions.

4.3.6 Mirrlees Life Extension Project

As noted in Section 4.1, the Whitehorse Diesel Units WD1, WD2 and WD3 are the three largest units in the Whitehorse diesel plant. Although planned for retirement at an earlier date, Yukon Energy was able to delay the retirement of the units largely as a result of the closure of the Faro Mine.

BC Hydro's Condition Assessment in 2004 recommended that the retirement of these units be seriously considered if significant further use was anticipated (*Section 3.1: Current Facilities Condition Assessment*). Assumptions regarding retirement of these units have at various times been based to a greater or lesser extent on the following cited issues:

- The units' condition is becoming unacceptably poor, and would require substantial investment to bring them back up to a utility quality condition;
- The units are poorly suited to the current operating regime of stop-and-start operation;
- Parts and technical support are lacking and expensive; and,
- The units are expensive to operate and maintain.

Despite these limitations, the retirement of the Mirrlees engines will necessitate major new capacity-related investment in the near term (particularly under the new capacity criteria, but also to a lesser degree even under the previous criteria). In addition, the YUB recommended in its 1992 Report on the utilities' Resource Plan that before the Companies commit to the construction of a supply option they should critically assess a number of factors including "the necessity for diesel retirements". As a result, Yukon Energy is currently undertaking a critical assessment of the potential for a "Life Extension Project" for the units. Such a project must, at a minimum, ensure the above concerns with respect to condition can be fully addressed (including reclaiming the previous full 14 MW combined nameplate ratings).

If feasible, such an option would materially reduce capacity shortfalls in the next five to six years; it would also materially reduce capital costs relative to those needed for any other available option to meet WAF near term capacity requirements. Such an option, if practical, is expected to involve capital costs (2005$) potentially in the order of $0.5 million to $1.0 million for each unit (with material risks that costs could not be readily estimated with any degree of certainty before the project is undertaken, as the

status of internal parts and mechanisms cannot be readily ascertained until the tear-down is underway). In addition there would be substantial initial work in the order of $1.0 million to $1.5 million related to shared aspects of the Whitehorse diesel facility systems requiring material improvements (such as cooling systems, fuel delivery systems, foundation, etc.).

There remain two key concerns with the Mirrlees: the cost and availability of parts and support from the manufacturer, and the suitability of the units to the current Yukon operating environment.

With respect to the manufacturer, it will not be prudent for Yukon Energy to proceed with any Mirrlees Life Extension project unless Yukon Energy can receive clear and reliable assurances that the manufacturer can provide full competent and cost-effective parts and technical support for these units for the next 10-20 years. Recent Yukon Energy experience indicates this concern to be very material. Yukon Energy is in the process of assessing the manufacturer's claims that they can continue to provide competent support on these units, including discussing Yukon Energy's recent experiences with the manufacturer, and seeking references from other utilities who have pursued a similar course of action.

With respect to the operating environment, despite a full tear-down overhaul, the Mirrlees units will remain low speed base load units which are poorly suited to the current Yukon operating environment (stop-and-go operating, limited running hours). This limitation cannot be fixed. However, it is not sufficiently severe to rule out a Life Extension project option, given competitiveness on other grounds as well as the expected use primarily for reserve rather than planned operation purposes (see Section 4.4 regarding "Assessment" below).

Yukon Energy is aware that Northwest Territories Power Corporation ("NTPC") has plans to retire their two KV16 Mirrlees units in Yellowknife in the next number of years (NTPC has already retired a similar unit in Inuvik; the Yellowknife units are similar in running hours to Yukon Energy's units, but about six to seven years newer). The NTPC retirement plans are due primarily to two concerns: part and technical support availability, and suitability to a stop-and-go unattended operating environment. Further discussions with NTPC are planned to compare experiences on these two matters.

If the Mirrlees Life Extension project is pursued and 14 MW of capacity is restored for these units, by 2012 additional diesel capacity will still be required under the capacity planning criteria (capacity shortfalls of 4.7 MW would exist under the Base Case, 0.7 MW under the Low Sensitivity Case, 7.5 MW under the Base Case with mines, and 12.7 MW under the High Sensitivity Case with mines).

Overall, likely costs (2005$) for the Mirrlees Life Extension project to 2012 can be estimated for screening purposes as follows, assuming that added requirements beyond 14 MW are met though additional diesel capacity[15]:

- **Base Case:** Mirrlees Life Extension at $3.0 million to $4.5 million, plus 4.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total ***$6.8 million to $8.7 million***.
- **Low Load Sensitivity:** Mirrlees Life Extension at $3.0 million to $4.5 million plus 0.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$3.6 million to $5.1 million***.
- **Base Case with Mines:** Mirrlees Life Extension at $3.0 million to $4.5 million, plus 7.5 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total ***$9.0 million to $11.3 million***.
- **High Load Sensitivity including Mines:** Mirrlees Life Extension at $3.0 million to $4.5 million, plus 12.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total ***$13.2 million to $15.9 million***.

In summary, the capital cost (2005$) of the Mirrlees Life Extension Project plus other diesels as required to meet peak loads to 2012 is expected to cost in the range of $6.8 million to $8.7 million, with potential under various load developments to range from $3.6 million to as high as $15.9 million.

Timing with respect to the Mirrlees Life Extension is expected to be quite flexible. Major tear-down overhauls can likely be scheduled on six months notice, and major upgrades to common facilities can likely be staged so as to meet in-service requirements of the overhauled units (although the lead times will in all likelihood be slightly longer than for overhauls, due to design requirements). The project can also likely be staged over a number of years (summers) if preferable. The project is assumed to be suitably organized in an orderly fashion by sequencing one unit per year from 2007 to 2009 (starting with the largest) with common facilities upgrades occurring in 2007. Work on the existing units and facilities that disrupt current capability must occur during summer months (as the units are needed during winter to provide firm capacity).

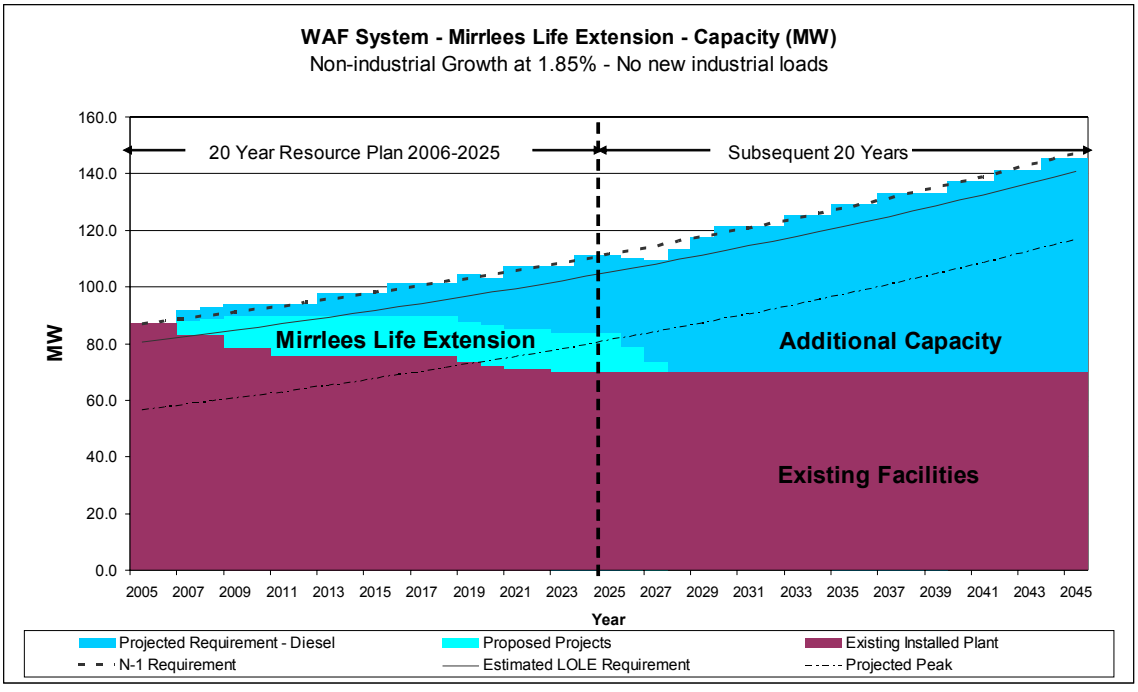
[15] See Section 4.3.7 for a more detailed review of costs for additional diesel units. As a rough measure for screening purposes, diesel units installed for capacity reserve purposes without a need for major "Green Field" support systems (e.g., fuel tanks, substations, control systems) are estimated to cost (2005$) in the range of $800,000 to $900,000 per MW (e.g., $3.2 to $3.6 million for a 4 MW unit). Under the Mirrlees Life Extension option the Whitehorse diesel plant facilities would be utilized for the Mirrlees units, and costs for additional diesels therefore may tend to be higher than otherwise assumed, particularly if a new diesel generation site would need to be developed for these added units.

For the added diesel units that are assumed to be required, issues also arise with respect to locating such diesel units if the entire Mirrlees Life Extension project is pursued. Were the three Mirrlees to be retired, the three "bays" of the existing diesel plant would allow three new units to be installed (units of 8 MW are expected to fit readily into the existing bays, allowing for up to 24 MW of new capacity; units of 11 MW or larger may also fit, but require further consideration). However, if the Life Extension is pursued, these bays will be in use by the Mirrlees and new units will require modifications or expansions to the existing building, or pursuit of other options with respect to unit location.

The Mirrlees Life Extension project impact on WAF capacity, plus other diesels as required to meet capacity requirements, is illustrated in Figure 4.11 (at Base Case loads). This figure focuses on a Life Extension project to add 20 years to the lives of the Mirrlees units. Under this forecast scenario, one new diesel unit (about 4 to 5 MW) would be required in 2007.

One potential variation on implementing the Life Extension project could involve Life Extension of the two largest Mirrlees units (10 MW total) combined with replacement of the smaller third Mirrlees unit (4 MW) with a larger 8 or 11 MW new unit. Under this variation, there would be no need for any other new diesel unit by 2012.

Figure 4.11:
Mirrlees Life Extension



4.3.7 Whitehorse Diesel Replacement/Expansion Project

The Whitehorse Diesel Replacement/Expansion project encompasses various potential concepts of meeting all capacity requirements (including those driven by Mirrlees retirements) using new diesel units at Whitehorse. This could include various combinations of unit sizes (e.g., approximately 4 MW or 8 MW or potentially others such as 11 MW or 15 MW) sequenced as needed to meet load requirements as well as other implementation practicalities. Ongoing investigations are examining issues and costs related to alternative ways to implement this generic option, including common plant upgrade requirements.

Purchase of new diesel units is likely the most flexible approach possible to addressing capacity shortfalls, as units can be sourced that are properly suited to standby use in a wide range of sizes and specifications. However, due to presently high worldwide demand for new diesel units, lead times for new orders from initial commitment through to in-service (including engineering, manufacture, delivery, installation and commissioning) can be on the order of 18 months, which is well above the traditional lead time for new units. As note earlier, work on the existing units and facilities that disrupts current capability must occur during summer months (as the existing units are needed during winter to provide firm capacity).

Diesel units installed at the current Whitehorse plant, without the need for major "Green Field" support systems (e.g., fuel tanks, substations, control systems), are estimated to cost (2005$) in the range of $800,000 to $900,000 per MW[16]. Estimated capital costs (2005$) to 2012 for screening purposes of the Whitehorse Diesel Replacement/Expansion Project are as follows:

- **Base Case:** 18.7 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$15.0 million to $16.8 million***.
- **Low Load Sensitivity:** 14.7 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$11.8 million to $13.2 million***.
- **Base Case with Mines:** 21.5 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$17.2 million to $19.4 million***.
- **High Load Sensitivity including Mines:** 26.7 MW requirement for new diesels at $0.8 million to $0.9 million per MW, for a total of ***$21.4 million to $24.0 million***.

[16] By way of example, based on prices recently quoted to YEC and estimates for costs to install and commission at Whitehorse, a 4.3 MW EMD 16-265H using 6.9 kV generators has been estimated to cost (2005$) about $730,000 per MW ($3.1 million), and a 7.8 MW new 7.8 Wartsila 18V32 using 13.8 kV generators has been estimated to cost (2005$) about $740,000 per MW ($5.8 million). In addition, common plant upgrade costs of $1.0 million have been estimated to apply in each case (assuming installation at the current Whitehorse plant to replace the Mirrlees units, which are assumed to be removed and replaced with from 12 to 24 MW, depending on the unit size selected). Together, these costs average at between $786,000 and $808,000 per MW (depending on the units size selected).

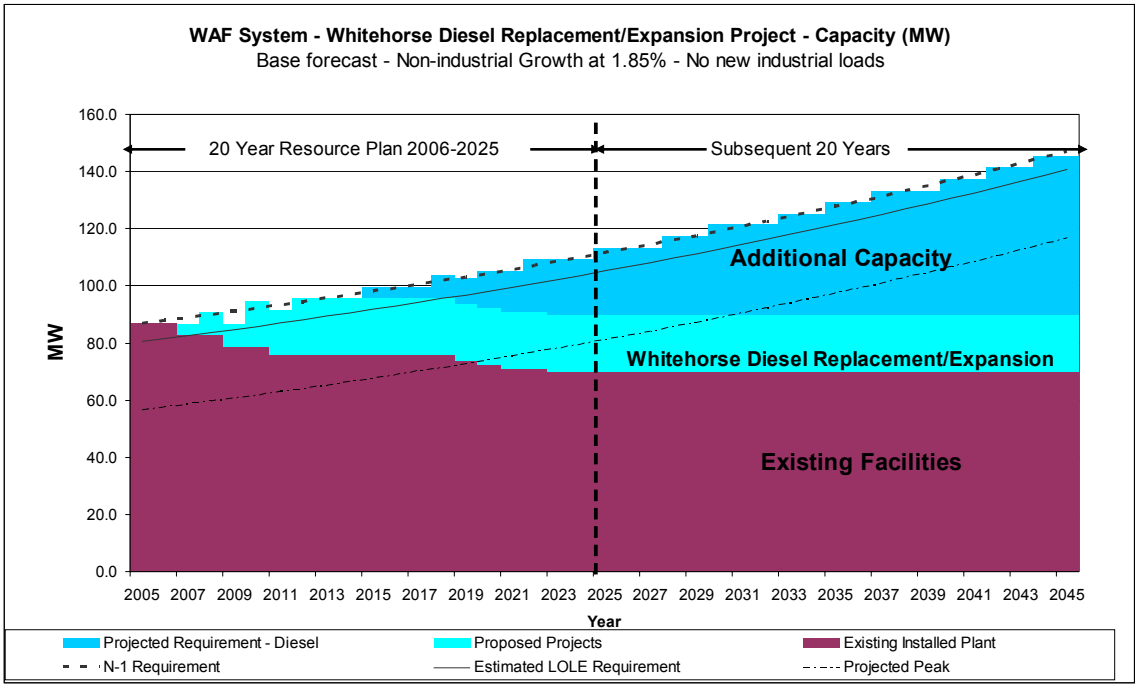
In summary, the capital cost (2005$) of the Whitehorse Diesel Replacement/Expansion Project as required to meet peak loads to 2012 is expected to be in the range of $15.0 to $16.8 million, with potential under various load developments to range from $11.8 million to as high as $24.0 million.

For the first three units installed, there is little issue with space or support systems at the current Whitehorse diesel plant, as the three bays vacated by the retired Mirrlees are of sufficient size to accommodate the noted 4 MW or 8 MW units and perhaps up to 11 MW or larger.

However, issues begin to arise if either a) more than three units are required in the sequence to 2012 (as would occur with new units of 4 MW rather than 8 MW, or would occur under the High Load Sensitivity Scenario with Mines which requires more than three 8 MW units) or b) units are required at a rate faster than the Mirrlees are planned to be retired. If this arises, modifications or expansions will be required to the existing building, or other options required regarding unit location.

The Whitehorse Diesel Replacement/Expansion Project impact on WAF capacity is illustrated in Figure 4.12 (at Base Case loads and assumed increments generally at 4 MW units). Under this forecast scenario, an added diesel unit would be required in 2007, another 4 MW unit would be required in 2008, an 8 MW unit would be required in 2010, and a further 4 MW unit in 2012.

Figure 4.12:
Whitehorse Diesel Replacement and Expansion



4.3.8 Aishihik 2nd Transmission Line Project

The Aishihik Transmission Line is a key component of the WAF 138 kV system. It connects 30 MW of hydro generation from Aishihik to major load and generation centers at Whitehorse and beyond. The Aishihik 2nd Transmission Line Project is a near term option for potential development under the new capacity planning criteria if the existing Mirrlees diesel units at Whitehorse are confirmed to be retired. The project concept is to establish a redundant circuit for Aishihik generation to reach the remainder of the WAF system at Whitehorse.

The net effect of this project under forecast loads would be a reduction in the N-1 capacity planning criteria "reserve" currently of about 15 MW, approximately equal to adding 15 MW of new diesel units. Under the LOLE criteria, the Aishihik 2nd Transmission Line project benefit currently is 8.0 MW. However, under the Base Case forecasts with current facilities, the N-1 criteria is the key factor in requiring new capacity in the near term[17]. Subject to timing issues for its in-service, the project would eliminate the need for any new capacity under Base Case load forecasts until 2012.

Pending results of the current Mirrlees Life Extension investigations, Yukon Energy has not proceeded with material work to date on potential routing options for the Aishihik 2nd Transmission Line project. There exist a number of options to connect to any of 3 substations in the Whitehorse area, or alternatively potentially to the WAF grid line north to Carmacks. Regardless of the routing, the project requires that full redundancy on the delivery of power to the Whitehorse is to be established, including substation components and Whitehorse area transmission connections.

Preliminary costing (2005$) indicates a transmission line development cost (planning, permitting, design and construction) for the simplest project alternative roughly paralleling the existing line on the order of $16 to $19 million. The total costs (2005$) to meet capacity requirements to 2012 with the Aishihik 2nd Transmission Line project are therefore currently estimated for screening purposes as follows:

- **Base Case:** Aishihik 2nd Transmission Line at $16 to $19 million, plus 4.5 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$19.6 million to $23.1 million***.
- **Low Load Sensitivity:** Aishihik 2nd Transmission Line at ***$16 to $19 million*** fully satisfies the capacity requirements to 2012.

[17] In contrast, if the Aishihik 2nd transmission line was to be built, the LOLE criteria would become the driving factor by 1.1 MW.

- **Base Case with Mines:** Aishihik 2nd Transmission Line at $16 to $19 million, plus 13.5 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$26.8 million to $31.2 million***. The substantial diesel requirement over and above the Base Case is due to the fact that with 9 MW of mining loads, the LOLE criteria becomes the driving consideration in new capacity, which only credits the Aishihik 2nd transmission line project with 8.0 MW rather than the 15 MW under the N-1 criteria.
- **High Load Sensitivity including Mines:** Aishihik 2nd Transmission Line at $16 to $19 million, plus 18.7 MW requirement for new diesel at $0.8 million to $0.9 million per MW, for a total of ***$31.0 million to $35.8 million***.

In summary, the capital cost (2005$) of the Aishihik 2nd Transmission Line Project plus additional new diesel units as required to meet peak loads to 2012 is expected to be in the range of $19.6 to $23.1 million, with potential under various load developments to range from $16 million to as high as $35.8 million. In particular, costs under this scenario (without examining any other potential benefits noted below) are materially increased by the presence of the potential mining loads.

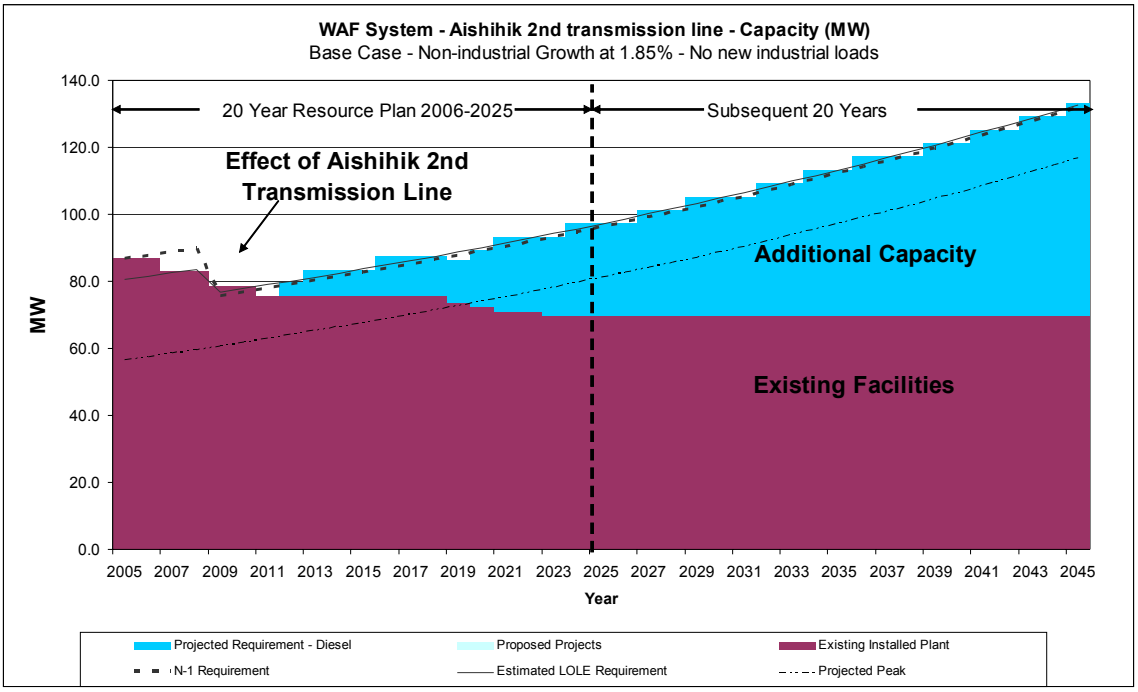
The Aishihik 2nd Transmission Line project would somewhat reduce operating costs compared to diesel in the near term as the project would allow for greater flexibility to keep Aishihik on-line during line maintenance activities which may serve to reduce diesel energy generation that would otherwise be required. In contrast, an equivalent 15 MW of diesel units would require some new spending on diesel fuel in order to maintain and exercise the units regularly.

The development of the new transmission line would involve much longer lead times from commitment to in-service than the other options noted above (potentially three years or more after a commitment to do detailed planning and construction), as well as be less flexible in the near term given the impact of an addition of 15 MW all at one time (compared to diesels which can be added in selected increments as desired). For the purposes of planning, it is not expected that an Aishihik 2nd Transmission Line could be in service any earlier than 2009, which would additionally raise concerns over capacity shortfalls in the 2006-2008 period (under the assumption that under Base Case conditions it may not be sensible to install sufficient new diesel engines (8 MW) to address this two to three year capacity shortfall).

In addition, due to the nature of transmission line contracting, it would not be possible to develop a materially more reliable estimate of the capital costs until such time as permitting and environmental approvals were completed, final tenders were received and contracts concluded (likely requiring a planning cost expenditure of about 10% of the capital cost, or about $1.6 to $1.9 million to get to this stage).

Figure 4.13 below illustrates the capacity criteria benefits of twinning the Aishihik line. Under Base Case assumptions, new diesel (about 4 to 5 MW) would not need to be added to the system until 2012.

Figure 4.13:
Aishihik Second Transmission Line 2009



In addition to ensuring existing Aishihik capacity can remain substantially more reliable to the system, the Aishihik 2nd Transmission Line project also has the benefit of enhancing the opportunity provided by two projects to provide additional capacity at Aishihik:

1. The 7 MW Aishihik 3rd Turbine.
2. A re-runnering of the existing Aishihik turbines for potentially up to 6 MW of added capacity.

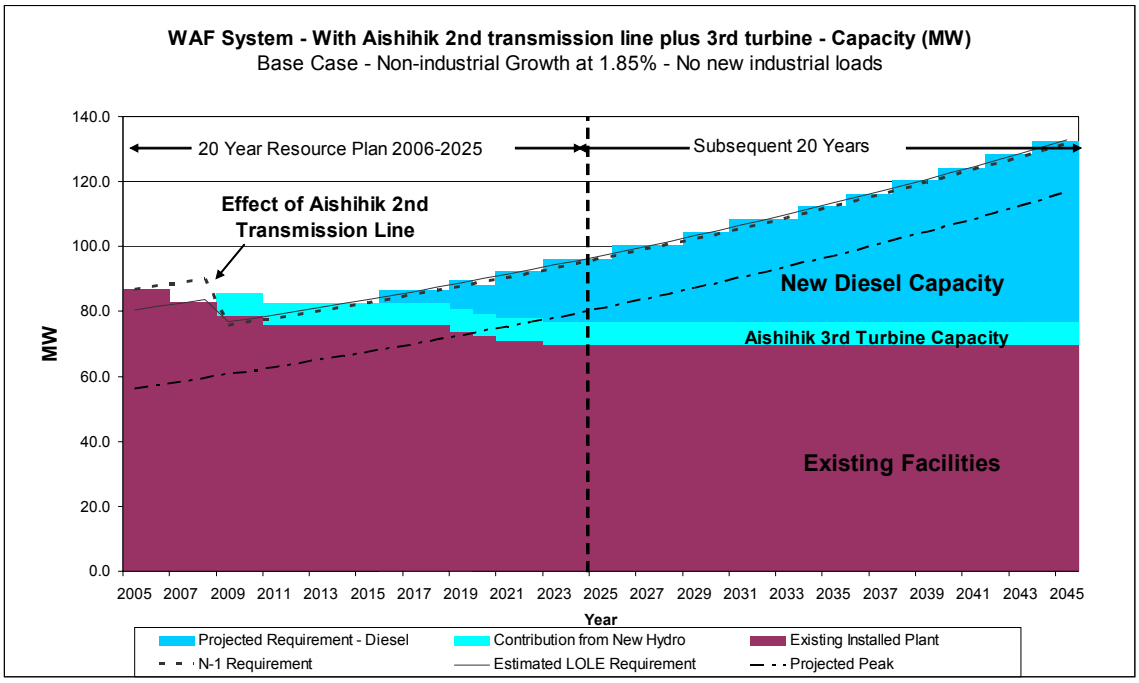
The Aishihik 3rd Turbine is discussed in detail in section 4.3.2. At this time, there is insufficient definition on the potential Aishihik re-runnering project to determine likely costs and practical full capabilities; however, re-runnering projects in other jurisdictions are frequently pursued as cost-effective sources of new capacity and/or energy.

In the event the Aishihik 3rd Turbine project is pursued independently as an “opportunity” project in the near term, development of the Aishihik 2nd Transmission line (under Base Case load conditions) would provide 22 MW of firm capacity, which would allow for a full retirement of the Mirrlees engines and defer

until 2016 the need for any new diesel units on the WAF system. However, without an Aishihik 2nd Transmission line, the Aishihik 3rd Turbine project cannot be considered reliable capacity under the N-1 criteria and only 0.6 MW of the 7 MW can contribute to the Load Carrying Capability under the LOLE criteria. Accordingly, the added capacity value of the Aishihik 2nd Transmission Line become 22 MW under the N-1 criteria and 14.4 MW under the LOLE criteria[18].

Figure 4.14 below notes, under Base Case assumptions, the added benefit of a third turbine separately from new diesel (in this case the 3rd Turbine is assumed to be placed in service in 2009, with new diesel not required until 2016)[19].

Figure 4.14:
Aishihik Second Transmission Line in 2009 (with Aishihik 3rd Turbine in 2009)



[18] Under N-1 criteria with the Aishihik 2nd Transmission Line, a full 37 MW (30 MW existing plus 7 MW for 3rd Turbine) is now recognized at Aishihik (versus no MW recognized without the 2nd Transmission line), less 15 MW for loss of one unit (which once again becomes the largest single contingency event at the time of winter peak), resulting in a net firm capacity gain due to the 2nd line of 22 MW. Under LOLE criteria, the Aishihik 2nd Transmission Line benefit is 8.0 MW regarding the existing Aishihik capacity plus 6.4 MW regarding the Aishihik 3rd Turbine (0.6 MW of the 7 MW would be recognized without the 2nd transmission line), resulting in a net firm capacity gain due to the 2nd line of 14.4 MW.

[19] Approximately 20-24 months are estimated to be required from commitment of the Aishihik 3rd Turbine project until it comes into service. Accordingly, this project could, if so required, be brought into service by as early as during 2008.

4.3.9 Supplemental Project Options

Supplemental project options can serve to complement the major "opportunity options" as well as the major replacement and expansion options noted above. These supplemental project options have the potential to increase capacity, but are not of a sufficient size to materially address the near term capacity shortfall forecast for WAF. These options also remain relatively undefined at this time.

a) **Other facility enhancements that are preliminary and likely far too small to address the entire forecast shortfall:** Supply-side enhancement opportunities are limited by site and/or unit specific opportunities to increase winter peak capacity. Examples under consideration include re-runnering of the two existing Aishihik units (although any new capacity would be subject to the same N-1 constraints as the existing units), and re-runnering of Whitehorse hydro units WH3 and WH4.

b) **Projects without sufficient definition to pursue in the near term:** A range of possible longer-term projects related to the Southern Lakes, as well as Atlin Lake Top Storage have the potential to increase capacity and energy outputs of the Whitehorse Rapids plant (as well as potentially to establish new generation south of Whitehorse). However, these projects are not considered to be potential options to meet near term capacity focused needs, as they are not sufficiently defined or studied at this time. Yukon Energy is currently undertaking a study to update and refine its knowledge of the specific hydrology of the southern lakes area, but until this work is completed, it is difficult to know the potential for cost-effective water management (or hydro generation) structures in the region.

c) **Projects with no reliable capacity contribution:** New wind generation, small scale run-of-river hydro generation, solar, major new DSM initiatives or various other potential new generation technologies are not typically considered by utilities to provide reliable capacity towards meeting near term capacity shortfalls of the type forecast in Yukon.

d) **Projects that require major energy load to be economic:** New storage hydro projects, biomass generation (e.g., wood), and coal generation are not considered to be feasible cost effective options to meet near term capacity focused needs. These projects can only typically be developed when systems require both capacity and sustainable new energy that would otherwise need to be supplied by higher cost options; in Yukon's case past experience has shown that these projects can only be developed on a cost-effective basis when there is sufficient energy being generated with diesel, and substantial certainty that this diesel generation would continue well into the future absent a major capital intensive new generation development of this type (see Chapter 5).

e) **Addition of new diesel generation capacity at Carcross (likely by YECL) of about 1 MW:** Carcross and the connections to Tagish are the only WAF communities of reasonable size (over about 300 people) which do not have local diesel generation installed. In the event that new diesel generation is required on WAF, it may be prudent to locate a small portion of this generation (likely about 1 MW) in the Carcross or Tagish area.

4.4 ASSESSMENT

Assessment of the above near term major project options (i.e., options costing $3 million or more for commitment before 2009) focuses on system optimization and economics for opportunity projects, and on requirement to address the new capacity planning criteria for capacity-related projects.

- **Opportunity Projects:** Assessment of the three identified opportunity projects is set out in Section 4.4.1 below. These three projects reflect both qualitative benefits from maximizing the use of existing investments and infrastructure, as well as quantitative economic benefits from enhanced hydro energy and/or capacity availability to serve loads.
- **Capacity-related projects:** Assessment based on the revised capacity planning criteria, as described in Chapter 3 (Section 3.4), is set out in Section 4.4.2 below. Under these criteria, and assuming retirement of the Mirrlees units, new capacity is needed on WAF under the Base Case in 2006 (0.7 MW), with an 18.7 MW forecast shortfall in 2012[20]. The MD system has no forecast capacity shortfalls by 2012 under the revised capacity planning criteria in the absence of new major industrial loads.

There is no economic opportunity in the near term to develop new capital intensive energy projects such as hydro or coal (without major new industrial loads at the level discussed in Chapter 5) outside of the identified opportunities regarding enhancements to existing facilities.

Resource options are assessed and/or screened over the near term and beyond, based on technical feasibility (including timing), cost efficiency and effectiveness, reliability, and risk (in particular risks related to future load requirements developing differently than indicated by current forecasts). Section

[20] Assessment based on the previous capacity planning criteria is not addressed. Under the previous criteria, and assuming retirement of the Mirrlees units, no new capacity would be needed on WAF under the Base Case until 2010 (0.6 MW), with a 5.6 MW forecast shortfall in 2012. Meeting these requirements would not require cost commitments by Yukon Energy of $3 million or more before 2009. However, even if the previous capacity planning criteria were still in place, it would remain relevant to assess the feasibility of 10 to 20 years Life Extension for the three Mirrlees diesel units at Whitehorse as a cost effective way to retain 14 MW of capacity capability on WAF.

4.4.3 below examines the expected effects of preferred near term projects on overall utility costs and rates.

4.4.1 Assessment of Opportunity Projects

There are three ways that the identified major opportunity projects can provide qualitative and quantitative benefits to Yukon power systems:

- **Peaking diesel fuel use reductions:** Although WAF loads today are at a level where surplus hydro exists on this system, peaking diesel is becoming required on the coldest days of the year and a reasonably high load growth rate is driving the system towards further requirements for peaking diesel each year. Expansion of Aishihik capacity is particularly beneficial in this regard until load growth in effect removes most of the opportunities for secondary sales.
- **Firm winter capacity benefits:** Certain enhancements to existing facilities can provide additional firm capacity to aid in meeting the WAF firm capacity shortfalls noted above. This applies to the Marsh Lake Fall/Winter Storage project and to the Carmacks to Stewart Transmission Line project, but does not apply to the Aishihik 3rd Turbine in any material way unless and until the Aishihik 2nd Transmission Line is developed.
- **Long-term average hydro energy benefits**: Finally, over the long-term, projects that bring new long-term average hydro energy can provide the ability to displace diesel fuel once loads grow to the point of diesel being required for baseload purposes (either through retail customer load growth or the addition of new industrial customers). This benefit applies to all three of the identified “opportunity” projects.

Table 4.2 provides a summary of the near term opportunity projects, including capital costs, in-service timing. Capacity and energy benefits, and present value assessments (for at least two options) of the long-term net diesel costs savings after consideration of project capital and operating costs.

Table 4.2:
Summary of Near Term Opportunity Projects to 2012 (2005$ millions)

PROJECT[21]	BASIS FOR PROJECT	PROJECT CONTRIBUTION[22]
IN PROJECT PLANNING STAGES (PRE-CONSTRUCTION ACTIVITIES, INCLUDING YUB REVIEW)		
Aishihik 3rd Turbine (2009) Capital cost: $7 million	Economic opportunity for "Supply Side Enhancement" to existing facilities.	• Hydro peaking capability (7 MW). • Long-term energy enhancement (5.4 GW.h/year). • no contribution to required firm capacity criteria without 2nd Aishihik Transmission. • Long term net diesel cost savings of $4.1 million (NPV, 2005$) under Base Case load forecasts
COMMITTED PROJECTS PROCEEDING TO PROJECT PLANNING STAGES (INCLUDING YUB REVIEW)		
Marsh Lake Fall/Winter Storage (2007) Capital cost: up to $1 million	Economic opportunity for "Supply Side Enhancement" to existing facilities.	• 1.6 MW of firm capacity toward criteria, plus • Hydro peaking capability, plus • 7.7 GW.h/year long-term energy. • Long term net diesel cost savings of $10.0 million (NPV, 2005$) under Base Case load forecasts.
Carmacks to Stewart Transmission Line Project (2008) Capital cost: $35 million funded by YTG as required to ensure no adverse rate impacts.	Expansion of WAF system to interconnect WAF and MD, and to link two mine projects to WAF hydro surplus. (YTG funding of capital cost to ensure no adverse rate impact).	• Enhance near term link for new mines to WAF hydro surplus. • No new MD supply to WAF unless connect WAF and MD systems. • Once connected, up to 6 MW of enhanced capacity for criteria, and up to 15 GW.h/year added hydro energy (decreasing over time).

[21] Table 4.2 is in 2005$. This table does not indicate the discounted present value of capital costs given in-service dates, the life of each option, or the rate-related impacts of depreciation, interest and return on equity.

[22] NPV long-term net diesel savings reflects ratepayer NPV diesel savings less NPV for capital and operating costs of the project. Present values are assessed over an assumed 65 year life based on the assumed in-service dates, a discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre (peaking) and 3.9 kW.h/litre (baseload), diesel fuel prices at $0.65/litres (2005$), diesel O&M at $0.016/kW.h (2005$) and inflation at 2%/yr. No firm capacity or secondary sales benefits are included. See Appendix C for NPV long-term net diesel savings for the Aishihik 3rd Turbine Project (without and with Marsh Lake Fall/Winter Storage).

The costs and time requirements for the identified "opportunity" projects vary significantly, and are material when assessing each option. Based on Table 4.2, the following summary observations are provided:

- **Marsh Lake Fall/Winter Storage**: The least costly option (up to $1 million estimated cost) and potentially fastest to implement option (potential in-service by fall 2007) is the Marsh Lake Fall/Winter Storage project, where the only major work required is to secure the relicencing as needed. Under these circumstances, it is readily apparent that, once developed, the project's economic benefits materially exceed its economic costs during the 20-year planning period as well as during the longer-term. Table 4.2 indicates long term net diesel savings of $10.0 million (NPV, 2005$) under Base Case loads.
- **Aishihik 3rd Turbine**: In contrast, even though the necessary licensing is in place, the Aishihik 3rd Turbine project requires both material costs (estimated currently at about $7 million) as well as material time to implement (earliest likely in-service may be 2008, but more reasonably scheduled for 2009). Under these circumstances, more detailed economic and financial assessments are needed to determine whether the project is likely to yield net economic benefits during the planning period (even though long term net benefits are likely to occur, based on assessments done in the past). Table 4.2 indicates long term net diesel savings of $4.1 million (NPV, 2005$) under Base Case loads.
- **Carmacks to Stewart Transmission Line**: This project will proceed only if Yukon Government funding ensures no adverse impact on ratepayers. Accordingly, costs are not a driver in its assessment in this Resource Plan, i.e., if developed under these terms, its costs will be required to be competitive with the least cost options then available to meet system requirements. The project is in the early project planning stages and at the earliest could be in service between mid-2008 and mid-2009.

More detailed assessment reviews are provided below of each project.

4.4.1.1 Aishihik 3rd Turbine Project

Under Base Case or higher loads without other sources of new hydro energy, the present value savings from displaced diesel for the Aishihik 3rd Turbine option are expected to offset fully its capital costs. Specific economic assessment cases are reviewed below (see Appendix C for more detailed tables setting out the economic and financial present value assessments by year over the 65 year assumed economic life of this project):

- **Base Case with no other projects:** Under Base Case conditions, assuming a 2009 in-service the present value (2005$) over the 20 year planning period of these diesel cost savings is approximately equal to the costs that would be imposed on ratepayers of the third turbine (depreciation, interest, return on equity, O&M) based on diesel prices at $0.65/litre (2005$); this present value is beneficial by $4.1 million over the 65 year life of the project[23].
  - This reflects a NPV of diesel fuel and O&M savings of $11.2 million (2005$, largely increasing throughout the period) and a NPV cost of the project (capital plus O&M) of $7.1 million.
  - It ignores benefits from increased ability to make secondary sales[24].
  - Under this scenario, the project would require 8 years from in-service until it was a net positive impact on annual rates (to 2017)[25].
  - The impact on YEC's revenue requirement in any given year over the 20 year planning period would vary from about negative $0.67 million (first year) to a savings of about $1.44 million (2022) without including any secondary sales benefits in the near term.

- **Base Case with Mines:** If Aishihik 3rd turbine is developed concurrently with about 10 MW of new mining load (the "base case with mines" scenario), the project net benefits over the 20 year planning period total $3.7 million (NPV, 2005$) and $7.9 million over the 65 year life of the 3rd turbine project. In this case, the project is a positive impact on revenue

[23] Assuming a nominal discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre for peaking and 3.9 kW.h/litre for baseload, diesel fuel prices at $0.65/litres (2005$), diesel variable O&M at $0.016/kW.h (2005$) and inflation at 2%/yr. Depreciation over 65 years is consistent with the "waterwheels, turbines and generation" category of assets as approved in the 2005 Required Revenues and Related Matters Application.

[24] Yukon Energy does not presently have sufficient load data to analyze the potential revenue benefits related to increased number of hours of secondary sales availability. In rough terms, winter secondary sales average at about 3 MW, or about $198/hour at the current 6.6 cents/kW.h rate effective January 2006 (the rate approved by the YUB in Order 2005-12 was 5.2 cents/kW.h, effective January 2005 with ongoing quarterly adjustment to reflect changes in hearing oil prices). The Aishihik 3rd turbine will reduce the number of hours of diesel generation required on the system by about 127 hours in 2009 (first year of in-service) to about 1004 in 2021. In practice, secondary sales are interrupted for much longer than actual diesel generation time, as these sales can be interrupted for 24-48 hours in advance of expected cold weather. Even at the 127-1004 hour range of actual diesel generation, added secondary revenues would approximate $25,000 to $199,000 per year over the period (prior to WAF requiring base load diesel, which would lead to a total secondary sales interruption year round).

[25] Were Marsh Lake Fall/Winter Storage developed separately in advance of the Aishihik 3rd turbine (in 2007), the NPV of the project under Base Case loads over 20 years would become negative $1.0 million, and positive $3.1 million over the life of the project (ignoring secondary sales benefits), with 9 years required from a 2009 in-service to net annual cost savings to ratepayers (by 2018). Under this scenario, and without further development of mine loads or additional load growth, a delay of 1-2 years may be advisable (decision to proceed in 2009 for in-service in 2011) which would reduce the number of years of adverse rate impact back to 7, with an NPV over the period to 2025 (reflecting only 15 years of project service to that time) of negative $0.3 million (lifetime NPV savings of $3.8 million, compared to $3.1 million if developed at 2009 after Marsh Lake, or $4.1 million if developed at 2009 with no Marsh Lake).

requirement by year 3, with the annual impact varying from negative $0.10 million (first year) to $1.44 million (2022)[26].

In summary, the Aishihik 3rd turbine project is an economically viable upgrade to the existing system that can be economically pursued in the near term. The project economics are enhanced to the degree that mine loads arise in the near term. The Resource Plan reflects commitment to this project for an in-service of 2009 (requiring major design and tendering, as well as a YEC Board of Directors decision to construct, to occur in late 2007/early 2008)[27]. Projects assessed in subsequent sections of this Chapter presume successful implementation of this project by fall 2009.

4.4.1.2 Marsh Lake Fall/Winter Storage Project:

The Marsh Lake Fall/Winter Storage project provides three sources of benefits:

1. **firm capacity** (1.6 MW towards both N-1 and LOLE),
2. **ability to avoid peaking diesel** (via extra 1.6 MW of hydro available at peak times before YEC must run diesels), and
3. **increase to long-term average energy** (7.7 GW.h but varies somewhat based on system loads).

As a source of new capacity alone, the expected costs of the project are not expected to be more than $1 million (primarily related to environmental licencing and mitigation works) and equate to $0.625 million/MW (compared to $0.8 to $0.9 million/MW for new diesel).

However, the capability to enhance the system with added peaking ability as well as added long-term average energy equally justifies the Marsh Lake project (at an expected net present value of $10.0 million in diesel savings to ratepayers (2005$) over the life of the project (at Base Case loads) with $1.9 million (2005$) of these savings occurring during the period of the Resource Plan to 2025).

[26] Were Marsh Lake Fall/Winter Storage developed separately in advance of the Aishihik 3rd turbine (in 2007) under the Base Case with Mines load forecast, the NPV of the Aishihik 3rd Turbine project over 20 years would become positive $2.6 million, and positive $6.7 million over the life of the project, with three years required from a 2009 in-service to net annual cost savings to ratepayers (by 2012). This assessment is not adversely affected if the Carmacks-Stewart Transmission Project is also developed in 2008 (see Appendix C).

[27] In the event that Marsh Lake Fall/Winter Storage is pursued, mine loads are not proceeding towards commitment, and WAF loads are below forecast through 2006 and 2007, it may become necessary to delay the decision to construct by one to two years or more, depending on load conditions and forecasts at that time, in order to minimize potential adverse rate impacts in the early years of the project.

Accordingly, the Resource Plan reflects commitment to proceeding to the licencing and detailed technical stages with this project for in-service by August 2007 or August 2008. Projects assessed in subsequent sections of this Chapter presume successful implementation of the Marsh Lake Fall/Winter storage project by August 2007.

4.4.1.3 Carmacks to Stewart Transmission Project:

This project is being examined using Yukon Government funding, on grounds separate from near term WAF capacity needs.

As Yukon Energy cannot independently justify the interconnection on any reasonable current economic grounds based on specific diesel savings or capacity benefits, the proposal to proceed with the project is solely linked to external factors related to Yukon Government funding and the development of the two mines. Accordingly, assessment of other project options in this Resource Plan does not presume development of this interconnection.

The portion of this project from Carmacks to at least Pelly Crossing is likely to be in place if and when the Minto and/or Carmacks Copper mines are supplied with WAF grid power[28]. Accordingly, if and when it becomes clear that these mine loads will develop for WAF, extension of this transmission project from Pelly Crossing to Stewart Crossing (to provide full interconnection of the MD and WAF grids) is likely in any event to be a technical option to provide WAF access to additional capacity (about 6 MW) and surplus hydro energy (about 15 GW.h).

- The cost effectiveness of this interconnection option will continue to depend on Yukon Government funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy.
- In this situation, assessments will need to consider the extent to which the surplus hydro made available under this load situation will yield WAF economic benefits during the planning period that serve to offset at least some of the capital costs through both diesel unit cost savings and extended maintenance of secondary sales revenues.
- Full assessment of this option will also need to address risks related to re-opening of the UKHM mine (or other new industrial developments) which would reduce or eliminate the MD surplus hydro, as well as potential new opportunities provided by the interconnection, such

[28] Together, these mines are currently expected to require between 9 and 11 MW of peak power, and up to about 60 GW.h/yr of energy. The added net peak load imposed on WAF by these mines will depend on the extent to which these new mining operations develop their own on-site diesel plants either for backup or other reasons (potentially including interim operation prior to the arrival of utility power, or for benefits associated with waste heat during certain seasonal operations).

as potential additional enhancements for the existing Mayo hydro facility (including enhanced peaking capability) or other new generation opportunities in the MD area.

4.4.2 Assessment of Capacity-Related Projects

With the adoption of new capacity planning criteria, major investments in the near term are required to adequately serve forecast WAF loads. This conclusion is consistent over a wide range of possible load forecast conditions, which indicate WAF capacity shortfalls beginning in 2006 and increasing to between 15 MW and 27 MW by 2012 for the current customer classes plus potential mining operations. In contrast, the MD system has no forecast capacity shortfalls by 2012 under the revised capacity planning criteria in the absence of new major industrial loads.

Based on assessment of the "opportunity" projects reviewed in Section 4.4.1 above, the Resource Plan assumes commitment to the Aishihik 3rd Turbine project for in-service at 2009 and to the Marsh Lake Fall/Winter Storage project for an in-service date of August 2007. Accordingly, these projects are assumed to be in-service at the noted dates for the purposes of assessing the requirement for capacity-related projects. However, because the proposal to proceed with the Carmacks to Stewart Transmission Line project is solely linked to external factors related to Yukon Government funding and the development of the two mines, assessment of capacity-related project options does not presume development of this interconnection. Accordingly, the possibility of the Carmacks to Stewart Transmission Line project (as an option) is included in the assessment of the capacity-related project options.

Table 4.3 summarizes the capital cost (2005$) estimates outlined in Section 4.3 for screening purposes related to the near term major resource options to address capacity shortfall requirements. These initial screening cost estimates assume additional diesel units as the default option to provide any remaining capacity needed beyond that provided by the major project option, as well as the opportunity projects presumed to be in place (Aishihik 3rd turbine at 2009 and Marsh Lake Fall/Winter Storage at 2007)[29].

[29] Capacity required over and above major project options are lower than noted in *Section 4.3 Options* due to the assumed in-service of Marsh Lake Fall/Winter Storage in 2007 and Aishihik 3rd turbine (where relevant) in 2009.

Table 4.3:
Comparison of Near Term Capacity-focused Options to 2012
Assuming Marsh Lake Fall/Winter Storage in 2007 and Aishihik 3rd Turbine in 2009
Without Carmacks to Stewart Transmission Project Interconnection of WAF and MD
(Capital costs (2005$ millions) - No present value assessments)

MAJOR PROJECT OPTIONS	**ADDITIONAL DIESEL REQUIREMENT BY 2012 and costs if met with new diesel capacity**[30]						**TOTAL COSTS TO 2012**
	Base Case Loads		***Low Sensitivity***		***High Sensitivity with Mines***[31]		
	Capacity	Cost	*Capacity*	*Cost*	*Capacity*	*Cost*	
Mirrlees Life Extension (14 MW; $3.0 to $4.5 million)	3.1 MW	$2.5 to $2.8 million	*0 MW (0.9 MW surplus)*	*$0*	*10.5 MW*	*$8.4 to $9.5 million*	**Base Case**: $5.5 - $7.3 million **Range**: $3.0 - $14 million
Whitehorse Diesel Replacement / Expansion (expected maximum of 33 MW[32])	17.1 MW	$13.7 to $15.4 million	*13.1 MW*	*$10.5 to $11.8 million*	*24.5 MW*	*$19.6 to $22.1 million*	**Base Case:** $13.7-$15.4 million **Range**: $10.5 - $22.1 million
Aishihik 2nd Transmission Line in 2009 (22 MW at N-1 and 14.4 MW at LOLE; $16.0 to $19.0 million)[33]	0 MW (4.1 MW surplus)	$0	*0 MW (8.1 MW surplus)*	*$0*	*10.1 MW*	*$8.1 to $9.1 million*	**Base Case**: $16.0 - $19.0 million **Range**: $16.0 - $28.1 million

[30] Costs to meet calculated shortfall in capacity, at $0.8-$0.9 million per MW (2005$) – assessment does not reflect optimization of unit size increments. Estimates assume Carmacks to Stewart Transmission is not developed (with development of this project, capacity shortfalls to be supplied by additional diesel would be reduced by about 5 to 6 MW in 2012).

[31] The Base Case with Mines capacity shortfalls in 2012 are 5.2 MW less than shown here for High Sensitivity with Mines.

[32] Capital costs at $0.8-$0.9 million per MW (2005$); 33 MW is expected to be possible at the existing Whitehorse Rapids diesel plant using 3 - 11 MW units. Beyond 33 MW, consideration is required of site options given limitations of existing building and site.

[33] If an Aishihik 2nd transmission line is constructed, the WAF system capacity requirements become driven by the LOLE criteria not the N-1. Consequently, although the Aishihik 2nd transmission line provides 22 MW load carrying capability under the N-1 criteria, and 14.4 MW under the LOLE criteria, the net effect of constructing the line under the Base Case conditions is 21.2 MW (from a 17.1 MW shortfall to a 4.1 MW surplus at 2012), reflecting that with the 2nd line the LOLE criteria rather than the N-1 criteria creates the ultimate capacity requirement.

Assessment of options to address near term requirements remains dependent upon ongoing investigations to define in more detail each option's conditions and costs. The major Resource Plan near term options to address capacity shortfalls are assessed below in light of current information and the revised capacity planning criteria requirements. The assessment is addressed under two main situations regarding the technical feasibility of the Mirrlees Life extension option, assuming that it will be determined within the next few months to be either feasible or not feasible.

4.4.2.1 Assuming Mirrlees Life Extension Project is Technically Feasible

If the Mirrlees Life Extension project is technically feasible, this is the clear least cost option to provide 14 MW of reliable near term capacity. At $3.5 to $4.5 million for all three units, this option costs from $250,000 to $321,000 per MW. These costs are well below those needed for diesel replacement/expansion (at $800,000 to $900,000 per MW), or the costs for an Aishihik 2nd transmission line. Mirrlees Life Extension can also be developed incrementally as needed.

Notwithstanding these obvious advantages, serious technical issues are still being addressed to determine if this option is feasible and capable of providing full life extension of 10-20 years (including all required parts and technical support from the manufacturer). It is expected that an initial decision will be made in first quarter of 2006 based on an assessment of the capability of the manufacturer to provide technical resources and support, references of other utilities who have pursued life extension options with similar Mirrlees units, and refined expected costs of the option based on further assessment of both overhaul requirements and shared facility requirements (which are ongoing).

If the Mirrlees Life Extension option is determined to be feasible and acceptable on technical grounds, a series of steps and assessments will remain to address the expected near term capacity shortfalls and other near term resource development opportunities. These assessments are set out below:

1. **Proceed with initial Mirrlees 5 MW Unit Life Extension project in 2007**: The first step will involve Yukon Energy contracting out a first "teardown" level of overhaul on one of the units to occur during the summer of 2007 (focusing likely on the 5 MW unit to be retired currently in 2007). The common diesel plant upgrade work would also be undertaken at the same time (at an estimate cost of $1.0 to $1.5 million). Yukon Energy is proposing this schedule in light of the current expectation that the maximum cost commitment for this first unit would not exceed $2.5 million (2005$). Under this scenario, the WAF system would experience an expected capacity shortfall during the winter of 2006/07 of about 0.7 MW prior to the planned capacity work in 2007.

2. **Proceed with the other two Mirrlees unit Life Extensions in 2008 and 2009**: The other two unit Life Extension projects would be proceeded with on a timely basis. Prior to proceeding with each of these projects, which are currently expected to cost up to $1.0 million (2005$) per unit, Yukon Energy would review the experience gained from Life Extensions carried out to date.

3. **Preferred Options to meet the Remaining Capacity Shortfall on WAF (3.1 to 10.5 MW)**: Even with provision of 14 MW from the Mirrlees Life Extension project, Yukon Energy will still need under the Base Case load conditions to develop at least an additional 3.1 MW new capacity by 2012 (and this added requirement could range up to 10.5 MW under the high load cases examined). Adoption of the Life Extension option will affect the assessment of the other remaining options to provide the balance of the capacity requirement (based on the assessments below, the Carmacks to Stewart Transmission Line Project, if developed with Yukon Government funding, could provide a preferred way to provide up to about 6 MW of added firm capacity):

   a) **Whitehorse Diesel Expansion options would be limited - may need to assess other locations for additional diesel unit units as a default option:** The option of developing Whitehorse Diesel Expansion might not be feasible within the current building or even potentially at the current plant site under these conditions, and it may be necessary to assess other locations for any additional diesel unit options. Costs for diesel expansion at a new location as a default planning option involving 4 MW or larger units are likely to approximate $1 million per MW. A variation that may merit consideration is Life Extension on the two larger (5 MW nameplate) Mirrlees units, plus replacement of the smaller Mirrlees unit (4 MW nameplate) with an 8 or 11 MW new unit to secure the needed capacity.

   b) **2nd Aishihik Transmission Line not likely to be cost effective option:** The Aishihik 2nd Transmission Line project by itself is not likely to be cost effective in the near term under these conditions, given its cost (currently estimated at $16 to $19 million) and its “lumpy” delivery of 22 MW of effective capacity all at one time.

   c) **Carmacks to Stewart Transmission Line can be attractive with Minto and Carmacks Copper Mine Loads:** The portion of this project from Carmacks to at least Pelly Crossing is likely to be in place if and when these mines are connected to the WAF grid. Accordingly, if and when it becomes clear that these mine loads will develop for WAF, extension of this transmission project from Pelly Crossing to Stewart Crossing (to provide full interconnection of the MD and WAF grids) is likely in any event to be a

technical option to provide WAF access to additional capacity (about 6 MW) and surplus hydro energy (about 15 GW.h); the cost effectiveness of this option may also be resolved based on Yukon Government funding to ensure no adverse effect on ratepayers relative to any other option. (See Section 4.4.1.3 for further review of this option. [34])

4.4.2.2 Assuming Mirrlees Life Extension is Not Technically Feasible

If the Mirrlees Life Extension project is not technically feasible and the Mirrlees units must be retired, the key initial decision becomes whether or not to develop the Aishihik 2nd Transmission Line Project. As noted in Table 4.3, the Aishihik 2nd Transmission Line fully addresses the capacity requirements of the Base Case loads.

In summary the near term choice under these conditions is between the Aishihik 2nd Transmission Line Project (22 MW of near term capacity benefits under N-1, 14.4 MW under LOLE)[35], versus reliance on major Whitehorse Diesel Replacement/ Expansion for at least the same amount of new near term capacity (17.1 MW, with potential to range from 13.1 MW to 24.5 MW). As reviewed below, current information does not necessarily indicate a clear preferred approach under these conditions. Ongoing investigations will continue to assess these options if it becomes clear that the Mirrlees Life Extension option is not technically feasible.

Technical, cost and risk issues assessed with regard to this choice (see below) underline the nature of the problems and opportunities associated with selecting the Aishihik 2nd Transmission Line option at this time rather than pursuing Whitehorse Diesel Replacement/Expansion on an incremental basis in the event that the Mirrlees Life Extension is not feasible:

1. **Cost effectiveness of capacity benefits for Aishihik 2nd Transmission Line option is affected by several factors**: Initial review of capital costs per MW indicates that the Aishihik Transmission Line option is likely to cost from $0.73 to $0.86 million per MW (2005$) under the N-1 condition (from $16 to $19 million, to provide 22 MW) or from $1.11 to $1.32 million per MW (2005$) under the LOLE condition (for 14.4 MW firm load carrying capability).

[34] Assuming Mirrlees Life Extension is implemented, the Carmacks to Stewart Transmission Line would displace up to about 6 MW (depending on the load case assumed) of new diesel expansion capacity costing about $1 million per MW (2005$).

[35] Given that the Aishihik 3rd Turbine is economic on its own for energy-related reasons in the near-term, the benefits of the Aishihik 2nd Transmission line are 22 MW under N-1 (i.e., if Aishihik 3rd Turbine is already built prior to the line, the line would serve to reduce the "N-1" factor from 37 MW (the total capacity output of Aishihik) to 15 MW (the largest single wheel at Aishihik).

2. The cost effectiveness of this option is affected by several factors:
   - Transmission Line Capital Cost is lower than comparable Diesel Replacement/Expansion Capital Cost under non-industrial scenarios: This transmission project capital cost under N-1 is estimated to be slightly lower than the capital cost (2005$) expected for Whitehorse Diesel Replacement/Expansion ($0.8 to $0.9 million per MW). This however ignores the addition risks related to transmission line cost estimating compared to new diesels, as set out below.
   - Transmission Line Capital Cost is higher than diesel if LOLE criteria applies with sufficient mine development: The cost competitiveness of the Aishihik 2nd Transmission Line option is eroded in the event that mine development is sufficient to reduce its effective capacity contribution to only 14.4 MW (in the event that the LOLE criteria becomes dominant over the N-1 criteria).
   - Added Offset benefits possible from Aishihik 2nd Transmission Line if develop future Aishihik capacity via re-runnering: The Aishihik 2nd transmission line enables the opportunity for other potential capacity-related projects at Aishihik (as yet relatively undefined) focused principally on re-runnering the existing units for added capacity output of potentially up to 6 MW. Although this potential future project has not been costed or had sufficient technical or environmental analysis (such as flow velocities), re-runnering is often viewed in other jurisdictions as a cost-effective way to enhance the existing system for added capacity (and/or energy). Without the Aishihik 2nd Transmission Line project, it is unlikely that rerunnering at Aishihik would be economic (sicne it would not provide any effective ability to contribute to firm WAF capacity during the winter peak).

3. **Timing and Cost Risk Concerns with Aishihik 2nd Transmission Line options:** Key concerns with regard to the Aishihik 2nd Transmission Line Project include the timing and substantial costs needed to deal with planning, permitting, and approvals prior to receiving solid capital cost estimates via the tendering process. If a preliminary commitment to the project was in place in 2006, planning and firm cost estimates would not likely be completed until well into 2007 at the earliest and the transmission line's in-service would in all likelihood be no earlier than 2009. During the period to 2009, capacity shortfalls on the WAF system would grow to 7.1 MW (related to both load growth and retirement of the first Mirrlees WD3). On these matters (timing, and the delayed certainty with respect to cost estimates, and the risks of capacity shortfalls in the interim) the Whitehorse Diesel Replacement/Expansion option is expected to have a clear advantage.

4. **Load Risk Concerns with Aishihik 2nd Transmission Line options:** The potential cost effectiveness of the Aishihik 2nd Transmission Line combined with the Aishihik 3rd Turbine project is dependent on load conditions. This is because the project provides more capacity than is required at 2012 under the Base Case and Low Sensitivity scenarios, but is of lesser capacity value under the very high sensitivity case scenarios with mines (14.4 MW, compared to 22 MW under N-1) which clearly exceed Base Case forecasts[36] while also not becoming so high due to new industrial mine loads as to cut back the effective capacity benefits[37].

5. **Issues regarding 2nd Transmission Line Overlap with Carmacks to Stewart Project:** Concurrent development of the Carmacks to Stewart Transmission Line project with the Aishihik 2nd Transmission Line Project could create adverse overlap issues for Yukon Energy with regard to planning, permitting, design and construction if the Carmacks to Stewart project is proceeding as reviewed in 4.4.1. Conversely, in the even of the Base Case with Mines loads, the two project could together meet the overall capacity shortfall by 2012[38].

6. **Carmacks to Stewart Transmission Line can be attractive with Minto and Carmacks Copper Mine Loads:** The portion of this project from Carmacks to at least Pelly Crossing is likely to be in place if and when these mines are connected to the WAF grid. Accordingly, if and when it becomes clear that these mine loads will develop for WAF, extension of this transmission project from Pelly Crossing to Stewart Crossing (to provide full interconnection of the MD and WAF grids) is likely in any event to be a technical option to provide WAF access to additional capacity (about 6 MW) and surplus hydro energy (about 15 GW.h); the cost effectiveness of this option may also be resolved based on Yukon Government funding to ensure no adverse effect on ratepayers relative to any other option. (See Section 4.4.1.3 for further review of this option.)[39].

[36] This option is clearly not cost effective even when assessed over 40 years to 2045 under the Low Sensitivity case. Even under Base Case loads, securing 40-year net present value benefits can be very sensitive to assumed costs and diesel saving magnitudes.
[37] Net benefits over 40 years, for example, will be minimal under some cost and diesel saving assumptions at 25 MW mine loads.
[38] Under such joint development without Mirrlees Life Extension, the Carmacks to Stewart Transmission would displace about 5 MW of new diesel costing about $0.8 to $0.9 million per MW (2005$).
[39] Regardless of the selection of Aishihik 2nd Transmission project or Diesel Replacement/Expansion (assuming Mirrlees Life Extension is not implemented), in the event that the Minto and Carmacks Copper mines are developed the Carmacks to Stewart Transmission Project would appear likely to displace by 2012 up to about 6 MW of new diesel costing $0.8 to $0.9 million per MW.

4.4.3 Schedule and Sequencing of Alternatives

Based on the review of opportunity and capacity-related projects above, the potential scheduling and sequencing of these near term projects is illustrated in Figure 4.15.

As indicated in Figure 4.15, both opportunity projects and capacity-related projects are required to be initiated and pursued in the near term to address constraints (Marsh Lake Fall/Winter Storage and Capacity-Related projects to address capacity shortfalls; Carmacks-Stewart Transmission Line to address opportunity to service mines in the region, as well as access YTG infrastructure funding).

The exception to current timing constraints is the Aishihik 3rd turbine. This project has some flexibility regarding the scheduling and in-service date (as it does not contribute to firm capacity shortfalls). As indicated in Appendix C, the economics of the project are considerably improved if it is in service as of the start of any new mining loads. However, without new industrial loads and with Marsh Lake Fall/Winter Storage proceeding, it may be advantageous to delay Aishihik 3rd turbine by about two years compared to the timing in Figure 4.15; this decision can be part of the late 2007 assessment by YEC as to whether to proceed with the project at that time.

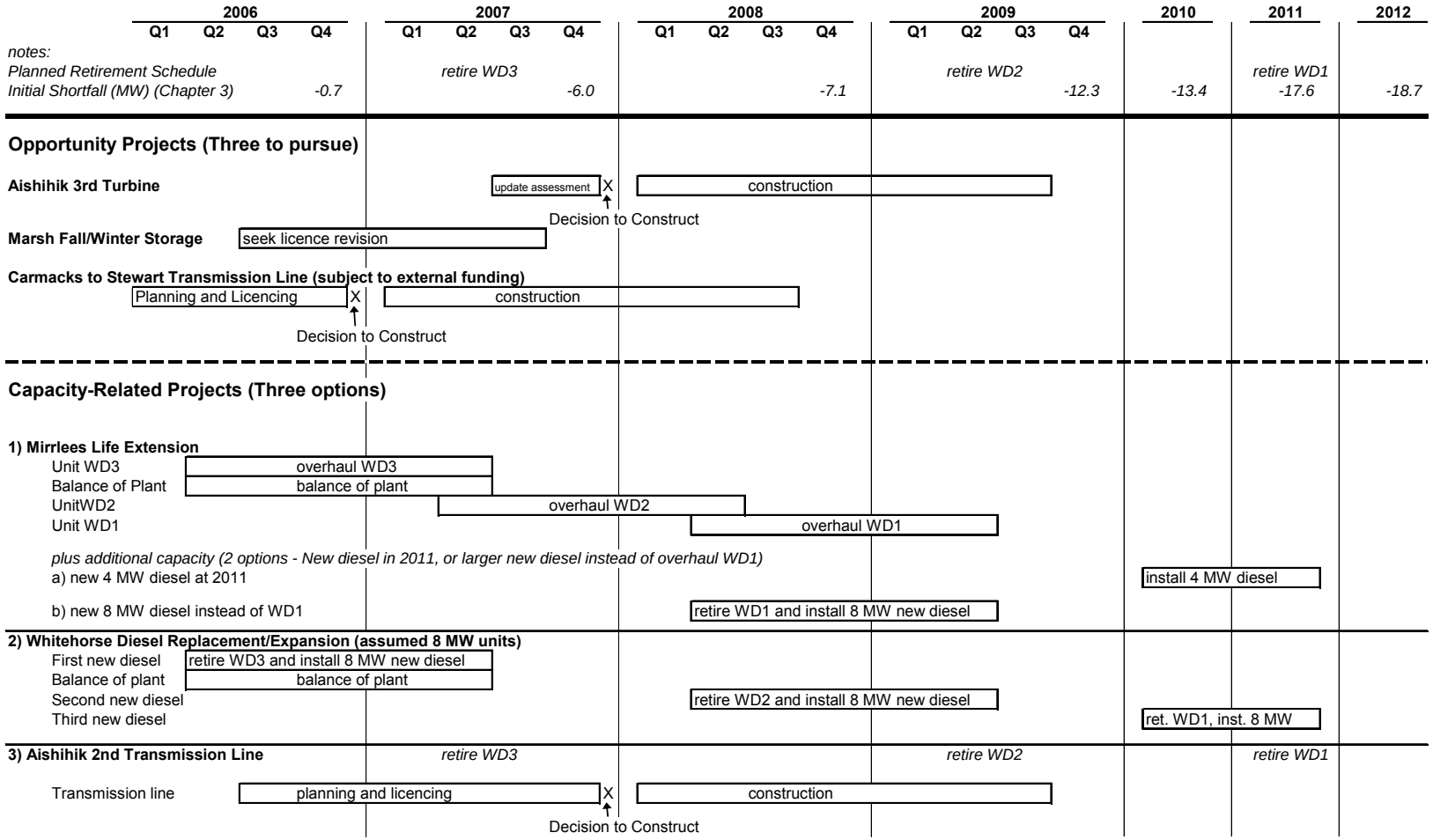
4.4.4 Rate related Impacts of Near Term Options

This section provides a brief examination of the expected effects of preferred near term projects on overall utility costs and rates.

Separate financial assessment is required of the effect of any project on rates, as rates for any given year are set based on annual costs (including depreciation, interest and return on equity) rather than the lifetime long-term costs of projects in service. For capital intensive projects such as hydro or transmission, these annual costs tend to be at a maximum in the first few years of the project (when rate base balances are highest) while benefits can in many cases extend and grow many years into the future (50-100 years in some cases).

Under current rates and OIC 1995/90, Yukon-wide rate impacts are likely to arise of about 1% if utility costs (revenue requirements) are increased in any one year by $360,000 compared to alternatives.

Figure 4.15:
Timing and Sequencing of Opportunity and Capacity-Related Projects



Two key aspects of rate impacts arise with respect to the near term projects:

1. **Opportunity Projects seek to put in place economic assets that provide long-term benefits:** The relative rate impacts of the three opportunity projects vary depending on the particulars of the project:
   a) **Aishihik 3rd turbine:** As reviewed in *section 4.4.1*, the Aishihik 3rd turbine project provides long-term rate benefits. In the first years of the project, however, there is the potential for adverse rate impacts (see Appendix C for more detailed tables):
      i. **Base Case Assumptions:**, Under Base Case assumptions, much like other capital intensive hydro projects, the annual costs of the project will outweigh the annual benefits for a number of years (until offset by inflation and load growth). At a maximum (year 1 if developed in 2009) this impact will be less than 2%, which declines through 2017 (2018 if develop Marsh Lake Fall/Winter Storage first) after which it becomes a positive and growing rate benefit.
      ii. **Base Case with Mines:** If about 10 MW of new industrial loads are connected to the system in the near term (consistent with the two mines now proposed north of Carmacks), the maximum adverse rate impact (year 1 if developed in 2009) will be 0.3% (0.9% if Marsh Lake Fall/Winter Storage previously developed), and by year 3 will be a positive and growing rate benefit compared to the situation without the project (year 4 if Marsh Lake Fall/Winter Storage previously developed).

      In this case, some benefits of the capital intensive Aishihik 3rd turbine increase each year as the value of diesel displaced increases with inflation or other upward fuel price drivers. However, the Aishihik 3rd turbine project imposes the highest costs on ratepayers in the early years.

      In summary, although very attractive economically over the long-term, the Aishihik 3rd turbine project will result in adverse rate impacts in the first year of the project under all near term cases assessed (0.3% to almost 2%), with this impact lasting 2-8 years (this is similar to the MD Transmission Project, which was forecast to be a beneficial project for ratepayers over its life, but did result in the need to address what would otherwise have been adverse rate impacts in the first two years via flexible debt financing from YDC).
   b) **Marsh Lake Fall/Winter Storage:** This project brings firm capacity, peaking capacity and long-term energy benefits. The costs of the project (estimated at no more than $1 million) reflect a maximum cost for the firm capacity of $0.625 million/MW, which is

cheaper than new diesel (assuming all capital costs of the Marsh Lake project are calculated in the cost/MW, ignoring energy benefits). Ignoring energy benefits, the capital-related costs of Marsh Lake at the maximum $1 million level would drive annual depreciation costs of $0.016 million plus interest and return on equity costs in the first year of about $0.078 million plus O&M costs of about $0.005 million. At a maximum, the project will be an upward rate driver of about 0.28%, offset by the savings in peaking diesel (which exceed this level by 2013).

c) **Carmacks-Stewart interconnection:** This project will only be developed if funded via no-cost capital (e.g., Yukon government funding) to a level that ensures no adverse rate impacts on ratepayers. The value of a potential Carmacks-Stewart interconnection will erode over time if the surplus hydro energy and installed capacity available for exchange between the two grids from this project reduce over time with load growth (or new industrial loads) on either system (as will occur at some point if load growth continues without development of new lower cost capital intensive energy resources). However, this limit only occurs to the extent that the flexibility provided by the interconnection does not enable development of attractive new generation projects (such as facility enhancements at the existing Mayo plant or other hydro opportunities in the MD area).

2. **Cannot avoid investment in new capacity, which will tend to be upward rate driver:** The adoption of the revised capacity planning criteria requires that under Base Case load assumptions a material investment in new capital spending will be required by 2012 assuming Mirrlees life extension is implemented, and higher investment if other alternatives are pursued. This amount is over and above normal utility capital amounts for re-investment and facility renewal (which tend to have a relatively stable impact on rates). The major new capacity-driven capital spending to 2012 results in relatively little change to other utility costs. The resulting rough estimations of gross impacts on rates at 2012 are as follows for the screening options noted in Table 4.3[40]:

a) **Mirrlees Life Extension:** With a $5.5 million to $7.3 million capital investment by 2012 (2005$), resulting revenue requirements are likely to be increased by about $0.6 million to $0.8 million (at about 30 years depreciation on diesel assets and 7.52% average cost of capital) or in the range of 1.7% to 2.2% impact on rates.

[40] The calculations do not reflect estimated rate base values at 2012, which would be higher than simple capital cost estimates due to inflation between 2005$ and the actual date of in-service, and be reduced by depreciation from the date of in-service to 2012.

b) **Whitehorse Diesel Replacement/Expansion:** At an estimated Base Case requirement for $13.7 million to $15.4 million capital investment by 2012 (2005$), resulting revenue requirements are likely to be increased by about $1.5 million to $1.7 million (at 30 years depreciation on diesel assets and 7.52% average cost of capital) or in the range of 4.1% to 4.6% impact on rates.

c) **Aishihik 2nd transmission line:** Base Case costs of $16.0 million to $19.0 million (2005$) by 2012 (at 50 years depreciation for transmission line, 7.52% average cost of capital) with resulting annual costs of $1.5 million to $1.8 million, or rate impacts in the range of 4.2% to 5.0%.

The gross impacts noted above are full impacts to address capacity shortfalls to 2012 under the revised criteria. These gross impacts do not address the fact that major capital spending is required by 2012 even under the previous capacity planning criteria to address a shortfall of 5.6 MW under Base Case loads[41].

4.5 PROPOSED ACTIONS

Four separate major investments are proposed for Yukon Energy generation and transmission commitment before 2009, three with anticipated costs of $3 million or more. These proposed major projects will address near term requirements and opportunities to 2012 and together will provide over 21 MW of new WAF firm winter capacity by 2012 (i.e., enough new firm capacity to meet WAF capacity shortfalls that would otherwise be expected by 2012 of 18.7 MW under the Base Case forecast and 21.5 MW under the Base Case forecasts plus the Minto and Carmacks Copper mine loads). The four major proposed projects are reviewed below, along with contingency provisions and other proposed actions before 2012:

1. **Aishihik 3rd Turbine Project:** This project, which was initially reviewed in the 1992 YUB Resource Plan hearing, will provide 7 MW of added peaking capability[42] and about 5.4 GW.h/yr of long-term average hydro energy supply at the existing Aishihik generation station at a capital cost of about $7 million (2005$). Under Base Case loads without any new industrial developments, this project is expected to be economic within the planning period to

[41] If full Mirrlees Life Extension is pursued under Base Case loads under the previous criteria (to secure 14 MW of capacity by 2012, but worth 12.6 MW under the existing capacity planning criteria due to 10% diesel reserve factor, securing a 7.0 MW surplus and ensuring the units are not lost to disrepair and neglect), an estimated $3.0 to $4.5 million in capital costs would be expected to be incurred, for an annual rate impact cost of about $0.3 to $0.5 million or 0.9% to 1.4%.

[42] Without twinning of the Aishihik Transmission Line, none of this added Aishihik capacity is recognized under the N-1 WAF capacity planning criteria, and only 0.6 MW is recognized under the LOLE WAF capacity planning criteria.

2025 based solely on its diesel operating cost saving benefits for the WAF grid, including displacement of peaking and then baseload diesel as WAF loads increase. Yukon Territorial and environmental approvals for the project were received in the new Aishihik Water Licence.

a) Accordingly, this project will proceed with final planning activities to enable a final decision during 2007 to start construction for in-service by October 2009.

b) If Marsh Lake Fall/Winter Storage is developed without any additional non-industrial load growth or new industrial loads emerging, the final decision to start construction is proposed to be deferred until late 2009 for in-service in 2011 or 2012.

2. Marsh Lake Fall/Winter Storage licence revision: This project, which was not reviewed in the 1992 Resource Plan hearing, will increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and increase long-term average hydro energy from this facility by about 7.7 GW.h/year at a capital cost of no more than $1 million.[43] Yukon Energy will undertake the project planning activities, including consultation and environmental licensing, as required to seek amendment of the Whitehorse Rapids water licence to enable modified operation of Marsh Lake within its current lake levels to enhance fall/winter storage. Basically no new physical works are expected to be required for this project. Project approval is forecast by August 2007 (although provision is made in the event that the new Yukon environmental licencing regime requirements delays completion of the licence amendment to 2008). The effects of the proposed licence amendment are summarized as follows:

a) **Remain within current lake level limits:** In all cases, the water levels with the amended licence will remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake).

b) **Licence amendment changes the "controlled maximum" level:** The proposed amendment would change the licenced "controlled maximum" level that YEC can maintain upwards by about one foot; however, during uncontrolled periods of summer and fall (when YEC currently has no control over the lake and it is operating under an entirely natural regime), Marsh Lake has been known to peak at two feet above the YEC "controlled maximum" level. The effects of the proposed change are as follows depending on water conditions:

[43] This estimated capital cost is made up of the costs for licencing, any required mitigation works and any potential facility modifications

i. **Non flood year operation other than a drought:** This project would allow Yukon Energy to reduce the amount of water it releases in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period. No effect is to occur under these conditions in any year prior to August 15, other than under drought conditions (see below).

ii. **Flood year operation:** During flood years, there would be no change in the flood levels experienced on Marsh Lake, and no change to operations would be made during August and September until after flood levels subside.

iii. **During drought years:** Current licence provisions to help alleviate summer drought levels on Marsh Lake through "early closures" of the Lewes Dam would remain, and would likely be adapted to alleviate further summer drought conditions to ensure the lake reached the full supply capacity level in each year.

3. **Carmacks-Stewart Transmission Line Project:** This project will fully interconnect the MD and WAF grids as well as facilitate WAF transmission access to potential new mine loads at Minto and Carmacks Copper, providing 5.6 MW of additional firm near term capacity and 15 GW.h/year of additional near term energy for WAF[44]. Development of this project, which is estimated to cost about $35 million (2005$), is subject to provision of Yukon Government funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy. Based on external funding to assure no adverse impact on ratepayers from project development, planning activities will proceed with the Carmacks-Stewart project to enable a decision to proceed with construction early in 2007 for an in-service date in approximately late 2008.

4. **Mirrlees Life Extension Project:** Subject to confirmation of technical feasibility that is expected to be determined within the first quarter of 2006, the Mirrlees Life Extension Project will conclude final planning activities in 2006 in order to provide in-service during 2007 through to 2009 to provide an additional 14 MW of firm WAF capacity at a cost of up to $4.5 million (2005$).

[44] Added capacity and energy supplied to WAF by this interconnection are subject to MD loads, and will decline as MD loads increase. Reopening of the UKHM mine or other new industrial developments on MD, for example, would reduce MD surplus capacity and hydro energy available to WAF. In contrast, potential additional enhancements at the existing Mayo hydro facility or other new generation opportunities in the MD area could enhance overall WAF/MD power supply in the event of Carmacks-Stewart Transmission line development.

a) **First Mirrlees unit in service by October 2007:** By the summer of 2006 planning work and commitments for construction/implementation will begin on the first Mirrlees unit (5MW) at a cost of up to $2.5 million (2005$)[45] in order that in-service will occur before October 2007.

b) **Other two Mirrlees units by October 2008 and 2009**: Life Extension for the other two Mirrlees units will proceed thereafter for expected in-service in 2008 and 2009, subject to review of the experience gained from Life Extension of the first unit and the possible Yukon Energy consideration of replacing the third Mirrlees unit (4 MW) with a larger capacity new diesel unit (e.g., 8 MW or 11 MW unit).[46]

5. **If Mirrlees Life Extension is not technically feasible, implement diesel replacement/expansion and/or other project options as appropriate:** Without the Mirrlees Life Extension option providing 14 MW of firm capacity, the key near term choice is between the option involving Whitehorse Diesel Replacement/Expansion (capability for three units with combined capacity of up to at least 33 MW) versus the Aishihik 2nd Transmission Line (providing 22 MW under N-1 criteria and about 14.4 MW with LOLE criteria)[47].

Although the expected capacity shortfall can technically be met with the Aishihik-related option, this is not expected to be the lowest cost option to 2012 under Base Case loads and also this is not the lowest cost long-term option under higher loads including mines. The Aishihik-related option also exposes the WAF grid to near term and growing capacity shortfalls until it is completed.

Accordingly, the Diesel Replacement/Expansion option will be implemented as follows in the

[45] This cost includes a "teardown" level of overhaul and the common diesel plant upgrade work necessary to undertake the Mirrrlees Life Extension Project.

[46] In the event that Mirrlees Life Extension proceeds but the Carmacks-Stewart Transmission Line is not developed in the near term, replacing the third Mirrlees unit with an 11 MW new diesel would more than replace the capacity that otherwise would have been provided by the Carmacks-Stewart Transmission Project.

[47] In this context, the Aishihik-related option has been examined for possible implementation assuming that it is feasible to commit development of the Aishihik 2nd Transmission Line by 2009 at the latest; under this option, material near term capacity shortfalls would still occur until the Aishihik 2nd Transmission Line was in service.

event that Mirrlees Life Extension is not technically feasible[48]:

a) **First Diesel Unit (8 to 11 MW) needs to be installed by October 2007** Yukon Energy will need under these circumstances to proceed with final planning work on this project by summer 2006, including orders for the necessary engine unit (with cancellation provisions) in order that the unit can be installed by October 2007 at a capital cost (2005$) of up to about $7.2 million (8 MW) or $8.8 million (11 MW). This will include updating any common diesel plant systems necessary for connection of a new unit.

b) **Other Diesel Units**: Once the first unit is committed, it is expected that up to two additional diesel units (depending on the unit size selected) will be implemented thereafter as required for in-service before 2012.

6. **Ongoing monitoring of existing customer load forecasts and new industrial development opportunities:** In order to facilitate ongoing assessment of generation and transmission options and requirements, Yukon Energy monitoring of annual customer class load trends (peak capacity and seasonal energy) on each grid is required. In addition, Yukon Energy will continue to monitor directly with developers and government specific new industrial development opportunities for grid power service, including assessment of any mine site power contribution to the supply of reliable grid peak capacity.

7. **Other Small Enhancement Projects:** Continued routine utility investment is recommended in assessing and proceeding with projects to enhance existing facilities at a cost less than $3 million. This includes:
   - study of the hydrology of the Southern Lakes, and potentially pursuing small water control structures in this region (new generating stations to manage water plus generate hydro power would, if proposed in the future, exceed $3 million);
   - continued pursuit of opportunities to cost-effectively rewind or re-runner existing hydro generating units at Whitehorse and Aishihik; and,
   - assessing need and timing for a potential 1 MW diesel unit installation at Carcross/Tagish (likely by YECL).

[48] Diesel Replacement/Enhancement will also be the option pursued as required in the event that other major projects do not proceed as proposed, e.g., the Carmacks-Stewart Transmission Line Project (which is assumed to provide 5.6 MW by late 2008) and/or the Marsh Lake Fall/Winter Storage (which is assumed to provide 1.6 MW by fall 2007 or 2008). In the event that mine loads are connected to WAF without completion of the Carmacks-Stewart Transmission, Yukon Energy will review the feasibility of the Aishihik 2nd Transmission Line project.

5.0 INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

This chapter addresses planning activities that Yukon Energy may be required to carry out in order to be able to start construction on generation and transmission projects before 2016 (beyond those projects noted in Chapter 4 for commitment in the near term before 2009), largely to meet the needs of potential major industrial customers.

Industrial development scenarios and opportunities include possible new mines, or other major potential developments in Yukon including the Alaska Highway Natural Gas Pipeline project. This chapter focuses on project resource options that have the potential to meet the new capacity and energy needs associated with four potential industrial development scenarios (10 MW, 25 MW and 40 MW industrial development scenarios, and the Alaska Highway Pipeline).

The sections for this chapter are as follows:

- Section 5.1: Planning Approach and Timeline
- Section 5.2: Requirements
- Section 5.3: Options
- Section 5.4: Pre-Assessment and Screening
- Section 5.5: Proposed Actions

5.1 PLANNING APPROACH AND TIMELINE

Planning activities to proceed with other generation or transmission projects beyond 2009 and before 2016 are being driven by the potential needs of a diverse range of possible major industrial developments and the possible energy requirements and/or opportunities related to such developments[1].

Chapter 4 has shown that new near term industrial loads of up to 10 MW within the 20 year planning period typically give rise to capacity-focused resource options[2]. In contrast, new industrial loads above 10 MW within the 20 year planning period may create opportunities for energy-focused resource projects.

[1] Section 4.2.4 shows, under Base Case loads (without new industrial loads), WAF diesel generation remains below 10 GW/h/year until after 2020, and increases only to 28 GW.h/year in 2025. Near term development of the Aishihik 3rd Turbine and Marsh Lake Storage as proposed in Chapter 4 would reduce this Base Case WAF diesel generation, e.g., to about 15 GW.h/year in 2025.

[2] Near term WAF industrial loads of up to about 10 MW could increase this Base Case WAF diesel generation to about 40 GW.h by about 2016 (with development of Aishihik 3rd Turbine and Marsh Lake Storage as proposed in Chapter 4, this WAF diesel generation would be about 25 GW.h/year in 2016); however, in Section 4.2.6 such new near term mine loads are not expected to be sustained beyond about 10 years (i.e., beyond about 2017 if mine developments occur in 2007/2008).

Chapter 5 examines these energy opportunities in the context of the different possible load situations outlined in Chapter 1 (Figure 1.2), the significant uncertainties associated with such load possibilities, and the lead times and other needs associated with Yukon Energy protecting appropriate resource options related to these different possible loads.

The planning approach in this Chapter parallels that used in Chapter 4; namely:

1. **System capability** (part of *Section 5.2: Requirements*) over the intended 20-year horizon as well as to 2045 is reviewed.
2. **System requirements** (part of *Section 5.2: Requirements*) are reviewed over the 20-year plan horizon and to 2045, focusing on key characteristics for each of the four representative industrial load scenarios.
3. **Forecast New Facilities Requirements** (part of *Section 5.2: Requirements*) are reviewed over the 20 year planning term and implications to 2045, focusing on opportunities to develop new capital intensive energy projects with potential to displace future diesel-fuel generation required under each industrial load scenario.
4. **Resource Options** (*Section 5.3: Options*) to meet energy requirements under each industrial load scenario are identified and summarized to the extent that representative non-diesel generation resource projects can be defined today.
5. **Assessment of Options** (*Section 5.4: Pre-Assessment and Screening*): given the limited degree of information available today on most resource options, preliminary pre-assessment and screening of the identified options focuses primarily on “technical” considerations (how well various project sizes and location fit each scenario’s potential load requirements). Where available, screening also considers to a limited degree “economic pre-assessment” of these options based on available information about the likely Levelized Cost of Energy or “LCOE” of each generation component.

This chapter sets out the actions that Yukon Energy proposes to take during the planning period to prepare for potential industrial development scenarios and opportunities beyond the near term, and to protect future opportunities to develop generation and transmission in a timely but cost-effective way. The planning activities proposed in this chapter are intended to strike a balance between the opportunities and risks associated with bulk power resource options selected to supply future Yukon industrial development.

5.1.1 Need to Consider and Balance Several Key Factors

Yukon and other experience in Northern Canada dramatically demonstrate how past industrial developments provided the opportunity to develop new generation and transmission infrastructure in a cost effective way, and how that infrastructure continues to yield sustained lower cost energy benefits to local residential and commercial power users long after the initiating industry has been closed[3].

The existing hydro at Aishihik and Mayo and the 4th wheel at Whitehorse were all linked directly with industrial developments which are now closed, as were the major hydro developments at Snare, Bluefish and Taltson in NWT (developed to service either mines that are now closed, or in the process of closing). Only areas in Northern Canada that have had industrial customer mining load have the benefits today of access to significant low-cost hydro.

Yukon and other Northern Canada experience also demonstrates that power resource planning regarding specific industrial developments can involve long pre-development timelines as well as considerable uncertainty and risk.

Accordingly, Yukon Energy needs to maintain a balanced approach to planning for grid power service to major new industrial loads. In particular, the approach must ensure that Yukon Energy is sufficiently prepared so as to "protect" feasible options to proceed with its own desirable resource projects quickly as needed should new industrial loads develop, while at the same time not spending more than is prudent to protect and advance such resource projects by, for example, proceeding to detailed feasibility stages based on mere load speculation or industrial development scenarios that are highly uncertain. Overall, this balance must be struck between two basic considerations:

a) **Readiness and Timing in relation to supplying new loads:** Due to industrial development planning and construction constraints, there may be limited time after a development's load uncertainties are resolved for Yukon Energy to proceed with the new generation and transmission needed to supply a new industrial load development with grid-based power. In particular, planning, designing, licencing and constructing new generation or transmission can, in many cases, take at least as long if not longer than similar planning, commitment and construction for a new industrial development such as a mine. If not

[3] Section 2.1.1 in Chapter 2 reviews how today's hydro generation and transmission facilities, developed in the past often in response to specific industrial mine-related load opportunities, are the key factor causing Yukon power costs today to typically be lower than those found in Alaska or the NWT.

sufficiently prepared and ready, new grid-based power service opportunities will be missed, likely in favour of on-site generation by the industrial customer. The potential significance of each such opportunity to Yukon's power system in the near and long-term merits careful consideration, along with assessment of the requirements to be sufficiently prepared and ready.

b) Costs, timelines and Risks for resource project planning: The planning phases for new generation or transmission can be costly and require many years of work prior to Yukon Energy being in any position to undertake final commitments to proceed with construction (with corresponding risks that potentially substantial spending on planning studies will indicate a project is not feasible). Understanding the likely costs, timelines, and risks associated with planning specific power resource options is an important precondition to assessing the likely requirements to be sufficiently prepared and ready.

As noted, when considering grid-based power supply options to new industrial loads, the key factors to be balanced in this regard relate both to the industrial development under consideration and to Yukon Energy:

- **Industrial Development factors**: Considerable uncertainty often persists as to timing and prospects to start and complete construction for a major new industrial development; even after successfully developed, material risks and uncertainties can remain as to the length of time for ongoing operation as well as the ability to meet ongoing financial obligations. Key factors in this regard include:
  - **Non-power uncertainty and risk factors:** In general, the key planning considerations and uncertainties for specific industrial developments derive from market, resource or other factors not related to power supply. Although power can be a cost factor that needs to be considered by potential industrial operations, such as mines or pipelines, it is often just one factor among many key considerations (such as financing, markets, licencing, or facility design).
  - **On-site power considerations:** Many major industrial developments if needed can rely upon on-site diesel generation or even (in some instances) their own fuel resource supply (e.g., coal for a coal mine, wood waste for a pulp mill, or natural gas for a natural gas pipeline) and will if required proceed without waiting upon development of access to utility grid-based power supply. In some instances, on-site generation may even provide opportunities to utilize waste heat or waste resources that can be used to supply energy; on-site generation capability may also provide critical requirements during construction or be needed as reliable backup to grid power during operation.

on-site generation capability may also provide critical requirements during construction or be needed as reliable backup to grid power during operation.

- **Short operating life and/or small scale power need:** In instances where a short operating life of (say) five to ten years is expected or at risk, or where the scale of the development involves relatively small power requirements, the incentive to incur material up front capital costs for connection to grid-based power may be severely reduced.
- **Cases where access to grid power is critical:** In some special cases, the feasibility of a specific industrial development may also be critically dependent upon access to grid-based power that is supplied at costs materially less than diesel fuel generation. In such instances, joint planning with the utility will be a key consideration to the industrial development's ability to proceed.

- **Yukon Energy factors**: Yukon Energy can also face a range of its own specific uncertainties and risks related to supplying grid power to major industrial developments. Key factors in this regard include;
  - **Inability to select or "forecast" in advance which industrial development scenario will unfold**: Based on current information, Yukon Energy cannot select or "forecast" in advance on any reliable basis (sufficient, for example, to commit material planning resources on any prudent basis) what level or scope or type of major industrial development is likely to occur by any specific time period under review in this Resource Plan.
  - **Limited value to current information**: Until uncertainties are resolved for a specific industrial development, it is typically also not practical or cost effective based on currently available information (regarding both the industrial development and the power resource options to supply its needs) to plan and assess in any detail how Yukon Energy may serve that development. If and when a development proceeds, its specific energy, power capacity and timing requirements (and the costs and needs for resource options to supply such requirements) in many cases are likely to vary significantly from current estimates.
  - **Limited time to respond to a new development once its major uncertainties are resolved:** As noted above, Yukon Energy will typically have only a very limited time to respond after uncertainties are resolved for a new industrial development before it becomes necessary to undertake power supply commitments; in many instances, as noted above, an industrial development will also simply proceed to use on-site diesel generation if Yukon Energy cannot commit on a timely basis to supply grid-based power.

- **Costs and time to develop new bulk power supply resources:** Yukon Energy may need to develop at least some new bulk power resources to supply grid power in response to a new industrial development. Opportunities to supply grid power that are contingent on planning, permitting and developing material new transmission and/or capital intensive non-diesel fuel generation resources are likely to require many years of work involving major capital costs prior to Yukon Energy even being in a position to make final commitments to proceed with construction of the needed resource projects – and capital intensive construction projects may then require several additional years (and cost risks) before coming into service.
- **Need to assess, and secure YUB approval of, ongoing rates:** Yukon Energy needs also to examine in advance the likely ongoing rate implications and risks, both for the potential industrial customer and for other Yukon ratepayers, and to secure YUB approval of any rate to be charged with regard to commitments to supply any new "major industrial customer" (as defined in OIC 1995/90).
- **No market value to power if developed but not needed in Yukon:** Unlike many southern jurisdictions with export connections, Yukon Energy cannot secure any economic value from projects except from sales to customers in Yukon, due to the lack of grid interconnections with external markets. In this regard, there is considerably more risk today to developing capital intensive bulk power projects in Yukon than in, say, Manitoba or British Columbia. This is because failure of local loads to develop as planned in Manitoba or BC can be offset by the opportunity to sell more power on export markets than otherwise would be the case. In contrast, once Yukon commits to a major capital intensive resource supply project, if the load does not develop or remain as planned the resource project has the potential to have zero or very limited value[4].
- **Resource Projects of a scale at or beyond Yukon Energy's current capability:** In some industrial development scenarios examined in this Resource Plan, the magnitude of required new generation and transmission opportunities may be at or beyond the current capability of Yukon Energy, or other Yukon entities, to finance and construct. For example, Yukon Energy presently has about $57 million in equity, while some of the

[4] This exact situation occurred with the construction of Whitehorse unit #4 in the 1980s. This unit basically provides almost exclusively summer energy, which was only of value at that time if the Faro mine was operating. However during construction of unit #4 the Faro mine closed, such that at the time of commissioning, the unit provided no economic value to the system. Since that time, substantial periods of operation of the Faro mine have provided opportunities to capture good economic value from unit #4. However, had the mine shut for good in the 1980s, unit #4 may have not been of any material value to the WAF system for decades after it was commissioned. Today, limited quantities of surplus hydro can be sold at lower secondary rates, however the potential is somewhat limited and is of lower value that full firm energy sales.

resource options considered in this Chapter approach $500 million to $600 million capital costs for generation alone (plus amounts for substantial transmission upgrades), and would involve the need to assess financial approaches and partnerships, potentially including participation by the Governments of Yukon and Canada. Such additional complications would likely increase planning timeframes and would also likely involve assessing options regarding sharing of risks associated with the projects.

5.1.2 Regulatory and Policy Framework

As a regulated utility, Yukon Energy's planning and developments occur within a regulatory and policy framework relating to its power supply developments and regulated rates charged to recover utility costs of service.

Where new industrial customers are located within areas presently served by Yukon Energy grid power, Yukon Energy must take into consideration its typical utility "obligation to serve" new loads that request electrical service. In contrast, Yukon Energy is not automatically required to serve new industrial loads that are located far away from the current Yukon grids unless the customer (or government) is prepared to fund directly the transmission costs and risks required for Yukon Energy to connect the new load to the grid[5]. In this regard, it is broadly assumed that major new industrial customers located materially away from the current grids would not be added to the Yukon grid systems due primarily to the constraints of incremental transmission connection costs. Without such connections, it is also assumed that a new major industrial load would typically be supplied by isolated on-site diesel generation with all costs being excluded from YUB consideration for the purpose of Yukon wide regulated rate setting (in accordance with OIC 1995/90).

The existing WAF system today can provide substantial (approximately 90 GW.h/year under normal water flows) attractive low-cost surplus hydro power to new industrial customers. The clear implication is that new industrial customers in reasonable proximity to WAF currently have major opportunities to secure material cost savings by purchasing WAF power supplies rather than using on-site diesel generation. Securing new industrial customers on WAF to allow sale of this surplus power at firm rates will also be a beneficial rate driver for all existing Yukon Energy and YECL firm customers, not only on WAF but throughout Yukon (due to the rate directive provisions of OIC 1995/90 which in effect integrate all utility

[5] As with new connection to WAF or MD by new non-industrial customers, transmission or distribution costs driven by new industrial customers are assumed to be funded by the industrial customer themselves (or by government), except to the extent that there is a cost effective case for Yukon Energy to invest in hooking up new industrial customers at a benefit to current ratepayers (pursuant to principles established in the Electric Service Regulations).

costs to equalize retail customer class rates through Yukon)[6].

However, the current WAF hydro power surplus is being reduced by ongoing normal growth in non-industrial customer firm loads, such that Secondary Energy sales on WAF that rely on surplus hydro power are expected to be fully curtailed by 2023 under the Base Case load forecast reviewed in Chapter 4 (see Figure 4.2).

Larger or longer-term new industrial power loads connected to WAF or MD that require energy materially beyond available surplus hydro power would, absent the development of new power resource options, drive major new diesel generation on these grids. Accordingly, Yukon Energy needs to identify and consider carefully the options and impacts to service such new industrial developments. For example, it may not be sensible to develop new transmission to service a mine (with associated transmission line losses) if the power is being largely generated via diesel at Whitehorse, when the same power could likely be generated at the mine site using diesel without the associated transmission losses. New grid extensions will similarly have limited long term value to the extent that they end up being used to transmit diesel generated power rather than hydro or other lower cost based power. Overall, looking at longer-term implications, such new industrial loads are likely to be attractive economically to the existing grid system only if they allow development of new capital intensive low-cost generation, such as occurred with the original opportunities to develop Mayo or Aishihik.

Accordingly, for new bulk power projects that may be developed in response to industrial development opportunities, Yukon Energy needs to assess the economics of the project (including attendant risks), the potential rate impacts on other utility customers as well as for the new industrial customer, and overall Yukon policy objectives.

On the matter of overall policy objectives, in other jurisdictions various broad policy objectives regarding resource development guide electrical system expansions[7]. In Yukon, the traditional energy policy

[6] Up to 30 GW.h of this surplus hydro may currently be sold to secondary energy customers; however, interruption of such secondary sales (as well as use of the balance of the current hydro surplus) to service firm industrial loads will secure much higher revenues for Yukon Energy without incurring material increases in its costs. Under regulated rates, the net benefits of such rate revenue improvements will therefore flow through to reduce overall regulated rates below levels that would otherwise apply. Yukon Energy and YECL customers will accordingly benefit to the extent that rate reduction savings do not simply serve to reduce Rate Stabilization Fund subsidies funded by the Yukon Government.

[7] An example is the BC government directive that BC Hydro not develop nuclear power. In contrast, at times Newfoundland has had a moratorium on developing new small hydro.

objectives have been focused on development, where economically feasible, of local resources compared to imported diesel fuel. Consequently, at times since it was established, Yukon Energy (along with Yukon Development) has assessed, requested proposals, and in some cases conducted research and development projects on the following: Eagle Plains crude oil, wind generation, diesel/coal combined cycle generation (based on coal from Division Mountain), new hydro (including small Independent Power Producer (IPP) hydro projects), diesel/solar hybrid, biomass generation and geothermal resources (many of these at scales well below that needed to supply industrial customers). Planning for major new supply continues to reflect largely the broad "development of local resources" objective where economically feasible.

5.1.3 Planning Framework

The planning framework in this chapter focuses on information that is currently available and on activities Yukon Energy (and the YUB) can control – monitoring potential loads as they develop, conducting appropriate screening and pre-feasibility work on potentially attractive generating and transmission options, and conducting phased and managed feasibility work where appropriate in advance of industrial developments becoming firmly committed to ensure Yukon Energy "protects" the ability to respond when necessary within the timelines required.

To ensure that relevant longer-term service implications are considered, Yukon Energy examines load scenario requirements in this chapter out to the year 2045; however, the analysis addresses only those generation or transmission supply options that may be required to commence development before 2016.

The analysis and project options identified in this chapter build on the Chapter 4, assuming commitment prior to 2009 for resource projects proposed in Chapter 4. In particular, capacity requirements noted in this Chapter reflect adoption of the revised capacity planning criteria (as set out in Section 3.4) as well as prior commitment to and completion of a Mirrlees Life Extension Project (at 14 MW) plus about 4 MW new diesel capacity by 2012 pursuant to the primary contingent recommendations of Chapter 4 to address "Base Case" loads. This chapter also presumes near term development of Marsh Lake Fall/Winter Storage (1.6 MW of added firm capacity) as well as the Aishihik 3rd Turbine project as proposed in Chapter 4[8], without the Aishihik 2nd Transmission Line project (such that the Aishihik 3rd Turbine has no effect on meeting the N-1 capacity planning criteria and only 0.6 MW towards the LOLE criteria), and

[8] In addition to any capacity-related impacts, Marsh Lake Storage and the Aishihik 3rd Turbine as proposed in Chapter 4 together add about 13 GW.h/year to long-term average WAF hydro energy supply (assuming sufficient WAF loads).

takes into consideration the possible near term development of the Carmacks to Stewart Crossing Transmission as reviewed in Chapter 4.

As noted, Chapter 5 identifies four representative industrial development "scenarios" (rather than "forecasts") in order to identify basic planning options for the Resource Plan to consider with regard to different ranges of potential industrial load sizes (as well as load timing, expected life and general location). Individual industrial development opportunities and/or resource supply projects, however, are not the focus of the Chapter 5 analysis.

Four key factors are simultaneously considered in the Chapter 5 screening of potential new resource supply options for each WAF industrial load scenario:

1. **Generation cost of energy supplied by new resource (LCOE):** A primary consideration is the basic generation cost of energy supplied by output from any new resource (with typical focus on overall unit cost per kW.h as opposed to cost per MW of capacity). For the purposes of initial screening, "levelized costs of energy" or LCOE can be used to determine the unit costs/kW.h at the project site of energy produced. Levelized costs reflect the costs of the plant amortized over its life (all kW.h units available to be produced by the plant) assessed on real dollar (2005$) economic terms (i.e., assuming the levelized unit cost after 2005 increases with inflation each year).
    - LCOE focuses only on key generation cost components for a resource option as needed to screen or compare alternative resource options.
    - LCOE for hydro supply projects accordingly focuses in most instances only on capital costs, as these tend to establish the primary overall generation cost for this option. Operating and maintenance costs for large projects can be quite modest (0.5% of capital cost based on BC Hydro estimates) which would tend to increase the LCOE by about 9.4%. Smaller hydro project operating and maintenance costs may vary up to 1.0% to 1.5% of capital cost, which can increase LCOE by 18.8% to 28.3% over the levels estimated in this chapter.
    - In the case of other resource options which involve material fuel operating costs (e.g., diesel generation, or thermal generation using coal, wood biomass or natural gas) it is also necessary that the LCOE reflect fuel as well as capital costs (if the capital costs are also likely to be a key part of the option's overall costs).
    - LCOE automatically takes into consideration variations in the economic lives of alternative resource options.
    - LCOE implicitly assumes that all energy generated over the economic life of a resource option is sold at rates that fully recover the LCOE costs, i.e., this screening tool does not

address the extent to which a resource option may be oversized to meet forecast loads, or otherwise mismatched with forecast loads (in terms of, say, seasonal consideration).

2. **Location of supply and cost of transmission to loads:** If attractive supply options (such as hydro) can be identified that offer lower levelized generation costs of energy (LCOE) than diesel power generation, it is necessary also to screen separately based on location, as low-cost supply options that are materially away from existing transmission systems may not be able to support the costs of major new transmission to connect to the system (particularly for small plants). Similarly, in some cases supply options that are too remote will result in transmission losses that undermine otherwise attractive LCOEs.

3. **Load fit with resource option supply:** Despite a new low cost source of supply being available to Yukon Energy (as assessed based on LCOE per kW.h as well as on location relative to the forecast loads), the overall economics of a resource option also depend ultimately on the supply having actual economic value to the system (such as by displacing energy that otherwise would have needed to be generated using diesel fuel). If some or all of the power provided by a new supply source is surplus to system firm load requirements (e.g., becomes spilled hydro) even very low cost resource options can be uneconomic to the overall power system. Key considerations for section 5.4 on "pre-assessment and screening" therefore focus on "load fit", or how well any given resource project might fit the load requirements (energy in particular) over the next 40 years, how many years of surplus energy may arise if a resource project were to be constructed, and the market risks associated with potential pre-mature closure of industrial customers.

4. **Other associated charges, such as "water rentals" and taxes:** For hydro resource projects that are developed in BC, additional annual charges will be levied on the project that would not be in place if the project was located in Yukon. It is therefore relevant to consider these additional charges when screening such projects in the Resource Plan.

Other major screening factors must separately be considered within the process for evaluating, developing and constructing new power generation facilities, such as environmental factors which may preclude certain developments, or drive material added capital or operating costs (such as for environmental mitigation activities).

The organization and approach adopted in Chapter 5, with its focus on four different industrial load scenarios, reflect the overall importance of "load fit" within the resource option screening process. As reviewed in Sections 5.3 and 5.4, the scale of the industrial loads associated with each scenario drives the identification of relevant resource option technologies. Based on initial screening for this basic "load fit", further screening can then be carried out in accordance with the four key factors noted above.

5.2 REQUIREMENTS

There is a diverse range of industrial development opportunities that could develop in the Yukon during the 20 year planning period, providing an equally diverse range of potential opportunities to develop new energy resources.

At present, base metal prices in particular are at high levels and mining exploration in Yukon has expanded. Yukon Energy has worked with the Government of Yukon Mineral Development Branch to identify potential future mining industrial customers based on specific prospects and proponents, as well as based on the nature of the development, its expected life, and its location in relation to developed grid power.

Larger opportunities may be presented by an Alaska Highway Pipeline, and information on the potential loads for pipeline pumping (which could be served by electricity under certain circumstances) has been included in the planning exercise.

Potential industrial developments considered in this chapter are detailed in *Table 5.1 Industrial Development Opportunities*. Locations of these potential developments are indicated in *Figure 5.1: Map of Industrial Development Opportunities and Power Infrastructure*.

Figure 5.1:
Map of Industrial Development Opportunities and Power Infrastructure

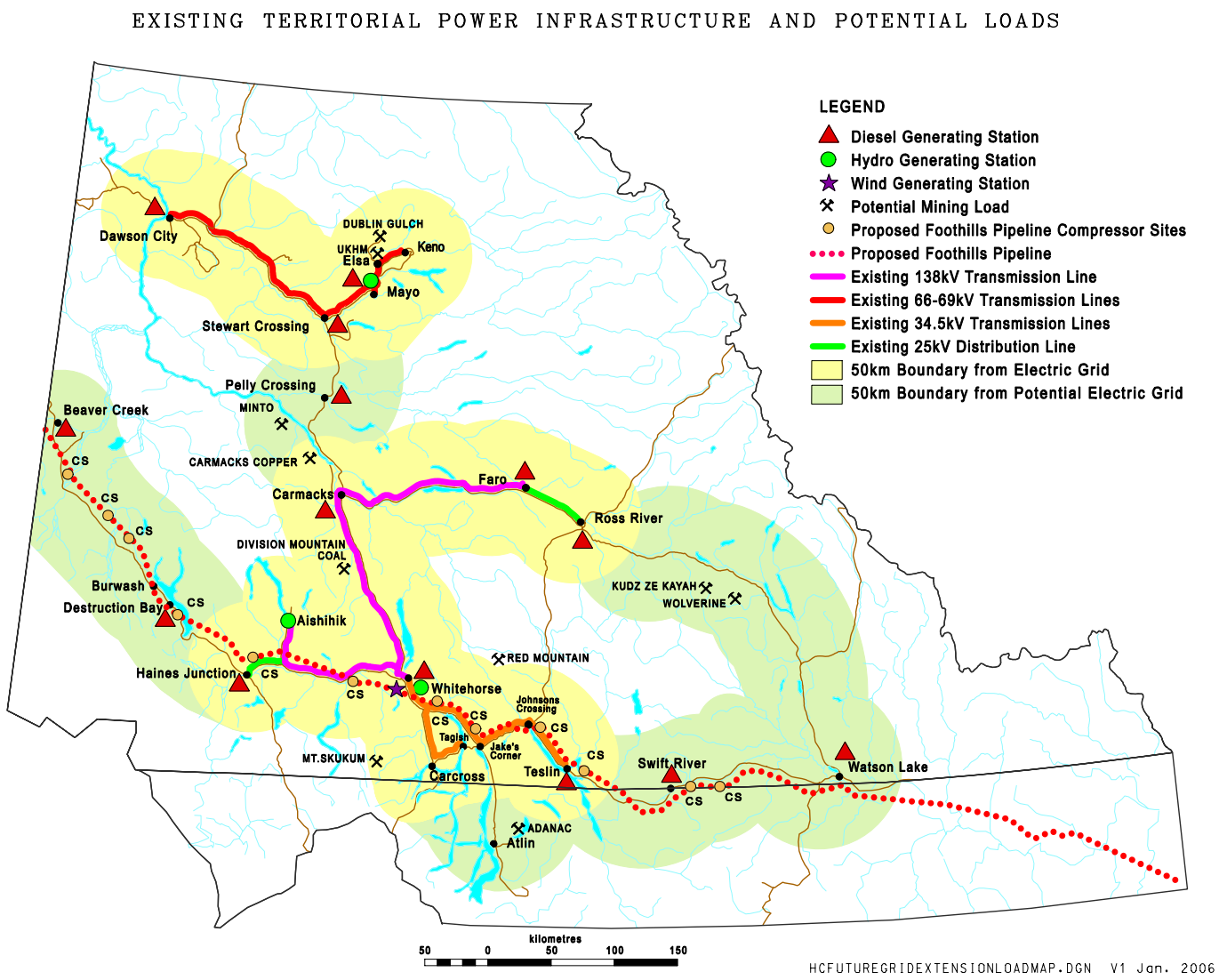


Table 5.1:
Industrial Development Opportunities

Project	Proponent	Location	Grid	Commodity	Road Access	Distance To Grid (km)	Peak Demand (MW)	Annual Energy (GW.h)	Project Life	Assumed In-Service Date
Alaska Highway Pipeline, WAF										
120 MW to 360 MW[1]										
Kluane Compressor	Foothills Pipeline	kmp 214 Destruction Bay	WAF	Natural Gas	Alaska Highway	147.2	30	223.4	30	2012-15
Champagne Compressor	Foothills Pipeline	kmp 378 Stony Creek	WAF	Natural Gas	Alaska Highway	3	30	223.4	30	2012-15
Marsh Lake Compressor	Foothills Pipeline	kmp 455.8 Marsh Lk. Outlet	WAF	Natural Gas	Alaska Highway	30	30	223.4	30	2012-15
Rancheria Compressor	Foothills Pipeline	kmp 739.2	WAF	Natural Gas	Alaska Highway	330	30	223.4	30	2012-15
Potential Mine Developments, WAF										
11 to 20 MW										
Division Mountain Coal	Cash Minerals Ltd.	Braeburn	WAF	Coal	Klondike Highway	20	15	105	15	2010
Red Mountain	Tintina Mines Ltd.	80 km NE of Whitehorse	WAF	Moly	no road access	83	11 to 20	81 to 126	20	2009
Adanac	Adanac	124 KM SE of Whitehorse (in BC)	WAF	Molybdenum	road via Altin	approx. 120	15	Unknown	20	2010
1 to 10 MW										
Minto Property	Sherwood Mining Corp.	100 km NW of Carmacks	WAF	Cu, Ag, Au	Klondike Highway	98	2	14	12	2007
Carmacks Copper	Western Silver Corp.	28 km NW of Carmacks	WAF	Cu, Ag, Au	Freegold Road	53	7	50	8.5	2008
Wolverine	Yukon Zinc	130 km SE Ross River	WAF	Cu, Pb, Zn, Ag, Au	Robert Campbell	273	5.1	37	9	2009
Kudz Ze Kayah	Teck	110 km SE Ross River	WAF	Cu, Pb, Zn, Ag, Au	Robert Campbell	218	8.8	63	11	2011
Mt. Skukum	Tagish Lake Gold Corp	40 km W of Carcross	WAF	Au, Ag	Annie Lake Road	47	1.5 to 2.7	11 to 20	8	2008
Potential Mine Developments, MD										
1 to 10 MW										
Dublin Gulch Property	Strata Gold Corp.	40 km N of Mayo	MD	Au	road north of Elsa	27	4	20	10	2009
UKHM	Under YTG Management (in due diligence)	Elsa	MD	Ag, Zn, Pb	Elsa	0	2	14	5	2007

1-The initial four compressor stations are shown here. Up to eight additional compressor stations (each with similar 30 MW potential load) could be added within the following four to five years. The pipeline electrical loads in this table assume use of electric power rather than natural gas from the pipeline to run these compressor stations. There will also be some ancillary pipeline power loads in any event (not shown here) even if the compressor stations use natural gas.

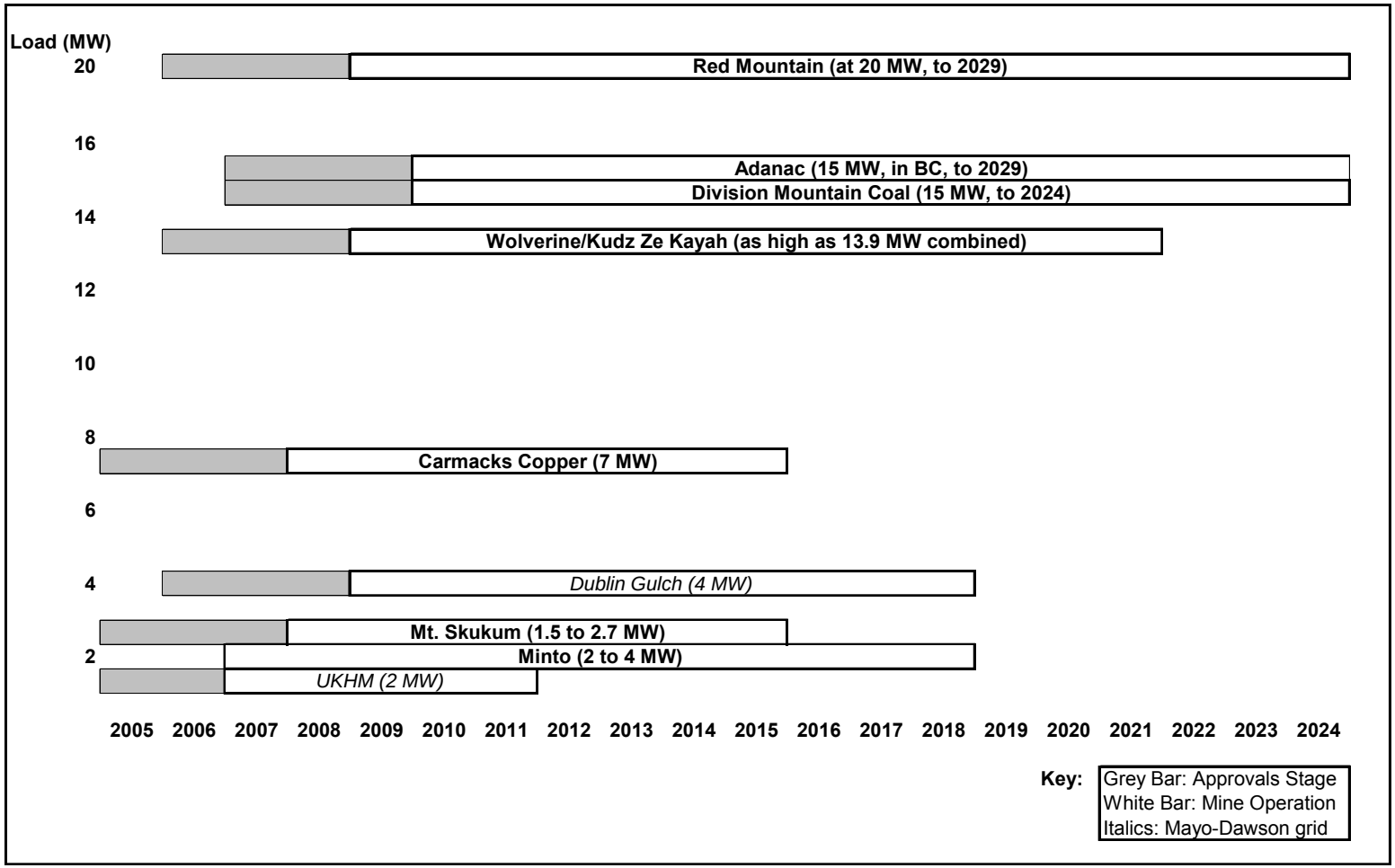
Figure 5.2 Earliest In-Service Dates and Power Loads for Potential Mine Developments illustrates the currently estimated potential timelines associated with mining load opportunities being considered.

Individual industrial developments noted in Table 5.1 and Figure 5.2 could result in possible new generation projects starting construction before 2016, based on industrial load requirements ranging from 2 MW to 360 MW and energy requirements ranging from 11 GW.h to 2,680 GW.h per year, and with service lives ranging from 5 to 30 years or more.

Many of the potential industrial mine loads considered in this chapter are well beyond the bounds of existing transmission, which may limit opportunities for grid service unless other outside funding (such as YTG) is available to enable the connection and eliminate potential adverse rate impacts. The mine developments noted in this chapter are within 273 km of either the WAF or MD grids (see Table 5.1).

When considering the potential "start dates" and development uncertainties for any of the mine projects considered in this chapter it is relevant to note that many of the industrial developments being considered today have been under active consideration as "near term development" prospects for some time. Yukon Energy's internal Resource Plan update process in 1996/97, for example included many of these projects as "advanced mineral projects" relevant at that time for possible power requirements, including Minto, Kutz Ze Kayah, Dublin Gulch, UKHM and Carmacks Copper as projects then engaged in environmental permitting (with all of these developments then expected to use on-site diesel, except for Carmacks Copper and UKHM which were then expected to secure grid power), and including Division Mountain Coal (grid power) and Mt. Skukum (on-site diesel) as projects with anticipated environmental review. Rates approved by the YUB from the 1996/97 GRA included a "New Mine Rider" (Rider K) to address adjustment of retail rates throughout Yukon in the event either Carmacks Copper (WAF) and/or UKHM (Mayo system) was connected to a system in 1996 or 1997.

Figure 5.2:
Earliest In-Service Dates and Power Loads for Potential Mine Developments



To address forecasting uncertainty regarding these industrial development opportunities, four "scenarios" have been selected related to industrial development. Given the range of potential development options, the four scenarios allow Yukon Energy to identify basic planning options relevant to consider in the Resource Plan. If and when specific loads of a certain magnitude develop, Yukon Energy can at that time refine and develop specific plans for serving the load.

Industrial Development Scenarios and Opportunities identified for this Resource Plan focus on the WAF grid (includes possible MD supply options if the Carmacks-Stewart Transmission project is developed) and include:

- **Scenario 1: A 10 MW WAF Industrial Scenario:** This scenario includes one to two smaller mines, which are represented in the analysis by the addition of the Minto (2 MW to 4 MW) and Carmacks Copper (7 MW) mines.
- **Scenario 2: A 25 MW WAF Industrial Scenario:** This scenario includes multiple major developments comparable overall to the traditional load impact of the Faro Mine when it was operating. This scenario is roughly based on the development of three mines, focused on: Minto (2 MW to 4 MW), plus Carmacks Copper (7 MW) and either Red Mountain (11 MW to 20 MW) or Division Mountain coal for export markets (15 MW).
- **Scenario 3: A 40 MW WAF Industrial Scenario:** A larger 40 MW scenario is considered to focus on a potential major mining industry development scenario in Yukon. This scale of mining power load would be in excess of the loads experienced when the Faro mine was operating. As an example, such a scenario could be enabled by the development of Minto (2 MW to 4 MW), plus Carmacks Copper (7 MW) plus Red Mountain at the largest load level assumed to date Mountain (11.3 MW to 20 MW, likely at larger end of scale) plus Division Mountain coal for export markets (15 MW).
- **Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario:** This largest scenario is based on the development of an Alaska Highway Natural Gas Pipeline in the 2012-2015 period and assumes that this development elects to use electricity for pipeline compression. The magnitude of power use is based on an initial four compressor stations at 30 MW each, ultimately being expanded over time to 12 compressor stations at 30 MW each, each with a life of 30 years.

All scenarios forecast non-industrial loads at the Base Case level from Chapter 4 and reflect schedule in-service of projects recommended in Chapter 4 including Aishihik 3rd Turbine, Marsh Lake Fall/Winter Storage and Mirrlees Life Extension. For simplicity, it is also assumed that additional diesel capacity (about 3-4 MW) is developed to meet the balance of the Base Case capacity required by 2012; as noted

in Chapter 4, Base Case options in this regard include replacing the smaller third Mirrlees unit (4 MW) with a larger new diesel unit (8-11 MW).

The following Chapter 5 requirements analysis also initially assumes reliance on new diesel generation to supply additional new capacity required to meet new industrial loads.

5.2.1 Scenario 1: A 10 MW WAF Industrial Scenario

Within the next number of years, there is a credible scenario of Yukon Energy potentially connecting service to two mining loads at Minto (Sherwood Mining Corporation) and Carmacks Copper (Western Silver Corporation). Analysis of a 10 MW load scenario, however, is applicable for other potential load developments of a similar scale (including potentially Mt. Skukum gold at 2 MW, Red Mountain in its smallest form at 11 MW, or major expansion of transmission along the Robert Campbell highway to connect Kudz ze Kayah at 8.8 MW or Wolverine at 5.1 MW should other non-utility funding be available to develop transmission along this route).

Focusing on the development of Minto and Carmacks Copper, the projects together would likely have a capacity requirement of 9 MW to 11 MW, and up to 64 GW.h of annual energy sales (about 70 GW.h of annual generation). The projects are not expected to be long-lived. Minto is expected to start in 2007 and run for 12 years. Carmacks Copper is expected to start in 2008 and run for 8.5 years. These starting dates may be delayed by other processes and development timelines.

The Scenario 1 loads are equivalent to the "Base Case with Mine Loads" discussed in detail in section 4.2.6 of Chapter 4, except that the Chapter 5 approach to determining requirements presumes previous near term completion (before 2012) of the Mirrlees Life Extension and installation of 3-4 MW of additional diesel generation, as well as near term development of Marsh Lake Fall/Winter Storage (by 2008) and the Aishihik 3rd Turbine (2009).

Capacity: Based on the revised capacity planning criteria (see Chapter 3), up to 6-7 MW of mining load can be added to the WAF system without driving a need for any new capacity. Even the addition of 10 MW of mining load may not drive any need for new capacity if this new load is either matched with some degree of on-site diesel capability at the mines, or peaks at times other than the current coincident peaks of residential and commercial customers on the coldest days of the year[9]. However, absent any on-site

[9] Assuming only modest on-site diesel in each case (about 20-40% of the peak load), there would be no incremental requirement for capacity on the YEC system in order to serve this scale of mining load.

diesel at the mines, development of this scale will drive an added capacity requirement of up to about 2-3 MW by 2012 compared to the Base Case[10].

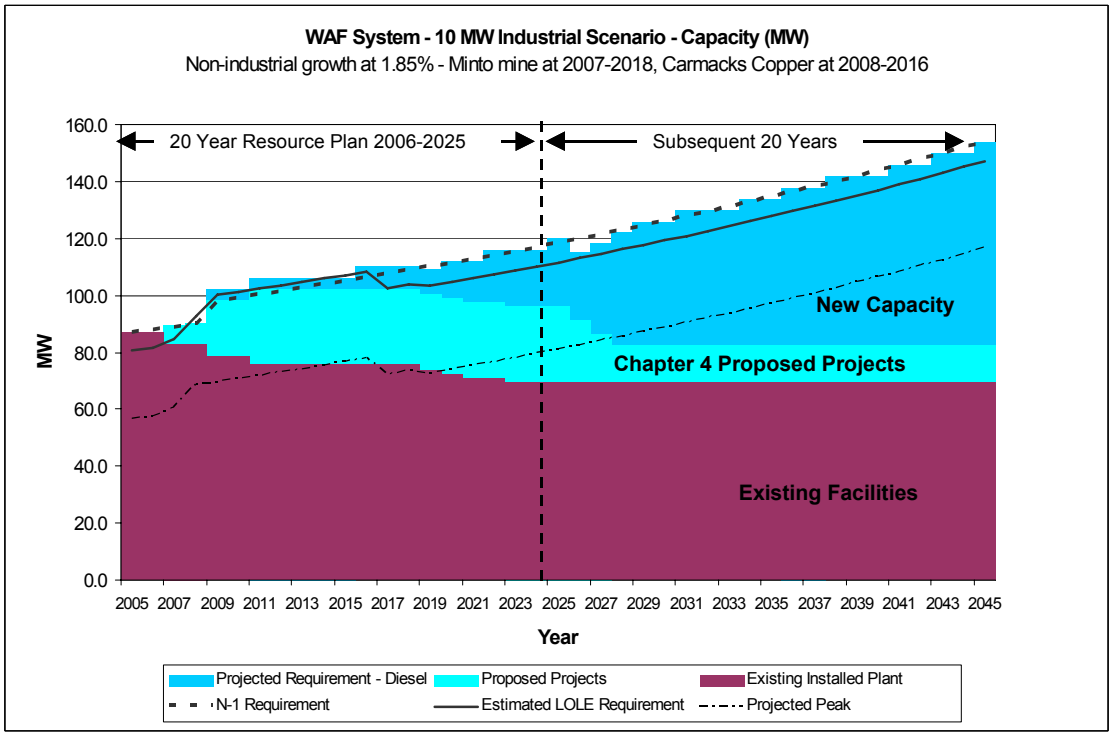
The WAF integrated system peak loads once the two mines are connected would approach the 65-70 MW level, growing to about 78 MW by the end of the mine life[11],

With the current installed plant (and including the proposed 7 MW of hydro from the Aishihik 3rd Turbine and 1.6 MW of new capacity with the Marsh Lake Fall/Winter Storage), YEC can reliably supply about 62 to 63 MW of peak load with hydro (higher in some winters depending on Yukon River flows). Consequently, Yukon Energy would need to rely at times on dispatching up to 15 to 16 MW of diesel capacity during a relatively limited number of hours at the coldest times of the winter to meet peak loads. This is well within the system capability from a reliability/capacity perspective.

[10] Based on the earlier more detailed review in Section 4.2.6, prior to addition of the Aishihik 3rd turbine and Marsh Lake Fall/Winter Storage, the two mines add 2.8 MW to the firm WAF capacity needed (assuming no on-site mine diesel capacity). This is because the mines are assumed at 9 MW (2 MW for Minto plus 7 MW for Carmacks Copper) but 6.2 MW of this load can be carried under the LOLE criteria without driving a need for new capacity (once the mines are connected, the LOLE criteria drives new capacity additions, not N-1). However, later in Chapter 4, the Aishihik 3rd turbine project is proposed to proceed, which adds 0.6 MW to LOLE load carrying capability, so the incremental effect of the mine loads drops to 2.2 MW. Accordingly, the incremental impact on capacity requirements in 2012 due to these two mines would be about 2.2 MW. However, it is noted that a portion of the 2.2 MW requirement may be met by either on-site diesel, or by Chapter 4 projects that add capacity beyond the strict amounts required through 2012. (Chapter 4 assumed, to meet Base Case loads, 18.7 MW is installed separately through implementation of the Chapter 4 proposed actions regarding Marsh Lake Fall/Winter Storage at 1.6 MW, Mirrlees Life Extension at 14 MW plus at least 3.1 MW of new diesel at Whitehorse to address the remaining shortfall. As noted in Chapter 4, a 4 MW new diesel unit may be installed (resulting in a surplus of 0.9 Mw at 2012 under Base Case conditions), the third (4 MW) Mirrlees unit might be replaced by new diesel at from 8 to 11 MW (resulting in surplus capacity under Base Case of between 0.9 and 3.9 MW), or the Carmacks to Stewart Transmission might be developed (providing surplus capacity under Base Case conditions of 1.9 to 2.9 MW of added capacity).)

[11] Chapter 5 assumes that new mine loads are consistent throughout the winter, even at very low temperatures – this may not be correct as some mining operations are limited in terms of the activities they can pursue once temperatures drop to very cold levels.

Figure 5.3:
Scenario 1: WAF Capacity Requirements



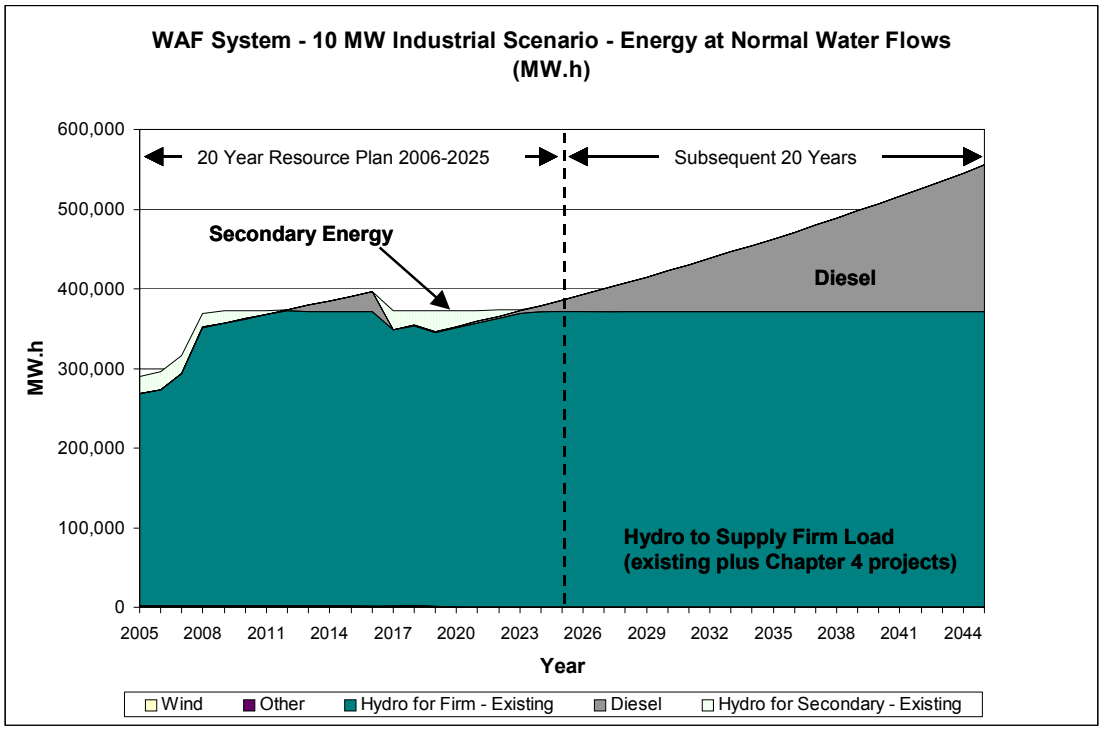
Energy: Under this scenario, surplus WAF hydro would provide most of the incremental energy needs if the mines are connected to WAF. From an energy perspective, the development of Minto and Carmacks Copper are well suited to the current scale of system surplus hydro. At the assumed time of their expected connection (2007-2008), basically the entire loads of these two customers can likely be served with surplus hydro for most of the year (with the relatively minor exception of winter peaking as noted above, subject to receiving further confirmation regarding the seasonality of the loads).

However, diesel generation use would increase throughout the period while the mines are connected. Assuming development of Marsh Lake Storage and the Aishihik 3rd Turbine (as proposed in Chapter 4 to capture energy benefits as noted), diesel generation of 2 GW.h to 25 GW.h per year would arise in the period 2012-2016 (prior to the expected closure of Carmacks Copper in 2017)[12]. After 2017, surplus

[12] Over the life of the two mines as assumed in Scenario 1, about 10% of the incremental energy requirement is supplied by diesel generation in Figure 5.3.

hydro would return to the system for about 7 years to 2023, when base load diesel would again be required, in this case due to non-industrial load growth.[13]

Figure 5.4:
Scenario 1: WAF Energy Requirements



The load balance information above notes a small incremental requirement for diesel generation under this scenario. However, over the next 20 years (the period of the current Resource Plan) the maximum diesel requirements at normal water flows in any year is about 25 GW.h/year, with only 4 of the 20 years above 10 GW.h/year. Diesel requirements for the remaining 16 years vary from about 0.1 GW.h/year to 8 GW.h/year and average about 2 GW.h/year. Under this load scenario, it would be difficult to justify even considering new energy projects for commitment before 2016 based on mine loads of up to 10 MW that are not sustained well beyond 2016[14].

[13] See Appendix C, Table C.5 for a review of diesel requirements by year assuming these two mine loads as well as development of Marsh Lake Fall/Winter Storage and the Aishihik 3rd Turbine.

[14] Variations on Scenario 1 might change this conclusion, i.e., if the same mine development was delayed until about 2016, sustained levels of diesel generation into the future 20 years and beyond would be much higher. However, this type of variation provides minimal guidance to Yukon Energy Resource Plan activities during the next several years.

5.2.2 Scenario 2: A 25 MW WAF Industrial Scenario

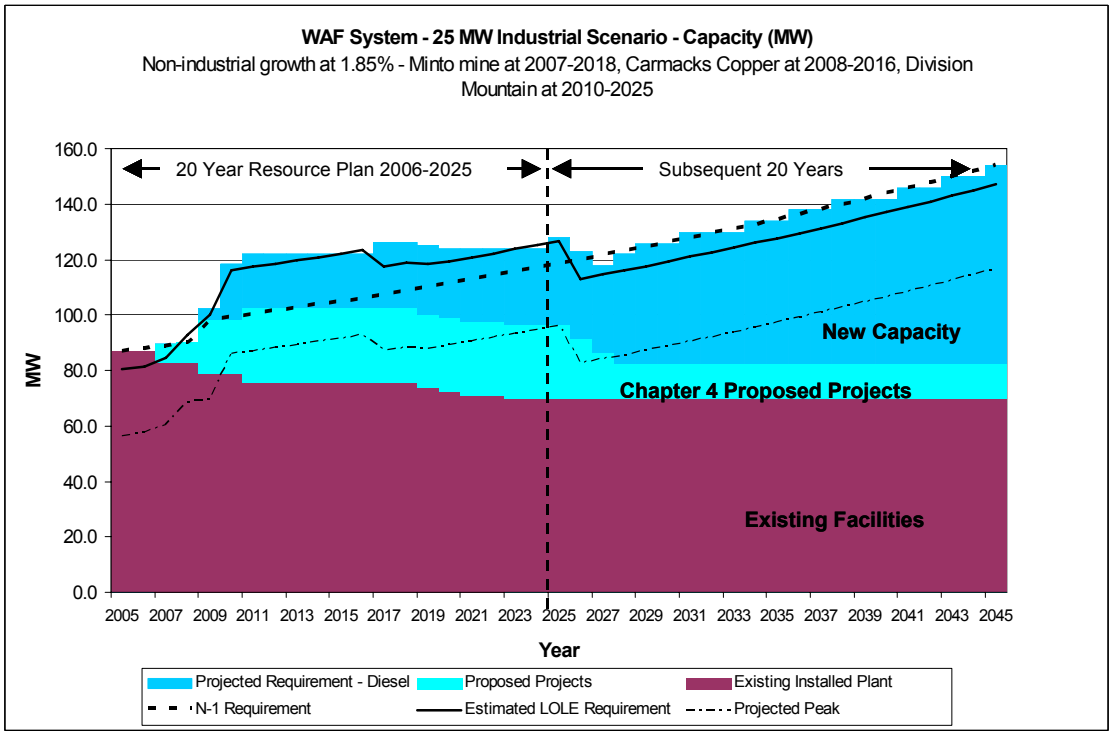
The 25 MW industrial scenario focuses on a larger load development, based on service to Minto and Carmacks Copper via new transmission north from Carmacks, plus additional major industrial load in the 10-20 MW range, with serious potential candidates being Division Mountain coal (15 MW, at Braeburn on existing WAF transmission) or Red Mountain (11.3 MW - 20 MW, north of Johnson's Crossing, requiring 70-100 km or more of new major transmission).

The scenario is examined assuming development of Minto, Carmacks Copper per the loads in Scenario 1, plus Division Mountain coal (15 MW load assumed at 105 GW.h/year from 2010 for 15 years). Overall supply requirements are similar to what existed to supply the Faro mine loads when it was last operating, and approximate 180 GW.h/year of incremental generation when all three mines are operating.

Capacity: If this scenario were to arise, Yukon Energy would face substantial requirements for new capacity in excess of that indicated in Chapter 4. This added capacity required for these industrial loads would potentially be up to an additional 17.2 MW of new diesel units or equivalent capacity, assuming minimal on-site diesel installations at the three mines[15].

[15] As noted in the summary of requirements, the scenario case is modeled using a maximum 24 MW of industrial load. Of this amount, and assuming development of the Aishihik 3rd Turbine, 6.8 MW of industrial load may be carried under the LOLE criteria without a need for new capacity (over Base Load N-1 requirements), and 17.2 MW of new capacity is therefore required.

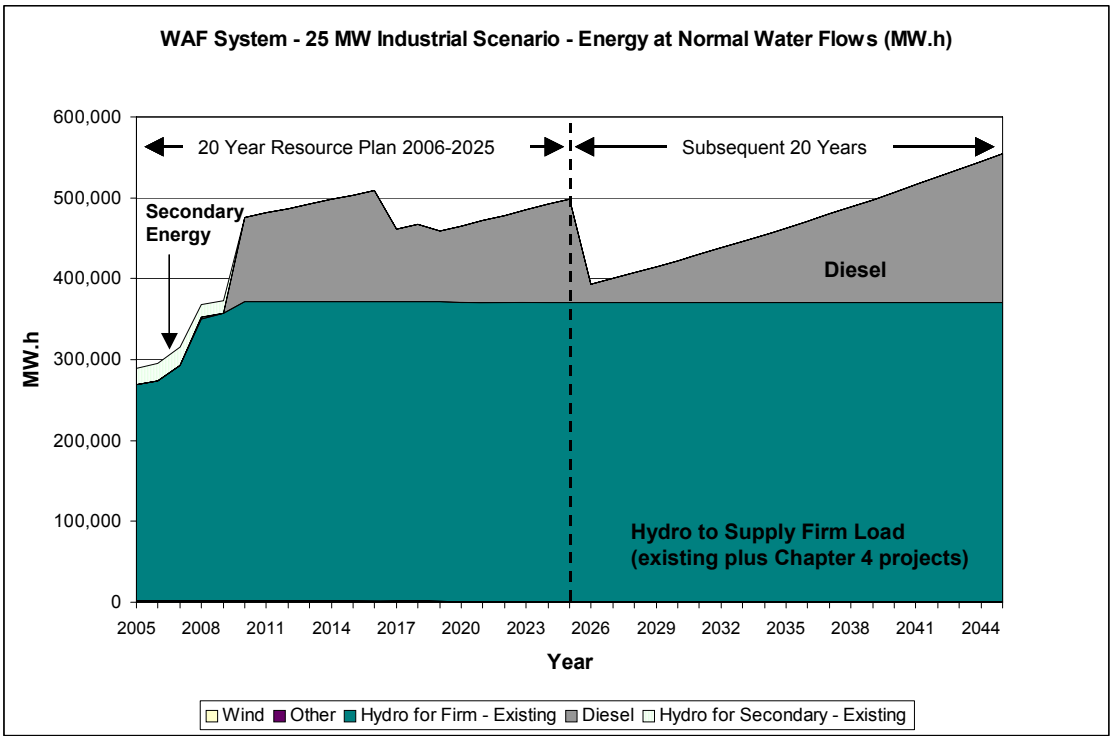
Figure 5.5:
Scenario 2: WAF Capacity Requirements



The WAF integrated system peak loads once the two mines are connected would approach the 85-95 MW level during the mine lives under the assumptions adopted. However, given the scale of the mine loads in this case and without development of new non-diesel generation, the WAF diesel units would be operating for basically the entire year (similar to when Faro was in operation) so “peaking diesel” would no longer be a relevant concept for the YEC WAF system.

Energy: This scenario gives rise to major new requirements for diesel baseload generation, which over the life of the mines would supply about 70% of the mine load incremental generation. Without new development of hydro or other capital intensive generation, WAF diesel fuel generation required would range from about 90 to 140 GW.h/year for a period of 16 years (from 2010 to 2025); thereafter, as the new industrial loads close, diesel generation would approximate 21 GW.h/year (growing each year by 7 to 8 GW.h as WAF non-industrial load grows) and not reaching the 100 GW.h per year level again for 10 years (until 2036), well outside the horizon of the current Resource Plan.

Figure 5.6:
Scenario 2: WAF Energy Requirements



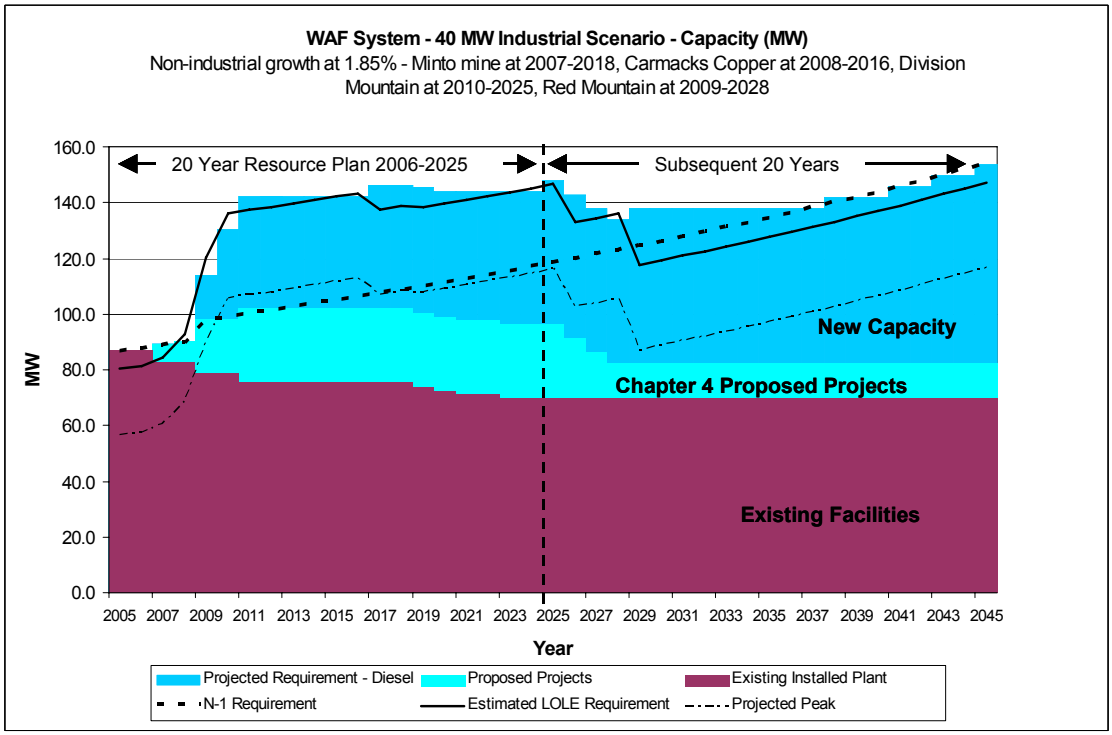
5.2.3 Scenario 3: A 40 MW WAF Industrial Scenario

This scenario is based on an assumption that Yukon Energy is able to connect service to numerous new mining developments and that these developments coincide in the next 10 years. A larger scenario in excess of the Faro mine, this scenario could potentially include the same mines identified in the 25 MW industrial scenario, with the development of the Red Mountain mine. Other possible development combinations in this scenario (but more distant from current grids) including Adanac (15 MW) and Kutz Ze Kayah and Wolverine (8.8 and 5.1 MW) should other non-utility funding enable transmission development along this route.

The specific scenario developed for analysis assumes four new mines all coming into service no later than 2010. These mines include Minto, Carmacks Copper, and Division Mountain per Scenario 2 (the 25 MW scenario), plus Red Mountain assumed to be developed at 20 MW and 126 GW.h/year from 2009 for 20 years (also requiring 70-100 km or more of new major transmission). Without new development of hydro or other capital intensive generation, overall generation supply requirements would approximate 315 GW.h/year when all four of these mines are operating.

Capacity: The scale and duration of development of this major combination of mining loads is such that material increases in system installed capacity are required to service the loads. Yukon Energy would face substantial requirements for new capacity in excess of that indicated in Chapter 4. This added capacity required with these industrial loads would be more than 35 MW of new diesel units or equivalent capacity, assuming minimal on-site diesel installations at the four mines[16].

Figure 5.7:
Scenario 3: WAF Capacity Requirements

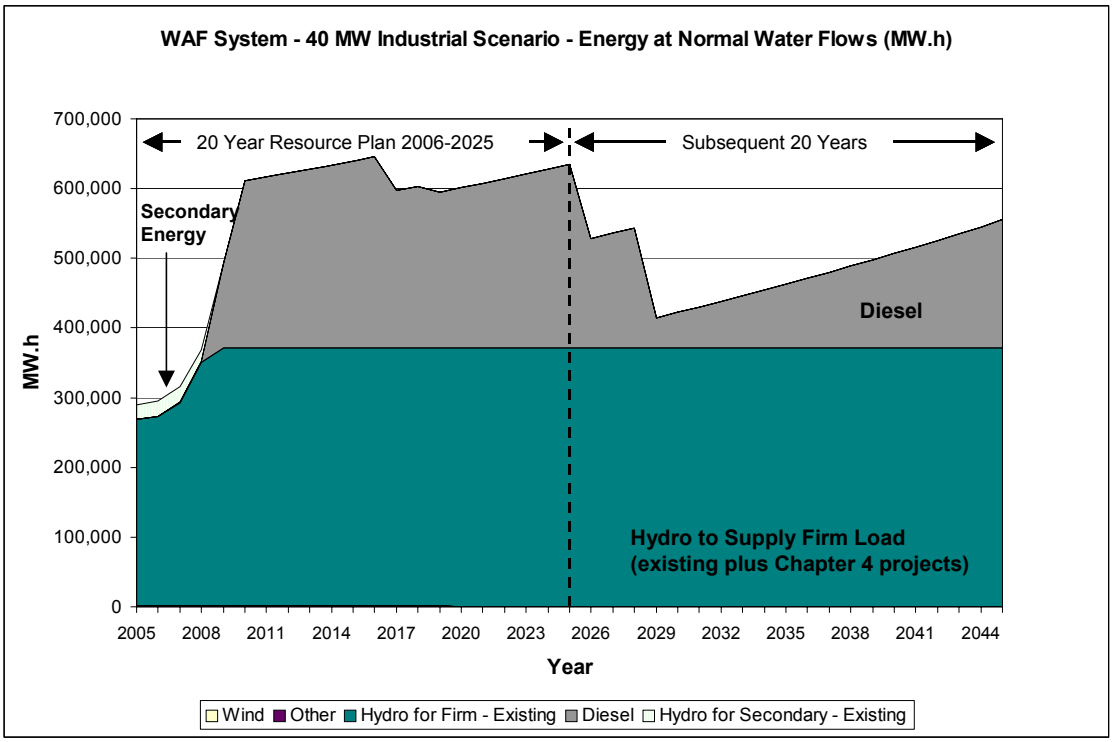


Energy: From an energy perspective, the development of 40 MW of industrial load well exceeds the current scale of system surplus hydro. For a period of 16 years, the magnitude of diesel generation under this scenario (if all new energy was supplied by diesel fuel generation) would range from 220 to 275 GW.h at normal water flows, with four additional "shoulder" years before and after the peak averaging 120 to 170 GW.h. Without new development of hydro or other capital intensive generation, over the life of the mines diesel generation would supply about 85% of the mine load incremental generation.

[16] As noted in the summary of requirements, the scenario case is modeled using a maximum 44 MW of industrial load. Of this amount, and assuming development of the Aishihik 3rd Turbine, 6.8 MW of industrial load may be carried under the LOLE criteria without a need for new capacity (over Base Load N-1 requirements), and 37.2 MW of new capacity is therefore required.

After the period of mine closures (assumed here at 2029), the WAF system under this scenario would be back down to a non-industrial load level that requires all the existing hydro output plus about 44 GW.h of diesel generation, and it will take approximately 13 years (assuming no additional new industrial developments) before it increases back to the 150 GW.h of diesel generation level (to 2042). This period is well beyond the current 20 year Resource Plan framework.

Figure 5.8:
Scenario 3: WAF Energy Requirements



5.2.4 Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline

The largest potential industrial power load in the near-term in Yukon is the Alaska Highway Pipeline. For the purposes of current planning, Yukon Energy is working with initial plans that four compressor stations each potentially requiring 30 MW and 223 GW.h/year for 30 years may require service (totalling up to 120 MW and 894 GW.h/year). The earliest in-service date for the first four compressors is assumed to be in the 2012-2015 period, assuming development of the pipeline by this time as well as use of electric power rather than natural gas from the pipeline to run these compressor stations. Up to eight additional

30 MW compressors could be added within the following four to five years (potential total 360 MW and 2,680 GW.h/year for this scenario).

Under normal circumstances, a natural gas pipeline operating in remote areas will power compressor stations with direct drive natural gas compressors without the use of electricity. In areas where there is access to low cost electrical power, pipelines have been converting to electrically powered compressors. In Yukon, the terms of the current agreement relating to this pipeline state that the proponent will be required to use electric compression if it can be provided on a "reasonably economic" basis. Accordingly, the Scenario 4 potential power load is contingent not only on the pipeline being developed as assumed, but also on Yukon Energy being able to establish that it can provide a "reasonably economic" electricity option for the pipeline to use electric compression.

Capacity and energy graphs indicating existing supply versus new 120-360 MW loads for Scenario 4 are not meaningful, given the current installed winter capacity for the entire WAF grid at only 87 MW.

5.3 OPTIONS

New generation options to supply future industrial developments focus on energy rather than capacity requirements.

New industrial WAF power loads beyond Scenario 1 levels would lead to increased reliance on available diesel generation to meet incremental baseload energy requirements[17], and high costs associated with non-peaking diesel energy generation would thereby create opportunities to develop new supply resources to displace the need for incremental diesel energy generation. In each scenario, non-diesel energy resource development opportunities are shaped by the magnitude and duration (seasonal and multi-year) of the incremental baseload energy that would otherwise need to be supplied by available diesel generation.

Yukon Energy has identified on technical grounds an initial list of potential generation options to examine

[17] "Baseload" here means annual energy generation other than "peaking" energy generation. "Peaking" energy generation is generation that occurs in any year only over short-term periods (hours or days) to aid in meeting the peak demand (MW) for electricity, typically during business day hours in winter; peaking generation units accordingly will typically operate only a small percent of the time in any year (e.g., say up to 10% to 15% of total annual hours). In contrast, typical baseload generation units will typically operate for most of the time in any year, e.g., Whitehorse Rapids hydro units (40 MW capacity) on a long-term basis will generate about 246 GW.h/year, implying average annual operation at about 70% of annual capacity. Due to seasonal as well as peaking operation, long-term average annual energy generation at Aishihik approximates only about 40% of the plant's 30 MW capacity.

for each of the four WAF industrial development scenarios (in addition to diesel generation as a standard default option, and transmission required to connect new industrial loads and/or new generation under each scenario).

At this stage, further to discussions related to the 1992 YUB hearing, the Resource Plan also considers briefly potential development of resource options by IPPs.

5.3.1 Overview of Resource Supply Options

Major power resource supply technology options considered in this chapter for possible commitment before 2016 fall into one of three categories: hydro, thermal (coal, or potentially biomass), or natural gas. Potential interconnection to the BC grid is also considered with the pipeline scenario.

For the major supply options considered, the relevant technology characteristics of each type are critical to considering its suitability to the loads to be served during the planning period. Beyond the major supply technology options considered in this chapter, a number of other technology options have been reviewed and determined to not provide the necessary characteristics for major development options in Yukon at this time. Details on the following additional technology options are set out in *Appendix A: Generation Technologies*), along with review of the major technologies addressed below in this chapter:

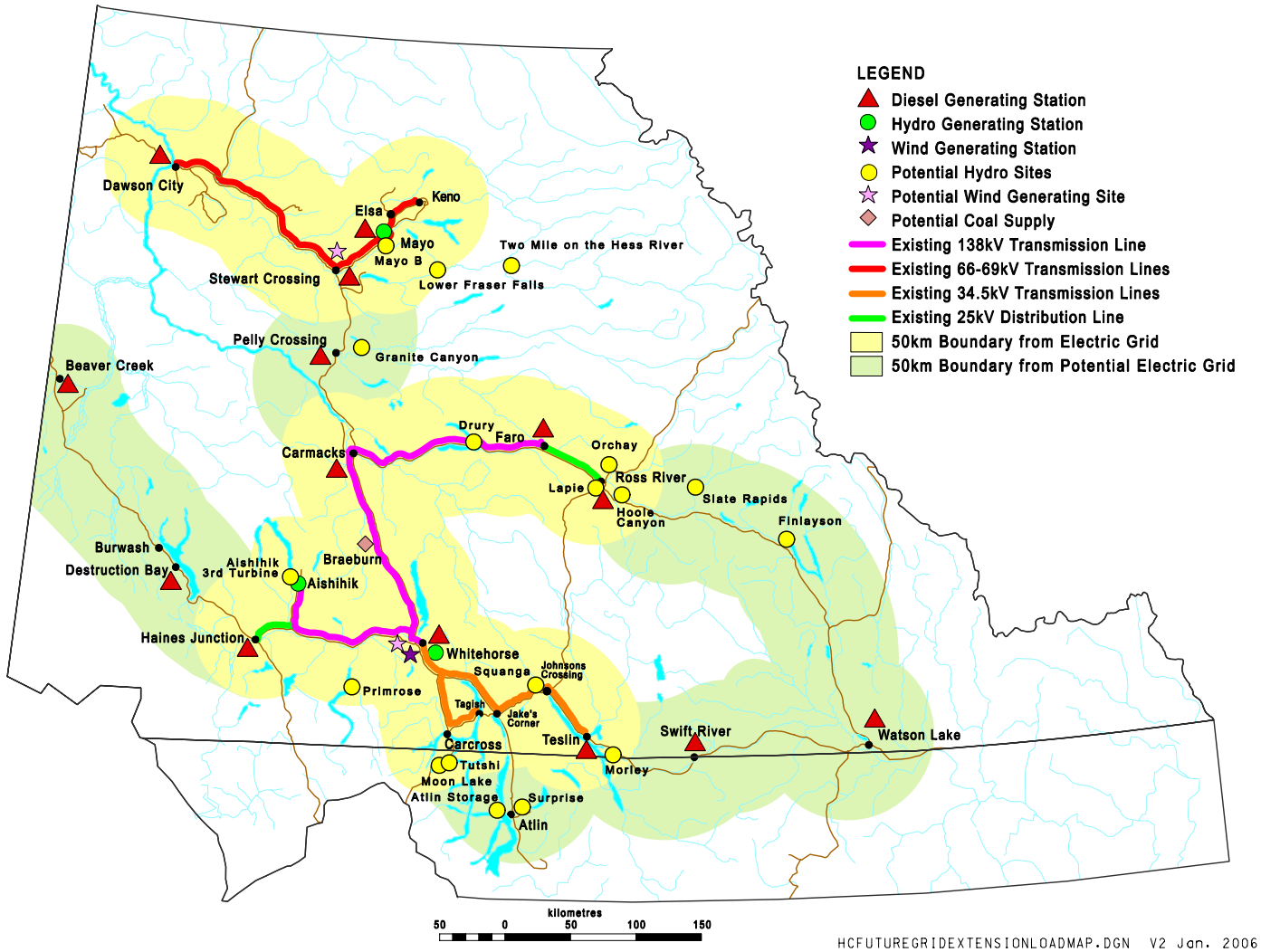
- Wind
- Coal-bed methane
- Hydrogen
- Nuclear
- Biomass
- Geothermal
- Solar
- DSM

Before reviewing supply options specific to each of the four WAF industrial development scenarios, the technology characteristics for each of the major supply technology options considered in this chapter are highlighted separately below. In addition, potential consideration of IPPs to develop these major resource options is also reviewed.

Figure 5.9: Map of Potential Supply Option Sites provides an overview of hydro and coal site option locations examined in this chapter in the context of the current WAF and MD power supply infrastructure, identifying as well areas within a 50 km boundary from current and potential electric grids.

Figure 5.9:

Map of Potential Supply Option Sites



5.3.1.1 Hydro Technology Characteristics

The potential hydro supply options identified in the Resource Plan for the Yukon are detailed in *Table 5.2: Potential Hydro Resource Options* as well as in *Appendix B: Hydro Project Options*.

Table 5.2:
Potential Hydro Resource Options[1]

	Grid	Installed MW	GWh	Capital Cost (2005$millions) (excl. trans.)	Trans. Distance (km)	Protected under Yukon land claims	In BC	Capital Cost LCOE (cents/KWh) excl. trans (2005$ real)
Existing Hydro Enhancements								
Aishihik Diversions	WAF	0	total of 24	n/a	0	X		n/a
Atlin Storage	WAF	2	9	n/a	0		X	n/a
Very Small Hydro Projects (1-4 MW)								
Drury	WAF	2.6	23	31	0	X		7.2
Squanga	WAF	1.75	8.3	12	5			7.7
Orchay	WAF	4.2	27	47	15			9.2
Morley	WAF	4	22	31	30	X		7.5
Lapie	WAF	2	10	14	8			7.4
Small Hydro Projects (5-10 MW)								
Moon	WAF	8.5	50	51	66		X	5.4
Surprise	WAF	8.5	50	50	100		X	5.3
Tutshi	WAF	7.5	50	79	25		X	8.4
Mayo B	MD	10	48	101	0			11.2
Medium Hydro Projects (10-30 MW)								
Primrose	WAF	28	141	191	100			7.2
Finlayson	WAF	17	129	179	230			7.4
Large Hydro Projects (30-60 MW)								
Hoole	WAF	40	275	412	100			8.0
Slate	WAF	42	252	422	172			8.9
Two Mile Canyon on the Hess	MD	53	280	380	n/a	X		7.2
Very Large Hydro Sites (60+ MW)								
Granite	WAF	80 (up to 250)	660	706	125	X		5.7
Fraser Falls	MD	100 (up to 450)	613	555	n/a			4.8
Yukon River *(such as Rink Rapid, Eagles Nest, Five Fingers)*	WAF	various 75-240	n/a	n/a	n/a			n/a

[1] See Appendix B for more information on specific hydro options and for review of Capital Cost LCOE (2005$).

Hydro resource options exist under each of the four industrial development scenarios, addressing new energy requirements that emerge when loads develop sufficiently to fully utilize the current hydro generation surplus on each grid. Hydro is a proven technology in Yukon and considerable effort has been spent over the years to assess and catalogue potential for hydro throughout the territory. Key characteristic of hydro generation include the following:

- **High initial cost of plant, with very low to zero variable costs:** This key characteristic of hydro derives from the nature of the "fuel" – running water. Consequently, once hydro

plants are constructed, they need for economic reasons to be used on a sustained ongoing basis (unless intermittent use is done simply to store water for more cost effective future peaking, seasonal or other use) as there are very little cost savings if the plant is not in use. This leads to situations such as now exist on WAF, where hydro fixed costs are shared across less energy sales than would be the case if the existing hydro assets could be fully utilized by higher firm loads. This is also the economic basis for current WAF and MD secondary sales, essentially to help spread the fixed costs of the hydro plant across more kW.h output units. Consequently, it is difficult to justify hydro projects unless maximum use can be made of the entire output in as many years as possible. The convenient corollary is that hydro project costs are largely incurred up front as capital outlays, so over time the annual expenses accounted for hydro facilities tend to be very stable (with real or constant dollar costs tending to decline[18]) compared with diesel or coal, where nominal fuel costs do tend to increase over time with inflation (among other factors).

- **Very long project lives:** In conjunction with very low variable costs, hydro projects tend to have a very long economic life (in some cases 100 years or more) and accordingly economic justifications for such projects typically also assume sustained and effective use throughout a correspondingly long economic life. As a result the exposure risks related to market requirements or other factors for new hydro projects extend farther into the future than facilities that are expected to provide similar benefits over shorter economic lives.
- **Long lead times for permitting, approvals and construction, with substantial investment in planning studies required in advance of determining full project feasibility and making commitments:** The time required to assess, licence and construct a hydro project is much lengthier than for most other generation technologies. The 1992 Resource Plan reviewed in detail the planning stages for a typical hydro project that might have been considered at that time.

Hydro generation project feasibility in each instance is sensitive to certain key factors:

- **Water availability:** Knowledge of dependable flows; head under natural (run of river) water conditions; potential options for reservoir storage and/or diversions; availability of water throughout the year, particularly during winter peak periods; and opportunities for seasonal or multi-year reservoir storage.

[18] By way of example, consider that the bulk of the initial Whitehorse Rapids hydro plant was built in the 1950s for $7.2 million. Today's costs for this plant include depreciation on the $7.2 million as well as interest on the undepreciated component of this original capital cost.

- **Generation site:** Foundation conditions; general terrain; and access during construction and operation.
- **Project location:** Distance from existing and expected future loads; and transmission requirements.
- **Regulatory approvals:** Environmental and socio-economic impacts; and mitigation requirements.

When undertaking hydro project planning, there is a need for sequential planning stages given the relatively high potential planning costs for each potential site. Experience establishes that project selection should be in clearly defined stages in order to control time and cost commitments, to account for environmental regulatory requirements as well as technical, economic and financial issues, and to allow for an orderly project screening and assessment before commitment and construction of any project without unnecessarily committing excessive capital for assessing multiple sites to the same level of detail.

The 1992 Resource Plan set out three levels or stages for hydro project planning and selection in Yukon, with the need for any site to proceed successfully through all three stages before any commitments may be considered.

- **Level 1/Stage 1 – River Reconnaissance/Inventory (all sites):** Air reconnaissance to locate/evaluate potential sites; existing water flow data. In the 1992 Resource Plan, Level 1 was estimated to cost $20,000 per site (resulting cost estimates considered to be within +/- 50%). Yukon Energy has developed an inventory of many sites in Yukon and in northern BC that have been studied in the past (primarily by NCPC or Government of Canada, and reviewed from time to time by Yukon Energy). Based on inventory of sites studied in the past, Yukon Energy has identified certain sites in this Resource Plan with the potential to meet the forecast electricity needs of Yukon under each of the four industrial development scenarios.
- **Level 2/Stage 2 – Site Reconnaissance/Pre-Feasibility:** Field investigations to evaluate foundation conditions, preliminary hydrological studies, preliminary office studies (power availability, structural lay-outs and capital costs at +/- 25% accuracy), confirm or reject some of the key initial assumptions in an inventory study and provide some data needed for further studies if justified. In the 1992 Resource Plan, Level 2 was estimated to cost $80,000 per site. Level 2 was achieved at a minimum for all sites reviewed in the 1992 Resource Plan report.

- **Level 3/Stage 3 – Feasibility Studies**: Further field investigations (geological reports, foundation investigations through test pitting and drilling, construction material investigations to finalize sources), site topography (scale 1:20,000 or 2 m contours), updated hydrology, environmental and socio-economic studies, consultations with First Nations and others, detailed office studies (to determine structure sizing and location, final concept, power availability, and project capital cost at +/-20% accuracy). In the 1992 Resource Plan, Level 3 was estimated to cost $400,000 per site. Level 3 should be substantially completed prior to any decision to proceed to licensing; required for regulatory submissions, construction contract packages, financing arrangements. Level 3 review was started on only some of the projects examined in the 1992 Resource Plan report (only some of the small scale projects).

The cost today to carry out each Stage/Level of site specific planning would be higher than indicated in the 1992 Resource Plan, both to reflect current day dollars and to reflect any current projects that are larger or more complex than those considered in 1992. Costs to proceed through full scale feasibility studies, licencing/permitting and final design/costing prior to any final commitments for even a "small" hydro project (5-10 MW) might, for example, range from $5 to $10 million[19].

Yukon Energy will only proceed with the final design and construction of sites (effectively Level 4 or Stage 4) that are required (based on load growth, or commitments by industrial customers), that can be successfully licensed in a timely manner, and that are not expected to have a long-term adverse impact on ratepayers relative to other available options.

5.3.1.2 Coal and other Thermal Technology Characteristics

Environmentally sound coal generation is considered in this chapter consistent with past reviews in Yukon based on a presumed pre-development of local supplies (Division Mountain). Coal development solely for power generation, and associated costs of mine development, is not considered.

Coal generation has been reviewed a number of times for application in Yukon. Coal in particular as a fuel source has also been examined in many other jurisdictions beyond Yukon, and is a major generation option that is subject to extensive ongoing technology development to address emissions controls as well as other features (see also Appendix A). Key characteristics of coal relevant to the WAF system are as follows:

- **Economics very sensitive to size of plant:** Repeated assessment of coal potential in Yukon has focused on 20 MW size, as that is the largest single unit that WAF could handle

[19] Estimate based on 10% of estimated capital costs from Table 5.2.

within operating reliability considerations. Economic preference exists for larger plants up to 50 MW or more to secure lower costs per kW.h of output. This size sensitivity extends to capital costs and operating costs (i.e., largely need same material staff complement for 20 MW plant as for 50 MW[20]). However, energy output from larger potential sizes of plant at perhaps 360 GW.h per year (50 MW) are well in excess of most WAF scenario requirements other than the Pipeline.

- **Technologies for use of coal have been advancing at a rapid pace**, particularly with regard to reducing emissions. Any coal generation plant would have to be environmentally sound in order to be considered by Yukon Energy.
- **Facility life of 20-30 years can be well suited to Yukon loads:** The industrial loads in Yukon can allow for large loads of limited life, with risks of major reductions at the end of the life of the mine(s). With a hydro development, the long life of the facility can increase the exposure to this market risk, while the 20-30 year life of coal or other thermal plants is better suited to the timelines of mine life for many developments and to the mitigating of risks of load decreases when the mine closes.

Similar to coal, biomass generation (i.e., wood waste) is subject to the same economic constraints. Specifically, the fixed costs (including fixed operating and maintenance costs) do not vary dramatically with the size of the operation or the load. In these circumstances, economic viability hinges on relatively large and virtually constantly run facilities. As a general principle, however, biomass generation in Yukon would not typically become economic unless three key conditions are met (these same conclusions have also recently been cited as preconditions for biomass electricity generation in Alaska - see Appendix A):

1. The fuel (typically wood) must be available from a source that would otherwise have to pay to dispose of it. Economic biomass generation is not typically possible even outside Yukon with a wood product that has a cost to harvest. Biomass generating facilities at a minimum typically need a secure source of forestry waste biomass such as sawdust or bark waste from a pulp mill that is in close proximity to the biomass generating plant or even (in at least some cases) that can be delivered to the plant for free; for this precondition to apply, there often has to be savings achieved from avoided disposal costs.
2. The wood-fired power displaces diesel power.
3. The waste heat from the biomass generation also must be of economic value on-site, or be able to be sold.

[20] An earlier study for YDC indicated that 13 staff FTE would be required to operate a 20 MW plant. This number was not sensitive to size (in the extreme, a 1 MW plant was considered and determined to still require 12 staff FTE).

To date, proposals discussed in Yukon do not meet any of these three key criteria, and accordingly the thermal biomass option is not considered likely to be economically feasible for commitment prior to 2016 for any of the industrial development scenarios being considered.

5.3.1.3 Natural Gas Technology Characteristics

Natural gas generation is a major supply option to southern utilities (as well as NWT in Inuvik) that may become an option in Yukon if the Alaska Highway Pipeline project proceeds. The current expectation is that any pipeline developed along the Alaska Highway will allow access for at least the major centers to natural gas for local distribution. However, there appears to be uncertainty as to pricing regimes for bulk gas delivered to Yukon.

In terms of the Resource Plan, potential for Natural Gas availability focuses on three major areas:

- **Natural Gas used by the pipeline for compression:** As reviewed earlier in Section 5.2.4, under normal circumstances a natural gas pipeline operating in remote areas will power compressor stations with direct drive natural gas compressors without the use of electricity. In areas where there is access to low cost electrical power, pipelines have been converting to electrically powered compressors. In Yukon, the terms of the current agreement relating to this pipeline state that the proponent will be required to use electric compression if it can be provided on a "reasonably economic" basis. Outside of compressors, pipelines have reasonably material other electrical loads (including potentially cooling loads) that may be ideal candidates for grid power service even if compressor loads are determined to be better served directly by natural gas.
- **Natural Gas for Yukon power generation:** Regardless of whether the pipeline operator uses natural gas or electrically powered compression, the pipeline will likely create opportunities for natural gas based power generation in Yukon. Evidence from southern jurisdictions and NWT indicates that natural gas generation is a major technology option for new power generation and can be well ahead of diesel in terms of costs, reliability and impact on the environment. In addition, unlike coal, natural gas generation is more readily "scalable" to sizes suitably for Yukon as well as more suited to timely regulatory review and approvals and flexibility to operate in response to load variations.
- **Natural gas availability to Yukoners for heating supply:** Natural gas will become a heating supply option for residential and commercial customers under the pipeline scenario. In 1977 Foothills did include a proposal to provide natural gas to communities along the pipeline route including Beaver Creek, Burwash Landing, Destruction Bay, Haines Junction, Whitehorse, Teslin, Upper Liard, and Watson Lake. Although electrical heating is no longer

considered to be a major component of Yukon Energy's loads, there is likely to be some reduction in load (including winter peak loads) from electrical heating customers converting to natural gas.

5.3.1.4 Independent Power Producers

Power delivered to a grid (e.g. through purchases by Yukon Energy) from IPPs rather than generated from assets owned and operated by regulated utilities typically follows the underlying technology characteristics for the generation source used, e.g., IPPs developing hydro sites have some of the same characteristics as utility-developed hydro site projects noted above.

IPPs in certain instances can offer specialized skill, experience, or knowledge that may allow a specific supply option to be cost effectively developed by the IPP to meet utility requirements as stipulated in its contract with the IPP; such contracts are also intended to provide the IPP with unregulated profit incentives to be efficient and effective in supplying such generation outputs. However, there are some unique non-technology characteristics of IPPs that were reviewed in some detail at the 1992 Resource Plan hearings, and that merit specific attention as they may potentially drive material additional risks to a utility and its ratepayers compared to regulated utility power supply projects:

- **Unit pricing, including issues of levelized costs and sharing of benefits from diesel displacement:** As of 1992, the last major YUB review of IPP matters, there remained significant issues outstanding in regards to approaches to pricing for potential IPPs in Yukon. Major issues relate to how to determine the "value" of the IPP to the system (typically based on avoided costs for the system, which can be difficult to calculate for various supply types), how to share between the IPP developer and the utility ratepayers the "benefits" associated with developing lower cost generation, and the potential use of "levelized" nominal prices for IPPs (which tend to provide higher real prices in the near-term and lower real prices over the long-term, and are typically preferred by IPP developers). At a basic level, it is likely that hydro supply projects that can effectively displace regulated utility diesel generation will yield material avoided cost savings within Yukon; however, while almost all such savings will typically go to the benefit of ratepayers when such hydro projects are developed by a regulated utility, the IPP development option introduces a separate step whereby some (or perhaps even all) of the avoided costs savings can be captured by the IPP developer.
- **Take-or-pay contracts:** Similar to other Yukon generators, IPP developers would likely have no market for their power other than the utility. Financing for such IPP projects is expected to require the utility to commit to a "take-or-pay" contract that means the utility will be committed to buy most or all of the project's output at full prices, whether the utility

requires the power or not and perhaps even whether the IPP is able to sustain production of the power. As a result, market and likely other risks of the development can in effect be fully borne by the utility rather than by the IPP developer, even though the IPP may capture most or all of any avoided cost benefits when the facility is able to displace diesel generation. Under some potential IPP arrangements, avoided costs benefits may be locked in for the IPP developer (and paid for by ratepayers as though the diesel savings were in fact occurring) regardless as to whether in fact any such diesel cost savings are being realized by the utility.

- **Delivery of power/reliability:** If an IPP project on a system in Yukon is not functioning at any point in time, regardless as to whether or not the utility must still make payments to the IPP, there is the separate risk that the utility (due to default by the IPP) may not be able to meet its committed supply of power to its ratepayers. However, the utility itself typically has little or no control over the IPP facility, its maintenance activities, emergency procedures, or scheduling and thus can run into problems with the continuity of supply to its customers. For this reason, it is difficult for a regulated utility to treat IPP or other generation not under utility control as "firm" supply for a regulated utility system[21]. A utility also has no control (beyond penalties) over the construction of IPP projects and whether the IPPs can in fact meet key contracted commitments such as in-service date.
- **Financial guarantees:** IPP producers typically seek external bank financing for portions of the capital cost of their facilities. For this reason, these producers typically require power purchase contracts from the regulated utility with strong terms in favour of the IPP and may also include various guarantees from the utility, ultimately focusing the lender's assessment of their risks onto the financial strength of the utility. The end result can be effective requirements for the utility to backstop or guarantee the risks of the private investor to further disproportionately focus the risks of any development on the utility itself and its ratepayers.

Consequently, as discussed in the 1992 hearing, it is difficult to establish an IPP arrangement in Yukon that would reflect a fair sharing of the risks between the utility (and its ratepayers) and the private IPP developer. Yukon Energy in 1996 did complete a major call for "Expressions of Interest" including for IPP supply,. This call yielded some potential focused opportunities for future investigation of small IPPs should material loads develop and base load diesel become an ongoing requirement. However, as noted

[21] As an example, the Snare-Yellowknife system in NWT has a hydro facility that was previously owned and operated by one of the mines. NTPC had a supply agreement with the mine to meet their peak loads in the event the hydro site was not producing. Consequently, when the capacity criteria was assessed for the entire grid, this hydro station was not considered firm capacity for the purposes of planning the system. In 2003 NTPC purchased this station and, now that it no longer is owned and operated as an IPP, it is now included in the new firm capacity planning approach for the system.

in the 1992 hearing, IPP focus in Yukon to date has been on small projects - other than small hydro projects, it remains unclear how difficult it will be in Yukon to develop or negotiate an IPP arrangement to suitably share risks on resource projects of any material size.

5.3.2 Options for Scenario 1: A 10 MW WAF Industrial Scenario

A 10 MW industrial scenario would not likely require the addition of capacity or energy projects. Up to 6-7 MW of industrial load can be added to the system without driving a need for new capacity. Depending on the seasonality of the load and quantity of on-site diesel generation installed by the mines, it is possible that all of the 10 MW in new load could be served without driving a need for new capacity.

There is also a current ability to serve about 90 GW.h per year of energy from existing surplus hydro, decreasing as non-industrial load grows over the life of the mines. Under this scenario, there remains some diesel generation required for peaking and, as the non-industrial load grows, some requirements for baseload diesel. However there is limited value to any new hydro or thermal generation to displace diesel fuel, as the number of hours per year of diesel requirements remains quite limited.[22] In addition, the specific early mine developments considered in Scenario 1 are of relatively short duration (i.e., mine shutdowns are assumed to occur in 2016 and 2017), with the result that surplus hydro is expected to remain under this scenario for half of the 20 year planning period (from 2006 to 2009, and from 2017 to 2022).

As a result, any opportunities for new generation developments are likely limited to existing hydro enhancements (including those identified in Chapter 4, Section 4.3.6) and/or possibly the smallest of the hydro sites identified in Yukon, at most, and likely only those that can provide both capacity and energy benefits. A list of "very small hydro projects" (1-4 MW) is provided in Table 5.2 and in *Appendix B: Hydro Project Options*. Among these options, only Drury is considered to be reasonably well defined at this time.

5.3.3 Options for Scenario 2: A 25 MW WAF Industrial Scenario

A 25 MW industrial scenario, which would be similar to WAF loads experienced when the Faro mine was operating, would provide opportunities for the addition of both capacity and energy. Without new development of hydro or other capital intensive generation, incremental WAF diesel generation required under the Scenario 2 case examined in Section 5.2.2 would range from about 90 to 140 GW.h/year for a

[22] Over the life of these two mines with the timing assumed in Scenario 1, only about 10% of the incremental energy requirement would need to be met by generation beyond that available from current hydro surplus resources (assuming average long-term flows).

period of 16 years (from 2010 to 2025) out of the 180 GW.h/year of overall increased energy required due to the new industrial developments.

Under the Scenario 2 case examined in Section 5.2.2, if no new capital intensive generation was developed and the WAF system had to be served solely with incremental diesel, the assumed industrial loads would only be supplied about 30% with surplus hydro and about 70% with incremental diesel generation over their life. Under these conditions, (i.e., if diesel generation is to be relied upon to supply the incremental energy requirement), there is no apparent basis for Yukon Energy developing any new transmission interconnections to the bulk of this mine load (with the associated risks and transmission losses) rather than the mines simply using isolated diesel plants at their mine site.

However, this scale of industrial load on the WAF system would provide material potential opportunities to develop new capital intensive generation on WAF. If the assumed industrial loads arise, diesel requirements over the life of the industrial loads (absent new capital intensive generation) would approximate 90-140 GW.h/year; however, after the mines close, diesel generation on WAF would fall back to about 21 GW.h/year, growing at about 7 to 8 GW.h/year as non-industrial load grows. Accordingly, the size range of new capital intensive generation suitable for this magnitude of load is likely to be about 50 GW.h per year, or about 7-10 MW of reasonably high capacity factor generation (such as those reviewed in 1992 when the Faro mine was operating)[23]. If such development could be pursued, there would remain 7-10 MW of other new “reserve” capacity required (for largely peaking or standby) where low capital costs are the driving economic factor (i.e., likely new diesel units) over and above the commitments recommended in Chapter 4.

Hydro projects in excess of about 7-10 MW size would impose risks of substantial periods of surplus hydro after the planned closure of the mines (with 10 years required for diesel consumption to move back up to 100 GW.h/year from 2026 to 2036) outside of risks related to premature closure of one or more mines under this scenario.

In contrast, as reviewed below, the scale of diesel generation displacement offered by Scenario 2 appears to be too small to support any feasible thermal coal supply options, even though the overall mine life assumed better fits thermal than hydro supply alternatives.

[23] At that time, projects up to about 8 MW per year and 50 GW.h/year were considered (implied annual capacity factor of 70%).

Hydro: Options can include those identified for the 10 MW scenario (very small hydro projects), as well "small hydro projects" (5-10 MW) and Existing Hydro Enhancements noted in Table 5.2 and *Appendix B: Hydro Project Options*. Aside from Drury, each of these options is considered to be relatively undefined at this time.

The projects identified reflect a lack of suitable hydro sites identified to date in this size range in Yukon. The primary supply options considered in 1992 in this size range (such as Moon Lake as well as Surprise Lake) are in BC and consequently attract significant additional charges for water rental fees and taxes.

Thermal – Coal: There are no credible opportunities to develop coal generation at this scale. As reviewed earlier, the practical minimum size coal development considered for Yukon has been 20 MW, which roughly equates to 144 GW.h/year or well in excess of the requirements under this scenario (other proposals have focused on coal generation in excess of this range up to 50 MW).

5.3.4 Options for Scenario 3: A 40 MW WAF Industrial Scenario

Under the 40 MW scenario, as under the 25 MW scenario, any loads connected to the WAF clearly push the system well onto diesel. Without new development of hydro or other capital intensive generation, incremental WAF diesel generation required under the Scenario 3 case examined in Section 5.2.3 would range from 220 to 275 GW.h/year for a period of 16 years, with four additional "shoulder" years averaging about 120 to 170 GW.h/year. After these mines close (assumed to be 2029), diesel generation on WAF for non-industrial loads would fall back to about 44 GW.h/year, growing at about 7 to 8 GW.h/year as non-industrial load grows.

If diesel was relied upon to supply loads of this magnitude, the industrial loads in effect would only be supplied about 15% with existing surplus hydro and 85% with incremental diesel generation over their life. As noted above for the Scenario 2 case, if WAF diesel generation is to be relied upon there is no apparent basis for Yukon Energy developing any new transmission interconnections to the bulk of this mine load (with the associated risks and transmission losses) rather than the mines simply using isolated diesel plants at their mine site. Consequently, if such loads are to be considered for connection to WAF, a major focus is required on developing new capital intensive generation larger than the 50 GW.h/year (7-10 MW) examined under Scenario 2 options.

New capital intensive energy projects in the range of 50 GW.h/year (about 7-10 MW) would be expected to be fully utilized in each year of this scenario. In contrast, long-term capital intensive energy projects in the range of 150 GW.h/year (in the range of 20-30 MW if baseload) would experience about 13 years or

more of surplus energy after the closure of the mines until non-industrial load growth consumed the excess output. Projects in excess of this level would see about 20 years of sustained use, then significant periods where they far exceed system requirements.

Overall, hydro project options above about 100 GW.h per year may be difficult to justify unless there is substantial expectation of subsequent industrial loads after 2024, and solid measures to address downside risks of premature mine closings. Thermal coal project options, however, with levels of energy generation of about 150 GW.h/year that are focused on a 20-year life may become feasible at this scale of mine loads. Each of these options is reviewed below, and is considered to be relatively undefined at this time.

Hydro: Hydro projects to supply the 40 MW scenario result in significant issues with respect to load stability and economic value of power over their life after the planned closure of the mines (outside of risks related to premature closure). This is because hydro projects are very long-term investments that can produce power well beyond the expected life of the mine being considered.

At this size range, options can include those identified for the 5-10 MW scenario (small hydro projects), as well "medium hydro projects" (10-30 MW) noted in Table 5.2 and *Appendix B: Hydro Project Options*.

At this size range, projects can support some costs for new transmission, so generation sites within about 50-100 km or more of the established 138 kV grid become worthy of investigation.

Thermal – Coal: Under the 40 MW scenario, the scale of new requirements increase to a point where opportunities may arise to develop coal or other thermal generation. The practical minimum size coal development considered earlier (1992) for Yukon has been 20 MW which roughly equates to 144 GW.h/year or in the range of the new energy requirements under this scenario. As coal plants have a life more consistent with the mine lives being considered (often assessed for project planning and feasibility at 25 years, although many plants outlive this), the technical fit of a coal plant to the loads under this scenario is better than hydro in this size range.

The economics of coal generation are very sensitive to the price of the coal, as well as to the quality of the coal and emissions standards, which can materially impact the capital costs required for the plant (for example, ash handling and dealing with sulphur in the coal). A 1995 assessment of coal power generation prepared for YDC by H. A. Simons Ltd. using Division Mountain coal determined a $50 million capital cost (1995$) excluding mine development costs, as well as about $2 million (1995$) for non-fuel annual

operating and maintenance costs (including 13 staff positions). Further assessment in 1996 focused on the potential for coal at $30/tonne to allow for power generation (using a 20 MW plant) at 8 cents/kW.h (1996$).

Based on these earlier 1995/96 estimates, a coal plant could be constructed and operated on the following basis:

- 25 year life at 20 MW, 144 GW.h (a 20 year life is also assessed below).
- $61 million capital cost (2005$), $2.5 million per year non-fuel operating cost (2005$) excluding taxes.
- Coal requirements of 102,000 T per year at $37/T (1995 estimate of $30/T inflated to 2005$).
- Oil requirement of 2.3 million litres at $0.65/litre (2005$) – based on 1995 estimate of 2,220 T/year[24].

The result is an 8.3 cents/kW.h LCOE (2005$, real), excluding transmission and taxes (but in this case including operating and maintenance costs, unlike hydro LCOE costs quoted above, given substantial O&M costs for coal generation) [25].

5.3.5 Options for Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario

Compared to the existing Yukon WAF system (firm non-industrial load of about 270 GW.h per year, installed winter capacity of about 90 MW), the pipeline loads for the first four stations at 120 MW and 894 GW.h/year, are massively in excess of system capability or conditions experienced to date.

Little work has been done since the 1950s and 1960s on hydro sites of the size relevant to this scenario. Any such hydro generation development would involve concurrent major transmission development needs which have not been assessed or costed to date in any detail, although some preliminary transmission concepts have been reviewed.

Timing needed for planning and licensing major generation and transmission projects is likely in excess of ten years, given the need at the outset for extensive and costly pre-feasibility and feasibility studies. This suggests that the pipeline would be operating for many years before the new hydro generation would be

[24] Based on the 1996 study, oil is required to supply the facility during start-up and back up duty. Given increases in the cost of oil since this study was completed, a newer coal plant may have a revised optimal balance between oil and coal, but this has not been assessed.

[25] Coal generation developed to supply a 20 year project life would result in the LCOE being increased to 8.7 cents/kW.h compared to 8.3 cents/kW.h for a 25 year project life (2005$, real)

available. The need for the pipeline operator to install gas compressors at the outset will further reduce the cost effectiveness of the new hydro options. However, previous reviews in Yukon (including the Lysyk inquiry) noted the key importance of the pipeline operator installing stations that can be readily converted to electrical service at a later date if power cannot be coordinated for delivery from the outset of pipeline operation.

The range of potential options for Scenario 4 is reviewed below.

Hydro: Hydro projects to supply the Pipeline scenario are of a magnitude not well understood or recently studied in Yukon. At this size range, options can include more modest "large hydro projects" (30-60 MW) noted in Table 5.2 and *Appendix B: Hydro Project Options* for supply to one or more individual stations, or "very large hydro projects" (60+ MW) for major integrated supply to multiple compressor stations.

At this size range, major redevelopment of Yukon transmission would be required, so transmission is an unresolved issue for all potential generation sites.

Thermal – coal: Power generation from coal can reasonably provide the magnitude of power required to service the pipeline. However, no serious work has been completed in Yukon regarding potential coal developments of this scale. In addition, at least initially coal is not likely to be considered economically viable as supply to electrical compression for the pipeline, as electrical compression is typically attractive to pipeline operators only in low cost hydro-based jurisdictions where rates can be below 6 cents/kW.h to as low as almost 3 cents/kW.h or lower depending on interruptibility (but not typically resorting to electrical compression in higher priced non-hydro jurisdictions dominated by coal).

Interconnection with the BC Grid: There are limited attractive projects in Yukon that have the capability to serve the full power needs of the pipeline. It is possible that such potential new loads would form the basis for BC to extend transmission from BC that would connect Yukon (near Watson Lake) with generation assets located in BC. This option could radically change power supply costs and options in Yukon to the extent that major load centres (e.g., WAF and MD as well as Watson Lake) were linked to this new grid connection.

5.4 PRE-ASSESSMENT AND SCREENING

The options identified under the various scenarios above reflect potential opportunities to put in place capital intensive but overall lower cost sources of supply than alternatives of grid-based diesel supply or isolated diesel supply to the mines.

In assessing grid-based diesel supply, current diesel price forecasts indicate about $0.70/litre to $0.75/litre for Whitehorse for 2010 (based on $50 to $55 US per barrel, 2010$ for NYMEX light sweet crude, reflecting current oil futures markets), equating to about $0.21/kW.h to $0.22/kW.h (2010$, or $0.20/kW.h in 2005$)[26] including modest variable operating and maintenance costs (such as lube), assumed at 0.016/kW.h in 2005$. These costs provide a benchmark for assessing the potential cost competitiveness of any other resource option. These costs also provide an indication of potential ratepayer impacts relating to connection of major new industrial loads if in the end these loads must be supplied through incremental diesel generation.

Based on the information now known to YEC, all potentially feasible generation options noted in the previous sections including their associated transmission, can potentially be economically developed as an alternative to diesel, so long as system loads allow full to near-full use of their output over the life of the project.

There are two major areas of uncertainty, however, that limit ability to develop full detailed assessment of options and conclusions regarding economic and technical feasibility at this time for any specific industrial development scenario:

- There is not sufficient definition of the loads and timing of industrial customers (outside of perhaps Minto at 2-4 MW).
- All project supply options identified above to address these scenarios are at best moderately defined, and most remain relatively undefined. In terms of the hydro project staging, few projects are at Level 2 (Site Reconnaissance/Pre-Feasibility) while most are at Level 1 (River Reconnaissance/Inventory) and in many cases (especially for medium to large projects) even the Level 1 work was completed many decades ago under different expected generation concepts and constraints so is of limited value. Thermal projects are at a similarly early stage in conceptual planning.

The focus of the following pre-assessment and screening is initially on technical pre-assessment and load fit (i.e. how well does the project fit the load requirements under any specific load scenario). As noted, cost effective opportunities to displace diesel generation require full to near-full effective energy use of a resource option's output over its life.

[26] For modeling purposes, fuel costs have been assumed at 65 cents/litre for 2005, inflating at 2% per year, to total 71.77 cents/litre in 2010.

Subsequently, economic pre-assessment is also considered to look at the screening options with respect to economic factors. Within the economic pre-assessment, diesel generation is assumed to be the default source for all energy not supplied by hydro or other resource options under the 10 MW, 25 MW and 40 MW scenarios, as diesel generation provides supply with relatively limited risk related to timing and/or capital costs. Diesel generation is not a reasonable supply option under the pipeline scenario, where the alternative to electrical compression is natural gas driven compression.

5.4.1 Technical Pre-Assessment and Load Fit

The assessment of how well various supply options fit the load requirements focuses around options of various types and size ranges. The analysis focuses on scale of loads relative to scale of various resource project options; however, as noted in Section 5.3, the assumed timing of loads as well as their duration can also be of critical importance in assessing resource options[27].

The load fit assessment is provided separately below for each different supply option technology and scale grouping:

Hydro – Enhancements (Aishihik diversions at no capacity, 1.8-17.7 GW.h/year; Atlin Storage at 2.0 MW, 9.0 GW.h/year; also other potential options being assessed in Southern Lakes; potential planning costs for these projects are estimated to be about $100,000 to $200,000 per project): These projects involve maximizing the value from the existing investments. Under the industrial development scenarios, each focuses on the potential to provide energy as well as in some cases capacity. The projects are all likely to be of relatively modest size that could be relevant under basically all potential industrial scenarios. The planning costs for these projects are estimated to be between $300,000 and $600,000.

Hydro – Very Small (1-4 MW, 5-30 GW.h/year, $12-$47 million; potential planning costs of $1.2 to $4.7 million prior to decision to proceed with project): The projects in this size range

[27] By way of example, a ten year delay in the Scenario 1 mine loads would enhance opportunities to develop at least very small hydro projects (to the extent that non-industrial loads would then have grown sufficiently to sustain long term use of the new energy supply). Similarly, the duration assumed for each mine development load examined is of critical importance in the assessment of resource supply options, e.g., capital intensive supply options can much more easily accommodate loads of 40 years duration than loads of only 10 years duration. In this regard, Scenario 2 and 3 load opportunities relate as much to assumed mine duration (at 15 to 20 years) as to the assumed level or scale of these loads; Scenario 4 load opportunities, with 30 year durations, also elate to more than only scale.

(Drury at 2.6 MW or larger, Squanga at 1.75 MW, also Morley (4 MW), Lapie (2 MW) and Orchay (4.2 MW)) are likely beyond the limits of what can be enabled by the 10 MW industrial development assumed in Scenario 1. The technical assessment of these projects relies on serving a role to supply energy in excess of existing system hydro capability, in order to displace diesel related to serving incremental mine loads while they are in operation, and to displace diesel serving non-industrial loads once the mines close at about 2016-2018. However, absent mine development at or above 10 MW extending through to at least 2020, it is not apparent that the load fit is sufficiently consistent to enable projects of even this very small size range to be feasible. Should they be developed, these projects are well within the financial capability of Yukon Energy/YDC to pursue, including measures to protect against downside market or load related risks.

Hydro – Small (5 -10 MW, 30-70 GW.h/year, $50-$101 million; potential planning costs of $5.0 to $10.1 million prior to decision to proceed with project): Projects in this size range (Moon at 8.5 MW, Tutshi at 7.5 MW, Mayo B at 10 MW) can be enabled by industrial developments in the 25 MW range with relatively limited downside risk outside of premature mine closures over a life of at least 15 to 20 years[28]. These projects are in a size range that can be financed under traditional structures by YEC and YDC, and that YDC likely has the financial capability to "backstop" with respect to various market-related risks. Ongoing current efforts in the southern lakes area may yet identify further potential in this size range for other projects or comparable sized enhancements to the Whitehorse Rapids facility by way of water management projects.

Hydro – Medium (10-30 MW, 70-150 GW.h/year, $179-$191 million; potential planning costs of $17.9 to $19.1 million prior to decision to proceed with project): Sites in this size range (including Primrose at 19-30 MW and Finlayson at 17 MW) only fit the WAF load profile under the largest 40 MW mining scenarios discussed (Scenario 3), which focused on the opening of four mines simultaneously (Minto, Carmacks Copper, Division Mountain and Red Mountain) with lives of 15 to 20 years for most of the load. However, even under these conditions the hydro projects are likely much too large for the system after the closure of the mines (assuming mine closure prior to about 2035), and as such would rely on either new mining loads at that time to sustain the level of WAF energy 20-25 years from now, or would have substantial surplus for likely far many years. In this regard, projects in this size range may also have a difficult time competing with coal with respect to load fit compared to the life of the generating station[29].

[28] Appendix B, Figure B-2 provides a review example of load fit for Moon Lake hydro and the 25 MW Industrial Scenario 2.

[29] Appendix B, Figure B-3 and Figure B-4 provide a review example of load fit for Primrose hydro and the 25 MW Industrial Scenario 2 and 40 MW Industrial Scenario 3.

Serious issues also arise with respect to "market"-related risks in this case such as premature mine closings and even delays in initial development. In addition, these projects are likely at the limits of what YEC/YDC can finance within the existing financial structure. At these limits of the financial capability of YDC and YTG, it would become necessary to identify and/or develop suitable mechanisms within Yukon to "backstop" the downside market risks associated with projects of this size.

Hydro – Large (30-60 MW, about 150-300 GW.h/year, $380-$422 million; potential planning costs of $38.0 to $42.2 million prior to decision to proceed with project): These projects exceed the size required for any credible mining load or combination of loads examined in this Resource Plan and would require well in excess of 40 MW of new mining loads – no such loads or load combinations have been identified to date. Project options in this range focused on Hoole at 40 MW, Slate at 41.6 MW, and Two Mile Canyon on the Hess at 53 MW. There may be options to develop these sites for portions of a pipeline load (1-2 compressors of the planned 4-12 compressor pipeline development), but in all likelihood the economics of a pipeline case will more readily facilitate projects in the 60+ MW range and not multiple projects in the 30-60 MW range. In addition, these projects appear to be at or beyond the absolute limits that Yukon Energy and Yukon Development could potentially finance under any conditions without potential external support or guarantees, such as from Canada.

Hydro – Very Large (60 MW+, over 500 GW.h/year, $555 million+; potential planning costs in excess of $50 million prior to decision to proceed with project): These projects cannot be considered for any practical development without a committed pipeline load (or equivalent) using electricity for compression, and without major transmission system development or redevelopment to handle this scale of generation. The projects identified to date include Granite at 80-250 MW, Fraser Falls at 100-450 MW, and various Yukon River sites at 100-500 MW. Yukon Energy would also need to address financial capability to even plan and carry out pre-construction activities on these projects, as costs for even these pre-development stages would likely exceed Yukon Energy's ready financial capability. Costs for development would require either major financial partners or government debt guarantees from Canada as commitments are likely beyond the capability of Yukon to guarantee.

Thermal – Coal: Development of environmentally sound coal in a size range of 20 MW or more cannot be seriously considered on the WAF system, given current technology, outside of major industrial developments in the range of 40 MW or higher (i.e., well in excess of the Faro Mine when it was operating). In the event very large industrial mine developments do arise in the 40 MW range, however, coal may be a better fit to the life of the load than hydro, and would therefore merit further consideration at that time.

Coal may provide opportunities within the 25 MW scale of industrial load development (similar to Faro-sized load) if constraints on technical feasibility and cost for coal generation projects smaller than 20 MW can be in some way be addressed. Earlier proposals that considered a technology for 15 MW combined coal/oil system have since been abandoned. However, it will remain relevant to monitor technology developments in this area. The capital costs of a coal facility are in a size range that can be financed under traditional structures by YEC and YDC, and YDC likely has the financial capability to "backstop" with respect to various market-related risks.

Coal options must be environmentally sound to be considered. The feasibility of coal generation will depend to some extent on the cost of employing state of the art technologies to reduce emissions.

Coal options also need to address directly who would be responsible for providing this resource, and under what terms and conditions would Yukon Energy secure such supplies. In the event that a coal mining project is developed for export markets, the coal for local thermal markets may become readily available. It is not clear how such supplies could be economically secured, however before such time as a coal mining project is developed for export markets. Other relevant aspects also require further considerations, including ash disposal.

Thermal – Biomass: In the event that Yukon develops a source for waste wood, of sufficient scale and duration, that would otherwise have a cost associated with disposal (e.g., someone willing to pay Yukon Energy or an IPP to dispose of it) there may develop an option for biomass generation. Currently, no such source of biomass supply is apparent in the time period for this Resource Plan. However, given similar fixed cost constraints as for coal, even if such a source was secured it is not likely that this type of generation would fit the load profiles under any but the largest industrial development scenario (e.g., a 20 MW plant enabled by 40 MW of industrial load).

Natural Gas: The pipeline scenario (Scenario 4) will likely create opportunities for natural gas based power generation in Yukon.

Evidence from southern jurisdictions and NWT indicates that natural gas generation is a major technology option for new power generation and can be well ahead of diesel in terms of costs, reliability and impact on the environment.

In addition, unlike coal, natural gas generation is more readily "scalable" to sizes suitable for Yukon as well as more suited to timely regulatory review and approvals and flexibility to operate in response to

load variations. Natural gas generation is also likely to be located near to the main load centres, and thus not subject to the same transmission costs and risks as noted for many other supply options.

It is premature at this time, however, to assess likely charges that will apply for natural gas supplies when they become available[30].

5.4.2 Economic Pre-Assessment

Given a solid load fit in technical pre-assessment, Yukon Energy has an ability to consider in a preliminary way the likely economics of projects to assist in any screening effort. Four key factors come into consideration in this pre-assessment:

1. **Preliminary Generation Capital and fuel-related Levelized Cost/kW.h (LCOE):** At a simple preliminary level, the LCOE noted above can provide a useful screening tool for the various options under consideration.

   Compared to assumed prices for solely the variable cost of diesel at 20 cents/kW.h in 2005$, all supply projects reviewed above have substantial opportunities to produce power over the long-term at a cost lower than diesel.

2. **Transmission Required to access main WAF Grid:** For hydro projects in particular, investment in transmission to connect remote sites with the established transmission system, and associated losses, can be a material factor in project economics. Transmission costs that begin to exceed about 10%-15% of the project costs can be difficult to overcome.

   Rough assumptions to date are that projects in the 1-4 MW range cannot support any material transmission costs beyond simple connection (i.e., must be basically on the established transmission, preferably 138 kV) while 5-10 MW projects may be able to support transmission of 50 km (to perhaps as high as 100 km at a maximum). Projects in the 10-30 MW range may be able to allow for transmission somewhat over 100 km.

   For the large to very large projects (30-60 MW and 60+ MW) there has not been any serious effort to screen based on incremental transmission costs, as this can only likely be usefully considered once loads have been identified and required upgrades or additional circuits to

[30] The Mackenzie Valley Pipeline proponents currently have a proposal before the National Energy Board that includes plans to provide access to gas from the pipeline for use by communities in the NWT along the pipeline route. This proposal, and the current NEB review, may provide guidance as to possible future charges applicable in Yukon after pipeline development in this area.

existing transmission can be incorporated into the assessment – such planning is not possible in the absence of further information about potential loads.

3. **Extra Fees, Charges or Process costs related to hydro developments in BC:** For hydro projects in BC, there is a material additional cost and risk associated with both licencing due to interprovincial processes, as well as water rentals and taxes.

   In Yukon, Yukon Energy does not pay and has complete future protection against any water rentals that may be levied by the federal government for use of waters for power generation. However, such fees are commonplace in other jurisdictions and can result in material costs for the utility (in Manitoba, water rental rates are 0.3 cents/kW.h for generation; rates in BC have been as much as 0.5 cents/kW.h but have recently been under review – the BC charges also include additional amounts for storage of water, as well as taxes). The economics of projects located in BC will require close monitoring of these rates to ensure that these costs are fully included in planning assessments of BC project economics.

4. **Impacts on rates:** Separate economic assessment is required of the effect of any projects on rates, as rates for any given year are set based on annual costs (including depreciation, interest and return on equity) rather than the lifetime long-term costs of projects. Past Yukon experience with the Faro mine well indicates that even long-term economic investments (such as Whitehorse turbine #4) can result in substantial rate impacts in some years when loads drop below the point where the assets are providing economic value[31]. Based on examples in Appendix B, major new hydro projects that have otherwise attractive lifetime LCOE costs can give rise to the potential for serious rate impact risks in some years if loads decline.

   A separate issue with respect to capital intensive projects such as hydro is that annual costs which drive rates are at a maximum in the first few years of the project (when rate base balances are highest). However, the benefits of capital intensive projects tend to increase over time as the value of any diesel displaced increases with inflation or other upward fuel

[31] Past experience with the Faro mine and Whitehorse #4 indicate rate impacts of 20-40% are possible when the Faro mine experienced shut downs in 1993 and 1997/98. This level of rate impact, however, likely understates the true full potential rate impact from major mine closures (i.e., closures for mines that account for a dominant share of WAF loads as was the case with the Faro mine when operating), as in the case of Whitehorse #4 the Government of Canada (via the Canada Flexible Term Note) retained most of the risks with respect to such loads. Absent this mechanism, the rate impact of the 1998 Faro closure would have been about $1 million higher than ultimately experienced (almost 3% higher than the 18.74% increase that ratepayers experienced).

price drivers (this is similar to the Mayo-Dawson Transmission project which will achieve material savings for ratepayers over its life, but did result in the need to address what would otherwise have been adverse rate impacts in the first two years via flexible debt financing[32]). Projects reviewed in the 1992 Resource Plan indicated potential for one to three year adverse impact on rates before savings compared to diesel begin to arise for ratepayers (using a diesel price of $0.26/litre), while Mayo-Dawson Transmission project initial reviews had at times determined the potential for five to ten year adverse impact on rates absent YDC flexible financing (ultimately the flexible financing was only required for 2003 and 2004).

However, due to the higher price of diesel fuel today, rate impacts from each of the resource supply option projects identified above are expected to be positive in year 1 assuming the full output is available to offset diesel generation. For example, Drury at a capital cost of $31 million (2005$) has the potential to offset 23 GW.h of diesel ($4.6 million per year, based diesel on $0.20/kW.h in 2005$). The year 1 costs of Drury (2005$) will total approximately $2.3 million for interest and return on equity (7.52% cost of capital times $31 million[33]) plus about $0.6 million for depreciation (using an aggregate life of hydro-related assets for depreciation of 50 years, and no reserve for salvage). In short, the capital costs of Drury would drive a $1.7 million lower overall system costs in year 1 than supplying this same 23 GW.h with diesel (this ignores what would likely be a relatively small operating and maintenance cost for Drury, but also ignores capital cost benefits from the 2.6 MW of capacity Drury brings to the system avoiding some investment at times in diesel engines).

For Level 2 projects (at this time only includes Drury), full economic assessment can be undertaken once certainty is developed with respect to sustained industrial loads beyond Minto (i.e., Minto is not sufficient to justify any scale of new capital intensive generation).

5.5 PROPOSED ACTIONS

Yukon Energy proposes planning activities as set out below to address a wide range of potential industrial development scenarios beyond the near term, and to protect future opportunities to commit development of additional generation and transmission projects before 2016 in a timely and cost-effective way in the

[32] At this point in time, overall average retail rate increase impacts are likely to be about 1% if utility regulated costs are increased in any one year by $360,000. Rate impacts need to be assessed in this regard by comparing a specific resource option to the available alternative resource options. It is relevant to note that this assessment may prove a resource option to save money relative to diesel, thereby allowing lower rates than would be required with diesel generation, while in reality (due to the need to develop new generation in any event to serve major new loads) overall rates are still being increased.

[33] Note also that Drury has very limited transmission costs required for the facility.

event that one or more of these industrial development scenarios materialize. Planning activities are organized by industrial development load scenario, identifying proposals as to how to approach each load scenario should it arise. "Pre-commitment" activities are also addressed which encompass planning activities Yukon Energy proposes to carry out prior to any certainty or commitment on the part of potential new industrial loads.

5.5.1 Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario

This industrial development scenario (which provides for near term development and operation between 2007 and 2018 of the Minto and Carmacks Copper mines) supports commitment of modest existing hydro enhancements, but does not support commitment of any new hydro site development before 2016 unless mine loads of at least 10 MW are sustained well beyond 2016. Consideration of the smallest hydro site options (1-4 MW) could potentially be supported in the event that 10 MW mine load development extends through to at least 2020. In this context, the following planning activities are recommended in the event these mine loads are seriously being considered for development prior to 2016:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should then proceed to commit the Aishihik 3rd Turbine, the Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments.
  - If not already committed, Aishihik Diversions and Atlin Storage should then be advanced to Level 2 studies, including system-wide water and load dispatch modeling, to quantify the energy benefits under this scenario.
  - Ongoing assessment of the Southern Lakes should be completed to identify additional water control or small hydro opportunities to enhance Whitehorse Rapids output.
- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission line is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility, including enhanced peaking capability.
- **New WAF hydro site development:** If industrial and overall load development commitment is such that both new capacity and baseload diesel generation energy are required through to at least 2020 (and there is no clear indication of more major industrial development scenarios emerging during the 20 year planning period), planning activities should be carried out to enable commitment of a very small hydro site development (1-4 MW, 5-30 GW.h/year)[34] able to provide new capacity and displace diesel energy.

[34] Present estimates of the costs are $12-$47 million generation capital cost (2005$) with potential generation planning costs of $1.2-$4.7 million prior to a decision to proceed with construction.

- Based on current information, this would indicate that the hydro site at Drury should at that time be advanced to full Level 3 studies that include consideration of variations that maximize capacity.
- Possible consideration might also be given to Level 2 studies for Squanga as a utility project or IPP, and/or for Morley, as potential alternatives for comparison to Drury.
- Consideration must include means to mitigate downside risks should industrial loads close prematurely.
- Actual development in each or these cases will involve investments greater than $3 million, or long-term contract commitments in excess of $3 million present value to IPPs, and therefore YUB review will be sought prior to project commitment.

- **Other activities regarding DSM:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused primarily on reduction of system peak demand.

5.5.2 Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 for development of more than 10 MW (70 GW.h/year) but less than about 20-25 MW (comparable to the Faro mine) for a period through to at least 2025, planning activities should be carried out to enable commitment to develop new hydro site resources to provide approximately 50 GW.h per year to WAF.

For potential hydro projects, key options to be considered at such time as greater load certainty develops regarding this level and duration of industrial load are as follows:

- **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-term recommendations, planning should proceed to commit the Aishihik 3rd Turbine, the Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work, and existing WAF hydro plant upgrade assessments (see proposals for Scenario 1).
- **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission is developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible enhancements at the existing Mayo hydro facility (including any feasible enhanced peaking capability).
- **New hydro site development:** If industrial and overall load development commitment on WAF before 2016 is such that WAF baseload diesel generation energy of more than 10 MW (70 GW.h/year) is then required through to at least 2025 (and there is no clear indication of more major industrial development scenarios establishing new WAF industrial loads in excess

of about 20 MW (about 125 GW.h/year) emerging during the 20 year planning period and extending beyond 2025, planning activities should then be carried out to enable commitment of a small hydro site development (7-10 MW, about 50 GW.h/year[35]) able to provide diesel displacing energy to WAF.

- New hydro options focused on Yukon-based projects, if available, would be the preference.
- However, given limited attractive projects in this size range identified in Yukon to date, further Level 1 and 2 activity should be undertaken if timing permits in areas within 50 km of existing 138 kV WAF transmission focused initially on scans of the various inventory studies completed by NCPC or others.
- Sites in BC, including Moon Lake and Tutshi[36], should have Level 2 studies updated in preparation for this possible load scenario, particularly focusing on the costs and risks associated with interprovincial licencing requirements and water rentals. Level 3 studies should then proceed if warranted.

- **Coal supply possibilities:** In the event that the loads of this scale develop and coal also becomes available from developed Yukon sources, coal generation technology should be reviewed in the event that timing permits to determine the potential for an economic and environmentally sound coal development at sizes below 20 MW, sized as appropriate to fit the industrial loads being developed at that time.
- **Other activities regarding DSM and wind:** If loads of this scale and duration develop, further consideration will be given to DSM programming focused on both the reduction of system peak demand and energy conservation, and development of new wind generation (if attractive sites near established utility grids can be identified).

Actual development of new hydro sites (or any other new generation site) in each case will involve investments greater than $3 million, so YUB review will be sought prior to project commitment. In addition, for larger scale developments, planning and feasibility work may exceed the $3 million level, so there is the potential for YUB review at this earlier stage as well.

5.5.3 Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario

If industrial loads are committed on WAF before 2016 of more than about 20-25 MW (150 or more GW.h/year) for a period through to at least 2030, resulting in forecast baseload WAF diesel generation

[35] Present estimates of the costs are $50-$100 million generation capital cost (2005$) with potential generation planning costs of $5-$10 million prior to a decision to proceed with construction.

[36] No further work should proceed on Surprise Lake so long as the community continues its plans to develop micro-hydro at the site.

energy of more than about 150 GW.h/year to be required until at least 2030, then planning activities can reasonably proceed to consider commitments before 2016 to develop new hydro site or coal generation resources of 20-30 MW to provide 130-150 GW.h per year of long-term energy (20 or more years) to WAF.

- **Load uncertainties and low probabilities today:** The industrial loads required to reach the above levels at this time involve significant uncertainties and low probabilities.
- **New medium scale hydro site development (20-30 MW, 130-150 GW.h/year):** The development of generation and transmission to serve these loads, based on currently identified potential hydro sites (Primrose and Finlayson), would involve substantial generation capital costs ($179-$191 million (2005$), excluding transmission, as well as very large planning costs (about $20 million) prior to a decision to proceed with construction. Such costs are likely at or beyond the limits of YEC's current financial capabilities and involve material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line.
- **Coal supply thermal generation possibilities:** Coal resource options of this scale could involve far less capital than comparable new hydro sites, provided that coal supply as such was otherwise available from developed Yukon sources. The scale at 20 MW (140/GW/h/year[37]), however, is still very small for coal thermal technology and would require careful Level 2 and 3 screening and feasibility assessments to confirm its potential feasibility.

For potential generation projects related to the above scales, it is not apparent today that there is sufficient likelihood of this major development scenario arising to justify major investment at this time in planning and feasibility studies for medium new hydro or small coal plants. Accordingly, no specific planning activities are recommended at this time. Future decisions with respect to the level of effort and expense in this area will reflect YEC's ongoing assessment of the probabilities of the required loads developing. For projects of this scale, even early planning and feasibility work (at least on hydro sites) will exceed the $3 million level, in which case YUB review will be sought before proceeding with specific planning commitments of $3 million or more.

5.5.4 Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario

The Scenario 4 pipeline loads at this time involves significant uncertainties as regards timing and magnitudes. However, given the implications of this industrial development for all aspects of Yukon power utility activities, and its clear possibility to come into service within the 20-year period for the

[37] The present estimate of the costs are $ 61 million thermal plant capital cost (2005$), excluding transmission or coal resource development costs, with potential generation planning costs of $6 million or more prior to a decision to proceed with construction.

current Resource Plan, one key activity recommended for the near-term regarding Scenario 4 involves continued active monitoring of this development as well as active planning to identify and assess all potential related material impacts, options and opportunities, including:

- Major power supply options for the pipeline for compression (focusing initially on short listing and assessing at Level 1 knowledge large scale hydro site options and related transmission requirements).
- More modest power supply opportunities focused on compressor station "station service" loads.
- Options to use natural gas for power generation to serve cost effectively other incremental industrial loads.

The development of generation and transmission to serve these pipeline loads is likely well beyond the limits of YEC's current financial capabilities as well as involving material costs and risks related to investments in feasibility and planning long before final decisions to proceed can occur or plants brought on-line. Accordingly, prior to carrying out any planning activities beyond Level 1 assessment of any specific site or technology specific studies, it is proposed that Yukon Energy identify and assess options that would address this constraint, e.g., joint venturing with others, and/or options to secure external government or other financing.

5.5.5 Proposed "Pre-commitment" activities

Prior to any certainty developing regarding the industrial scenarios that may arise, it is proposed that Yukon Energy remain focused on certain key planning activities to ensure protection of the options to address new load requirements. Yukon Energy proposes the following activities in this regard:

- **Monitoring of Industrial load developments:** Yukon Energy will continue to monitor closely potential load development and related spin-off residential and commercial impacts, including necessary discussions with mineral exploration companies active in Yukon, key officials in Yukon government working with mines and other industrial developments, and relevant industry associations. Separately, YEC will maintain ongoing monitoring of potential Alaska Highway pipeline developments and factors that may impact electrical loads in Yukon (including potential for electrical compression).
- **Southern Lakes hydrology assessments:** Continued assessment and studies of the hydrology of the southern lakes area, including identification of potential for water control structures to enhance output of Whitehorse Rapids, as well as potential hydro generation sites.

- **Other existing hydro facility enhancements:** Continued focus on projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases, Mayo. This includes full Level 3 and 4 studies on the Aishihik 3rd turbine and updating Level 2 studies on Aishihik diversions. Where suitable, activities should be carried out in conjunction with other normal Supply Side Enhancement planning by Yukon Energy, such as re-runnering.
- **Level 1 and 2 assessments to identify preferred 5-30 MW scale Yukon hydro sites**: There is an option to invest in further surveying the potential of other Yukon based hydro generation sites to try to identify good sites in the 5-10 MW range (within about 50 km of existing high voltage transmission) and to advance credible candidates in the 5-30 MW range through Level 2 assessments (including ongoing monitoring of hydrology) in order to identify more clearly preferred sites to develop for possible loads within this range. However, this activity is costly and may require assessment of a number of sites. No activities in this regard are recommended today; however, in the event that at least one large industrial load (such as Red Mountain or Division Mountain) proceeds to advanced licencing and likely commitment stages, it is proposed that this initial work should proceed quickly to determine if the sites identified to date are indeed the best candidates or if there are other Yukon-based sites that should be seriously considered, and to identify specific projects for Level 3 feasibility assessments.
- **Ongoing monitoring of hydrology**: Active hydrology monitoring will proceed where feasible for all hydro sites likely to be serious candidates for future development within the 20 year planning period. The monitoring may be periodic (seasonal flow information, current cost of $1,000 per year per site) up to a full-time recording station (at a current cost of $30,000 (initial costs) plus ongoing costs of between $10,000 to $15,000 per year).

APPENDIX A:
POWER RESOURCE TECHNOLOGY OPTIONS

APPENDIX B:
HYDRO PROJECT OPTIONS

APPENDIX C:
AISHIHIK 3RD TURBINE ASSESSMENT

APPENDIX A:
POWER RESOURCE TECHNOLOGY OPTIONS

A.1 POWER RESOURCE TECHNOLOGY OPTIONS

This Appendix provides a brief overview of technology options for providing power resources, either through new generation (supply side) or through Demand Side Management.

A substantial review of power resource options and technologies was provided in the 1992 Yukon Resource Plan. More recent power resource technology overviews have been prepared for northern conditions, most notably the Alaska Power Association overview titled *New Energy for Alaska* published in March 2004 (available online at http://www.areca.org/areca/energy_sys.htm) and a more site-specific review[1] "*Galena Electric power – A Situational Analysis (*pre-publication draft)" (available online at http://www.iser.uaa.alaska.edu/Publications/ Galena_power_draftfinal_15Dec2004.pdf) .

For each technology option reviewed, the scope of consideration from the 1992 Resource Plan is noted, as well as more recent information from either the Alaska studies, or other Yukon specific information compared to 1992.

A.1.1 DIESEL

The 1992 Resource Plan was directed, as per OIC 1992/92 to consider "contracts and commitments for non-diesel fuel generation". At the time, diesel generation was being used for a substantial part of the WAF supply. As such, diesel was not reviewed as a supply option, but was reviewed as the "base case" for comparison of non-diesel alternatives.

Diesel generating units have relatively low capital costs (approximately $1 million per MW), and high operating costs. Consequently, diesel units are typically well-suited to meeting reserve capacity requirements and short-term capacity needs during system peaks. Diesel is also well suited to isolated regions where loads are small (such as the Yukon isolated communities), where loads do not have very long lives (such as temporary applications or short lived mines) or where the heat from the operation of the diesels is of economic value (such as in certain industrial operations). Since diesel units can be turned off when they are not needed (and because of the relatively low capital costs), diesel units provide a relatively lower risk source of supply if loads are uncertain (as load decreases can be met with cost increases from putting the unit on standby).

[1] The draft was published in December of 2004, and provides an overview of generation options for an Alaskan community of 800 people. The options considered for Galena included: diesel, coal, nuclear, and a grid connection.

Diesel is expensive for utility operations running to provide sustained energy on a regular basis throughout the year.

Since 1992, efficiencies of new diesel units have occurred. The 1992 resource plan was based on efficiency of 3.7 kW.h/year and the most efficient units now in service on WAF are cited at 3.9 kW.h/litre (installed in early 1990s). However, the more recent Alaska studies cite potential efficiencies in the 4.18 kW.h/litre range for the most efficient new units (15.8 kW.h/gallon) at maximum efficiency. This maximum may be unattainable over any sustained operating period with normal start-up, shut-down, load variations, and other factors, but does reflect improvements since the 1992 review.

A.1.2 HYDRO

Hydro options were studied extensively as part of the 1992 Resource Plan Submission. In addition to the information provided in the main Resource Plan document in 1992, a separate binder (Supply Side: Binder A), contained detailed information on hydro options evaluated by the utilities.

Hydro generating plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units. Hydro options have the potential to meet the needs of the Yukon under industrial development scenarios.

Hydro options for the Yukon are identified in detail in *Chapter 5: Industrial Developments and Opportunities*, and significant specific characteristics and issues related to hydro are discussed in particular in *Section 5.3: Options*., and *Appendix B: Hydro Project Options*.

A.1.3 WIND

At the time of the 1992 Resource Plan, the Yukon utilities had no wind generation in operation, but wind power was identified as a potential future supply option. Since that time, Yukon Energy, with the support of Yukon Development and the Government of Yukon, has gained considerable experience with wind generation for utility supply. This includes operation of two turbines on Haeckel Hill on WAF (a Bonus 150 of 150 kW installed in 1993 and a Vestas V47 of 660 kW installed in 2000) as well as numerous wind

monitoring projects throughout Yukon[2]. At this time, Yukon is consistently cited as a leader in assessing the commercial potential and technical considerations of wind generation in northern climates.

Key issues with respect to wind generation are capital costs (particularly for smaller units), capacity limitations and wind availability. Capital costs for wind generation have been declining in recent years, but remain quite high for installation in Yukon, where major new support systems can be required (transmission and roads are typically required to install wind generation in new sites, which are typically high elevations sites in Yukon). Wind is also not a form of reliable capacity to utility systems, as it is not dispatchable and is an intermittent resource, consequently wind does not make a contribution towards planning for meeting the peak commitments of a utility. Wind is well suited, however, to larger hydro-based systems that have material storage (such as WAF) once material expensive diesel generation begins to be dispatched.

More important to wind economics, the feasibility of wind is very sensitive to wind regime and availability. Utility industry experience indicates that wind economics essentially require a capacity factor of 30%[3] while high grade commercial installations may be higher. By comparison, wind turbines installed in Yukon have only been able to achieve an average capacity factor of 22% given the wind regime and other operational factors (such as rime icing, which can substantially reduce wind output) and a Community Wind Resource Assessment program run by YDC has surveyed a number of sites in Yukon (focused on potential customer wind installations) with capacity factors of 2% to a little over 10%. Two utility focused projects were investigated at Destruction Bay and Old Crow. Each was found to have an uneconomic wind regime compared to project costs.

Wind generators can be installed reasonably quickly (outside of the time to order new units, which today have significant lead times due to market demand). Capital costs risks related to wind primarily relate to associated infrastructure (such as roads and transmission lines needed to access the proposed site).

Capital costs for new wind generators continue to reduce in price fairly substantially. However, the scale of new wind turbine models is also growing, and is now approaching a range that would not be able to be easily integrated into Yukon systems other than WAF (1.5 MW or more per unit). On WAF, future industrial loads that push the system onto material diesel generation may enable commercial

[2] Sites at Mt. Sumanik, Destruction Bay, Haines Junction, Tagish, Whitehorse, Dawson City, and Ferry Hill have been undertaken since the early 1980s. Three locations suitable for wind generation were identified in the WAF area: Haeckel Hill, Mount Sumanik and Flat Mountain. Monitoring of potential commercial wind sites continues, including under the Yukon Development Community Wind Resource Assessment Program.

[3] p. 8, Yukon Energy Resources: Wind. March 1997.

development of wind as a complement to other resources reviewed in this plan. Given the rapid evolution of the wind industry and technology, updated assessment of the potential for wind will need to made once potential industrial loads become further defined.

In the north, the Northwest Territories Power Corporation has excluded wind generation from their resource planning for the current time, as a result of the challenges of operating wind turbines. In Alaska a number of remote communities have developed wind generation to supplement isolated diesel, but there are not utility wind turbines on the major interconnected systems. Also, the challenges associated with wind regime (capacity factor), as well as infrastructure costs (including transmission, as well as installation costs requiring major cranes) are noted to be a barrier.

A.1.4 BIOMASS

As of the 1992 Resource Plan, biomass had been studied for the generation of power in the Watson Lake region[4].

Biomass use for thermal generation is subject to the economic constraints related to the fixed costs (including fixed operating and maintenance costs). These costs do not fall dramatically for smaller scale operations or loads. In these circumstances, economic viability hinges on large and constantly running facilities.

As a general principle, biomass generation does not typically become economic unless three key conditions are met. These same conclusions have also recently been cited as preconditions for biomass electricity generation by the Alaska Energy Authority and in some cases the Yukon Cabinet Commission on Energy[5].

1. The fuel (typically wood) must be available from a source that would otherwise have to pay to dispose of it. Economic biomass generation is not typically possible with a wood product that has a cost to harvest, or even (in at least some cases) that can be delivered to the plant for free; there has to be savings from avoided disposal costs.

[4] A 6 MW steam-fired turbine had been assessed (assuming the Watson Lake sawmill was in operation) and determined to have too long a pay back period. See in particular the Yukon Cabinet Commission on Energy publication entitled "Wood", September 1997.

[5] Wood-Fired Boilers for Rural Communities, Online: http://www.uaf.edu/aetdl/presentationsre02.html. Also the 1998 Yukon Cabinet Commission on Energy "Principles of Supply Options for the Yukon" noted "Although abundant in supply, wood is not generally seen as a cost effective way to generate electrical power unless it has little or no cost as a fuel source".

2. The wood-fired power displaces diesel power.
3. There is a substantial market for power and heat.

To date, proposals discussed in Yukon do not meet these three key criteria.

In the Yukon, one biomass proposal received to date involves a waste wood generation facility at Haines Junction. However, that proposal was largely focused on burning wood that was previously killed by beetle infestation which will likely not be useable by the time the loads develop. A 2002 Canadian Forest Service annual Forest Health Survey found that the infestation was slowing. Standing wood tends to start to lose its heating value within three years of dying, and the bulk of the deadfall is now more than three years old.

Further information on biomass can be found in *Chapter 5: Industrial Development Scenarios and Opportunities.*

A.1.5 COAL

Coal-fired generation was examined in detail in the 1992 Resource Plan.

The economics of coal generation are very sensitive to various factors, such as the quality of the coal and emissions standards, which can materially impact the capital costs required for the plant (for example, ash handling and dealing with sulphur in the coal). The practical minimum size coal development considered for Yukon has been 20 MW which roughly equates to 144 GW.h/year.

Technologies for use of coal have been advancing at a rapid pace, particularly in regards to reducing emissions. Recent studies in Alaska have also summarized and assessed the potential for small coal developments, including Atmospheric Fluidized Bed Combustion[6]. Although a number of studies were cited, no successful small scale (1-10 MW) electrical utility coal projects are known to be in service in the north.

Key to development of environmentally sound coal generation in Yukon is the development of indigenous coal deposits independently of power generation requirements.

[6] "Galena Electric Power – a Situational Analysis" as noted above.

Further information on coal can be found in *Chapter 5: Industrial Development Scenarios and Opportunities.*

A.1.6 COAL-BED METHANE

Coal-bed methane generation was not studied in the 1992 Resource Plan.

Coal-bed methane generation produces electricity by using a methane gas from coal seams and fractures in coal beds, to produce electricity with conventional turbines. In order for coal-bed methane to be economic, the site must be close to a population base. In Yukon, no developed resources for coal-bed methane are available.

The Alaska resource study considered the potential for coal bed methane. No utility generation from coal bed methane is in service in Alaska today. The Alaska summary document identified high exploration and drilling costs, and the disposal of water as the main challenges associated with coal-bed methane generation.

A.1.7 NATURAL GAS

Natural gas was not reviewed in 1992.

Natural gas as a source for power is only available where commercial sources of gas can be delivered. Currently gas in not available in Yukon for utility purposes. Natural gas is in use in Inuvik, NWT for both domestic use (home heating) and power generation via reciprocating engines.

The availability of gas in Yukon would provide opportunities for a dramatic shift in the power resource framework for Yukon. Gas is a flexible resource that easily allows for “scalable” generation (from small 30 kW micro-turbines through massive turbines of hundred of MW, and including reciprocating engines of the size range is use in Inuvik of 2-3 MW).

However, given the limitations of gas availability in Yukon today, there is no option for gas generation to meet near-term requirements (Chapter 4) but serious investigation is required of opportunities to use gas (or maintain the option to use gas when it arrives) under Chapter 5 scenarios. If in the near-term Yukon Energy pursues new diesel generating units, consideration will be given to the potential to secure units that can later be converted to natural gas or can be run as dual fuel units.

Alaska has devoted considerable time and energy to natural gas generation given the availability of gas in many key communities. This information and experience will be of significant value to Yukon should gas become available during the period covered by the Resource Plan.

A.1.8 GEOTHERMAL

Geothermal generation was not studied in the 1992 Resource Plan.

Using heat energy from a geothermal resource is practical only if the geothermal occurrence and the energy need are located in close proximity. Thus, the development of geothermal applications in the Yukon will first occur where geothermal resources are found close to populated areas. A major well registry, mapping and resource analysis project is presently underway which will assemble the existing and available information on the groundwater and ground-source heat potential in all Yukon communities.

Known geothermal resources in the Yukon are too low in temperature to produce steam that could be used to generate electricity on a cost-competitive basis. While geothermal temperatures in the range of 100°C to 180°C are required, Yukon geothermal resources have so far been identified in only the 15°C to 55°C range. As a result, the Yukon's geothermal resources are best suited for heat energy applications such as space or district heating.

The recent reviews from Alaska noted similar concerns with respect to location of geothermal resources in relation to loads, and high capital costs of installing geothermal generation.

A.1.9 HYDROGEN

Hydrogen generation was not studied in the 1992 Resource Plan.

Yukon Energy has assessed hydrogen as an option for energy storage for electrical power. Given current hydro surpluses, the potential exists for electrolysis during off-peak or summer seasons for storage and use during peak times (or for isolated system generation or other non-utility purposes). However, given the technical complexity including issues related to storage and transportation, and the capital costs of hydrogen systems, hydrogen has not been considered a feasible resource option at this time.

Similar conclusions from Alaska indicate "feasibility is unknown, and the prospects without further advances in technology and market development are poor"[7].

A.1.10 SOLAR

Solar generation was not studied in the 1992 Resource Plan.

Given the angle of the sun, the intensity of the sunlight received closer to the Arctic Circle is less than in southern jurisdictions. Solar radiation is greater in the summer time, when there is currently a hydro surplus in the Yukon. As such, solar power does not provide any potential value to the Yukon in the near term, but has the potential to provide value in future if it is used to offset diesel generation.

Solar power is characterized by high initial or capital costs, and potentially low operating and maintenance costs. In isolated areas where grid power is not an option, residential and small commercial applications for mining camps, lodges, especially those with higher or solely summertime use, solar power may be considered a viable option.

The recent work in Alaska similarly concluded in respect of solar generation that "this technology is generally not cost-competitive for utility use when other alternatives are available"[8].

A.1.11 NUCLEAR

Nuclear generation was not studied in the 1992 Resource Plan.

Nuclear generation was studied for the Alaskan community of Galena based on a 10 MW Toshiba 4S reactor, which was to be provided for free from the manufacturer as a North American "Reference Case". Nuclear power was found to have the potential to be cost-competitive compared to diesel or coal, assuming that diesel and coal costs result in higher operating costs. The rising cost of diesel fuel has the potential to increase the economic attractiveness of nuclear generation.

The primary uncertainties with respect to nuclear power in Alaska are security and technical feasibility. In Galena, it was estimated that a minimum of four, and a maximum of 34 guards would be required. The proposed reactor is also a new technology for North America and will likely not available on a commercial basis for many years.

[7] "New Energy for Alaska" Alaska Power Association. March 2004.
[8] "New Energy for Alaska" Alaska Power Association. March 2004.

For Yukon, there is no commercial availability for the type of nuclear generation studied for Galena, and its future commercial availability is unknown. However many characteristics (size, life, efficiency, cost) of the project considered for Galena could be very attractive for consideration in Yukon. Other relevant considerations (including security and waste disposal) will clearly need substantial further attention before the true potential for nuclear in Yukon can be assessed.

A.1.12 DEMAND SIDE MANAGEMENT

DSM options were studied extensively as part of the 1992 Resource Plan Submission. In addition to the information provided in the main document, a separate binder (Demand Side: Binder B), contained detailed information on DSM options evaluated by the Utilities. The approach to DSM in 1992 reflected the situation that existed at that time; the Faro Mine was still in operation. A summary of the approach to DSM was outline at page 8 of the Demand Side Management binder, "In the Yukon, significant opportunities exist for Energy (GWh) savings because of the high cost of diesel generation. However, savings opportunities through reduction in peak Demand (MW) are relatively small due to the low capital cost for installing new diesel generation facilities. The priority, therefore, for DSM programs in the Yukon at this time relates to strategic reduction in energy use." Given the closure of the Faro Mine, there is no longer an incentive to decrease annual energy use. Consequently, the focus of the 1992 DSM plan does not correspond with Yukon Energy's current needs.

Yukon has been actively and aggressively engaged in DSM activities of various types since 1992, and in particular since 2000. Major emphasis from entities such as ESC, YDC and Natural Resources Canada has focused on reducing loads on isolated diesel systems, reducing non-electrical energy consumption (such as oil heating) as well as major efforts by Yukon Energy to grow the WAF loads via Secondary Sales (with surplus hydro, the most pertinent WAF DSM programs focus on selling this renewable resource that would otherwise be wasted, rather than reducing consumption).

In the near-term in Yukon, the electrical system requirements are almost entirely related to peak capacity (Chapter 4). Most non-industrial DSM programming is generally more successful at energy reductions than capacity reductions. As such, DSM has limited potential to address utility requirements in the near-term. In addition, DSM activities in the near-term that lower peak demand levels, but reduce utility sales which are currently being made from surplus hydro will be an adverse rate driver in Yukon (as lost revenue from reduced sales will outweigh cost savings from reduced system peaks).

Over the longer term, and under the various industrial scenarios (Chapter 5), DSM activities have the potential to contribute to savings from diesel fuel generation. As such, DSM activities will in all likelihood become an important utility focus should such scenarios arise. However, as a major supply option, there are limits to the scale of savings available from DSM. For example, under the 25 MW scenario diesel consumption on WAF proceeds rapidly to more than 100 GW.h per year – given a current firm non-industrial WAF sales of 250 GW.h/year, it is not possible for DSM to provide the resources needed to address this scenario, and therefore major displacement of diesel must come from supply-side resources (such as new hydro generation).

Information on Yukon DSM is provided in greater detail in *Section 2.4.5: Demand Side Management and the Energy Solutions Centre.*

A.2 LITERATURE REVIEWED

A.2.1 HYDRO

BC Hydro's 2002 Small Hydro Assessment in Yukon and northern BC.

Yukon Economic Development. Yukon Energy Resources: Hydro. March 1997.
The article provided an overview of hydro generation in Yukon, and issues affecting development. The article indicated that facilities smaller than 20 MW as the most likely to succeed.

A.2.2 WIND

Yukon Development Corporation & Yukon Energy Corporation. The Winds of Change: The Story of Wind . Generation in the Yukon. March 2001.
The report summarizes the history of wind generation in the Yukon and the history of Yukon Energy's experimental turbines at Haeckel Hill. YEC installed Bonus 150 kW MARK III in 1993 at Haeckel Hill in 1993. However, the report indicates that even with the special modifications that had been made to the Bonus before it was installed, there are still some problems, especially the lower temperatures and rime icing. The capacity factor of the turbine is 21%. The Vestas V47-660 kW was installed in 2000. YEC forecast a capacity factor of 23% for the Vestas.

Yukon Economic Development. Yukon Energy Resources: Wind. March 1997.

The article provides an overview of wind development in Yukon, and factors affecting development. The report indicates that wind velocities are greater at higher elevations; and that wind has the greatest velocities in the winter months, correlating with the period of peak electrical demand. However, rime icing is a significant factor impacting reliability and production levels during the winter peak.

A.2.3 BIOMASS

Wood-Fired Boilers for Rural Communities, Online: http://www.uaf.edu/aetdl/presentationsre02.html

Yukon Economic Development. Yukon Energy Resources: Wood. March 1997.

The article provided an overview of Yukon's wood fuel resources and the factors affecting development. The report indicated that wood fuel is a source of residential heating fuel, and supports existing small industries in sawmilling and firewood cutting. Further potential for wood fuel, including limited export and as a means of producing electricity were also identified.

A.2.4 COAL

Yukon Economic Development. Yukon Energy Resources: Coal. March 1997.

The article provides an overview of Yukon's coal resources, and the factors impacting development. The local markets identified for coal, included power generation and industrial heating.

A.2.5 LITERATURE REVIEWED ASSESSING MULTIPLE GENERATION TECHNOLOGIES

A number of publications were reviewed that provided an overview of generation and/or demand side management options for the Territory. These publications are outlined below.

New Energy for Alaska. Alaska Power Association. March 2004.

The publication includes an examination of a number of alternative energy sources, including: battery energy storage systems; biomass power; clean coal; coal bed methane; cogeneration; diesel engine efficiency; fuel cells; geothermal; hydroelectric power; hydrogen; microturbines; solar; tidal energy; and wind turbines. Given the similarities between Alaska and the Yukon, the analysis provided relevant comparisons for the Yukon.

Galena Electric Power – a Situational Analysis (Draft Final Report). Prepared for the U.S. Department of Energy. December 2004.

The economics of electrical power generation options for the City of Galena, Alaska were identified. Given the similarities between Alaska and the Yukon, the analysis provided relevant comparisons for the Yukon.

Economic Development from Renewable Energy: Yukon Opportunities. Provided by Pembina Institute. October 1999.

The report summarizes the energy conservation and efficiency, key renewable energy resources, and their application in the Yukon. The economic benefits, environmental and social aspects of renewable energy, and strategic direction for renewable energy in the Yukon were examined.

Yukon Government Cabinet Commission on Energy. Energy Efficiency for the Yukon, 1998.

The report provided an overview of the potential for greater energy efficiency in the Yukon.

Yukon Government Cabinet Commission on Energy. Green Power Fund. 1998.

The report provided an overview of a Green Power Fund for the Yukon.

Yukon Government Cabinet Commission on Energy. Principles of Supply Options for the Yukon, 1998.

The report provided an overview of principles of supply options for the Yukon.

Yukon Economic Development. Yukon Energy Resources: Alternatives. March 1997.

Generation resources were identified and examined, including: solar energy, geothermal energy and refuse-derived energy.

Yukon Economic Development. Yukon Energy Resources: Oil & Gas. March 1997.

The article provides an overview of oil and gas generation in the Yukon, and the factors affecting their development. The article explored development activities, and environmental issues.

APPENDIX B:
HYDRO PROJECT OPTIONS

B.1 HYDRO PROJECT OPTIONS

Yukon Energy has developed an inventory of many potential hydro sites in Yukon and in northern BC that have been studied in the past (primarily by NCPC or Government of Canada, and reviewed from time to time by Yukon Energy). Based on the inventory of sites studied in the past, Appendix B reviews specific potential hydro sites over a range of sizes.

The projects in this chapter reflect the primary alternatives identified to date based on review of the numerous studies conducted in Yukon. In selecting the projects noted in this chapter, location was used as a key screening factor, as well as information available on the relative attractiveness of the various sites (as reflected in part in the rough qualitative and quantitative factors considered in the various Level 1 work on the projects, including potential integrated system benefits).

Rough assumptions to date are that hydro projects in the 1-4 MW range cannot support any material transmission costs beyond simple connection (i.e., must be basically on the established transmission, preferably 138 kV) while 5-10 MW projects may be able to support transmission of 50 km (to perhaps as high as 100 km at a maximum). Projects in the 10-30 MW range may be able to allow for transmission somewhat over 100 km.

For the large to very large projects (30-60 MW and 60+ MW) there has not been any serious effort to screen based on incremental transmission costs, as this can only likely be usefully considered once loads have been identified and required upgrades or additional circuits to existing transmission can be incorporated into the assessment – such planning is not possible in the absence of further information about potential loads.

No screening is applied in this section based on environmental or socio-economic considerations. Such considerations would become key considerations for projects that can progress through an initial "technical" screening of the type outlined in this Appendix and Chapter 5.

The hydro sites reviewed in this Appendix are summarized in Table B-1 and shown on the map in Figure B-1.

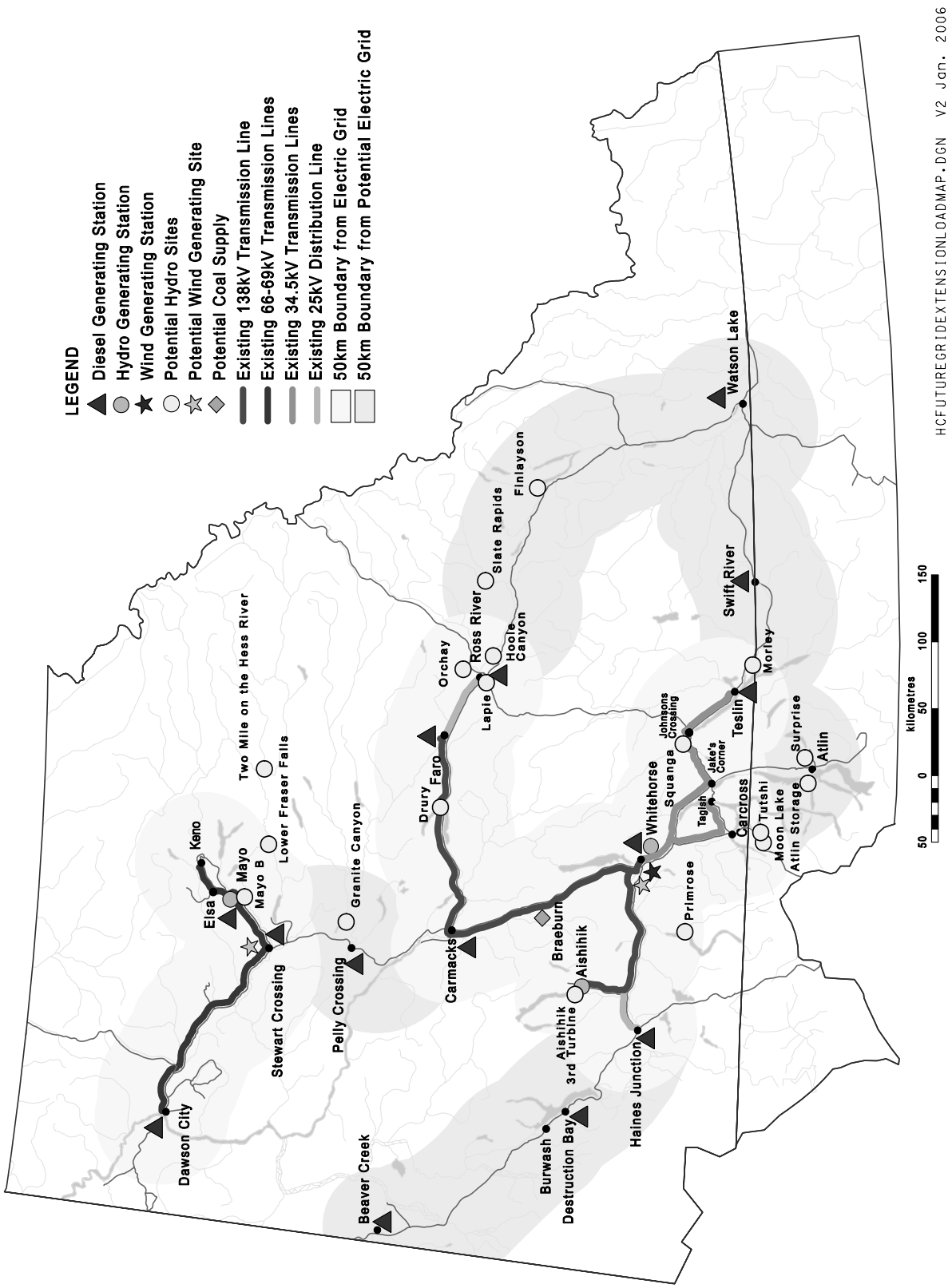
Table B-1:
Potential Hydro Sites

	Grid	Installed MW	GWh	Capital Cost (2005$millions) (excl. trans.)	Trans. Distance (km)	Protected under Yukon land claims	In BC	Capital Cost LCOE (cents/KWh) excl. trans (2005$ real)
Existing Hydro Enhancements								
Aishihik Diversions	WAF	0	total of 24	n/a	0	X		n/a
Atlin Storage	WAF	2	9	n/a	0		X	n/a
Very Small Hydro Projects (1-4 MW)								
Drury	WAF	2.6	23	31	0	X		7.2
Squanga	WAF	1.75	8.3	12	5			7.7
Orchay	WAF	4.2	27	47	15			9.2
Morley	WAF	4	22	31	30	X		7.5
Lapie	WAF	2	10	14	8			7.4
Small Hydro Projects (5-10 MW)								
Moon	WAF	8.5	50	51	66		X	5.4
Surprise	WAF	8.5	50	50	100		X	5.3
Tutshi	WAF	7.5	50	79	25		X	8.4
Mayo B	MD	10	48	101	0			11.2
Medium Hydro Projects (10-30 MW)								
Primrose	WAF	28	141	191	100			7.2
Finlayson	WAF	17	129	179	230			7.4
Large Hydro Projects (30-60 MW)								
Hoole	WAF	40	275	412	100			8.0
Slate	WAF	42	252	422	172			8.9
Two Mile Canyon on the Hess	MD	53	280	380	n/a	X		7.2
Very Large Hydro Sites (60+ MW)								
Granite	WAF	80 (up to 250)	660	706	125	X		5.7
Fraser Falls	MD	100 (up to 450)	613	555	n/a			4.8
Yukon River *(such as Rink Rapid, Eagles Nest, Five Fingers)*	WAF	various 75-240	n/a	n/a	n/a			n/a

Many of the above hydro projects arise from studies carried out by NCPC prior to 1987. In many cases these projects have not been subsequently reviewed in sufficient detail to confirm technical, economic or environmental acceptability for Yukon Energy to pursue today.

The above table also notes that some of the potential hydro projects identified here are "protected" under the Yukon First Nations land claims. Protection under the land claims agreements does not preclude the requirement to consult and work with local First Nations should Yukon Energy determine a need to develop these projects to supply load requirements. Furthermore, the extent to which such "protection" in each case may or may not extend to the elevations required to reach the maximum outputs noted in this Appendix has not yet been confirmed (because, as noted, further work has not yet been carried out since the initial studies).

Figure B-1:
Map of Potential Supply Options



B.1.1 LEVELIZED COST OF ENERGY

A primary consideration in screening potential new projects is the basic generation cost of energy supplied by output from any new resource (with typical focus on overall unit cost per kW.h as opposed to cost per MW of capacity). For the purposes of initial screening, "levelized costs of energy" ("LCOE") can be used to determine the unit costs/kW.h at the project site of energy produced. Levelized costs reflect the costs of the plant amortized over its life (all kW.h units available to be produced by the plant) assessed on real dollar (2005$) economic terms (i.e., assuming the levelized unit cost after 2005 increases with inflation each year).

- LCOE focuses only on key generation cost components for a resource option as needed to screen or compare alternative resource options during preliminary assessment stages[1].
- LCOE for hydro supply projects accordingly focuses in most instances only on capital costs, as these tend to establish the primary overall generation cost for this option[2]. Operating and maintenance costs for large projects can be quite modest (0.5% of capital cost based on BC Hydro estimates) which would tend to increase the LCOE by about 9.4%. Smaller hydro project operating and maintenance costs may vary up to 1.0% to 1.5% of capital cost, which can increase LCOE by 18.8% to 28.3% over the levels quoted in Table B-1.
- In the case of other resource options which involve material fuel operating costs (e.g., diesel generation, or thermal generation using coal, wood biomass or natural gas) it is also necessary that the LCOE reflect fuel as well as capital costs (if the capital costs are also likely to be a key part of the option's overall costs).
- LCOE automatically takes into consideration variations in the economic lives of alternative resource options.
- LCOE implicitly assumes that all energy generated over the economic life of a resource option is sold at rates that fully recover the LCOE costs, i.e., this screening tool does not address the extent to which a resource option may be oversized to meet forecast loads, or otherwise mismatched with forecast loads (in terms of, say, seasonal consideration).

[1] In BC, transmission costs to interconnect a project are considered in the levelized costing, but not overall transmission system upgrades required outside of the simple connection to the generation. In Yukon, screening of hydro projects is intended to be a quick and relatively simple process, so transmission costs to interconnect stations are not specifically estimated but are approximated in the screening process by focusing, for each scale of project, on only those projects a reasonable distance from developed transmission systems.

[2] Hydro project operating costs are modest compared to capital costs (outside of special charges such as BC water rentals, which need to be separately considered).

Levelized cost of energy as it is used in this Resource Plan for hydro focuses exclusively on hydro capital costs (excluding transmission and excluding O&M), estimated in 2005$ (includes 25% for owner's costs and contingency). Levelized costs are calculated by dividing the 2005$ capital cost of the project by a 65 year energy output (kW.h) of the project, discounted each year at a real discount rate of 5.41%. The real discount rate is determined by a nominal discount rate of 7.52% (based on YEC's costs of capital – 40% equity at 9.05% and 60$ debt at 6.5%) and inflation of 2%[3].

B.2 EXISTING HYDRO ENHANCEMENTS

Opportunities to enhance existing hydro in Yukon include items identified in Chapter 4 (such as re-runnering, Aishihik 3rd Turbine, Marsh Lake Top Storage and other potential opportunities in the Southern Lakes) as well as the Aishihik Diversions projects.

B.2.1 AISHIHIK DIVERSIONS

One set of projects that Yukon Energy has protected under the First Nations land claims (Champagne and Aishihik First Nation and Kluane First Nation as required) is the potential diversion of Long Lake (maximum 4.6 GW.h), Hutshi Creek (maximum 1.8 GW.h) and Gladstone Lake (maximum 17.7 GW.h) into the Aishihik Lake and Canyon Lake systems (total maximum potential energy of 24.0 GW.h per year). These projects have the potential to add energy with no new capacity Considerable further work would be required on these project before their respective feasibility can be assessed, including work to update capabilities and considerations with respect to licencing.

B.2.2 ATLIN STORAGE

NCPC studied and assessed the potential to optimize the water regime on Atlin Lake (an important upstream source of water for the existing Whitehorse Rapids hydro plant) to allow improved winter flows on the Yukon River. Although various potential scales exist, one option involves managing the lake within the natural range. This variant is expected to be able to provide 2.0 MW of enhanced Whitehorse Rapids firm capacity, plus 9 GW.h of additional energy (depending on loads). No reliable updated cost estimates

[3] This is generally consistent with major utilities considering long-term generation options. Other LCOE approaches have been used at times by other utilities when comparing to IPP projects, which attempt to address disparities in the length of IPP contracts compared to project service lives, the availability of low-cost financing to Crown utilities compared to IPPs, before-tax versus after-tax costs of Crown utilities versus IPPs, and elimination of federal government subsidies that may distort economic choices and fail to recognize that subsidies are a cost to taxpayers (see, for example, the 2005 BC Hydro Resource Options Report, section 4), The intent of such processes is to incorporate "societal perspectives" rather than focus on ratepayer perspectives. The Yukon Energy Resource Plan focuses primarily on utility and ratepayer perspectives.

are available, and significant complications are expected with respect to required interprovincial licencing processes should the project be advanced.

B.3 VERY SMALL PROJECTS (1-4 MW)

Very small hydro projects in the range of 1-4 MW may be candidates for development under Chapter 5 forecasts under the 10 MW industrial scenario or larger (at the very maximum that the 10 MW scenario can handle).

B.3.1 DRURY

Drury is a proposed 2.6 MW, 23 GW.h project that capitalizes on the head between Drury Lake and the confluence of Drury Creek with Little Salmon Lake. Drury was assessed in 1992, and remains the preferred candidate for scenarios with capacity and energy requirements consistent with Drury's output. The project has a capital cost of $31 million (2005$).

On a simple LCOE basis the costs of Drury are about 7.2 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes.

The 2.6 MW is a firm winter capacity number based on the assumption that the plant would be developed to operate at a very high load factor throughout the year (e.g., include all necessary storage to allow firm winter supplies). If a more variable and flexible operating regime were to be considered for Drury, additional capacity above 2.6 MW could be installed (larger capacity configurations up to 5.2 MW and 29 GW.h have also been recently considered, at a cost of $37 million – a gain of 2.6 MW and about 6 GW.h). Alternate project layouts and sizes must be evaluated to determine the optimum scheme.

The plant would interconnect with the 138 kV line which follows the highway from Carmacks to Faro and would give rise to very little transmission costs.

Yukon Energy has the Drury site protected under the Yukon First Nation land claims agreements.

B.3.2 SQUANGA

A small potential site at Squanga Creek, at 1.75 MW and 8.3 GW.h at a rough capital cost of $12 million for a run-of-river version (2005$). This creek is near Johnson's Crossing with a steep final drop into the Teslin River, where the project would be located. Yukon Energy did work on Squanga as part of the 1992

Resource Plan, focusing on a run-of-river design with primarily summer supply (only 500 kW of firm winter capacity). In 1992 the potential for year-round storage was also noted, but little recent study of the potential for this variation had taken place.

The simple LCOE of Squanga is about 7.7 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes.

In 1996 during the call for Expressions of Interest, Yukon Energy received an IPP proposal to develop Squanga at a similar run-of-the-river (limited winter capacity) configuration. Since that time, Yukon Energy/Yukon Development have been approached by private IPP developers interested in developing the Squanga site and YDC worked with one private outfit (via the Green Power Fund) with respect to further work. Continuing issues with Squanga relate to its limited ability as studied to provide winter capacity, and its location on a weak transmission link (the 34.5 kV system towards Teslin).

B.3.3 MORLEY, LAPIE AND ORCHAY

Three other sites in this size range that were recommended by the YUB for further water monitoring in 1992 (but not further assessment work) were Morley (past Teslin, 4 MW, 22 GW.h, $31 million (2005$)), Lapie (near Ross river, 2 MW, 10 GW.h, $14 million (2005$)) and Orchay (near Ross River, 4.2 MW, 27 GW.h, $47 million (2005$)). In each case, YEC has conducted water monitoring, but not undertaken the additional work required to advance the projects to the level of Drury in terms of technical assessment. In each case, projects may be limited by transmission, as they are not located on or near the 138 kV system.

Simple LCOE for these projects (excluding transmission, incremental operating and maintenance costs and taxes) varies from 7.4 cents/kW.h (Lapie) to 7.5 cents/kW.h (Morley) to 9.2 cents/kW.h (Orchay) (2005$, real).

Yukon Energy has the Morley site protected under the Yukon First Nation land claims agreements.

B.4 SMALL PROJECTS (5-10 MW)

Small hydro projects in the range of 5-10 MW may be candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger. These projects may also be part of a development plan under the larger 40 MW scenario.

B.4.1 MOON HYDRO SITE

The proposed Moon Lake project would have a capacity of 8.5 MW with 50 GW.h of annual generation at an estimated capital cost of $51 million (2005$). Potential exists for increasing the energy capability by the diversions of other small watersheds into Moon Lake. Additionally, the capacity could be increased to take greater advantage of the seasonal storage capability (other versions of Moon have been cited at as large as 14.6 MW for primarily winter peaking operation).

The simple LCOE of Moon is about 5.4 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes (also excludes water rentals – see below).

Moon Lake is located in northern BC on the east shore of Tutshi Lake, approximately 45 km south of Carcross, Yukon. Moon Lake provides the opportunity for seasonal storage of water (like Aishihik) focused on allowing summer flows to be stored for use during the winter. Due to the distance from the 138 kV transmission grid (about 66 km), a reasonably substantial amount of new transmission would be required[4].

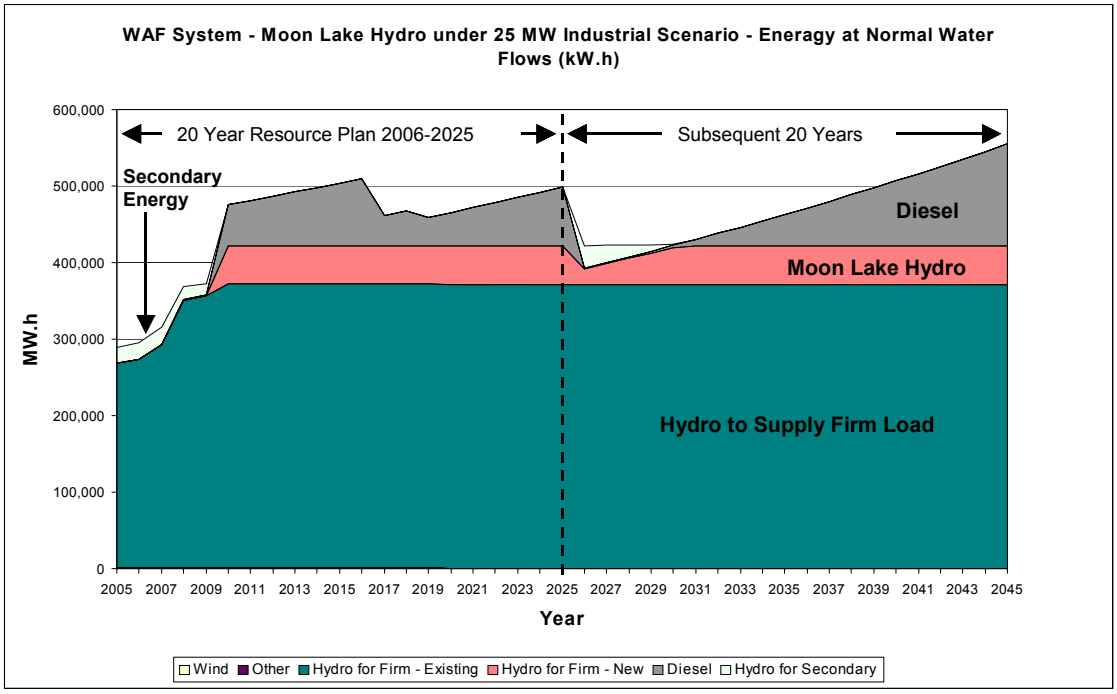
Because the Moon Lake project is located in BC, it would be subject to economic disadvantages due to material "water rental" payments and potentially property and school taxes that would be due to the BC government, as well as potentially more complicated licencing and regulations. The economic feasibility of operating in BC would need to be thoroughly assessed before proceeding with this project. Water rental payments to the BC government, for example, can likely add in the range of 0.5 cents/kW.h to the LCOE of the project.

In 1996, during the call for Expressions of Interest, Yukon Energy received a proposal from a local developer to either develop Moon Lake for Yukon Energy, or to develop the project as an IPP.
If developed in response to the 25 MW Industrial Development Scenario 2 (see Chapter 5: Section 5.2.2), it will become relevant to consider in detail the load fit of Moon to the loads to be developed. Under the 25 MW scenario loads, Moon would see full use of its energy output through 2045, with the exception of the 2026-2029 period (when surplus Moon hydro would arise, from 22 GW.h in 2026 reducing to 6 GW.h

[4] Although this transmission connection has not been priced, at a standard pricing of about $130,000 per km, plus substations, the rough capital cost could equate to $10 million. If this transmission line is solely providing a connection to Moon, the extra costs could increase the LCOE by 1.1 cents/kW.h

in 2029) as noted in Figure B-2. The impact of this 4 year surplus energy period is an increase in the LCOE of Moon over 65 years from 5.4 cents/kW.h (if all output could be used) to 5.6 cents/kW.h[5].

Figure B-2:
WAF Energy Requirements under 25 MW Scenario with Moon Lake Hydro



B.4.2 SURPRISE LAKE HYDRO SITE

In 1992, Surprise Lake was considered one of the key options for Yukon Energy in this size range. It was studied extensively in the early 1990's and a joint venture was contemplated with YEC, YECL and Synex to develop the project. It is an 8.5 MW project (50 GW.h) in two powerhouses estimated at $50 million (2005$).

In earlier review, significant concerns arose with respect to transmission requirements (more than 100 km from Jake's Corner to the site near Atlin, plus issues related to the 34.5 kV connection to Jake's Corner), regulatory requirements (due to location in BC), and economics due to material "water rental" payments and property and school taxes that would be due to the BC government as well as the local community.

[5] Full screening of Moon under a 25 MW scenario could therefore result in LCOE of 5.6 cents/kW.h for hydro capital costs reflecting "load fit", plus about 18.8% for hydro O&M based on 1% of capital cost (reflecting small projects, about $500,000 per year (2005$)), plus 1.1 cents/kW.h for transmission, plus 0.5 cents/kW.h for BC water rentals (ignoring taxes) for a total LCOE of 8.25 cents/kW.h (2005$, real).

More recently, the local community has indicated they are proceeding with a much smaller variant of the project to supply power solely to BC Hydro at Atlin. This development would likely preclude any future development of the full project as contemplated by Yukon Energy, and the project has been discarded by Yukon Energy as a likely development for Yukon needs.

B.4.3 TUTSHI AND OTHER HYDRO SITES IN THE SOUTHERN LAKES

There are a number of sites in the southern lakes that may provide opportunities for new generation, such as on the Tutshi River (7.5 MW installed, 50 GW.h, $79 million (2005$), LCOE of 8.4 cents/kW.h[6] plus water rentals to BC government). These projects serve to provide new generation as well as potentially enhance management of flow to the existing Whitehorse Rapids plant which provides added generation benefits (both capacity and energy). Yukon Energy is currently undertaking a hydrology study of this area along with site identification of potential water management structures or generating stations. Until that work is complete, all potential generation projects remain at the very initial stages of study.

Similar to Moon, a development of Tutshi under the 25 MW scenario would give rise to at least four years of surplus energy from 2026-2029. However, the actual annual flow patterns, flexibility and storage potential of Tutshi (and its associated impacts on Whitehorse Rapids) have not been recently assessed, and it is possible that surplus hydro would arise for more than four years if the plant output is not as able to be tailored to fit WAF loads as a Moon or other existing flexible resources such as Aishihik. The impact on LCOE from this surplus hydro under optimum conditions (a very flexible output from Tutshi) is an increase from 8.4 to 8.6 cents/kW.h; however the impact could be considerably more under a less flexible output.

B.4.4 MAYO B

The existing hydro site at Mayo has the potential to be enhanced by various changes in configuration, either to develop further head below the existing reservoir or an expansion of capacity utilizing the same head. This leads to multiple potential alternatives. However, as a supply option to WAF, these various projects are only of relevance if the Carmacks-Stewart transmission line is previously in service. The full capability of various potential Mayo enhancements to supply an interconnected WAF and MD system (as opposed to MD on its own) has not been fully studied, and should be re-examined in the event that the interconnection proceeds.

[6] As above, excludes transmission, incremental operating and maintenance costs and taxes.

One configuration alternative considered is a 10 MW, 48 GW.h, $101 million (2005$) variation based on a separate conveyance route from the existing reservoir to a new plant lower in elevation than the existing plant, which would be able to operate in parallel with the existing plant. This concept has an initial LCOE of 11.2 cents/kW.h. Various other concepts require further study. However, although work is still in preliminary stages, it must be recognized that it is possible no credible facility enhancements of this type exist at Mayo.

B.4.5 LACK OF OTHER YUKON-BASED HYDRO PROJECTS

There are very limited other potential hydro projects in the broad 5-15 MW size range identified in Yukon (as opposed to BC). One is near Faro, involving a diversion of the Anvil Creek and Rose Creek (9 MW, 70 GW.h, no reliable recent cost estimates available). Other identified projects are in the vicinity of Ross River (Prevost Canyon) or Pelly Crossing (Mica Creek) but have little to no reliable updated assessment of capital costs, transmission constraints and other key feasibility variables. Given the economic disadvantages of projects in BC (due to water rentals and taxes), it would be beneficial to secure generating station options in Yukon.

B.5 MEDIUM PROJECTS (10-30 MW)

Medium sized hydro projects have potential fit to the 40 MW industrial development scenario. However, key limitations arise with respect to the requirement for projects of this size once the mines close, as well as the risks of premature mine closures.

B.5.1 PRIMROSE/KUSAWA/TAKHINI HYDRO SITE

The potential Primrose generating station involves a number of potential concepts that were studied as alternatives to the Aishihik GS when it was constructed (studied in 1962, 1968, 1975, some more recent reviews). In general terms, the project involves developing hydro generation to capture the head between the high elevation Primrose Lake or Rose Lake and either Kusawa Lake or Takhini Lake.
Variations considered to date extend from about 19 MW to 30 MW and 100 to 180 GW.h. The primary concept reviewed to date is 28 MW, 141 GW.h/year estimated at $191 million (2005$). The LCOE under this scenario, consistent with the approaches used above, is about 7.2 cents/kW.h (2005$, real).

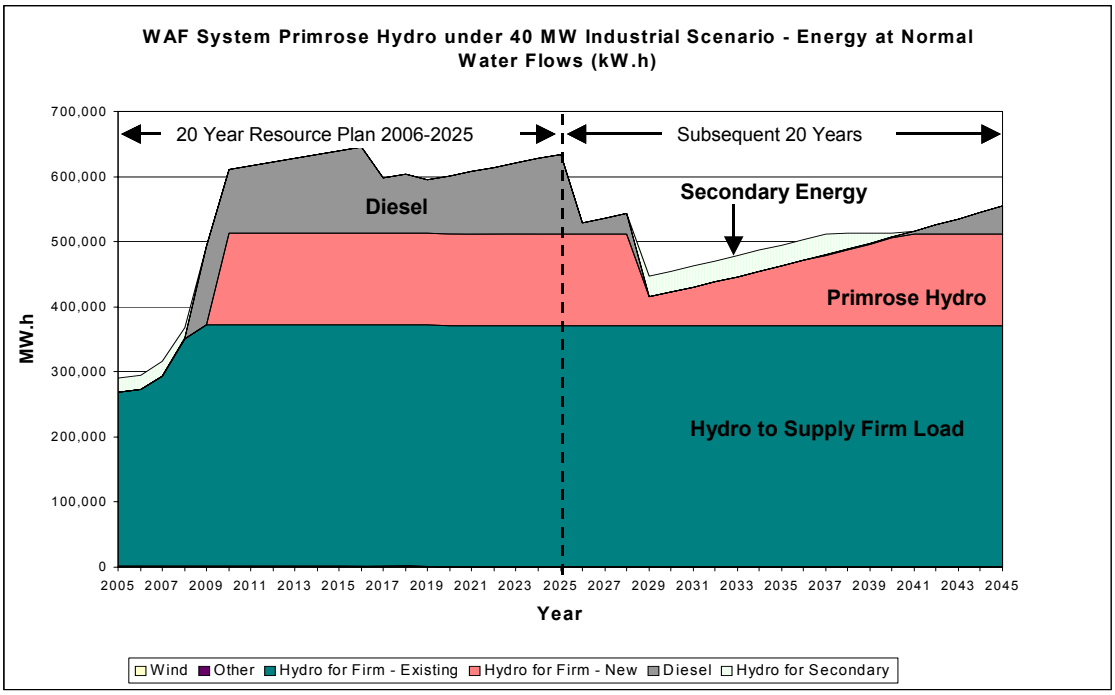
The site has reasonable access to developed transmission (less than 100 km, potential impact on LCOE of about 0.5 cents/kW.h). However, the site is located within an area that may be encompassed by a Park or special conservation area (subject to ongoing discussions with Yukon Government and the Kwanlin Dun, Champagne and Aishihik, and Carcross Tagish First Nations), which may limit development

opportunities. Primrose is not "protected" by notation under the Yukon First Nations land claim agreements. In addition, the Primrose River is glacial fed and carries large amounts of silt, which may pose technical problems for a generating station.

The project is located in Yukon, so would not be subject to economic disadvantages of BC locations due to "water rental" payments or property and school taxes, as well as the potentially more complicated interprovincial licencing regulations.

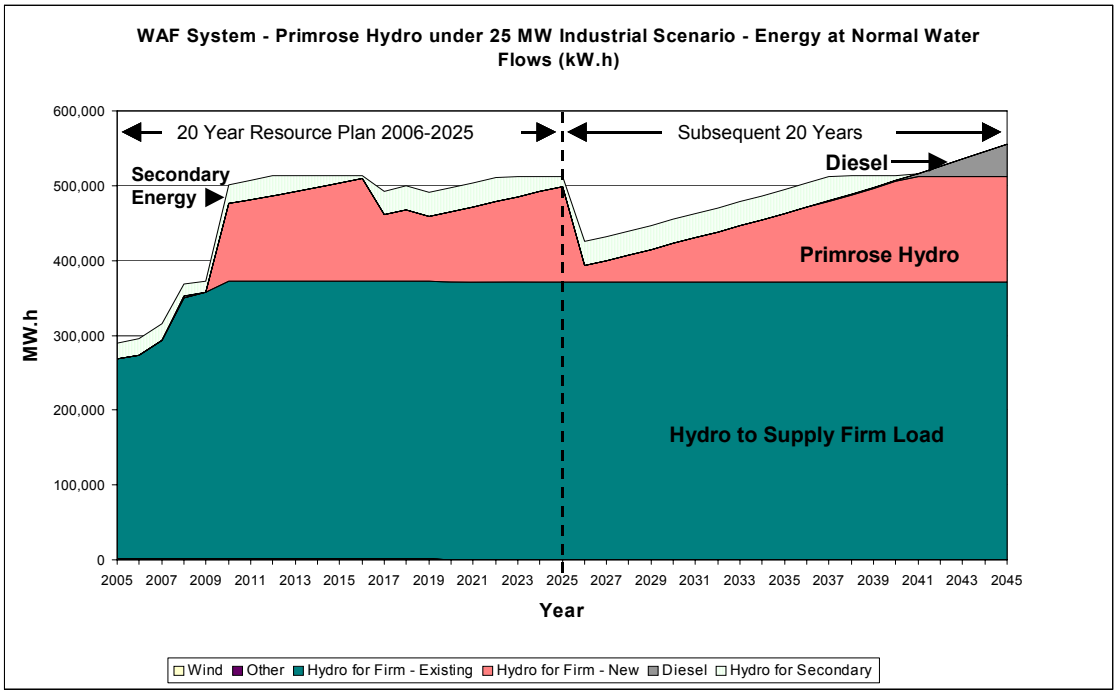
The key issues with Primrose or other hydro sites under the 40 MW scenario is the lack of load following closure of the mines, and the resulting potential for material surplus energy at that time (and potential consequent adverse rate impacts) as noted in Figure B3. In particular, were Primrose to be developed to service the 40 MW Industrial Scenario 3 (see Chapter 5: Section 5.2.3), its output would be fully utilized from the date of in-service to 2028. Starting in 2029 the facility would be in excess of WAF needs (about 2/3 of its output would be surplus), and the hydro surplus would extend through 2040. The consequent impact on project LCOE over 65 years is an increase from 7.2 to 7.7 cents/kW.h.

Figure B-3:
WAF Energy Requirements under 40 MW Scenario with Primrose Hydro



In contrast, were Primrose to be brought into service under the 25 MW industrial scenario, as noted in Figure B-4, the size would be well in excess of the system requirements in many years, and the consequent impact on LCOE would be an increase from about 7.2 cents/kW.h to over 9.0 cents/kW.h.

Figure B-4:
WAF Energy Requirements under 25 MW Scenario with Primrose Hydro



B.5.2 FINLAYSON HYDRO SITE

This potential project is on the Finlayson River, at Frances Lake well past Ross River near the Robert Campbell highway. It is potentially a 17 MW generating station (very high load factor, at 129 GW.h/year), and has a substantial transmission requirement (about 230 km). No recent reviews have been done of the potential costs of the station, but simple escalations from earlier capital cost estimates indicate potentially $179 million (2005$) (equivalent to an LCOE of 7.4 cents/kW.h in 2005$, real).

Finlayson is located in the Kaska area which has not signed a final agreement, so the status of any protection is not available.

Other larger hydro generating sites also exist in this area, along with significant future mining potential (Wolverine, Kudz Ze Kayah, others) which may enable a major system development along the Robert

Campbell highway at some point in the future. However, as a lone supply option, Finlayson is unlikely to be economic due to the substantial transmission requirements (which could add more than 1.2 cents/kW.h to the above LCOE).

B.6 LARGE PROJECTS (30-60 MW)

Large sized hydro projects have limited potential under any of the industrial load scenarios, with the exception of potential service to a limited number of compressors under the Alaska highway pipeline case.

B.6.1 HOOLE

Hoole is located on the Pelly River east of Ross River and is in the Kaska First Nations area which does not have final agreement on any protection for potential hydro sites. The project is a 40 MW, 275 GW.h/year facility at an estimated $412 million capital cost (2005$). Resulting LCOE is 8.0 cents/kW.h (2005$, real).

B.6.2 SLATE

Slate is similarly on the Pelly River east of Ross River, and is also in the area without final agreements as yet on protected sites (Kaska). The project is a 42 MW, 252 GW.h/year facility at an estimated $422 million capital cost (2005$). The resulting LCOE is 8.9 cents/kW.h (2005$, real))

B.6.3 HESS

Two Mile Canyon on the Hess is located east of Mayo and is protected in the Yukon land claims agreements. It is only of value to WAF if Stewart-Carmacks interconnection in place. The project is a 53 MW, 280 GW.h/year with an estimated $380 million capital cost (2005$). The resulting LCOE is 7.2 cents/kW.h (2005$, real)).

B.7 VERY LARGE PROJECTS (60 MW+)

Very large hydro projects have the potential to service most or all of the potential Alaska highway pipeline loads.

B.7.1 GRANITE CANYON

On the Pelly River (east of Pelly Crossing), Granite Canyon is a site that was studied by NCPC under a number of different concepts and sizes. Although the site is protected under the Yukon final agreements,

the extent to which development of the site can be accommodated within the "protection" areas has not yet been determined. Possible development concepts previously studied range from 80 MW (660 GW.h/year and $706 million capital cost (2005$)) or up to 250 MW or more. The LCOE is about 5.7 cents per kW.h (2005$, real) for the 80 MW version excluding transmission.

B.7.2 FRASER FALLS

On the Stewart River east of Mayo, possible concepts range from 100 MW up to 450 MW; the smallest version (100 MW, 613 GWh/year) has been estimated (2005$) to cost about $555 million, with LCOE for generation at about 4.8 cents per kW.h (2005$, real), excluding transmission costs.

B.7.3 VARIOUS OTHER LARGE YUKON RIVER SITES

Other sites have been identified on the Yukon River, well downstream of Whitehorse, ranging from 100 MW to 500 MW. No costs are available at this time for these options.

APPENDIX C:
AISHIHIK 3RD TURBINE ASSESSMENT

C.1 AISHIHIK 3RD TURBINE ASSESSMENT

Yukon Energy has reviewed the economics of a potential Aishihik 3rd turbine project under various assumptions, focused on a 65 year life. The assessment reviews five cases, as summarized in Chapter 4:

- **Section C-2:** Aishihik 3rd Turbine at 2009 under Base Case Loads
- **Section C-3:** Aishihik 3rd Turbine at 2009 under Base Case with 10 MW Mine Loads
- **Section C-4:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case Loads
- **Section C-5:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case with 10 MW Mine Loads
- **Section C-6:** Aishihik 3rd Turbine at 2011 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case Loads
- **Section C-7:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage and (2008) of Carmacks-Stewart (CS) under Base Case with 10 MW Mine Loads

In each case, there are two sets of tables presented:

- **Overall Project Economics (IRR based on cash flows):** The first indicates an overall cash flow analysis of the project, focused on determining the Internal Rate of Return (IRR) of the project (e.g., focused on one-time capital costs rather than "accounting" costs of depreciation or return on rate base used for ratemaking). This is basically the equivalent of the analysis of the Mayo-Dawson Transmission Line project provided in Table 5.4 of the YEC 2005 Required Revenues and Related Matters Application.
- **Ratepayer Impacts (NPV based on annual impacts on ratepayers):** The second table indicates the overall project lifetime NPV, the project NPV during the period of the current Resource Plan (2006-2025) and the annual impacts on ratepayers.

In each case, the economics do not include assessment of the expected beneficial impacts on secondary sales, particularly in the early years of the project[1].

A summary of the cases is provided in Table C1.

[1] Once the WAF system grows to the point of having "diesel on the margin" and no annual surplus hydro, all secondary sales will be interrupted, so no further impacts on secondary sales will occur as a result of the project; for a few years prior to the point of diesel on the margin, the 3rd Turbine project may also reduce the availability of secondary sales, as there will be less "surplus" hydro due to the 3rd Turbine allowing more of the water to be used to avoid peaking diesel.

Table C-1:
Summary of Aishihik 3rd Turbine Assessment Cases (2005$, $000s)

	IRR lifetime (%)	Ratepayer Costs/(Savings) (NPV) lifetime	Ratepayer Costs/(Savings) (NPV) 20 years	Years until beneficial rate impact
Section C2: Turbine in 2009 – Base Case Loads	10.81%	(4,075)	57	8
Section C3: Turbine 2009 – Base Loads with 10 MW Mines	16.31%	(7,854)	(3,722)	2
Section C4: Turbine 2009 – Base Loads – Marsh Lake Storage in service	9.95%	(3,104)	1,028	9
Section C5: Turbine 2009 – Base Loads with 10 MW Mines – Marsh Lake Storage in service	14.44%	(6,726)	(2,594)	3
Section C6: Turbine 2011 – Base Loads – Marsh Lake Storage in service	10.96%	(3,779)	291	7
Section C7: Turbine 2009 – Base Loads with 10 MW Mines – Marsh Lake Storage and Carmacks-Stewart in service	14.91%	(7,258)	(3,126)	3

C.2 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE LOAD

Table C-2A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forcast

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	177	177	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	279	279	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	399	-	(399)	3.48	115	115	81	7	not assessed	87	7,577	76	7,653	7,565
2010	-	-	-	3.9	-	547	-	(547)	3.48	157	157	113	10	not assessed	122	-	77	77	(45)
2011	-	-	-	3.9	-	741	0	(741)	3.48	213	213	156	13	not assessed	169	-	79	79	(90)
2012	-	-	-	3.9	-	999	42	(957)	3.48	275	275	205	18	not assessed	223	-	80	80	(143)
2013	-	-	-	3.9	-	1,341	126	(1,215)	3.48	349	349	266	23	not assessed	289	-	82	82	(207)
2014	-	-	-	3.9	-	1,786	230	(1,556)	3.48	447	447	347	30	not assessed	377	-	84	84	(293)
2015	-	-	-	3.9	-	2,352	351	(2,002)	3.48	575	575	456	39	not assessed	495	-	85	85	(409)
2016	-	-	-	3.9	-	3,055	493	(2,562)	3.48	736	736	595	51	not assessed	646	-	87	87	(559)
2017	-	-	-	3.9	-	3,909	674	(3,236)	3.48	930	930	766	66	not assessed	832	-	89	89	(743)
2018	-	-	-	3.9	-	4,926	911	(4,015)	3.48	1,154	1,154	970	83	not assessed	1,053	-	91	91	(963)
2019	-	-	-	3.9	-	6,116	1,228	(4,889)	3.48	1,405	1,405	1,205	103	not assessed	1,308	-	92	92	(1,216)
2020	-	-	-	3.9	-	7,488	1,646	(5,843)	3.48	1,679	1,679	1,469	126	not assessed	1,595	-	94	94	(1,500)
2021	722	-	(722)	3.9	185	8,327	2,186	(6,141)	3.48	1,765	1,950	1,740	151	-	1,891	-	96	96	(1,794)
2022	7,299	1,899	(5,400)	3.9	1,385	3,506	970	(2,537)	3.48	729	2,114	1,924	178	-	2,101	-	98	98	(2,003)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	-	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	34,845	29,445	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	42,053	36,653	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	49,394	43,994	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	56,871	51,471	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	64,486	59,086	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	72,242	66,842	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	80,142	74,742	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	88,188	82,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	96,383	90,983	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,729	99,329	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,230	107,830	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	121,888	116,488	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	130,706	125,306	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	139,687	134,287	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	148,835	143,435	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	158,151	152,751	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	167,640	162,240	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	177,305	171,905	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	187,148	181,748	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	197,174	191,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											10,246	947		11,193	5,669	1,068	6,738	(4,455)
																Internal Rate of Return			**10.81%**

Table C-2B: Aishihik 3rd Turbine Economics (65 years) - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	115	81	7	not assessed	87	117	565	76	758	670
2010	157	113	10	not assessed	122	117	557	77	750	628
2011	213	156	13	not assessed	169	117	548	79	743	574
2012	275	205	18	not assessed	223	117	539	80	736	513
2013	349	266	23	not assessed	289	117	530	82	729	440
2014	447	347	30	not assessed	377	117	522	84	722	345
2015	575	456	39	not assessed	495	117	513	85	715	220
2016	736	595	51	not assessed	646	117	504	87	708	62
2017	930	766	66	not assessed	832	117	495	89	701	(131)
2018	1,154	970	83	not assessed	1,053	117	487	91	694	(360)
2019	1,405	1,205	103	not assessed	1,308	117	478	92	687	(621)
2020	1,679	1,469	126	not assessed	1,595	117	469	94	680	(915)
2021	1,950	1,740	151	-	1,891	117	460	96	673	(1,218)
2022	2,114	1,924	178	-	2,101	117	451	98	666	(1,435)
2023	1,385	1,285	123	-	1,409	117	443	100	659	(750)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		10,246	947		11,193	1,236	4,813	1,068	7,118	(4,075)
7.52%								20 year NPV (2006-2025)		57

C.3 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-3A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	380	380	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	2,874	2,874	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	3,574	601	(2,973)	3.48	854	854	601	51	not assessed	653	7,577	76	7,653	7,000
2010	3,834	-	(3,834)	3.9	983	563	784	221	3.48	(64)	919	660	64	-	724	-	77	77	(646)
2011	9,209	3,809	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,014	97	-	1,111	-	79	79	(1,032)
2012	14,684	9,284	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	-	1,133	-	80	80	(1,053)
2013	20,428	15,028	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	-	1,156	-	82	82	(1,074)
2014	26,107	20,707	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	31,892	26,492	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	37,784	32,384	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	5,558	1,074	(4,484)	3.48	1,289	1,289	1,062	91	-	1,153	-	89	89	(1,064)
2018	-	-	-	3.9	-	6,809	1,432	(5,377)	3.48	1,545	1,545	1,299	111	-	1,411	-	91	91	(1,320)
2019	-	-	-	3.9	-	6,116	1,228	(4,889)	3.48	1,405	1,405	1,205	103	-	1,308	-	92	92	(1,216)
2020	-	-	-	3.9	-	7,488	1,646	(5,843)	3.48	1,679	1,679	1,469	126	-	1,595	-	94	94	(1,500)
2021	722	-	(722)	3.9	185	8,327	2,186	(6,141)	3.48	1,765	1,950	1,740	151	-	1,891	-	96	96	(1,794)
2022	7,299	1,899	(5,400)	3.9	1,385	3,506	970	(2,537)	3.48	729	2,114	1,924	178	-	2,101	-	98	98	(2,003)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	-	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	34,845	29,445	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	42,053	36,653	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	49,394	43,994	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	56,871	51,471	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	64,486	59,086	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	72,242	66,842	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	80,142	74,742	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	88,188	82,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	96,383	90,983	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,729	99,329	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,230	107,830	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	121,888	116,488	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	130,706	125,306	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	139,687	134,287	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	148,835	143,435	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	158,151	152,751	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	167,640	162,240	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	177,305	171,905	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	187,148	181,748	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	197,174	191,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,689	1,283		14,972	5,669	1,068	6,738	(8,234)
																Internal Rate of Return			**16.31%**

Table C-3B: Aishihik 3rd Turbine Economics (65 years) - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	854	601	51	not assessed	653	117	565	76	758	105
2010	919	660	64	-	724	117	557	77	750	27
2011	1,385	1,014	97	-	1,111	117	548	79	743	(368)
2012	1,385	1,034	99	-	1,133	117	539	80	736	(397)
2013	1,385	1,054	101	-	1,156	117	530	82	729	(427)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	1,289	1,062	91	-	1,153	117	495	89	701	(453)
2018	1,545	1,299	111	-	1,411	117	487	91	694	(717)
2019	1,405	1,205	103	-	1,308	117	478	92	687	(621)
2020	1,679	1,469	126	-	1,595	117	469	94	680	(915)
2021	1,950	1,740	151	-	1,891	117	460	96	673	(1,218)
2022	2,114	1,924	178	-	2,101	117	451	98	666	(1,435)
2023	1,385	1,285	123	-	1,409	117	443	100	659	(750)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		13,689	1,283		14,972	1,236	4,813	1,068	7,118	(7,854)
7.52%								20 year NPV (2006-2025)		(3,722)

C.4 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS

Table C-4A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	45	45	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	125	125	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	221	-	(221)	3.48	64	64	45	4	not assessed	49	7,577	76	7,653	7,604
2010	-	-	-	3.9	-	333	-	(333)	3.48	96	96	69	6	not assessed	74	-	77	77	3
2011	-	-	-	3.9	-	466	-	(466)	3.48	134	134	98	8	not assessed	106	-	79	79	(27)
2012	-	-	-	3.9	-	635	-	(635)	3.48	182	182	136	12	not assessed	148	-	80	80	(67)
2013	-	-	-	3.9	-	858	17	(840)	3.48	241	241	184	16	not assessed	200	-	82	82	(118)
2014	-	-	-	3.9	-	1,155	89	(1,066)	3.48	306	306	238	20	not assessed	258	-	84	84	(175)
2015	-	-	-	3.9	-	1,546	189	(1,357)	3.48	390	390	309	26	not assessed	336	-	85	85	(250)
2016	-	-	-	3.9	-	2,051	305	(1,746)	3.48	502	502	406	35	not assessed	440	-	87	87	(353)
2017	-	-	-	3.9	-	2,687	440	(2,247)	3.48	646	646	532	46	not assessed	578	-	89	89	(489)
2018	-	-	-	3.9	-	3,471	606	(2,864)	3.48	823	823	692	59	not assessed	751	-	91	91	(661)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	not assessed	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	not assessed	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	not assessed	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	not assessed	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											9,355	867		10,222	5,669	1,068	6,738	(3,484)
																Internal Rate of Return			**9.95%**

Table C-4B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	64	45	4	not assessed	49	117	565	76	758	709
2010	96	69	6	not assessed	74	117	557	77	750	676
2011	134	98	8	not assessed	106	117	548	79	743	637
2012	182	136	12	not assessed	148	117	539	80	736	588
2013	241	184	16	not assessed	200	117	530	82	729	529
2014	306	238	20	not assessed	258	117	522	84	722	463
2015	390	309	26	not assessed	336	117	513	85	715	379
2016	502	406	35	not assessed	440	117	504	87	708	267
2017	646	532	46	not assessed	578	117	495	89	701	123
2018	823	692	59	not assessed	751	117	487	91	694	(58)
2019	1,032	885	76	not assessed	961	117	478	92	687	(274)
2020	1,270	1,111	95	not assessed	1,206	117	469	94	680	(527)
2021	1,534	1,368	117	not assessed	1,486	117	460	96	673	(813)
2022	1,818	1,655	142	not assessed	1,796	117	451	98	666	(1,130)
2023	1,952	1,813	169	-	1,981	117	443	100	659	(1,322)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		9,355	867		10,222	1,236	4,813	1,068	7,118	(3,104)
7.52%								20 year NPV (2006-2025)		1,028

C.5 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-5A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	207	207	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	1,919	1,919	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	2,435	387	(2,048)	3.48	589	589	414	35	not assessed	450	7,577	76	7,653	7,203
2010	-	-	-	3.9	-	3,060	518	(2,541)	3.48	730	730	524	45	not assessed	569	-	77	77	(492)
2011	1,509	-	(1,509)	3.9	387	2,293	680	(1,613)	3.48	464	851	623	56	-	679	-	79	79	(600)
2012	6,984	1,584	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	-	1,133	-	80	80	(1,053)
2013	12,728	7,328	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	-	1,156	-	82	82	(1,074)
2014	18,407	13,007	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	24,192	18,792	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	30,084	24,684	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	3,969	718	(3,251)	3.48	934	934	770	66	-	836	-	89	89	(747)
2018	-	-	-	3.9	-	4,975	962	(4,012)	3.48	1,153	1,153	969	83	-	1,053	-	91	91	(962)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	-	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	-	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	-	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	-	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											12,663	1,181		13,844	5,669	1,068	6,738	(7,106)
																Internal Rate of Return			**14.44%**

C-5B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	589	414	35	not assessed	450	117	565	76	758	308
2010	730	524	45	not assessed	569	117	557	77	750	182
2011	851	623	56	-	679	117	548	79	743	64
2012	1,385	1,034	99	-	1,133	117	539	80	736	(397)
2013	1,385	1,054	101	-	1,156	117	530	82	729	(427)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	934	770	66	-	836	117	495	89	701	(135)
2018	1,153	969	83	-	1,053	117	487	91	694	(359)
2019	1,032	885	76	-	961	117	478	92	687	(274)
2020	1,270	1,111	95	-	1,206	117	469	94	680	(527)
2021	1,534	1,368	117	-	1,486	117	460	96	673	(813)
2022	1,818	1,655	142	-	1,796	117	451	98	666	(1,130)
2023	1,952	1,813	169	-	1,981	117	443	100	659	(1,322)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		12,663	1,181		13,844	1,236	4,813	1,068	7,118	(6,726)
7.52%								20 year NPV (2006-2025)		(2,594)

C.6 AISHIHIK 3RD TURBINE AT 2011 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS

Table C-6A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	45	45	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	125	125	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	221	221	-	3.48	-	-	-	-		-	-	-	-	-
2010	-	-	-	3.9	-	333	333	-	3.48	-	-	-	-		-	-	-	-	-
2011	-	-	-	3.9	-	466	-	(466)	3.48	134	134	98	8	not assessed	106	7,883	79	7,962	7,856
2012	-	-	-	3.9	-	635	-	(635)	3.48	182	182	136	12	not assessed	148	-	80	80	(67)
2013	-	-	-	3.9	-	858	17	(840)	3.48	241	241	184	16	not assessed	200	-	82	82	(118)
2014	-	-	-	3.9	-	1,155	89	(1,066)	3.48	306	306	238	20	not assessed	258	-	84	84	(175)
2015	-	-	-	3.9	-	1,546	189	(1,357)	3.48	390	390	309	26	not assessed	336	-	85	85	(250)
2016	-	-	-	3.9	-	2,051	305	(1,746)	3.48	502	502	406	35	not assessed	440	-	87	87	(353)
2017	-	-	-	3.9	-	2,687	440	(2,247)	3.48	646	646	532	46	not assessed	578	-	89	89	(489)
2018	-	-	-	3.9	-	3,471	606	(2,864)	3.48	823	823	692	59	not assessed	751	-	91	91	(661)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	not assessed	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	not assessed	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	not assessed	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	not assessed	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
2074			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,529	339	-	3,868	-	274	274	(3,593)
2075			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,600	346	-	3,945	-	280	280	(3,665)
PV (2005)	7.52%											9,320	864		10,184	5,102	962	6,064	(4,120)
																Internal Rate of Return			**10.96%**

Table C-6B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	-	-	-		-	-	-	-	-	-
2010	-	-	-		-	-	-	-	-	-
2011	134	98	8	not assessed	106	121	588	79	788	682
2012	182	136	12	not assessed	148	121	579	80	781	633
2013	241	184	16	not assessed	200	121	570	82	773	574
2014	306	238	20	not assessed	258	121	561	84	766	508
2015	390	309	26	not assessed	336	121	552	85	758	423
2016	502	406	35	not assessed	440	121	543	87	751	311
2017	646	532	46	not assessed	578	121	534	89	744	166
2018	823	692	59	not assessed	751	121	524	91	736	(15)
2019	1,032	885	76	not assessed	961	121	515	92	729	(232)
2020	1,270	1,111	95	not assessed	1,206	121	506	94	722	(485)
2021	1,534	1,368	117	not assessed	1,486	121	497	96	714	(771)
2022	1,818	1,655	142	not assessed	1,796	121	488	98	707	(1,089)
2023	1,952	1,813	169	-	1,981	121	479	100	700	(1,281)
2024	1,385	1,311	126	-	1,437	121	470	102	693	(744)
2025	1,385	1,337	128	-	1,466	121	461	104	686	(780)
2026	1,385	1,364	131	-	1,495	121	451	106	679	(816)
2027	1,385	1,391	134	-	1,525	121	442	108	672	(853)
2028	1,385	1,419	136	-	1,555	121	433	110	665	(891)
2029	1,385	1,448	139	-	1,587	121	424	113	658	(929)
2030	1,385	1,477	142	-	1,618	121	415	115	651	(967)
2031	1,385	1,506	145	-	1,651	121	406	117	644	(1,006)
2032	1,385	1,536	147	-	1,684	121	397	119	637	(1,046)
2033	1,385	1,567	150	-	1,717	121	388	122	631	(1,087)
2034	1,385	1,598	153	-	1,752	121	378	124	624	(1,128)
2035	1,385	1,630	157	-	1,787	121	369	127	617	(1,169)
2036	1,385	1,663	160	-	1,822	121	360	129	611	(1,212)
2037	1,385	1,696	163	-	1,859	121	351	132	604	(1,255)
2038	1,385	1,730	166	-	1,896	121	342	135	598	(1,298)
2039	1,385	1,765	169	-	1,934	121	333	137	591	(1,343)
2040	1,385	1,800	173	-	1,973	121	324	140	585	(1,388)
2041	1,385	1,836	176	-	2,012	121	315	143	579	(1,433)
2042	1,385	1,873	180	-	2,052	121	306	146	572	(1,480)
2043	1,385	1,910	183	-	2,093	121	296	149	566	(1,527)
2044	1,385	1,948	187	-	2,135	121	287	152	560	(1,575)
2045	1,385	1,987	191	-	2,178	121	278	155	554	(1,624)
2046	1,385	2,027	195	-	2,222	121	269	158	548	(1,674)
2047	1,385	2,068	198	-	2,266	121	260	161	542	(1,724)
2048	1,385	2,109	202	-	2,311	121	251	164	536	(1,775)
2049	1,385	2,151	207	-	2,358	121	242	167	530	(1,827)
2050	1,385	2,194	211	-	2,405	121	233	171	524	(1,880)
2051	1,385	2,238	215	-	2,453	121	223	174	519	(1,934)
2052	1,385	2,283	219	-	2,502	121	214	178	513	(1,989)
2053	1,385	2,328	224	-	2,552	121	205	181	508	(2,044)
2054	1,385	2,375	228	-	2,603	121	196	185	502	(2,101)
2055	1,385	2,422	233	-	2,655	121	187	188	497	(2,158)
2056	1,385	2,471	237	-	2,708	121	178	192	491	(2,217)
2057	1,385	2,520	242	-	2,762	121	169	196	486	(2,276)
2058	1,385	2,571	247	-	2,817	121	160	200	481	(2,337)
2059	1,385	2,622	252	-	2,874	121	150	204	476	(2,398)
2060	1,385	2,675	257	-	2,931	121	141	208	471	(2,461)
2061	1,385	2,728	262	-	2,990	121	132	212	466	(2,524)
2062	1,385	2,783	267	-	3,050	121	123	216	461	(2,589)
2063	1,385	2,838	272	-	3,111	121	114	221	456	(2,655)
2064	1,385	2,895	278	-	3,173	121	105	225	451	(2,722)
2065	1,385	2,953	283	-	3,236	121	96	230	447	(2,790)
2066	1,385	3,012	289	-	3,301	121	87	234	442	(2,859)
2067	1,385	3,072	295	-	3,367	121	78	239	438	(2,929)
2068	1,385	3,134	301	-	3,435	121	68	244	433	(3,001)
2069	1,385	3,196	307	-	3,503	121	59	249	429	(3,074)
2070	1,385	3,260	313	-	3,573	121	50	254	425	(3,148)
2071	1,385	3,325	319	-	3,645	121	41	259	421	(3,224)
2072	1,385	3,392	326	-	3,718	121	32	264	417	(3,301)
2073	1,385	3,460	332	-	3,792	121	23	269	413	(3,379)
2074	1,385	3,529	339	-	3,868	121	14	274	409	(3,458)
2075	1,385	3,600	346	-	3,945	121	5	280	406	(3,539)
PV (2005)		9,320	864		10,184	1,112	4,332	962	6,406	(3,779)
7.52%								20 year NPV (2006-2025)		291

SECTION C-7: AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE AND (2008) OF CARMACKS-STEWART (CS) UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-7A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & Carmacks-Stewart (CS) S - IRR based on cash flows ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenues	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	207	207	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	2,113	2,113	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	2,685	505	(2,180)	3.48	627	627	441	38	not assess	479	7,577	76	7,653	7,174
2010	-	-	-	3.9	-	3,379	667	(2,711)	3.48	779	779	559	48	not assess	607	-	77	77	(530)
2011	-	-	-	3.9	-	4,204	873	(3,331)	3.48	957	957	701	60	not assess	761	-	79	79	(682)
2012	-	-	-	3.9	-	5,171	1,137	(4,034)	3.48	1,159	1,159	866	74	not assess	940	-	80	80	(859)
2013	5,087	-	(5,087)	3.9	1,304	1,203	1,478	275	3.48	(79)	1,225	933	90	-	1,023	-	82	82	(941)
2014	11,374	5,974	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	17,777	12,377	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	24,298	18,898	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	4,735	1,014	(3,720)	3.48	1,069	1,069	881	75	-	957	-	89	89	(868)
2018	-	-	-	3.9	-	5,905	1,357	(4,548)	3.48	1,307	1,307	1,099	94	-	1,193	-	91	91	(1,103)
2019	-	-	-	3.9	-	5,365	1,194	(4,171)	3.48	1,199	1,199	1,028	88	-	1,116	-	92	92	(1,024)
2020	-	-	-	3.9	-	6,675	1,604	(5,071)	3.48	1,457	1,457	1,275	109	-	1,384	-	94	94	(1,290)
2021	-	-	-	3.9	-	8,189	2,141	(6,047)	3.48	1,738	1,738	1,551	133	-	1,683	-	96	96	(1,587)
2022	-	-	-	3.9	-	9,913	2,827	(7,087)	3.48	2,036	2,036	1,853	159	-	2,012	-	98	98	(1,914)
2023	3,787	-	(3,787)	3.9	971	8,070	3,681	(4,388)	3.48	1,261	2,232	2,072	187	-	2,259	-	100	100	(2,159)
2024	11,339	5,939	(5,400)	3.9	1,385	2,687	-	(2,687)	3.48	772	2,157	2,042	189	-	2,231	-	102	102	(2,129)
2025	19,030	13,630	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	26,863	21,463	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,842	29,442	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	42,968	37,568	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	51,244	45,844	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	59,674	54,274	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	68,259	62,859	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	77,003	71,603	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	85,909	80,509	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	94,980	89,580	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,218	98,818	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,628	108,228	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	123,211	117,811	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	132,972	127,572	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	142,913	137,513	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	153,039	147,639	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	163,351	157,951	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	173,855	168,455	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	184,552	179,152	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	195,448	190,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	206,545	201,145	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,162	1,214		14,376	5,669	1,068	6,738	(7,638)
																Internal Rate of Return			**14.91%**

Table C-7B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage & CS - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	627	441	38	not assessed	479	117	565	76	758	279
2010	779	559	48	not assessed	607	117	557	77	750	144
2011	957	701	60	not assessed	761	117	548	79	743	(17)
2012	1,159	866	74	not assessed	940	117	539	80	736	(204)
2013	1,225	933	90	-	1,023	117	530	82	729	(294)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	1,069	881	75	-	957	117	495	89	701	(256)
2018	1,307	1,099	94	-	1,193	117	487	91	694	(499)
2019	1,199	1,028	88	-	1,116	117	478	92	687	(429)
2020	1,457	1,275	109	-	1,384	117	469	94	680	(704)
2021	1,738	1,551	133	-	1,683	117	460	96	673	(1,011)
2022	2,036	1,853	159	-	2,012	117	451	98	666	(1,346)
2023	2,232	2,072	187	-	2,259	117	443	100	659	(1,600)
2024	2,157	2,042	189	-	2,231	117	434	102	652	(1,578)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		13,162	1,214		14,376	1,236	4,813	1,068	7,118	(7,258)
7.52%								20 year NPV (2006-2025)		(3,126)

GLOSSARY OF TERMS

BASELOAD DIESEL GENERATION:

Diesel generation operated to provide energy, due to a shortfall in annual energy (kW.h) from hydro (or other low variable cost generating sources).

BULK ELECTRICAL SUPPLY:

The generation and transmission part of an electrical grid that delivers power to the distribution system(s).

CAPACITY:

The load for which a generating unit, generating station or other electrical apparatus is rated either by the user or by the manufacturer.

COST OF SERVICE:

The total cost incurred to provide utility service, including expenses, taxes and return on investment. The cost of service may be thought of as an annual revenue requirement.

DEMAND:

The rate of flow of electricity demanded at one point in time and the maximum size (capacity) of facilities required to serve the demands of electric customers, usually expressed in kilowatts.

ENERGY:

The consumption of electricity over a period of time by customers of an electric system, usually expressed in kilowatt hours.

FIRM CAPACITY:

Capacity which is intended to have assured availability to the customers to meet all or a portion of the load requirements.

FIXED COST:

Those costs that do not vary with the number of kilowatt hours supplied. Examples would be depreciation and return on investment.

GIGAWATT:

One gigawatt equals 1,000 megawatts.

INDUSTRIAL CUSTOMER:

Defined in OIC 1995/90 as:

a) "major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer;

b) "isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer.

KILOWATT:

One kilowatt equals 1,000 watts, where a watt is an electrical unit of real power or rate of doing work. One kilowatt is equivalent to approximately 1.34 horsepower.

KILOWATT HOUR:

The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt hour equals 1,000 watt hours.

LOAD FACTOR:

The average load of a customer, a group of customers, or the system divided by the maximum load (usually expressed as a percentage). For example, assuming 48 kWh of usage for the day, the average is 48/24 or 2 kW. If the maximum capacity available is 4 kW, the load factor is 2/4 or 50%.

LOAD FORECAST:

The forecast energy and demand requirements of the customers (usually on a monthly or annual basis).

MAXIMUM CONTINUOUS RATING:

The generation output rating in megawatts that a generating unit can sustain on a continuous basis.

MEGAWATT:

One megawatt equals 1,000 kilowatts.

PEAKING DIESEL GENERATION:

Diesel generating operated over short-term periods (hours to days) to aid in meeting the peak demand (MW) for electricity, typically during daytime hours.

RE-RUNNERING:

The replacement of turbines at an existing hydro generating station with a modern, more efficient design.

RESERVE:

Excess generation capacity that is maintained to safeguard against losses of supply due to unexpected equipment failures.

RUN OF RIVER:

Hydro projects that do not have any material storage, and must generate power based on river flows at any given point in time.

SECONDARY ENERGY:

Energy sold on an interruptible basis for service to heating loads.

ACRONYMS

BES: BULK ELECTRICITY SUPPLY

DFO: DEPARTMENT OF FISHERIES AND OCEANS

DSM: DEMAND SIDE MANAGEMENT

ESC: ENERGY SOLUTIONS CENTRE

GRA: GENERAL RATE APPLICATION

IPP: INDEPENDENT POWER PRODUCER

LCOE: LEVELIZED COSTS OF ENERGY

LOEE: LOSS OF ENERGY EXPECTATION

LOLE: LOSS OF LOAD EXPECTATION

LOLH: LOSS OF LOAD HOURS

LOLP: LOSS OF LOAD PROBABILITY

MAPL: MAXIMUM ALLOWABLE PEAK LOAD

MCR: MAXIMUM CONTINUOUS RATING

MD: MAYO-DAWSON

MW: MEGAWATT

NCPC: NORTHERN CANADA POWER COMMISSION

NTPC: NORTHWEST TERRITORIES POWER CORPORATION

NWT: NORTHWEST TERRITORIES

UKHM: UNITED KENO HILL MINE

WAF: WHITEHORSE-AISHIHIK-FARO

YDC: YUKON DEVELOPMENT CORPORATION

YEC: YUKON ENERGY CORPORATION

YECL: YUKON ELECTRICAL COMPANY LIMITED

YTG: YUKON TERRITORIAL GOVERNMENT

YTWB: YUKON TERRITORIAL WATER BOARD

YUB: YUKON UTILITIES BOARD

Alexco Power Purchase Agreement

POWER PURCHASE AGREEMENT

BETWEEN

YUKON ENERGY CORPORATION

AND

ALEXCO KENO HILL MINING CORP.

AND

ELSA RECLAMATION & DEVELOPMENT COMPANY

AND

ALEXCO RESOURCE CORP.

DATED

SEPTEMBER 1, 2010

Davis:5203362.15
DM_VAN/262912-00049/7651578.3

Table of Contents
POWER PURCHASE AGREEMENT

PART 1 DEFINITIONS AND INTERPRETATION 2

1.1 Definitions 2
1.2 Schedules 9
1.3 Interpretation 9

PART 2 DURATION 10

2.1 Term 10

PART 3 INITIAL ACTIVITIES 10

3.1 Filing with YUB 10
3.2 Initial Mine Facilities Spurs 10
3.3 Initial Mine Facilities 10

PART 4 ELECTRICITY 11

4.1 Electricity to be Made Available 11
4.2 Alexco Forecasts 11
4.3 Points of Delivery 12
4.4 Maximum Electric Demand 12
4.5 Increase in Maximum Electric Demand, new Point of Delivery, or Addition of Affiliate 12
4.6 Alexco Standards for Usage of Electricity 14
4.7 ESRs 14
4.8 Commercial Operation Cessation Date 14

PART 5 CAPITAL COSTS 14

5.1 Initial Mine Facilities Spurs Capital Costs for Connecting Initial Mill and Initial Mine 14
5.2 Capital Costs for Other Mine Facilities Spurs 15

PART 6 BILLING/PAYMENT AND SECURITY 15

6.1 Alexco Power Bill 15
6.2 Canadian Funds 16
6.3 Failure to Render Invoice 16
6.4 Late Payment 16
6.5 Prepayments 16
6.6 Taxes 16
6.7 Fixed Charge 16

PART 7 METERING 17

7.1 Metering 17
7.2 Testing 17
7.3 Backup Metering 17
7.4 Costs 17

PART 8 FORCE MAJEURE 17

8.1 Force Majeure 17
8.2 Notice of Force Majeure 18
8.3 Exclusions 18

PART 9 REPRESENTATIONS AND WARRANTIES 19

9.1 YEC Representations and Warranties 19
9.2 Alexco Representations and Warranties 19

PART 10 DEFAULT 20

10.1 Event of Default 20
10.2 Remedies 20

PART 11 DECOMMISSIONING 21

11.1 Decommissioning Costs 21
11.2 Accrued Decommissioning Fund 21
11.3 Application of Accrued Decommissioning Fund and Payment of Decommissioning Costs 22

PART 12 DISPUTE RESOLUTION 22

12.1 Confidentiality of Process. 22
12.2 Stages. 23
12.3 Availability of Argument. 23
12.4 No Further Claims. 24
12.5 Continued Payment 24

PART 13 INDEMNITY 24

13.1 Limitation of Liability 24
13.2 Indemnification 24
13.3 Assertion of Claims 25
13.4 Defence of Claims 25

PART 14 ASSIGNMENT 26

14.1 Assignment 26

14.2 Sale of the Transmission Facilities 26
14.3 Sale of the Mine Facilities 27

PART 15 CONFIDENTIALITY 27

15.1 Confidentiality. 27
15.2 Exceptions. 27
15.3 Survival 28
15.4 Injunctive Relief 28

PART 16 GENERAL 28

16.1 Notices 28
16.2 Coordination of Communications 30
16.3 Amendment 30
16.4 Governing Law and Language 30
16.5 Submission to Jurisdiction 30
16.6 Severability 30
16.7 Entire Agreement 30
16.8 Further Assurances 31
16.9 Successors and Assigns 31
16.10 Waivers 31
16.11 Time 31
16.12 Counterparts 31
16.13 Joint and Several 31

POWER PURCHASE AGREEMENT

This Agreement dated September 1, 2010 is:

Between:

YUKON ENERGY CORPORATION, a Yukon Territory corporation, having an office at P.O. Box 5920, #2 Miles Canyon Road, Whitehorse, Yukon Territory, Y1A 6S7

("**YEC**")

and:

ALEXCO KENO HILL MINING CORP., a British Columbia corporation, having an office at 1150 - 200 Granville Street, Vancouver, British Columbia, V6C 1S4

("**AKHM**")

and:

ELSA RECLAMATION & DEVELOPMENT COMPANY LTD., a Yukon Territory corporation, having an office at 1150 - 200 Granville Street, Vancouver, British Columbia, V6C 1S4

("**ERDC**")

and:

ALEXCO RESOURCE CORP., a British Columbia corporation, extra-provincially registered in the Yukon Territory, having an office at 1150 - 200 Granville Street, Vancouver, British Columbia, V6C 1S4

("**AXR**")

Background:

A. AKHM and ERDC are each wholly owned subsidiaries of AXR, and AXR, AKHM, and ERDC are therefore Affiliates of each other.

B. Alexco is developing the Initial Mine Facilities with the intent of commencing milling operations at the Initial Mill Site and mining operations at the Initial Mine Site in 2010, and of developing other Mines and Mills in the District in the future;

C. YEC has agreed to sell to Alexco and Alexco has agreed to purchase from YEC Grid Electricity required by Alexco to operate the Mine Facilities in the District; and

D. The Parties have agreed to enter into this Agreement to set out their respective rights and obligations with respect to the sale and purchase of Grid Electricity by YEC to Alexco for Mine Facilities in the District.

Agreements:

The Parties agree:

PART 1
DEFINITIONS AND INTERPRETATION

1.1 Definitions

In this Agreement:

(a) **"Accrued Decommissioning Fund"** means a separate account to be set up by YEC under Part 11;

(b) **"Accrued Decommissioning Fund Amount"** means the amount standing to the credit of the Accrued Decommissioning Fund from time to time;

(c) **"Act"** has the meaning in Section 7.1;

(d) "**Affiliate**" has the meaning set out in the *Business Corporations Act* (Yukon Territory);

(e) **"Alexco"** refers collectively to AXR, AKHM, ERDC, and all Alexco Affiliates who become a Party to this Agreement under Section 4.5;

(f) **"Alexco Forecasts"** has the meaning in Section 4.2;

(g) **"Alexco Power Bill"** means the monthly bill sent by YEC to Alexco under Section 6.1;

(h) **"ampere"** means a unit of measurement of electric current, which is the rate that electrons flow in a wire (one ampere is 6.023 x 1023 electrons per second);

(i) **"Business Day"** means any day which is not a Saturday, Sunday, or a statutory holiday in the Yukon Territory or the Province of British Columbia;

(j) **"Capital Cost"** means all of YEC's reasonably incurred costs and expenses incurred in the design, engineering, procurement, construction, and commissioning of the Mine Facilities Spurs and YEC's costs and expenses reasonably incurred to negotiate and conclude this Agreement;

(k) **"Commencement of Delivery"** means, for any Mine Facility, the later of:

(i) the Mine Facilities Operation Date; and

(ii) if delivery of Grid Electricity by YEC at the Point of Delivery for that Mine Facility has not yet commenced, the date on which YEC provides written notice to Alexco that, in the reasonable opinion of YEC, the Mine Facilities Spurs for that Mine Facility are commissioned and are available for YEC to provide Grid Electricity to that Mine Facility from the Transmission Facilities and the Mine Facilities Spurs;

(l) **"Commercial Operation Cessation Date"** means the date on which:

(i) a Mine Facilities Shut Down Date has occurred for all Mine Facilities; or

(ii) Alexco no longer requires, acting reasonably under normal market and operating conditions, a combined Electric Demand at the Points of Delivery in excess of 1,000 kW;

(m) **"Commercial Operation Date"** means the first date on which Alexco actually receives Grid Electricity from YEC for a combined Electric Demand at the Points of Delivery in excess of 1,000 kW;

(n) **"Confidential Information"** has the meaning in Section 15.1;

(o) **"Decommissioning Costs"** means all decommissioning and other costs to be incurred by YEC and agreed to be recovered from Alexco (including, without limitation, costs to take down and remove facilities and costs to restore any property under applicable law, less credits for recovery sales of any materials removed and sold) reasonably required to remove such parts of the Mine Facilities Spurs to be decommissioned after a Mine Facilities Shut Down Date as YEC at that time may require to be decommissioned;

(p) **"Decommissioning Cost Payment"** means a payment to be made by Alexco to YEC under Section 11.2(c), that YEC will deposit in the Accrued Decommissioning Fund;

(q) **"Defaulting Party"** has the meaning in Section 10.1;

(r) **"Dispute"** means any dispute, difference, or disagreement between the Parties:

(i) as to the meaning, application, or implementation of this Agreement; or

(ii) as to whether an Event of Default has occurred;

(s) **"District"** means the entire area as shown in Figure C-1 in Schedule C;

(t) **"Electric Demand"** means the capacity at which Grid Electricity is delivered by YEC to Alexco for mining, processing, or manufacturing expressed in kV.A or kW, averaged over a rolling 15 minute period following YEC billing and metering practice for industrial customers receiving Grid Electricity;

(u) **"Electric Energy"** means electric energy, expressed in kW.h, delivered by YEC to Alexco under this Agreement;

(v) **"Electricity"** means Electric Energy and Electric Demand delivered by YEC to Alexco under this Agreement;

(w) **"ESRs"** means the Electric Service Regulations applicable to YEC, or any future replacement terms and conditions applicable to YEC, as approved by the YUB;

(x) **"Estimated Decommissioning Costs"** means, for any Mine Facilities Spur or part thereof, an amount equal to 25% of the Capital Costs incurred by YEC for that Mine Facilities Spur or part thereof;

(y) **"Event of Default"** has the meaning in Section 10.1;

(z) "**Event of Insolvency**" means any one or more of the following:

(i) if a Party files a petition for reorganization or for an arrangement under any applicable bankruptcy law or under any similar laws, now or hereafter in effect, is adjudged by a court of competent jurisdiction bankrupt, becomes insolvent, makes an assignment for the benefit of its creditors, admits in writing its inability to pay its debts generally as they become due, is dissolved, or suspends payment generally of its obligations;

(ii) if a petition is filed proposing the adjudication of a Party as a bankrupt or its re-organization under any applicable bankruptcy law or any similar law, now or hereafter in effect and:

A. the Party consents to the filing thereof;

B. the petition is not discharged or denied within 60 days after the filing thereof; or

C. the petition is not diligently defended against; and

(iii) if a receiver, receiver-manager, trustee, monitor, or liquidator (or other similar official) is appointed to take charge of all or substantially all of the business or assets of a Party and:

A. that Party consents to such appointment; or

B. the appointment is not discharged or withdrawn, or action is not taken by that Party to secure the discharge of that official, within 60 days after the appointment;

(aa) **"Firm Mine Rate"** means the rate set out in Schedule A, as may be amended by YUB from time to time;

(bb) **"Fixed Charge"** means the fixed charge rate as set out in Schedule A, as may be amended by the YUB from time to time;

(cc) **"Force Majeure"** means any event or circumstance suffered by a Party which is not within the reasonable control of the Party claiming Force Majeure and includes, without limitation:

(i) acts of God, including wind, ice and other storms, forest fires, lightning, floods, earthquakes, volcanic eruptions, and landslides;

(ii) strikes, lockouts, and other industrial disturbances, it being acknowledged that the settlement of strikes, lockouts, and other labour disturbances depends upon the agreement of employees and other third Persons and therefore is not wholly within the discretion of the Party involved;

(iii) epidemics, war (whether or not declared), terrorism, blockades, acts of public enemies, acts of sabotage, civil insurrection, riots, and civil disobedience;

(iv) acts or omissions of Governmental Authorities; and

(v) explosions and fires;

(dd) **"Government Approvals"** means all licences, permits, consents, authorizations, or approvals from, withholding of objection on the part of, or filing, registration or qualification with, any and all Governmental Authorities required for any particular decision, act, or event;

(ee) **"Governmental Authority"** means the government of Canada, the government of the Yukon Territory, a municipality or other political subdivision thereof, and any entity exercising executive, legislative, judicial, regulatory, or administrative functions including, without limitation, the YUB, if applicable;

(ff) **"Grid Electricity"** means Electricity delivered under this Agreement by YEC to Alexco from the Transmission Facilities, through the Mine Facilities Spurs to the Mine Facilities;

(gg) **"Initial Mill"** means the mill to be financed, designed, engineered, procured, and constructed by Alexco on the Initial Mill Site;

(hh) **"Initial Mill Site"** means those lands and premises to be used for the Mill that is to be located at Christal Lake, near Keno City, Yukon Territory as shown in Figure B-1 in Schedule B, including any related lands and premises and facilities to be used by Alexco to secure Grid Electricity at the Point of Delivery at the Initial Mill Site;

(ii) **"Initial Mine"** means the mine to be financed, designed, engineered, procured, and constructed by Alexco on the Initial Mine Site;

(jj) **"Initial Mine Facilities"** means the Mine Facilities for the Initial Mine and the Initial Mill;

(kk) **"Initial Mine Facilities Spurs"** means the Mine Facilities Spurs for the Initial Mine Facilities;

(ll) **"Initial Mine Site"** means those lands and premises used for the Mine that is located at as shown in Figure B-2 in Schedule B, including the related lands and premises and facilities currently used, and used in the future, by Alexco to secure Grid Electricity from YEC at the Point of Delivery at the Initial Mine Site;

(mm) "**Interest Rate**" means the interest rate charged by the lead banker of YEC from time to time on unsecured commercial loans made to YEC or if YEC does not have any unsecured commercial loans outstanding at such time, the variable nominal interest rate per annum being the prime interest rate of Canadian Imperial Bank of Commerce (or its successor) for Canadian dollar commercial loans in Canada as publicly declared from time to time as its prime rate;

(nn) "**kV**" means a kilovolt and one kilovolt equals 1,000 volts;

(oo) "**kV.A**" means a kV ampere and one kV ampere equals 1,000 volt-amperes;

(pp) "**kW**" means a kilowatt and one kilowatt equals 1,000 watts;

(qq) "**kW.h**" means a kW hour, the common unit of electrical energy, equal to one kilowatt of power supplied to or taken from an electric circuit for one hour;

(rr) **"Major Industrial Customer"** means a customer of YEC, or of any other regulated electric utility in the Yukon Territory, engaged in manufacturing, processing, or mining whose electrical service is inter-connected with electrical service provided to any other customer of such electric utilities and whose peak Electric Demand exceeds 1,000 kW or any future replacement definition or replacement service capacity threshold applicable to manufacturing, processing or mining activities of Alexco, as approved by the YUB;

(ss) **"Maximum Electric Demand"** means the maximum Electric Demand for Mine Firm Electricity that YEC is be obligated to deliver to Alexco at the Points of Delivery under Part 4;

(tt) "**Mill**" means any one or more mills developed and owned by Alexco, or one of Alexco's Affiliates who become a Party to this Agreement under Section 4.5. and located at the Mill Site that YEC agrees to provide Grid Electricity to under Section 4.5;

(uu) **"Mill Sites"** means those lands and premises to be used for the Initial Mill Site, and those lands and premises and facilities in the District to be similarly used by Alexco, or one of Alexco's Affiliates who become a Party to this Agreement under Section 4.5, for any future Mill that Alexco, or one of Alexco's Affiliates who become a Party to this Agreement under Section 4.5, develops in the District and that YEC agrees to provide Grid Electricity under Section 4.5, and **"Mill Site"** means any one of them;

(vv) "**Mine**" means any one or more mine projects developed and owned by Alexco, or one of Alexco's Affiliates who becomes a Party to this Agreement under Section 4.5, and located at the Mine Site that YEC agrees to provide Grid Electricity to under Section 4.5;

(ww) "**Mine Facilities**" means the Mills, the Mines, and any substations or facilities financed, designed, engineered, procured, and constructed by Alexco, or one of Alexco's Affiliates who become a Party to this Agreement under Section 4.5, to connect a Mill or a Mine to the Mine Facilities Spurs at a Point of Delivery to receive Grid Electricity from YEC under this Agreement, and **"Mine Facility"** means any one of them;

(xx) "**Mine Facilities Closure Date**" for any Mine Facility means the date that the Mine Facility has permanently ceased commercial operation;

(yy) "**Mine Facilities Operation Date**" for any Mine Facility means, as specified in a prior written notice provided by Alexco to YEC, the date on which Alexco wishes the commercial operation for that Mine Facility to occur;

(zz) **"Mine Facilities Shut Down Date"** with respect to a particular Mine Facility is the date provided by Alexco in writing to YEC on which YEC is to initiate permanent termination of any further delivery of Grid Electricity to that Mine Facility under this Agreement;

(aaa) **"Mine Facilities Spurs"** means the YEC transmission connections from the Transmission Facilities to the Points of Delivery, including any transmission line spurs and related switches, fuses, meters, transformers, or other equipment connecting the Transmission Facilities to the Points of Delivery, and "**Mine Facility Spur**" means any one of them;

(bbb) **"Mine Firm Electricity"** means Grid Electricity delivered by YEC to the Mine Facilities on a firm basis;

(ccc) "**Mine Sites**" means those lands and premises to be used for Initial Mine Site, and those lands and premises and facilities in the District to be similarly used by Alexco, or one of Alexco's Affiliates who become a Party to this Agreement under Section 4.5, for any future Mine that Alexco, or one of Alexco's Affiliates who become a Party to this Agreement under Section 4.5, develops in the District and that YEC agrees to provide Grid Electricity to under Section 4.5, and **"Mine Site"** means any one of them;

(ddd) **"MV.A"** means thousands of kV amperes;

(eee) **"MW"** means a megawatt, being the electrical unit of power which is equal to 1,000 kW or 1,000,000 watts;

(fff) **"MW.h"** means a MW hour, being the electrical energy equal to one megawatt of power supplied or taken from an electric circuit for one hour;

(ggg) **"Non-Defaulting Party"** has the meaning in Section 10.2;

(hhh) **"ohm"** means a unit of resistance and impedance. One ohm is the resistance of a conductor such that a constant current of one ampere produces a voltage of one volt between the ends of the conductor;

(iii) **"Parties"** means YEC and Alexco and, in the case of Alexco, includes any of Alexco's Affiliates who become a Party to this Agreement under Section 4.5, and **"Party"** means either of them;

(jjj) **"Person"** means an individual, firm, partnership, body corporate, or other legal entity, a government or any department or agency thereof, a trustee, any unincorporated organization and the heirs, executors, administrators, or other legal representatives of an individual, as the case may be;

(kkk) "**Point of Delivery**" means the point at a Mine Facility at which Mine Facilities Spurs are connected to the Mine Facility, with YEC's meter to be located at the Mine Facility side of the YEC disconnect switches and on the primary side of any transformation equipment used as part of the Mine Facilities Spurs and **"Points of Delivery"** means all such points;

(lll) **"Power Factor"** means the ratio at any Point of Delivery of the highest metered kW demand in a billing period to the highest metered kV.A demand in that same billing period;

(mmm) **"Service Charge"** means the late payment charge on any overdue account of YEC as provided for in the ESRs;

(nnn) **"Term"** has the meaning in Section 2.1;

(ooo) **"Transmission Facilities"** means YEC's 69 kV Mayo-Keno transmission facilities located north of Mayo, Yukon Territory, or any future replacement transmission facilities at similar or higher voltage;

(ppp) **"volt"** means the unit of electromotive force or voltage that if steadily applied to having a resistance of one ohm will produce a current of one ampere;

(qqq) **"watt"** the electrical unit of power and the rate of energy transfer when one ampere is passing across one volt; and

(rrr) **"YUB"** means the Yukon Utilities Board.

1.2 Schedules

The following Schedules are attached to and form a part of this Agreement:

Schedule A – Firm Mine Rate;

Schedule B –Initial Mine Facilities Spurs requirements for the Initial Mill Site and the Initial Mine Site; and

Schedule C - Map of District.

1.3 Interpretation

Under this Agreement:

(a) references to voltage are approximate;

(b) words importing the masculine gender include the feminine and neuter genders, and Persons, and words in the singular include the plural, and vice versa, wherever the context requires;

(c) all references to designated Parts and Sections are to the designated Parts and Sections of this Agreement;

(d) using separate Parts and Sections, providing a table of contents, and inserting headings are for convenience only and will not affect how this Agreement is interpreted;

(e) unless otherwise indicated, any reference to a currency is a reference to Canadian currency;

(f) except where otherwise specified, any reference to a statute includes a reference to such statute and to its regulations, with all amendments in force from time to time, and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute or regulation; and

(g) any reference to a Person includes a reference to any Person that is a successor to that Person.

PART 2
DURATION

2.1 Term

This Agreement will commence as of the date of this Agreement and, unless terminated earlier under this Agreement, will terminate on the date when a Mine Facilities Shut Down Date has occurred for all Mine Facilities and when decommissioning has been completed for all Mine Facilities Spurs and all of the Accrued Decommissioning Fund Amount has been used, set off, or refunded under Section 11.3 (the "**Term**").

PART 3
INITIAL ACTIVITIES

3.1 Filing with YUB

Upon execution and delivery of this Agreement, YEC will proceed diligently to file an application with the YUB seeking YUB approval of the Fixed Charge of $7,289 per month as set out in Schedule A. YEC will provide the YUB with such supporting documentation as required by the YUB for such application. Alexco will support the YEC application to YUB as YEC may reasonably require to obtain the approval of the YUB under this Section 3.1.

3.2 Initial Mine Facilities Spurs

Upon execution and delivery of this Agreement, YEC will exercise commercially reasonable efforts to design, engineer, procure, construct, and commission the Initial Mine Facilities Spurs so as to be able to provide Commencement of Delivery at the Initial Mill Site and the Initial Mine Site as soon as is reasonably possible on or before the Commercial Operation Date anticipated by Alexco, acting reasonably, or such date thereafter as is reasonably possible, and to supply Grid Electricity to the Initial Mill and the Initial Mine.

3.3 Initial Mine Facilities

Upon execution and delivery of this Agreement, Alexco will exercise commercially reasonable efforts, to finance, design, engineer, procure, and construct the Initial Mine Facilities on a timely basis to reach the Commercial Operation Date anticipated by Alexco, acting reasonably, as soon as reasonably practicable and not later than June 30, 2011. Alexco's current estimate of the commissioning of the Initial Mine Facilities is mid-September, 2010. Alexco's current estimate of the actual commercial operation of the Initial Mine Facilities is mid-October, 2010. Alexco will from time to time provide written notice to YEC of Alexco's progress under this Section 3.3 and Alexco's best estimate of the likely Commercial Operation Date and as soon as practical. Alexco will provide written notice to YEC of the Mine Facilities Operation Date for the Initial Mine Site and the Mine Facilities Operation Date for the Initial Mill Site. Alexco will ensure that the Initial Mine Facilities will be able to receive Grid Electricity from YEC at each Point of

Delivery on the Mine Facilities Operation Date for that facility and Alexco will receive Grid Electricity from YEC on the Commencement of Delivery for these Points of Delivery. YEC will provide written notice to Alexco of the date of the Commencement of Delivery for each Point of Delivery for the Initial Mine Facilities. The Parties will use commercially reasonable efforts to cooperate and coordinate their activities as described in this Section 3.3 to ensure the actual commencement of delivery of Grid Electricity at each Point of Delivery occurs at a time mutually agreed to by the Parties.

PART 4
ELECTRICITY

4.1 Electricity to be Made Available

From the Commencement of Delivery for the Initial Mill, YEC will deliver to Alexco and Alexco will purchase from YEC Grid Electricity as Mine Firm Electricity at the Firm Mine Rate until the Commercial Operation Cessation Date has occurred, subject to the Maximum Electric Demand and Electric Energy as follows:

(a) for the periods from the Commencement of Delivery for the Initial Mill until the first anniversary of the Commencement of Delivery for the Initial Mill Maximum Electric Demand of not more than 2,300 kV.A and Electric Energy of approximately 11,800 MW.h/year of Electric Energy at an average monthly peak Electric Demand of 1,850 kV.A, allocated to the following by Points of Delivery:

(i) **Point of Delivery at the Initial Mill:** Maximum Electric Demand of up to 1,550 kV.A and Electric Energy of approximately 7,600 MW.h/year; and

(ii) **Point of Delivery at the Initial Mine:** Maximum Electric Demand of up to 750 kV.A and Electric Energy of approximately 4,200 MW.h/year;

(b) thereafter, Maximum Electric Demand of up to 2,610 kV.A and Electric Energy of approximately 13,400 MW.h/year with the allocation to the Point of Delivery at the Initial Mill of Maximum Electric Demand of approximately 1,760 kV.A and of Electric Energy of approximately 8,800 MW.h/year.

4.2 Alexco Forecasts

Alexco will provide to YEC annual written forecasts ("**Alexco Forecasts**") of the Grid Electricity requirements of the Mine Facilities at the Points of Delivery for each of the succeeding five calendar years, so as to allow YEC to forecast the future Electric Demand and Electric Energy loads on its facilities. The Alexco Forecast will be provided to YEC eight months in advance of each calendar year end (unless otherwise agreed to by YEC in writing), starting upon execution and delivery of this Agreement, and will include load patterns showing the characteristics of the expected Mine Firm Electricity, including the characteristics for Electric Demand and Electric Energy on a monthly basis. Alexco will advise YEC in writing forthwith of any material change to the Alexco Forecasts for Mine Firm Electricity, including the

characteristics for Electric Energy or Electric Demand. During the first week of each month after Commencement of Delivery, Alexco will advise YEC by written notice of its estimated daily requirements for Mine Firm Electricity during the following month.

4.3 Points of Delivery

YEC will deliver Grid Electricity to Alexco and Alexco will receive Grid Electricity from YEC at the Points of Delivery.

4.4 Maximum Electric Demand

YEC's obligation to supply Mine Firm Electricity to Alexco will not exceed the Maximum Electric Demand in effect at any time at any Point of Delivery. Notwithstanding such Maximum Electric Demand, if Alexco receives from YEC Mine Firm Electricity Electric Demand in excess of the Maximum Electric Demand, Alexco will pay for the billing demand charge on all metered kV.A billing demand recorded at the Firm Mine Rate.

4.5 Increase in Maximum Electric Demand, new Point of Delivery, or Addition of Affiliate

(a) If Alexco:

(i) requires an increase to its Maximum Electric Demand in excess of that under Sections 4.1(a) or (b);

(ii) requires a new Point of Delivery for a new Mine Facility; or

(iii) wishes to add an Affiliate and that Affiliate's Point of Delivery and Electric Demand as a Party to this Agreement;

then Alexco will provide YEC with such written information and documentation as YEC may reasonably require for the:

(iv) amount of the requested increase in Electric Demand and the period of time during which the increase in Electric Demand is required;

(v) related increase in Mine Firm Electricity Electric Energy requirement;

(vi) specifications of any new Point of Delivery for such increase in Electric Demand; and

(vii) details of Alexco's Affiliate that wishes to be a Party to this Agreement;

together with such other information YEC may reasonably require to determine any related new Mine Facilities Spurs and related new Capital Costs and Points of Delivery;

(b) after receipt of the written information and documentation under Section 4.5(a), YEC will have a reasonable period of time to determine whether or not the Transmission Facilities and YEC's other facilities have the ability to supply and maintain that increased Electric Demand, Points of Delivery, or Affiliates requested by Alexco under Section 4.5(a) and what, if any:

(i) new Mine Facilities Spurs or other facilities and related new Capital Costs are estimated to be required;

(ii) potential requirement for an increase in the Mine Firm Rate related to such increase; and

(iii) potential new Decommissioning Costs provisions required for the Mine Facilities Spurs or other facilities;

and after having made a determination under this Section 4.5(b), YEC will forthwith provide written notice to Alexco of YEC's determination under this Section 4.5(b);

(c) following such written notice by YEC to Alexco under Section 4.5(b), if the Parties are unable to agree on the matters set out under Section 4.5(b) within a period of 90 days from the date of such written notice by YEC to Alexco, no increase in Maximum Electric Demand, addition of Points of Delivery, or addition of Affiliates will occur. For greater certainty the Parties' failure to agree on the matters set out in Section 4.5(b) will not be a Dispute and will not be subject to Part 12. For further greater certainty, the foregoing in no way limits the rights of, or remedies available to, either Party generally under applicable law or regulation, including but not limited to any rights to refer such failure to agree to a Governmental Authority;

(d) if the Parties are able to agree on the matters set out in Section 4.5(b) within 90 days then the Parties will enter such written amendments to this Agreement as the Parties may reasonably require to reflect such agreements, including without limitation, in the case of the addition of an Affiliate as a Party to this Agreement a written agreement under which such Affiliate agrees to be jointly and severally liable with Alexco and Alexco agrees to be jointly and severally liable with the Affiliate to perform the obligations of the other under this Agreement. If the Parties are unable to execute and deliver such agreements within a period of 120 days of the written notice under Section 4.5(b), no amendments to this Agreement will occur. For greater certainty the Parties' failure to agree on such written agreements will not be a Dispute and will not be subject to Part 12. For further greater certainty, the foregoing in no way limits the rights of, or remedies available to, either Party generally under applicable law or regulation, including but not limited to any rights to refer such failure to agree to a Governmental Authority.

4.6 Alexco Standards for Usage of Electricity

Alexco will regulate its electrical load so that the Power Factor for the Mine Facilities at any Point of Delivery is maintained within a reasonable operating range, as agreed to by the Parties from time to time, acting reasonably. Alexco will operate its equipment and use the Grid Electricity at the Mine Facilities so as not to endanger any of YEC's plant or equipment or cause any unacceptable fluctuations of YEC's electrical system. Alexco will comply with reasonable standards of operation as provided by YEC to Alexco by written notice from time to time. If Alexco fails to comply with these requirements or standards of operation so as to endanger any of YEC's plant or equipment or cause any unacceptable fluctuations on YEC's electrical system, YEC may by written notice to Alexco require that Alexco remedy the situation. Should Alexco fail to immediately comply with this Section 4.6 upon receiving such written notice regarding any Point of Delivery, YEC may immediately suspend the supply of Grid Electricity to Alexco at such Point of Delivery and continue such suspension until the situation is remedied. Upon receipt of such written notice Alexco may provide written notice to YEC that Alexco wishes YEC to operate any such equipment endangering YEC's plant, or equipment, or electrical system at Alexco's sole cost and expense. Upon receipt of such written notice YEC will provide written notice to Alexco as to whether YEC will operate such equipment and in such case Alexco will indemnify and save harmless YEC against any costs, damages, or losses associated with such operations.

4.7 ESRs

The ESRs apply to the Parties with regard to Grid Electricity delivered by YEC to Alexco under this Agreement including, without limitation, the provisions regarding the responsibility and liability of each Party. If there is an inconsistency between the ESRs and this Agreement the ESRs will govern.

4.8 Commercial Operation Cessation Date

Alexco will provide written notice to YEC of a Commercial Operation Cessation Date within 30 days of the occurrence of such Commercial Operation Cessation Date.

PART 5
CAPITAL COSTS

5.1 Initial Mine Facilities Spurs Capital Costs for Connecting Initial Mill and Initial Mine

(a) As at the date of this Agreement, the YEC estimate for the Capital Costs related to the Initial Mine Facilities Spurs to connect the Initial Mill and the Initial Mine is $330,000, and the YEC estimate for the Capital Costs to negotiate and conclude this Agreement is $100,000. Within 30 days of the execution and delivery of this Agreement, YEC will invoice Alexco for 50% of such estimated Capital Costs, and within 15 days of receipt of said invoice Alexco will pay the invoice to YEC.

(b) YEC will invoice Alexco for, and within 15 days of receipt of said invoice Alexco will pay to YEC, the amount by which the actual Capital Costs related to the Initial Mine Facilities Spurs exceeds the related amount invoiced under Section 5.1(a), within 30 days of the date on which YEC provides written notice to Alexco that, in the reasonable opinion of YEC, the Initial Mine Facilities Spurs for the Initial Mill and the Initial Mine are commissioned and are available to provide Grid Electricity to Alexco from the Initial Mine Facilities Spurs under this Agreement.

(c) YEC will invoice Alexco for, and within 15 days of receipt of said invoice Alexco will pay to YEC, the amount by which the actual Capital Costs related to the negotiation and conclusion of this Agreement exceeds the related amount invoiced under Section 5.1(a), as and when such actual Capital Costs are incurred and are invoiced to or paid by YEC.

(d) If the final actual Capital Costs for either the Initial Mine Facilities Spurs or the negotiation and conclusion of this Agreement are less than the related amount invoiced under Section 5.1(a), within a reasonable period of time of that determination YEC will set the difference off against any other amounts owed by Alexco to YEC under this Agreement or will refund the difference to Alexco.

5.2 Capital Costs for Other Mine Facilities Spurs

Alexco will pay to YEC the Capital Costs for any new Mine Facilities Spurs that YEC agrees to develop after the Initial Mine Facilities Spurs, as provided for in Section 4.5, with payment by Alexco to YEC of 50% of YEC's estimated costs for such facilities prior to YEC starting to order equipment for, or to construct, such new Mine Facilities Spurs, and with the balance of such Capital Costs to be paid by Alexco to YEC within 30 days of notice by YEC that such new Mine Facilities Spurs are commissioned and available to receive Grid Electricity to provide to Alexco. When the actual Capital Cost for such new Mine facilities Spurs is determined by YEC to be greater or less than the amount paid to date by Alexco, YEC will so notify Alexco in writing as soon as practical thereafter and an appropriate adjustment will be made between the Parties from the date such determination is made.

PART 6
BILLING/PAYMENT AND SECURITY

6.1 Alexco Power Bill

As soon as practicable following the last day of each month after the Commencement of Delivery for the Initial Mill, YEC will deliver the Alexco Power Bill to Alexco in writing setting out the amount payable to YEC by Alexco under this Agreement for all Electricity delivered by YEC to Alexco during such month. Alexco will pay YEC the amount set out in each Alexco Power Bill within 15 Business Days of the date of delivery of the Alexco Power Bill to Alexco. Electricity provided by YEC to Alexco will be charged to Alexco at the rates provided for in this Agreement. If permitted by the ESRs or YUB, the Electric Demand and Electric Energy at the

Points of Delivery will be totalled and only one bill will be issued for such Points of Delivery. If Alexco's Affiliates become a Party to this Agreement under Section 4.5 the amounts payable by such Affiliate will be included on the Alexco Power Bill and will be payable by Alexco and such Affiliate jointly and severally under this Part 6.

6.2 Canadian Funds

All payments by Alexco to YEC will be made in Canadian funds to an office or banker of YEC, as YEC may direct to Alexco in writing, at Whitehorse, Yukon Territory.

6.3 Failure to Render Invoice

Failure to render an invoice within the time periods set out in this Agreement will not abrogate YEC's right to receive payment of the Alexco Power Bill, Capital Cost, Decommissioning Costs, or other amounts payable under this Agreement.

6.4 Late Payment

Any payment to be made by Alexco to YEC under this Agreement that remains unpaid, in whole or in part, when due will be subject to a late payment charge at a rate of interest equivalent to the Service Charge calculated on the amount unpaid from the due date of payment until payment is made in full.

6.5 Prepayments

Any payments to be made by Alexco to YEC under this Agreement may be prepaid by Alexco at any time in whole or in part without penalty.

6.6 Taxes

All sales taxes, excise taxes, or similar charges payable on Electricity delivered to Alexco under this Agreement will be added to the Alexco Power Bill and paid by Alexco under Section 6.1.

6.7 Fixed Charge

Each time that a Major Industrial Customer proposes to commence for the first time to receive Grid Electricity from the Transmission Facilities, YEC will determine on a reasonable basis a proposed amended Fixed Charge applicable to Alexco reflecting an allocation of costs relating to the Transmission Facilities among the new Major Industrial Customer, Alexco, and all other Major Industrial Customers receiving Grid Electricity from the Transmission Facilities at that time. YEC will then, on a timely basis, make application to the YUB seeking the YUB approval of such proposed amended Fixed Charge. YEC will provide the YUB with such supporting documentation as required by the YUB for such application, and will use commercially reasonable efforts to obtain the approval of the YUB for such proposed amended Fixed Charge for Alexco, and Alexco will use commercially reasonable efforts to support such application by YEC.

PART 7
METERING

7.1 Metering

The Electricity purchased by Alexco under this Agreement will be measured and recorded at the Points of Delivery by revenue meters having one hour integrating intervals, which meters, will be types approved for revenue metering by Industry Canada and will comply with the *Electricity and Gas Inspection Act* (the "**Act**").

7.2 Testing

YEC will test its metering equipment under Section 7.1 and field test the metering installation in compliance with the Act. If requested to do so by Alexco, YEC will make additional tests or inspections of such installations, the expense of which will be paid by Alexco, unless Alexco has confirmed by such testing that the metering is faulty in which case such testing will be paid for by YEC. YEC will give reasonable written notice to Alexco of the time when any such test or inspection is to be made. Alexco may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate will be adjusted, repaired, or replaced by YEC to provide accurate metering. If a meter is found not to be functioning within the prescribed limit of error, the Electricity purchased will be determined under the Act.

7.3 Backup Metering

Alexco may, at its cost and expense, install a backup metering system to check YEC's metering system performance and, if so, Alexco will own, operate, and maintain this system, at Alexco's sole cost and expense.

7.4 Costs

All costs and expenses incurred by YEC, beyond normal reading and testing of meters and other costs that YEC is to pay under Section 7.2, in complying with its obligations under this Section 7.2 will be invoiced separately to Alexco by YEC and will be paid by Alexco upon receipt.

PART 8
FORCE MAJEURE

8.1 Force Majeure

Subject to Section 8.3, neither Party will be liable to the other Party for any delay in or inability of the first Party to perform its obligations under this Agreement if any such delay or inability is a direct result of Force Majeure.

8.2 Notice of Force Majeure

If a Party suffers a Force Majeure it will promptly notify the other Party in writing and within 10 days of becoming so aware will give written notice to the other Party:

(a) describing the Force Majeure in reasonable detail and stating, to the extent reasonably practicable at such time, its estimate of the duration of the Force Majeure;

(b) setting out in reasonable detail the obligations under this Agreement which it is unable to perform or will be delayed in performing as a direct result of the Force Majeure;

(c) containing particulars of the circumstances causing the Party to be unable to perform or delayed in performing its obligations under this Agreement as a direct result of the Force Majeure; and

(d) describing what needs to be done and what will be done to end the Force Majeure.

During a Force Majeure a Party invoking the Force Majeure will exercise commercially reasonable efforts to end the Force Majeure.

8.3 Exclusions

A Party may not invoke Force Majeure:

(a) for lack of money or credit;

(b) if the Force Majeure is the result of a breach by the Party seeking to invoke Force Majeure of a permit, certificate, licence, approval, or of any applicable laws, regulations, or orders;

(c) if the Party seeking to invoke Force Majeure has failed to use commercially reasonable efforts to prevent or remedy the situation and remove, so far as possible and with reasonable dispatch, the effects of the Force Majeure; or

(d) if the Force Majeure was caused by a breach of, or default under this Agreement or a wilful or negligent act or omission by the Party seeking to invoke Force Majeure.

If a Party is required to perform an obligation by a certain date or with a specified time period and the Party is delayed in performing that obligation by a Force Majeure the date or time for the performance of that obligation will be extended by a period of time equal to the length of the Force Majeure.

PART 9
REPRESENTATIONS AND WARRANTIES

9.1 YEC Representations and Warranties

To induce Alexco to enter into this Agreement YEC hereby represents and warrants to Alexco as of the effective date of this Agreement, upon each of which representations and warranties Alexco specifically relies, as follows:

(a) **YEC Corporate Organization and Authority:** YEC has been duly incorporated and is a validly existing corporation under the laws of the Yukon Territory, is in good standing with respect to all required filings in the office of the Registrar of Companies and has the full corporate power and capacity to execute and deliver this Agreement and perform its obligations under this Agreement.

(b) **Authorization, Consents, and Enforceability:** The execution and delivery of this Agreement by YEC and the consummation by YEC of the transactions contemplated hereby have been duly authorized by the Board of Directors of YEC and this Agreement constitutes valid and binding obligations of YEC, enforceable against YEC in accordance with its terms, subject to the availability of equitable remedies and enforcement of creditors' rights generally.

(c) **Compliance:** The entering into and compliance by YEC with this Agreement is legal, does not violate any provisions of any requirement of law and does not result in any breach of any of the provisions of, or constitute a default under any charter document, by-law, unanimous shareholder agreement, loan agreement, or other agreement or instrument to which YEC is a party or by which it is or its property may be bound.

9.2 Alexco Representations and Warranties

To induce YEC to enter into this Agreement Alexco hereby represents and warrants to YEC as of the effective date of this Agreement, upon each of which representations and warranties YEC specifically relies, as follows:

(a) **Alexco Corporate Organization and Authority:** Each of AXR, AKHM, and ERDC has been duly incorporated and is a validly existing corporation under the laws of the Province of British Columbia with respect to AXR and AKHM and the laws of the Yukon Territory with respect to ERDC and is in good standing with respect to all required filings in the office of the Registrar of Companies and has the full corporate power and capacity to perform business in the Yukon and to execute and deliver this Agreement and perform its obligations under this Agreement.

(b) **Authorization, Consents, and Enforceability:** The execution and delivery of this Agreement by AXR, AKHM, and ERDC and the consummation by AXR, AKHM, and ERDC of the transactions contemplated hereby have been duly

authorized by the respective Boards of Directors of AXR, AKHM, and ERDC and this Agreement has been duly executed and delivered by AXR, AKHM, and ERDC and constitutes valid and binding obligations of AXR, AKHM, and ERDC, enforceable against AXR, AKHM, and ERDC in accordance with its terms, subject to the availability of equitable remedies and enforcement of creditors' rights generally.

(c) **Compliance:** The entering into and compliance by AXR, AKHM, and ERDC with this Agreement is legal, does not violate any provisions of any requirement of law and does not result in any breach of any of the provisions of, or constitute a default under any charter document, by-law, loan agreement, or other agreement or instrument to which AXR, AKHM, or ERDC is a party or by which they or their property are or may be bound.

PART 10
DEFAULT

10.1 Event of Default

Each of the following events constitutes an "**Event of Default**" for a Party in question (the "**Defaulting Party**"):

(a) an Event of Insolvency of such Party; or

(b) any representation or warranty of such Party contained in this Agreement being untrue in any material respect unless the default is of a nature that can be cured and it is cured within 30 days, or such reasonable time period as may be required given the default, following receipt by the Defaulting Party of written notice from the other Party specifying the nature of the default and requiring that the default be cured; or

(c) any default (other than defaults of a non-material nature) by such Party in the performance or observance of any of the covenants, agreements, and obligations on its part to be performed or observed under this Agreement, unless the default is of a nature that can be cured and it is cured within 30 days, or such reasonable time period as may be required given the default, following receipt by the Defaulting Party of written notice from the other Party specifying the nature of the default and requiring that the default be cured.

10.2 Remedies

If an Event of Default under Section 10.1 occurs, any Party not in default (the "**Non-Defaulting Party**") may do one or more of the following:

(a) pursue any remedy available to it in law or equity, it being acknowledged by the Parties that specific performance, injunctive relief (mandatory or otherwise), or other equitable relief may be the only adequate remedy for an Event of Default; or

(b) if the Event of Default is curable, take all actions in its own name or in the name of the Defaulting Party as may reasonably be required to cure the Event of Default, in which event all payments, costs, and expenses incurred therefore will be payable by the Defaulting Party to the Non-Defaulting Party on demand with interest at the Interest Rate; or

(c) waive the Event of Default, provided any waiver of the particular Event of Default will not operate as a waiver of any subsequent or continuing Event of Default; or

(d) in the case of an Event of Default by Alexco under Section 6.1 YEC may suspend or discontinue the supply of Grid Electricity to Alexco but no such suspension or discontinuance by YEC will relieve Alexco of its obligations under this Agreement, including the obligation to make payment of any sum, nor will any such suspension or discontinuance constitute or be deemed to constitute rescission of this Agreement.

PART 11
DECOMMISSIONING

11.1 Decommissioning Costs

Alexco will be responsible for all Decommissioning Costs incurred by YEC. Alexco will provide YEC with written notice within 15 days of the occurrence of a Mine Facilities Closure Date at any Mine Facility. Alexco will exercise commercially reasonable efforts to provide YEC with not less than six months prior written notice of an anticipated Mine Facilities Shut Down Date at any Mine Facility, and will provide YEC with immediate written notice if Alexco reasonably anticipates that a Mine Facilities Shut Down Date will occur at any Mine Facility within less than six months time. Subject to receiving reasonable written notice of the Mine Facilities Shut Down Date for a Mine facility, on or before the Mine Facilities Shut Down Date for a Mine Facility YEC will provide written notice to Alexco of the parts of the Mine Facilities Spur to be decommissioned as soon as is feasible after the Mine Facilities Shut Down Date, and after such date YEC will exercise commercially reasonable efforts to carry out and complete such decommissioning as soon as is reasonably feasible.

11.2 Accrued Decommissioning Fund

YEC will establish the Accrued Decommissioning Fund account, and Alexco will make the Decommissioning Cost Payment to YEC, as follows:

(a) YEC will deposit the Decommissioning Cost Payment for any Mine Facilities Spur into the Accrued Decommissioning Fund, and invest the Accrued Decommissioning Fund at 6.5% interest per annum to fund YEC's regulated rate base during the Term under this Part 11;

(b) after the determination of the final Capital Cost incurred by YEC for a Mine Facilities Spur for any Mine Facility, YEC will inform Alexco in writing of the

Estimated Decommissioning Costs of the Mine Facilities Spur for that Mine Facility;

(c) at the same time as Alexco provides written notice to YEC (or a determination is made under this Section 11.2) of the Mine Facilities Closure Date for any Mine Facility, Alexco will make a Decommissioning Cost Payment to YEC equal to the Estimated Decommissioning Costs for those parts of the Mine Facilities Spur for that Mine Facility for which YEC has given written notice to Alexco under Section 11.1;

(d) if Alexco fails to notify YEC in writing of the occurrence of a Mine Facilities Closure Date for any Mine Facility, YEC may provide Alexco with written notice of Dispute on this matter.

11.3 Application of Accrued Decommissioning Fund and Payment of Decommissioning Costs

After the Mine Facilities Shut Down Date for a Mine Facility, the Accrued Decommissioning Fund Amount will be used to pay the actual Decommissioning Costs for those parts of the Mine Facilities Spur for that Mine Facility for which YEC has given written notice to Alexco under Section 11.1. If the actual Decommissioning Costs exceed the Accrued Decommissioning Fund Amount for such parts of that Mine Facilities Spur, Alexco will pay to YEC the amount of the excess. Such excess costs will be invoiced by YEC within 10 Business Days of the end of the month in which the costs are incurred. Alexco will pay YEC the amount set out in each such invoice on or before the 15th Business Day after the invoice is received. If the Accrued Decommissioning Fund Amount for such parts of that Mine Facilities Spur exceeds the actual Decommissioning Costs, YEC will:

(a) set the excess, if any, off against any other amounts owed by Alexco to YEC under this Agreement; and

(b) then refund the remaining excess, if any, to Alexco within 15 Business days after the actual Decommissioning Costs are determined by YEC.

PART 12
DISPUTE RESOLUTION

12.1 Confidentiality of Process.

The Parties will maintain the dispute resolution process set out in this Part 12 as confidential and such process will not be disclosed, unless otherwise required by law, by any Party to any other Person unless previously discussed and agreed to in writing by the Parties. For greater certainty, no part of the dispute resolution process will be open to the public.

12.2 Stages.

Disputes that arise among the Parties will progress, until resolved, through the following stages of the dispute resolution process:

Step 1: Within 10 days of one Party providing written notice to the other Parties that a Dispute exists, the Presidents of each of the Parties, or their nominees in the first instance or themselves if they cannot resolve the Dispute, will meet and make good faith efforts to resolve the Dispute through collaborative negotiation by:

(i) identifying underlying interests;

(ii) isolating points of agreement and disagreement;

(iii) exploring alternative solutions;

(iv) considering compromises or accommodations; and

(v) taking any other measures that may assist in resolution of the Dispute.

Step 2: If the Presidents of each of the Parties are unable to resolve the Dispute themselves within 30 days of the written notice under Step 1, either Party may give written notice to the other Party of a desire to commence mediation and the Parties will jointly appoint a mutually acceptable mediator within 30 days after the date that such notice is given. If the Parties are unable to agree upon the appointment of a mediator within 30 days after a Party has given notice of a desire to mediate the Dispute, either Party may apply to the British Columbia Mediator Roster Society for appointment of a mediator. The Parties agree that the mediation will be conducted under the Mediation Rules of the British Columbia Mediator Roster Society.

Step 3: If a Dispute has not been resolved through mediation under Step 2 within 30 days of the appointment of a mediator, either Party, by notice in writing to the other Party, may refer such unresolved Dispute to binding arbitration under the *Arbitration Act*, (R.S.Y., 2002, c.8). The Parties will agree upon an Arbitrator within 30 days of the notice of arbitration being provided, failing which the Arbitrator will be selected under the *Arbitration Act*, (R.S.Y., 2002, c.8). The decision of the arbitrator will be final and binding on the Parties.

12.3 Availability of Argument.

In any Dispute, a Party may raise any defence or argument that it would otherwise have been able to raise at law, equity, or otherwise, had the Dispute been referred to a court of competent jurisdiction, including a defence that the Dispute is statute-barred by the *Limitation of Actions Act*, (R.S.Y., 2002, c.139).

12.4 No Further Claims.

When Disputes are settled among the Parties to the Agreement under this Part 12:

(a) no further claim may be made; and

(b) no further compensation will be payable by any Party,

for the same Dispute.

12.5 Continued Payment

Pending resolution of any Dispute, Alexco will continue to pay to YEC any sums payable under this Agreement and YEC may avail itself of its remedy under Section 10.2(d) in relation to a failure by Alexco to do so.

PART 13
INDEMNITY

13.1 Limitation of Liability

No Party will be liable to the other Party in contract, tort, warranty, strict liability, or any other legal theory for any indirect, consequential, incidental, punitive, or exemplary damages arising under or in connection with this Agreement or in connection with the failure to perform or observe obligations under this Agreement. No Party will have any liability to the other Party except under, or for breach of, this Agreement provided, however, that this Section 13.1 is not intended to constitute a waiver of any rights of one Party against the other Party for matters which are unrelated to this Agreement.

13.2 Indemnification

(a) Alexco will indemnify and save YEC harmless for any loss or damage to property, death, or injury to Persons (or any claim against YEC in respect thereof) and all expenses relating thereto (including without limitation reasonable legal fees) suffered or incurred by YEC in connection with this Agreement resulting from any negligence or wilful default of Alexco in connection with the performance of its obligations under this Agreement or a breach by Alexco of its obligations under this Agreement. The indemnity will not extend to any loss, damage, death, or injury (or any claim in respect thereof) or any expenses relating thereto to the extent that it was caused by the negligence or wilful default of YEC or the failure of YEC to take reasonable steps in mitigation thereof. Notwithstanding anything to the contrary contained in the preceding sentence, nothing in this Section 13.2(a) will apply to any loss, damage, cost, or expense in respect to which, and to the extent that, YEC is compensated under any insurance, agreement, or through any other means.

(b) YEC will indemnify and save Alexco harmless for any loss of or damage to property, death or injury to person (or any claim against Alexco in respect thereof) and all expenses relating thereto (including without limitation reasonable legal fees) suffered or incurred by Alexco in connection with this Agreement from any negligence or wilful default of YEC in connection with the performance of its obligations under this Agreement or a breach by YEC of its obligations under this Agreement. The indemnity will not extend to any loss, damage, death, or injury (or any claim in respect thereof) or any expenses relating thereto to the extent that it was caused by the negligence or wilful default of Alexco or the failure of Alexco to take reasonable steps in mitigation thereof. Notwithstanding anything to the contrary contained in this preceding sentence, nothing in this Section 13.2(b) will apply to any loss, damage, cost or expense in respect of which, and to the extent that, Alexco is compensated under any insurance, agreement, or through any other means.

(c) If such injury or damage results from the joint or concurrent negligent or intentional acts of the Parties each will be liable under this indemnification in proportion to its relative degree of fault.

13.3 Assertion of Claims

Neither Party will be entitled to assert any claim for indemnification until such time as all claims of such Party for indemnification under this Agreement exceed an amount equal to $10,000, in the aggregate, at which time all claims of such Party for indemnification under this Agreement may be asserted; provided, however, that when such claims have been asserted the same rule will apply in respect of future claims. Notwithstanding the preceding sentence, either Party may assert a claim for indemnification regardless of amount upon the expiry or earlier termination of this Agreement or if such claim would otherwise be barred by the *Limitation of Actions Act*, (R.S.Y., 2002, c.139).

13.4 Defence of Claims

The indemnified Party will have the right, but not the obligation, to contest, defend, and litigate any claim, action, suit, or proceeding by any Person alleged or asserted against such Party in respect of, resulting from, related to, or arising out of any matter for which it is entitled to be indemnified under this Agreement, and the reasonable costs and expenses thereof will be subject to the indemnification obligations of the indemnifying Party under this Agreement provided, however, that if the indemnifying Party acknowledges in writing its obligations to indemnify the indemnified Party in respect of loss to the full extent provided by Section 13.2, the indemnifying Party will be entitled, at its option, to assume and control the defence of such claim action, suit, or proceeding at its expense and through counsel of its choice if it gives prompt notice of its intention to do so to the indemnified Party and, reimburses the indemnified Party for the reasonable costs and expenses incurred by the indemnified Party prior to the assumption by the indemnifying Party of such defence, and provides reasonably adequate security for any judgment for costs that might be imposed on the indemnified Party. The indemnified Party will not be entitled to settle or compromise any such claim action, suit, or proceeding without the prior

written consent of the indemnifying Party, which consent will not be unreasonably withheld or delayed. The indemnified Party will have the right to employ its own counsel and such counsel may participate in such action (but the fees and expenses of such counsel will be at the expense of such indemnified Party), provided that the:

(a) employment of counsel by such indemnified Party has been authorized in writing by the indemnifying Party;

(b) indemnified Party will have reasonably concluded that there may be a conflict of interest between the indemnifying Party and the indemnified Party in the conduct of the defence of such action;

(c) indemnifying Party will not in fact have employed independent counsel reasonably satisfactory to the indemnified Party to assume the defence of such action and will have been so notified by the indemnified Party; or

(d) indemnified Party will have reasonably concluded and specifically notified the indemnifying Party either that there may be specific defences available to it which are different from or additional to those available to the indemnifying Party or that such claim action, suit, or proceeding involves or could have a material adverse effect upon it beyond the scope of this Agreement.

If Sections 13.4(a), (b), (c), or (d) are applicable, then counsel for the indemnified Party will have the right to direct the defence of such claim, action, suit, or proceeding on behalf of the indemnified Party and the reasonable fees and disbursements of such counsel will constitute legal or other expenses under this Agreement.

PART 14
ASSIGNMENT

14.1 Assignment

Neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

14.2 Sale of the Transmission Facilities

If YEC disposes of all or any interest in the Transmission Facilities, the Mine Facilities Spurs or YEC's other assets required to meet YEC's obligations under this Agreement, YEC will ensure that the obligation to sell Grid Electricity from the Transmission Facilities or the Mine Facilities Spurs, on the same basis as provided for in this Agreement will continue and be assumed by the purchaser of such interest, for the Term. YEC will require, as a condition of the closing of the disposition of such interest, that the purchaser sign an agreement in a form satisfactory to Alexco, acting reasonably, which provides that the purchaser agrees to be bound by this Agreement.

14.3 Sale of the Mine Facilities

If Alexco disposes of all or any interest in the Mine Facilities, Alexco will ensure that the obligation to purchase Grid Electricity from YEC on the same basis as provided for in this Agreement will continue and be assumed by the purchaser of the Mine Facilities for the Term. Alexco will require as a condition of the closing of the disposition of the Mine that the purchaser sign an agreement in a form satisfactory to YEC, acting reasonably, which provides that the purchaser agrees to be bound by this Agreement for the Term.

PART 15
CONFIDENTIALITY

15.1 Confidentiality.

Except as required by law, and subject to Section 15.1, a Party will not disclose to a third person who is not a Party any information, data, or documents, supplied by one Party to the other Parties under this Agreement (collectively, the **"Confidential Information"**) without the consent of the other Party, such consent not to be unreasonably withheld.

15.2 Exceptions.

Section 15.1 will not:

(a) extend to information that is already in the public domain or becomes, after having been disclosed to a Party, generally available to the public unless the disclosure was made directly or indirectly by a Party in breach of this Agreement;

(b) prevent a Party from divulging Confidential Information in confidence to its Affiliates and to its or their officers, directors, employees, agents, or other representatives on a "need-to-know" basis;

(c) prevent a Party from divulging Confidential Information in confidence to third parties (provided the third party is subject to similar confidentiality restrictions), in order to permit the operation of the Mine or the Transmission Facilities, as the case may be, in the ordinary course, all on a "need-to-know" basis;

(d) prevent a Party from divulging Confidential Information to the extent required by applicable legislation or stock exchange requirements;

(e) prevent a Party from divulging Confidential Information to the extent necessary in connection with any dispute resolution commenced under this Agreement or any litigation commenced in respect of this Agreement;

(f) prevent a Party from divulging Confidential Information to the extent necessary, in confidence, to any financial institution for the purpose of obtaining financing for such Party or any of its Affiliates;

(g) prevent a Party from divulging Confidential Information to the extent required by any Governmental Authority having jurisdiction to require the production of such Confidential Information; and

(h) prevent a Party from divulging Confidential Information to the extent necessary, in confidence, to a prospective purchaser of the Mine or the Transmission Facilities or YEC's other assets required to meet YEC's obligations under this Agreement, as the case may be, on a "need to know" basis.

If any Party is required to disclose Confidential Information under Sections 15.2(d), (e), or (g), such Party will advise the other Party in writing in advance of any such disclosure where reasonable so that the other Party may take such action as they consider necessary to maintain the confidentiality of such Confidential Information, and will take reasonable steps to limit the extent of the disclosure and to make such disclosure confidential under the applicable legislation, stock exchange rules, or rules of any governmental or regulatory authority having jurisdiction, as the case may be.

15.3 Survival

The obligations of confidentiality in Section 15.1 will survive the termination or expiry of this Agreement indefinitely, and any Party who ceases to be a Party will continue to be bound by such obligations following such termination or expiry.

15.4 Injunctive Relief

Each Party acknowledges that all Confidential Information is proprietary to the disclosing Party and that breach of this Agreement by a Party may result in irreparable injury to the other Party. Accordingly, in the event of any breach of Section 15.1 by a Party, the other Party will be entitled to seek and obtain an order of specific performance, restraining order, or injunctive relief, in addition to any other legal or equitable remedies provided under this Agreement.

PART 16
GENERAL

16.1 Notices

Except as otherwise provided in this Agreement, any notice, direction, demand, request, or document required or permitted to be given by any Party to any other Party under this Agreement will be in writing and deemed to have been sufficiently given if signed by or on behalf of the Party giving the notice and delivered or transmitted by facsimile to the other Party's address or facsimile number as shown below:

To YEC:

Yukon Energy Corporation
P.O. Box 5920, #2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Attention: President

Facsimile: 867-393-5323

with a copy to:

Davis LLP
2800 - 666 Burrard Street
Vancouver, BC V6C 2Z7

Attention: John Landry

Facsimile: 604-605-3588

To Alexco:

Alexco Resource Corp.
1150 - 200 Granville Street
Vancouver, BC V6C 1S4

Attention: Clynton R. Nauman, CEO, President

Facsimile: 604-633-4887

with a copy to:

Fasken Martineau DuMoulin LLP
2900 - 550 Burrard Street
Vancouver, BC V6C 0A3

Attention: Kai Alderson

Facsimile: 604-631-3232

or to such other address or facsimile number or to the attention of such other official or individual as a Party will have most recently notified the other Party of in the manner hereinbefore provided. Any such notice, direction, request, or document will conclusively be deemed to have been received by the intended recipient on the date of delivery or transmission, as the case may be, except that if it is not received at such address or at the facsimile device by 5:00 P.M. on a Business Day (at the place of receipt) it will conclusively be deemed to have been received by the intended recipient on the next Business Day immediately following its receipt at such address or at such facsimile device.

16.2 Coordination of Communications

Each Party agrees to cooperate with the other Parties in order to coordinate all press, news, or other releases to private or public media groups in connection with this Agreement. Each Party will use all reasonable efforts to allow the other Parties to review such releases in advance of release and will comply with all reasonable requests from the other Parties as to the content or manner of publication of such releases.

16.3 Amendment

The only amendments, which may be made to this Agreement are amendments in writing which have been approved by the Parties.

16.4 Governing Law and Language

This Agreement will be governed by and construed under the laws of the Yukon Territory and applicable Canadian law and will be treated in all respects as a Yukon Territory contract.

16.5 Submission to Jurisdiction

Each of the Parties will:

(a) submit to the jurisdiction of the Yukon Territory courts;

(b) if not incorporated or registered in the Yukon Territory appoint an agent to receive service of any process in the Yukon Territory; and

(c) if any appointed agent is required, notify the others of the name and address of its appointed agent.

16.6 Severability

Each provision of this Agreement is intended to be severable and if any provision is illegal or invalid, such illegality or invalidity will not affect the validity of this Agreement or the remaining provisions.

16.7 Entire Agreement

(a) This Agreement and any other arrangement in writing between any of the Parties, which is entered into substantially contemporaneously with this Agreement constitute the entire agreement between the Parties relating to the subject matter of this Agreement and supersedes all prior negotiations and agreements, whether written, oral, implied or collateral, between the Parties, provided, however, that any confidentiality agreements, or confidentiality provisions contained in any agreements, executed between the Parties in connection with the transactions contemplated in this Agreement will continue in full force and effect and will survive any termination of this Agreement.

(b) No representation or inducement whether made by statement or delivery of data or other information of any kind or nature whatsoever and whether in writing, orally or in any other manner conveyed by any Party to any other Party survives the execution of this Agreement unless expressly made in this Agreement.

16.8 Further Assurances

As and so often as any Party may reasonably require, the Parties agree to execute and deliver further and other documents, assurances and conveyances as may be necessary to properly carry out the intention of this Agreement.

16.9 Successors and Assigns

This Agreement enures to the benefit of and will be binding upon the Parties and their respective permitted successors and permitted assigns.

16.10 Waivers

No provision of this Agreement may be waived except by a written instrument and any waiver of a provision:

(a) is valid only in respect of the specific instance to which it relates and is not a continuing waiver; and

(b) is not to be construed as a waiver of any other provision.

16.11 Time

Subject to Part 8, time is of the essence of this Agreement.

16.12 Counterparts

This Agreement may be executed in any number of counterparts with the same effect as if the Parties had signed and delivered the same document. All counterparts will be construed together and will constitute one and the same agreement. This Agreement will be duly executed and delivered if facsimile signature pages are exchanged by the Parties.

16.13 Joint and Several

The obligations, representations, and warranties of Alexco under this Agreement are joint and several obligations of each of AXR, AKHM, and ERDC.

This Agreement is executed in multiple originals effective as of the day and year first written above.

YUKON ENERGY CORPORATION

By: _____
Per: Authorized Signatory

ALEXCO KENO HILL MINING CORP.

By: _____
Per: ~~Authorized Signatory~~

ELSA RECLAMATION & DEVELOPMENT COMPANY LTD.

By: _____
Per: ~~Authorized Signatory~~

ALEXCO RESOURCE CORP.

By: _____
Per: ~~Authorized Signatory~~

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SCHEDULE A

FIRM MINE RATE

RATE SCHEDULE 39

INDUSTRIAL PRIMARY

AVAILABLE: Throughout the service areas of Yukon Energy Corporation (**"YEC"**) served by the Whitehorse-Aishihik-Faro and Mayo-Dawson systems.

APPLICABLE: To all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

RATE: Charges in any one billing month will be the sum of the following:

(a) Demand Charge of $15.00/kV.A of Billing Demand

(b) Energy Charge of 7.60¢/kW.h for all energy used.

(c) Fixed Charge

For service to Alexco mine and mill sites, the Fixed Charge each month will equal $7,289 as required under the Power Purchase Agreement (the **"PPA"**) dated September 1, 2010 between YEC and Alexco Resource Corp.(**"Alexco"**) for existing transmission connection to the mine and mill sites.

PEAK SHAVING CREDIT: For customers with an established Winter Contract Load in good standing, a Peak Shaving Credit in each billing month equal to 50% of the Demand Charge times the Peak Shaved Load.

MINIMUM MONTHLY BILL: The minimum monthly bill will be the sum of the Demand Charge and the monthly Fixed Charge, less any applicable Peak Shaving Credit.

PEAK SHAVED

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LOAD: Peak Shaved Load in any billing month is the amount by which then nominated Winter Contract Load is less than the Billing Demand for the month.

BILLING DEMAND: The Billing Demand will be the greater of:

(a) the highest metered kV.A demand recorded in the current billing month; or

(b) the highest metered kV.A demand recorded in the previous 12-month period including the current billing month, excluding the months April through September; or

(c) the contract minimum demand.

WINTER CONTRACT LOAD: A customer may, by six month written notice to YEC, nominate a Winter Contract Load at not less than two-thirds of the customer's contract maximum demand subject to the following conditions:

a) the customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b) below;

b) YEC will inform the customer at least one hour in advance, and not more than one day in advance, of a forecast temperature at Whitehorse being below -30 degree Centigrade; thereafter, until YEC informs the customer otherwise, the customer will be responsible for ensuring that its metered kV.A demand does not exceed the Winter Contract Load during any hour when the actual temperature at Whitehorse is below -30 degrees Centigrade; YEC will inform the customer forthwith when the temperature at Whitehorse is no longer forecast to be below -30 degree Centigrade within the next 24 hours;

c) the customer agrees that the contract for the nominated Winter Contract Load will continue until terminated by

written notice of not less than 12 months by the customer to YEC;

d) if during such contract period for the Winter Contract Load the customer's metered kV.A demand recorded, after YEC has provided notice as specified in paragraph (b) above, exceeds the Winter Contract Load when the temperature at Whitehorse is less than -30 degrees Centigrade, the Winter Contract Load contract will be terminated forthwith, the customer will forthwith be required to repay to YEC all Peak Shaving Credits determined within the previous 12 billing months, and the customer will also pay for that billing month to YEC as penalty an amount equal to four times the Demand Charge on the metered kV.A demand recorded in excess of the Winter Contract Demand; in addition, YEC reserves the right if so required to meet system loads when the temperature at Whitehorse is less than 30 degrees Centigrade during the then current month and the following 12 months to interrupt electricity supplied to the customer in excess of the previous Winter Contract Load.

BASE LOAD ENERGY:

A Base Load Energy amount per month may be established for a customer of 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

RATE MODIFICATIONS APPLICABLE:

For fuel adjustment rider, see Rider F. Rider F applied to energy charges only, set to $0.0 for fuel price forecast filed November 20, 2006.

Davis:5203362.15
DM_VAN/262912-00049/7651578.3

ELECTRIC SERVICE REGULATIONS:

The Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to YEC and every customer supplied with electric service by YEC in the Yukon Territory. Copies of the Electric Service Regulations are available for inspection in the offices of YEC during normal working hours.

SCHEDULE B

The Point of Delivery for the:

(a) Initial Mill Site is shown in Figure B-1 as the Keno Hill Mill Site Substation; and

(b) Initial Mine Site is shown in Figure B-2 as the Bellekeno Mine Drop Point.

The Mine Facility Spur for the Initial Mill Site includes a 69 kV transmission line of approximately 1.65 km connecting the Transmission Facilities to the Initial Mill Site as shown in Figure B-1.

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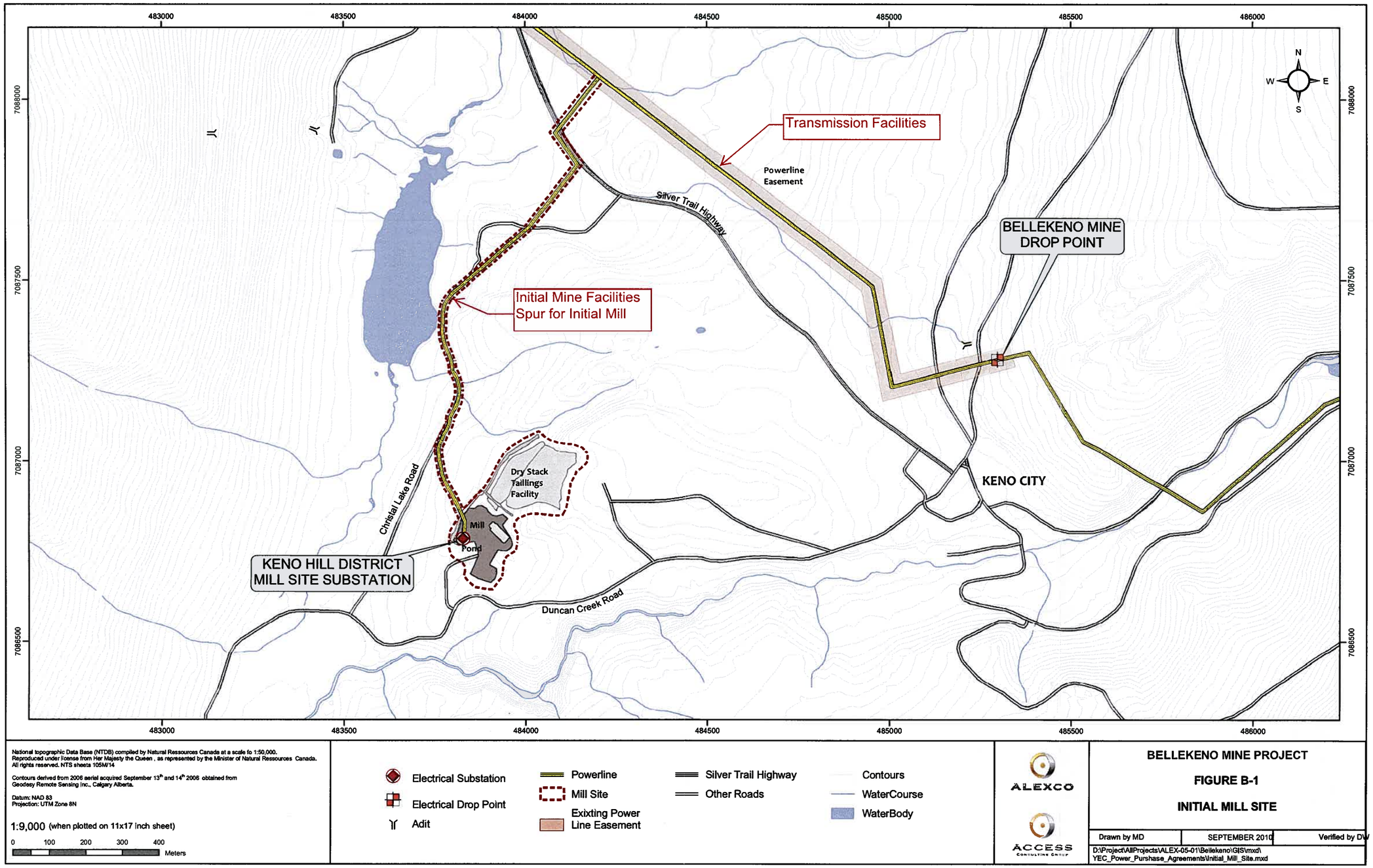

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Contours derived from 2006 aerial acquired September 13th and 14th 2006 obtained from Geodesy Remote Sensing inc., Calgary Alberta.

Datum: NAD 83
Projection: UTM Zone 8N

1:9,000 (when plotted on 11x17 inch sheet)

0 100 200 300 400 Meters

- Electrical Substation
- Electrical Drop Point
- Adit
- Powerline
- Mill Site
- Exixting Power Line Easement
- Silver Trail Highway
- Other Roads
- Contours
- WaterCourse
- WaterBody

ALEXCO

ACCESS Consulting Group

BELLEKENO MINE PROJECT

FIGURE B-1

INITIAL MILL SITE

Drawn by MD	SEPTEMBER 2010	Verified by DW

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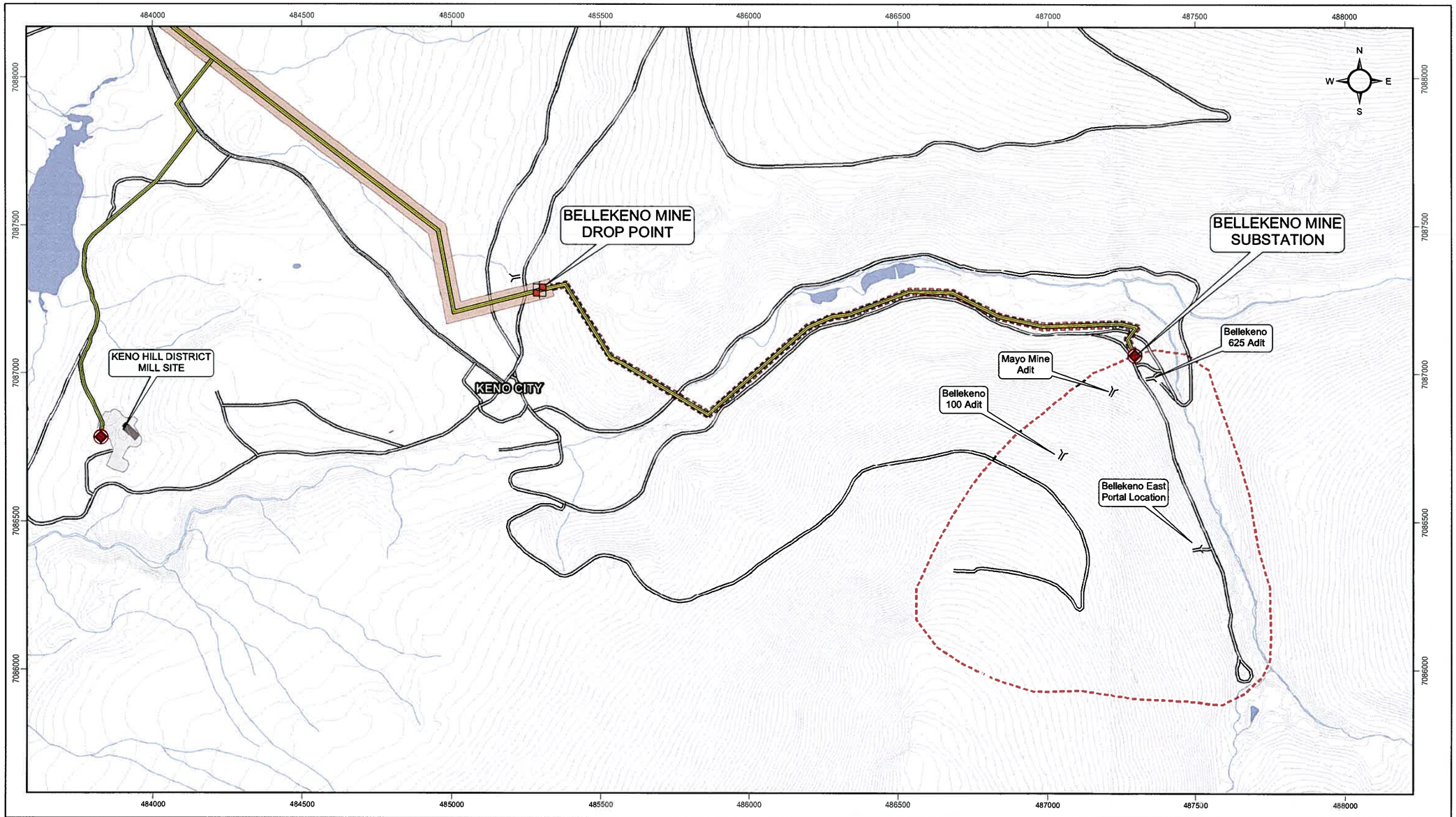

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Contours derived from 2006 aerial acquired September 13 and 14 2006 obtained from Geodesy Remote Sensing inc., Calgary Alberta.

Datum: NAD 83
Projection: UTM Zone 8N

0 125 250 500 750 1,000 metres

- Electrical Substation
- Electrical Drop Point
- Adit
- Powerline
- Silver Trail Highway
- Other Roads
- Mine Site
- Exixting Power Line Easement
- Contour
- Watercourse
- WaterBody

ALEXCO

ACCESS

BELLEKENO MINE PROJECT

FIGURE B-2

INITIAL MINE SITE

DRAWN BY MD	SEPTEMBER 2010	VERIFIED BY DW

D:\Project\AllProjects\ALEX-05-01\Bellekeno\GIS\mxd\YEC_Purshase_Agreement\Initial_Mine_Site.mxd

SCHEDULE C

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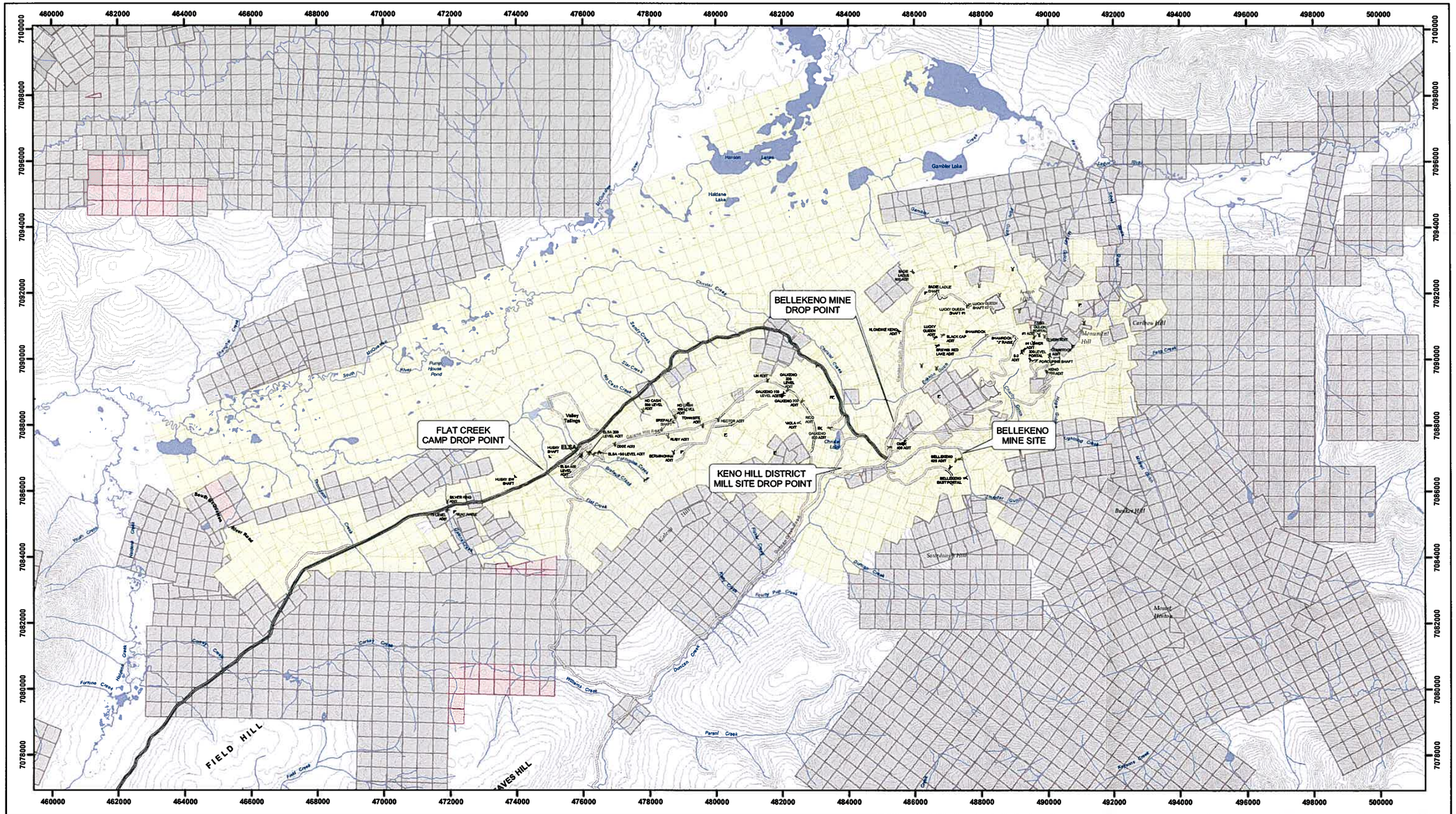
DM_VAN/262912-00049/7651578.3



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Datum: NAD 83
Projection: UTM Zone 8N

Mineral claim boundaires and ownership are current as of April 20th 2010.
Data obtained from Geomatics Yukon and Yukon Mining Recorder.

1:105,000 (when printed on 11 x17 inch paper)

0 0.5 1 2 3 4 5 km

ALEXCO

ACCESS

BELLEKENO MINE PROJECT

FIGURE C-1

DISTRICT AREA

Drawn By: MD	SEPTEMBER 2010	Verified by: DW

D:\Project\AllProjects\ALEX-05-01\Bellekeno\GIS\mxd\YEC_Power_Purshase_Agreements\District_Area

2011 Resource Plan Overview

YUKON ENERGY CORPORATION

OVERVIEW OF 20-YEAR RESOURCE PLAN: 2011-2030

July 2012

TABLE OF CONTENTS

INTRODUCTION 1
1.0 CURRENT CHALLENGES AND OPPORTUNITIES 4
2.0 BACKGROUND ON YUKON POWER SYSTEM 5
3.0 FUTURE YUKON POWER REQUIREMENTS – OVERVIEW 9
4.0 RANGE OF RESOURCE SUPPLY OPTIONS 13
5.0 YUKON UTILITIES – DEFAULT DIESEL PORTFOLIO REQUIREMENTS 15
6.0 NEAR-TERM RESOURCE OPTIONS TO DEFAULT DIESEL 26
7.0 LONGER-TERM RESOURCE OPTIONS TO DEFAULT DIESEL 40
8.0 SUMMARY CONCLUSIONS & RECOMMENDED PLANS 46

LIST OF TABLES

Table 4-1: Range of Resource Supply Options & Initial High Level Characterization 14
Table 5-1: New Diesel Grid Capacity Requirements for Resource Plan Scenarios: 2011-30* 24
Table 6-1: Overview of Resource Portfolio Near-Term Options Scenario A with DSM/SSE: 2011-2030 36
Table 7-1: Summary of Potential Hydro Sites 43
Table 7-2: Yukon Industrial Load Opportunities and Potential Hydro Sites 44
Table 8-1: Overview of Resource Options - Capabilities and Costs 51
Table 8-2: Overview of Near-Term Resource Options - Capabilities and Costs: Scenario A Loads with DSM/SSE (options that could start construction before 2015 – Default Diesel Capacity is new grid capacity required before 2030) 52

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030 **July 2012**

LIST OF FIGURES

Figure 2-1: Existing Yukon Power Infrastructure, Potential Supply Options, and Active & Potential Mine Load 6

Figure 2-2: Yukon Grid Generation – 1995-2010 (GW.h/year) 7

Figure 2-3: Yukon Grid & Off-Grid Diesel Generation – 1995-2010 (GW.h/year) 8

Figure 3-1: Existing System Capability to Supply Potential Grid Load & Potential Off-Grid Mine Loads: 2011-2050 Excludes DSM/SSE - 2011 Resource Plan 11

Figure 3-2: Total Yukon Non-Renewable Generation (Grid & Off-Grid): 2011-2030 Excludes DSM/SSE - 2011 Resource Plan 12

Figure 5-1: Diesel Energy Requirements (Grid & Off-Grid Utility) Resource Plan Scenarios 2011 Resource Plan[1] 17

Figure 5-2: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) at Scenario A 2015-16 load without DSM/SSE Grid load net of Fish Lake and Wind 19

Figure 5-3: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) with 21 MW Wind Project Displacing Diesel and Displacing Hydro at Scenario A 2015-16 load without DSM/SSE 20

Figure 5-4: YEC Annual Grid Diesel Generation Variability at Different 2015-2016 Grid Loads (GW.h/yr) 21

Figure 5-5: Diesel Energy Requirements - Sensitivity Tests re: Mine Load Extensions 23

Figure 6-1: Gross Energy Supply Capabilities by Near-Term Option (GW.h/yr during 2015-2019) – Compared to Diesel Requirements by Load Scenario with and without DSM/SSE (Net Energy Displacement of Diesel may be less than Gross Energy) 29

Figure 6-2: Average Annual Costs per kW.h for Near-Term Resource Options – 2015-2020 (Scenario A Load with DSM/SSE – Cost Inflation at 2%/yr; higher for LNG) 31

Figure 6-3: Forecast Lifecycle Cost of Energy (LCOE - 2010$) by Near-Term Option - Scenario A Load with DSM/SSE 33

Figure 6-4: Wind Project: Displacing Diesel and Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021) 34

Figure 6-5: Portfolio Option Yukon GHG (tonnes/year) – 2015-2030 Grid Scenario A with DSM/SSE, Off-Grid Diesel Community, & Off-Grid Mines 39

Figure 7-1: Overview of Planning Activities for Greenfield Hydro Supply Option Development - 2011-2021 45

INTRODUCTION

Yukon Energy's 2011 Resource Plan addresses generation and transmission priorities in Yukon for the 20-year planning period (2011-2030), focusing on:

- Resource options for implementation over the first five years (2011-2015); and
- Planning activities for implementation during the first five years to protect longer-term legacy resource development options for potential start of construction before or after 2021.

The 2011 Resource Plan updates the review of overall planning priorities and options as last provided in the 2006 Resource Plan. It was drafted in late 2011 based on then available information. Overall load forecasts and analysis of specific project options are subject to ongoing updates. As reviewed in the 2006 Resource Plan, several additional planning stages are required beyond the Resource Plan prior to any Yukon Energy decision to proceed with construction for any preferred project[1].

The Overview summarizes the 2011 Resource Plan document. Where relevant, the Overview also notes more recent information that may modify the earlier analysis.

Background on 2011 Resource Plan Process

The first activity Yukon Energy undertook preparing this latest 20-year resource plan was to seek input from First Nations and other governments, stakeholders and the public through meetings, workshops and a three-day energy planning charette held in March 2011.

The charette brought together Yukoners from all walks of life along with nationally and intentionally-recognized energy experts. Information and knowledge was shared and the participants provided a great deal of input in terms of what Yukon's energy future should look like.

Dr Mark Jaccard led off the proceedings by clarifying his experience regarding energy planning and urged participants to thoughtfully consider all of the choices available and to examine the alternatives from the point of view that all options have impacts and risks and all require trade-offs.

[1] Subsequent planning stages include: the final feasibility assessment, costing, design and contract arrangements (and related tendering to obtain final estimated costs); consultation with First Nations and others; all required external reviews, approvals and agreements (includes where relevant YESAB, DFO, YWB and other regulatory authorities as required, as well as seeking YUB review of near-term projects over $3 million).

Dr. Jaccard also talked to the gathering about how we determine and provide affordable energy:

- What role energy has in economic development;
- Future demand and supply; and
- The need to examine multiple objectives.

Along with providing a list of potential energy options that required further investigation and analysis, the charrette participants also helped Yukon Energy formulate four principles around which to base future energy decisions. They include:

- Reliability;
- Affordability;
- Flexibility; and
- Environmental Responsibility.

With these four principles as the lens through which all possible energy options were considered, Yukon Energy prepared later in 2011 a draft of a new 20-year resource plan that is summarized in this Overview for Yukoners to review.

Yukon Energy recognizes that the 2011 Resource Plan, as with its predecessor, is a living document that continues to evolve.

Yukon Energy has continued in fall 2011 and 2012 to date, for example, to hold workshops to examine in more detail specific resource options, including waste to energy, biomass, liquefied natural gas, and energy conservation. As noted in this Overview, new load forecast scenarios have also been developed since the draft 2011 Resource Plan to reflect updated information.

Yukon Energy will continue to use the draft 2011 Resource Plan to frame priorities and options for ongoing new assessments and analysis, without going back to amend or revise the draft as prepared in 2011.

All papers, reports, presentations and records from the energy charrette and workshops have been made available to the public on Yukon Energy's web site.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030 **July 2012**

Outline of Overview

The Overview summarizes the 2011 Resource Plan as follows:

- Current Challenges and Opportunities;
- Background on Yukon Power System;
- Future Yukon Power Requirements – Overview;
- Range of Resource Supply Options;
- Yukon Utilities – Default Diesel Portfolio Requirements;
- Near-Term Resource Options to Default Diesel;
- Longer-Term Resource Options to Default Diesel; and
- Summary Conclusions & Recommended Plans.

The Overview summarizes the 2011 Resource Plan as drafted in late 2011. Where relevant, the Overview also notes more recent information that may modify the earlier analysis. Updated load forecasts that Yukon Energy is currently using, for example, are provided in the Appendix A. Ongoing examination of specific resource options continues, using updated information and analysis as required.

Yukon Energy will review the Overview and draft 2011 Resource Plan with the public, and report on the results of this review, including any resulting adjustments to recommended plans for ongoing priority attention.

1.0 CURRENT CHALLENGES AND OPPORTUNITIES

Unprecedented growth is expected in Yukon-wide electricity requirements over the next decade, creating new generation challenges:

- **Near-Term Challenges** – To move quickly to meet new grid energy requirements emerging today with options that cost materially less than diesel generation while continuing the planning needed to develop longer-term Yukon power resources.

- **Longer-Term Opportunities** – Development as soon as feasible in future of hydro and other Yukon power resources to supply growing Yukon loads with reduced costs and emissions.

The 2011 Resource Plan assesses resource options in the context of current forecasts for overall Yukon energy and capacity requirements (i.e., off-grid as well as on-grid for all major power loads), agreed upon resource planning principles[2], and the assumption that Yukon Energy is proceeding with a robust and aggressive Demand Side Management/Supply Side Enhancement (DSM/SSE) program in response to Yukon Utilities Board Directives, government policy considerations and stakeholder comments.

Key challenges related to new generation requirements in Yukon include:

- **Higher Costs** – Higher costs to secure safe and reliable new resource supplies from utility operations on or off the grid will increase rates throughout Yukon. Electricity prices in Yukon today are relatively low due to legacy hydro. On Yukon's isolated grid, planning and capital costs are borne by ratepayers (no opportunity to 'overbuild' and sell to another market).

- **Higher Greenhouse Gas ("GHG") Emissions** – Higher GHG emissions from increased electricity generation in Yukon on and off the grid (including utility and non-utility operations) will challenge Yukon's ability to secure overall GHG emission reductions.

- **Flexibility Required** – The isolation of Yukon's electrical system requires flexibility to address a wide range of challenges, including: seasonal variations in loads and existing hydro generation; annual changes in grid hydro generation due to varying water conditions; development and/or shut down of major mine loads; and potential changes in competitive generation option costs due to new resource supplies becoming available (e.g., development of accessible natural gas in Yukon).

[2] The four key planning principles agreed to by the March 2011 Energy Charrette participants are reliability, affordability, flexibility and environmental responsibility.

2.0 BACKGROUND ON YUKON POWER SYSTEM

Yukon's centres continue to have residential and commercial electric rates that are lower than other northern centres in Canada, reflecting extensive reliance on low cost legacy hydro generation.

Figure 2-1 provides a map of existing power infrastructure, active and potential mine developments, the potential Alaska Highway Pipeline, and future power supply options in Yukon over the planning period. Areas within a 50 km boundary from the current and potential future electric grids are identified (based on the current southern highway structure).

Current and committed generation capacity in Yukon includes approximately 138 MW of installed generation on the integrated grid (approximately 92 MW YEC hydro, 0.8 MW YEC wind, 37 MW YEC diesel, 1.3 MW YECL hydro, and 6.8 MW of YECL diesel) and 8.4 MW of diesel generation in five separate off-grid diesel-served communities supplied by YECL (5.3 MW in Watson Lake, 2.0 MW in three Small Diesel zone communities along the Alaska Highway, and 1.1 MW in Old Crow).

The current integrated Yukon grid reflects material Yukon Energy developments since the 2006 Resource Plan, including completion in 2011 of the Carmacks-Stewart Transmission Project to connect the Whitehorse-Aishihik-Faro (WAF) grid and the Mayo-Dawson (MD) grid, expansion of Mayo hydro capacity from 5 to 15 MW (Mayo B project), and the 7 MW enhancement of the Aishihik hydro facility. As a result of substantial federal and Yukon funding contributions, in 2012 these new grid power assets are already yielding ratepayer cost savings due to displacement of otherwise required costly diesel generation.

Grid capacity planning is required to not exceed a Loss of Load Expectation (LOLE) of 2 hours per year and, for non-industrial loads, to provide capacity adequate to accommodate loss of the system's largest generating or transmission-related generation resource (the "N-1" standard). Current capacity planning also provides for sufficient winter peak capacity reserve to accommodate loss of the Aishihik transmission line connection to Whitehorse.

Off-grid mine development has recently commenced at the Wolverine mine located south east of Ross River. The 2011 Resource Plan highlights many other potential off-grid mine developments over the next decade (locations for these projects are noted on Figure 2-1).

Figure 2-1: Existing Yukon Power Infrastructure, Potential Supply Options, and Active & Potential Mine Loads

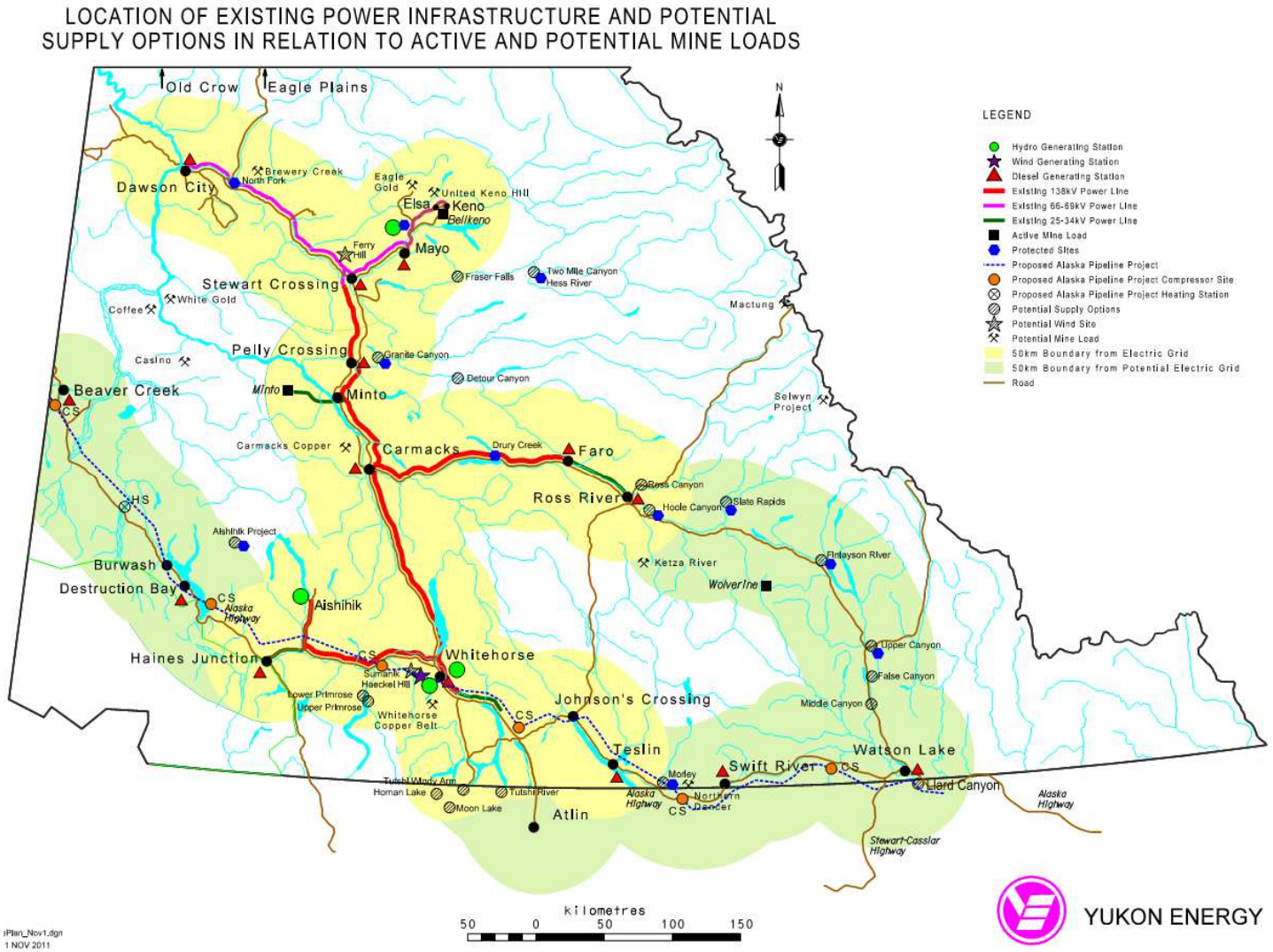
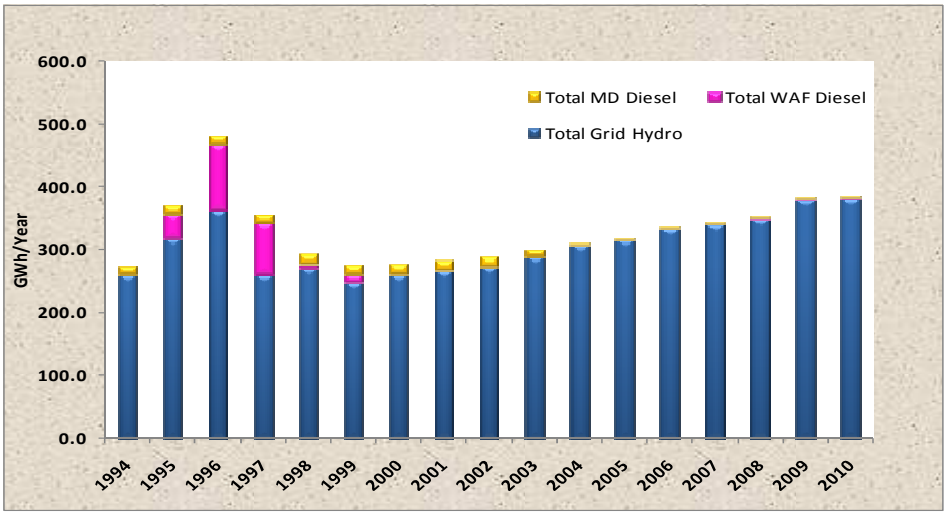


Figure 2-2 reviews historical power generation (1995-2010) by source for the WAF and MD grids. The following load changes are highlighted over this period:

- WAF – Faro mine closure in 1998 (82-100 GW.h/yr diesel immediately before shut down; no material diesel needed after shut down, except for low water year of 1999).
- WAF – Load growth since 1998 to the point that diesel generation starting to be needed again (impacts of non-industrial load growth plus recent Minto mine connection).
- Mayo Dawson – Grid expansion (15 GW.h/yr diesel reduction) – now connected to WAF.

Figure 2-2: Yukon Grid Generation – 1995-2010 (GW.h/year)

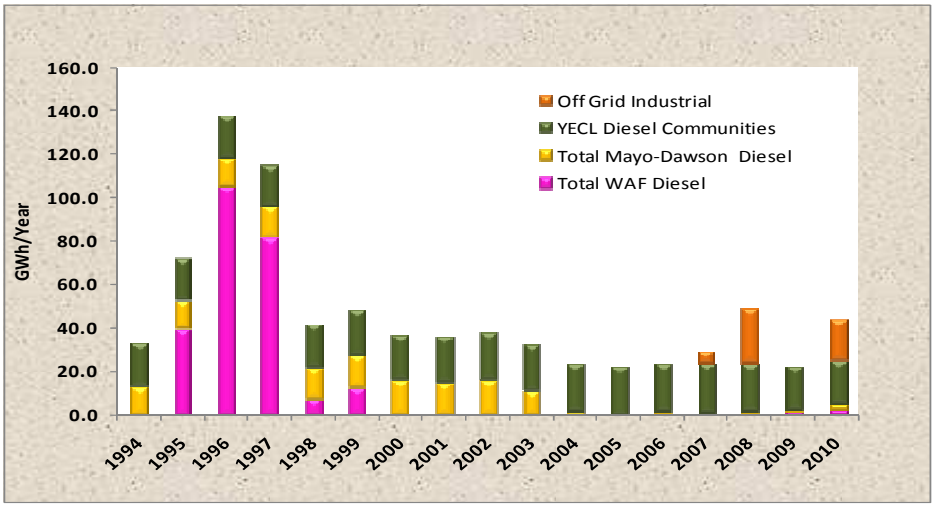


Grid Generation by Source (GW.h/year)	1995	1996	1997	1998	2000	2003	2005	2009	2010
Total Grid Hydro & Wind (Incl Fish Lake)	317.5	362.3	259.6	270.3	259.5	288.3	315.5	379.3	380.5
Total WAF Diesel	39.5	104.6	81.8	7.2	0.7	0.3	0.1	2.1	2.7
Total Mayo Dawson Diesel	12.9	13.6	14.0	14.6	15.3	11.1	0.5	0.5	2.4
Total WAF & MD Diesel	52.4	118.1	95.9	21.8	16.0	11.4	0.6	2.6	5.1
Total WAF & MD Generation	**369.9**	**480.4**	**355.5**	**292.1**	**275.5**	**299.6**	**316.1**	**381.9**	**385.6**

Figure 2-3 reviews historical (1995-2010) annual diesel generation and GHG emissions for the grid and off-grid loads. The following load changes are highlighted over this period:

- After closure of the Faro mine in 1998, off-grid communities accounted for almost all of the Yukon diesel generation.
- Off-grid Diesel Communities – YECL communities today at about 20 GW.h/yr (approximately 70.5% in Watson Lake).
- Off-grid Industrial – No off-grid mine loads until Wolverine in 2010 (19 GW.h that year).

Figure 2-3: Yukon Grid & Off-Grid Diesel Generation – 1995-2010 (GW.h/year)



Diesel Generation (GW.h/year)	1995	1996	1997	1998	2000	2005	2008	2009	2010
Total WAF Diesel Generation	39.5	104.6	81.8	7.2	0.7	0.1	1.2	2.1	2.7
Total MD Diesel Generation	12.9	13.6	14.0	14.6	15.3	0.5	0.4	0.5	2.4
Off Grid YECL Diesel Communities	20.0	19.2	19.1	20.0	21.0	21.8	22.1	19.8	19.8
Off-Grid Industrial	0	0	0	0	0	0	25	0	19
Total Yukon Diesel Generation	**72.4**	**137.4**	**114.9**	**41.8**	**37.0**	**22.4**	**48.7**	**22.4**	**43.9**

*OffGrid Indusrial sales in 2007 and 2008 relate to estimates (not actuals) for Minto mine prior to interconnection with WAF grid.

GHG Emissions (tonnes/year)	1995	1996	1997	1998	2000	2005	2008	2009	2010
GHGs WAF	27,668	73,189	57,283	5,039	510	80	850	1,495	1,882
GHG's Mayo Dawson	8,996	9,489	9,833	10,222	10,708	326	314	357	1,707
GHG's Off Grid Communities & Industrial	14,020	13,472	13,337	14,009	14,674	15,265	15,446	13,827	27,137
Total Yukon GHG's	**50,684**	**96,150**	**80,453**	**29,271**	**25,892**	**15,671**	**16,609**	**15,679**	**30,726**

3.0 FUTURE YUKON POWER REQUIREMENTS – OVERVIEW

Overall, forecast Yukon power requirements highlight the extent to which off-grid mine loads are expected to grow and dwarf grid loads within the next 5 to 10 years. To the extent this occurs, a fundamental shift will occur in Yukon power generation – affecting near-term opportunities for new fuel or other resource supply development options, ongoing Yukon GHG emissions, and potential options for future grid expansion concurrent with development of new longer-term legacy supply options in Yukon.

Figure 3-1 shows potential off-grid mine loads over a longer-term 40 year period (2011-2050) as projected in the 2011 Resource Plan. These off-grid mine loads are forecast to grow rapidly, surpassing grid loads as soon as the 2015-2020 time period, potentially exceeding 1,500 GW.h/year by 2020, and potentially continuing at over 1,300 GW.h/year for more than 20 years (beyond 2040) for new mines such as Casino, Selwyn and Northern Dancer. Off-grid projects are currently expected to rely upon diesel or LNG resource supply options for on-site power generation.

Figure 3-1 also shows over this same 40-year period (2011-2050) the existing Yukon grid system capability to supply potential grid loads as projected in the 2011 Resource Plan. Highlights from this figure include:

- Non-industrial grid load is projected in the 2011 Resource Plan to grow after 2010 at an annual rate of 2.26% based on recent trends[3].
- Grid connected mine loads are assumed in the 2011 Resource Plan to include Minto and Alexco (which are currently connected to the grid) plus Whitehorse Copper Tailings (assumed to be connected in 2013), Victoria Gold (assumed in the 2011 planning to be connected in late 2013) and Carmacks Copper (assumed in the 2011 planning to be connected in late 2014)[4].

[3] The 2011 Resource Plan forecasts were prepared using 2010 actual results and do not reflect current YEC forecasts for 2012 and 2013 based on more recent information. Based on current forecasts through 2013 and 2.26% annual growth thereafter (and grid loss now assumed at 8.7%), grid non-industrial loads would be about 7.7 GW.h/yr higher in 2015 than projected in the earlier 2011 Resource Plan (with similar increases for subsequent years). See Appendix A to this Overview for current load forecasts.

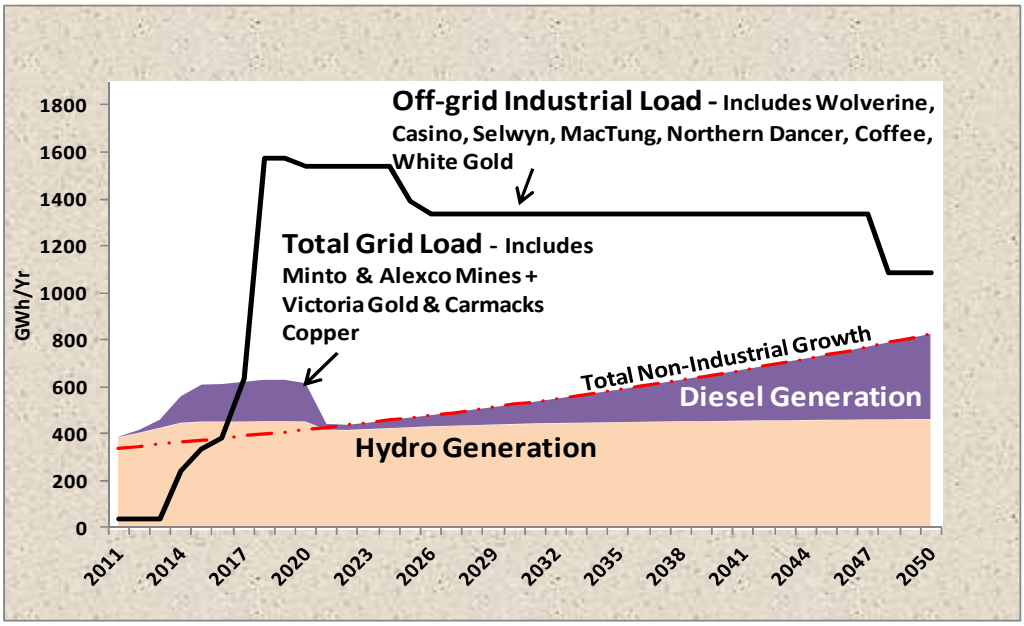
[4] Changes in expected grid mine load forecasts since the 2011 Resource Plan forecasts were prepared include: Minto load growth occurring later in 2012; somewhat lower Alexco loads and higher Whitehorse Copper Tailings mine loads by 2014; delay in connection of Victoria Gold load until start of 2015 and expectation that this load will peak in summer and extend for a longer life than the seven years assumed earlier. No specific timing is currently forecast for Carmacks Copper mine connection to the grid, although the mine's developer (Copper North Mining Corp.) has recently announced (April 26, 2012) plans to submit a proposal to YESAB in Q3, 2012 based on design changes for the plans for development and closure of the project, and expects to submit plans for the Quartz Mining Licence amendment, revised Closure Plan, and a new Water Use Licence application immediately thereafter. Other potential future mine connections to the grid include Brewery Creek (potentially starting in 2013), Rau Gold and Ketza River.

- Forecast grid diesel generation reflects the extent to which forecast grid loads exceed long-term average generation from existing and committed grid hydro and wind generation[5].
    - Assuming no new resource supply developments, forecast grid diesel generation requirements exceed 150 GW.h/yr (2015-2020) with Victoria Gold and Carmacks Copper.
    - Grid mine loads are forecast in Figure 3-1 to stop by the early 2020s; thereafter, ongoing diesel growth reflects only non-industrial growth; in light of this impact, the 2011 Resource Plan tests the sensitivity of new resource options to different potential extensions of related grid diesel requirements to 2025 and 2030.

The 2011 Resource Plan forecasts as highlighted in Figure 3-1 were used in the initial 2011 analysis, as summarized in this Overview, to provide the initial assessment of overall options and priorities. However, expected grid mine loads continue to evolve. Mine and non-industrial grid load forecasts have been updated for the 2012/2013 Yukon Energy General Rate Application filed in April 2012 - and based on this information, updated near-term grid load forecasts have been prepared (see Appendix A to this Overview). These updates assist in ongoing near-term planning for specific new resource project options.

[5] In these assessments, long-term average annual generation capability is assumed for existing hydro and wind resources (annual hydro generation capability is adjusted as required to reflect higher capability at higher annual grid load levels).

Figure 3-1: Existing System Capability to Supply Potential Grid Load & Potential Off-Grid Mine Loads: 2011-2050[6] Excludes DSM/SSE - 2011 Resource Plan



***Scenario B - Base Case Load Forecast with Victoria Gold, Carmacks Copper & WHCT**

	2011*	2015	2020	2025	2030	2035	2040	2045	2050
Grid Load/Hydro Supply Gap**	2	158	163	40	83	138	204	278	364
(Forecast Diesel Generation-GW.h/yr)									
Potential Off Grid Mines	37	332	1,538	1,390	1,338	1,338	1,338	1,338	1,088
(Forecast Diesel or LNG*** GW.h/yr)									
Total Yukon Diesel or LNG Generation (GWh/yr)	39	490	1,701	1,430	1,421	1,476	1,541	1,616	1,451
Total Potential GHG's (tonnes)	**26,962**	**343,073**	**864,118**	**674,435**	**667,793**	**706,413**	**752,282**	**804,481**	**689,306**

* 2011 diesel generation is based on long term forecast (not actuals)

** Assumes connection of Carmacks Copper and Victoria Gold to grid

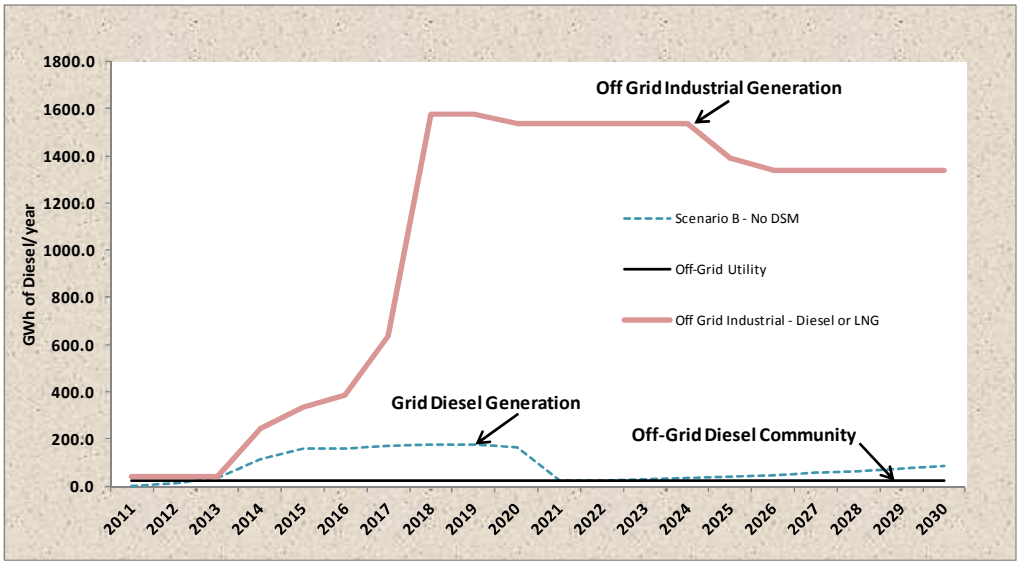
***Assumes Casino develops using LNG with combined cycel power generation & other off grid mines develop using diesel

Figure 3-2 shows non-renewable generation during the 20-year planning period (2011-2030) for all grid and off-grid loads (forecast off-grid diesel community generation and potential off-grid mine diesel) with an accompanying table showing related GHG emissions. The figure and table further highlight the extent to which potential off-grid mine diesel or LNG generation could dwarf grid diesel generation by as soon as 2018-2019.

[6] Potential Alaska Highway Pipeline Project compressor station power loads not included in the above figure could potentially add 1,470 GW.h/year of additional equivalent energy requirements (six compressor stations). Forecasts prepared in 2011 noted that this could occur by approximately 2020/21 and be sustained over 25 years in the event that GHG emissions initiatives support electrification initiatives. Ongoing events in 2012 suggest that this project may be materially delayed.

As noted above, forecast grid diesel generation reflects the extent to which forecast grid loads exceed long-term average generation from existing and committed grid hydro and wind generation. Absent DSM/SSE and new mine loads connected to the grid after forecast mine loads end, Figure 3-2 indicates that on-grid diesel generation is forecast to grow from being minimal in 2011 to 40 GW.h by 2025, i.e., almost twice as large as the off-grid diesel community generation. Continuation of recent non-industrial grid load growth is forecast (without DSM/SSE) to result in 83 GW.h of grid diesel generation by 2030.

Figure 3-2: Total Yukon Non-Renewable Generation (Grid & Off-Grid): 2011-2030
Excludes DSM/SSE - 2011 Resource Plan



Diesel* Energy Requirement	2011	2015	2020	2025	2030
Grid Diesel (YEC - Scenario B-no DSM/SSE)					
Diesel Generation (GW.h)	1.5	158.1	163.3	40.3	82.8
GHG Emissions (tonnes)	1,062	110,673	114,304	28,220	57,979
Off Grid Diesel Communities (YECL)					
Diesel Generation (GW.h)	19.9	20.4	20.9	21.5	22.1
GHG Emissions (tonnes)	13,936	14,247	14,644	15,053	15,473
Potential Off Grid Mine Diesel* (GWh)					
Diesel Generation (GW.h)	37.0	332.0	1,537.8	1,389.8	1,337.8
GHG Emissions (tonnes)	25,900	232,400	749,814	646,214	609,814
Total Yukon					
Diesel Generation (GW.h)	58.4	510.5	1,722.0	1,451.6	1,442.7
GHG Emissions (tonnes)	40,898	357,320	878,763	689,487	683,266

* Includes LNG for Casino mine

4.0 RANGE OF RESOURCE SUPPLY OPTIONS

The 2011 Resource Plan identifies and assesses near-term (i.e., can be committed before 2015) as well as longer-term (i.e., can start construction before 2021) resource options in Yukon. Table 4-1 provides an overview of resource options considered at Yukon Energy's March 2011 Charrette.

- **Near-term options** are identified, i.e., potentially available to start construction before 2015. In addition to diesel and DSM/SSE, these include the following resource options:
    - Hydro enhancements – Limited potential added supply from Mayo Lake storage[7], Marsh Lake storage, Aishihik licencing, Gladstone Diversion (cannot meet timing for short-term).
    - Thermal-Biomass – Wood biomass has potentially large supplies, relative to near-term needs (10 to 25 MW); municipal waste-to-energy (WTE) for up to 2.2 MW.
    - Thermal-LNG – Liquid natural gas (LNG) from BC gas source (potentially unlimited supply relative to Yukon needs over the planning period).
    - Wind – Ferry Hill or Mount Sumanik opportunities (up to 21 MW and about 56 GW.h/yr)
- **Longer-term options** are screened into the "hydro" greenfield site options potentially available to start construction by 2021 versus "other" options that require information, technology or other external action to be considered potentially available before 2021.
    - Longer-term hydro – Subject to adequate connected loads being committed and adequate ongoing resource planning being carried out prior to 2015, includes up to 70 GW.h/yr of small hydro (<10 MW) at 20-23 c/kW.h, over 2,070 GW.h/yr of medium hydro (11-60 MW) at less than 15 c/kW.h, and over 4,700 GW.h of large hydro (>60 MW) at less than 15 c/kW.h.
    - Other longer-term – Includes geothermal (needs exploration), nuclear (needs cost-effective proven technology, permitting experience), solar (needs cost-effective proven technology for Yukon market conditions), pipeline/natural gas (needs commitments by others re: Alaska Highway Pipeline [plans first gas by 2020, full gas by 2021], and/or potential Eagle Plain gas development), and grid connect to BC or Alaska (needs commitments by others).
- **Yukon Energy's resource planning principles** are also used to characterize at a high level each option as regards reliability, affordability, flexibility and environmental responsibility.

[7] The 2011 Resource Plan assumes that Mayo Lake Storage (1 metre of added bottom storage) is approved prior to assessing new resource options. The earliest in service for this project is currently estimated to be after winter 2013/14.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030 **July 2012**

Table 4-1: Range of Resource Supply Options & Initial High Level Characterization

		RELIABILITY Reliable winter peak capacity, & reliable development (timing & cost)	AFFORDABILITY c/kW.h ($2010) if fully utilized	FLEXIBILITY Ratepayer cost risks re Mine Load Reductions	ENVIRONMENTAL RESPONSIBILITY Env. impact mitigation - reduction of GHG Emissions
NEAR-TERM potentially available start to construction before end of 2014 (available no later than 2017)	DSM/SSE	MEDIUM - depends on uptake and type of DSM/SSE	HIGH - <10 c/kW.h	MEDIUM – reasonably flexible; curtailable as/when needed	HIGH
	Diesel – existing default option	HIGH - low cost peaking & reserve capacity on system; low regulatory risk	LOW- approx. 30 c/kW.h	HIGH – low capital cost; save fuel & operating cost when load not there (summer/mine shutdown)	LOW- higher GHG & emissions than any other option
	Hydro Enhancements	MEDIUM – reliable winter energy but high regulatory risk	HIGH <10 c/kW.h	MEDIUM – reasonable flexible; - winter storage; long-term value	HIGH
	Thermal - Biomass (incl. waste)	HIGH - baseload energy & capacity (no development planning to date)	MEDIUM - approx 15 c/kW.h; Scalability issues	LOW – not flexible – high capital cost; intended for yr-round energy supply	HIGH
	Thermal - Liquid Natural Gas (LNG)	HIGH - peaking & reserve capacity; low regulatory risk	MEDIUM/HIGH – < 15 c/kW.h	HIGH - low capital cost; save fuel & operating cost when load not there (summer/mine shutdown)	MEDIUM – 30% to 50% lower GHG emissions than diesel
	Wind	LOW – not add reliable peaking/ reserve capacity; not dispatchable; but low regulatory risk	MEDIUM – approx 15 c/kW.h; includes storage	LOW – not flexible – high capital cost & not dispatchable	HIGH
LONG-TERM HYDRO (greenfield) potentially available to start construction before 2021	Small Hydro (< 10 MW)	MEDIUM – reasonably reliable; medium regulatory risk	LOW to MEDIUM(15 to> 20 c/kW.h)	LOW – not flexible; high capital costs req's sustained demand (30+ yrs)	MEDIUM- HIGH – minimal emissions; large footprint
	Medium Hydro (11 to 60 MW)	MEDIUM – reasonably reliable; high regulatory risk	LOW to MEDIUM (10 to 20 c/kW.h)	LOW – not flexible; high capital costs req's sustained demand (30+ yrs)	MEDIUM- HIGH – minimal emissions; large footprint
	Large Hydro (> 60 MW)	MEDIUM – reasonably reliable; high regulatory risk	HIGH – 5 to 11 c/kW.h	LOW – not flexible; high capital costs req's sustained demand (30+ yrs)	MEDIUM – HIGH – minimal emissions; large footprint
OTHER LONG-TERM (require information, technology or other external action to be considered potentially available before 2021)	Geothermal (exploration)	HIGH re: energy & capacity LOW re: development risk as depends on successful exploration	HIGH - low cost to build and operate LOW– high exploration costs	LOW – not flexible; high capital cost req's sustained demand; Not dispatchable	HIGH – minimal emissions/ footprint
	Nuclear	HIGH – baseload energy & capacity	UNKNOWN	LOW – capital intensive; req's sustained demand;	LOW-MEDIUM – low emissions; nuclear-specific env. issues
	Solar	LOW - not dispatchable, dependant on sun availability	LOW - high cost at this time 20 to 60 c/kW.h & req storage	LOW - capital intensive; req's sustained demand;	HIGH
	Pipeline/ Nat gas	HIGH - provides peaking & reserve capacity; low reg. risk	MEDIUM to HIGH (high cost to establish)	HIGH - low capital cost; save fuel & operating costs when no loads	MEDIUM - lower GHG emissions than diesel
	Grid Connection (B.C. or Alaska)	MEDIUM-HIGH	LOW – high cost to provide	LOW - capital intensive; may enhance greatly flexibility in Yukon	MEDIUM-HIGH – offers clean energy options

Note: "Affordability" in this table is assessed assuming adequate load to fully utilize the resource, e.g., greenfield large hydro lifecycle costs of 5 to 11 cents/kW.h assume full use of the resource throughout a 65 year life. In practice, project feasibility for each option depends on forecast lifecycle costs (LCOE) based on forecast utilization of the option over its life.

5.0 YUKON UTILITIES – DEFAULT DIESEL PORTFOLIO REQUIREMENTS

The 2011 Resource Plan grid load forecasts indicate that the major near-term challenge is to reduce costs and GHG emissions by displacing diesel energy generation that would otherwise be required between 2014 and 2021. Higher costs for default diesel generated by Yukon Energy and Yukon Electrical will affect rates for utility customers throughout Yukon due to integrated and equalized rate setting directives to the Yukon Utilities Board.

Diesel is currently the "default" generation resource option in Yukon, i.e., diesel is the reliable, established and available supply option against which other new supply options must be assessed. The Default Diesel Portfolio option retains established diesel generation capacity on and off the grid (with unit replacements as required), and assumes new capacity is supplied only through new diesel units as required at relatively low capital costs. In effect, this option assumes that all forecast grid electrical energy and capacity requirements beyond those that can be supplied by currently existing or committed hydro and wind generation are reliably and flexibly met through diesel generation.

After an overview of overall default diesel portfolio costs and GHG emissions, Section 5 reviews load forecast scenarios for grid diesel generation requirements for energy and capacity. Key features of the Yukon grid default diesel use are then reviewed which drive flexibility requirements and ability to utilize new resources effectively, i.e., grid seasonality in diesel generation and annual variability in diesel generation due to annual changes in hydro generation. The sensitivity of grid diesel energy forecasts to a range of possible mine connection loads is outlined, and future off-grid diesel generation is also reviewed for utility communities and mines.

Default Diesel Portfolio Costs & GHG Emissions

The concerns raised by the Default Diesel Portfolio option are high costs and high GHG emissions, each of which derive from the use of diesel fuel[8].

Forecast grid generation accounts for a small portion of total GHG emissions forecast for the Yukon power generation sector[9]. This is the situation today (2011) and is forecast to remain the likely reality throughout the 20-year forecast period. Over the next several years prior to 2020, off-grid industrial load and related emissions are forecast to increase dramatically, effectively dwarfing on-grid load and GHG

[8] Costs are also required to replace all existing diesel capacity (and to provide added capacity as needed) during the planning period. However, with regard to meeting these capacity planning requirements, diesel is a low cost option with minimal site-related environmental impact concerns.

[9] See Figure 3-2 shows total Yukon non-renewable generation (grid and off-grid) GHG emissions during the planning period under each grid load scenario without DSM/SSE; the figure includes off-grid utility communities and existing plus potential off-grid industrial (mines).

emissions. Addressing the GHG emission challenge related to off-grid loads also raises new power planning considerations well beyond those addressed in the 2006 Resource Plan. The potential near-term surge in off-grid mine development, however, also raises the opportunity to examine new renewable resource development options for commitment prior to 2021 to expand the grid and help to supply power requirements for major new industrial developments.

Grid Diesel Requirements Load Scenarios with and without DSM/SSE - Energy

Each grid load scenario provides projections with no DSM/SSE and also with DSM/SSE that is assumed to secure a 67% reduction in annual non-industrial grid load growth each year starting in 2013[10].

Forecast utility grid (integrated WAF and MD grids) diesel energy generation requirements for the 2011 Resource Plan (GW.h and incremental energy costs/year) are provided in Figure 5-1 for the following three grid scenarios focused on near-term (i.e., to 2015) mine load connection prospects[11,12]. Existing diesel capacity on the grid is more than adequate to supply forecast energy requirements under each of these near-term load scenarios.

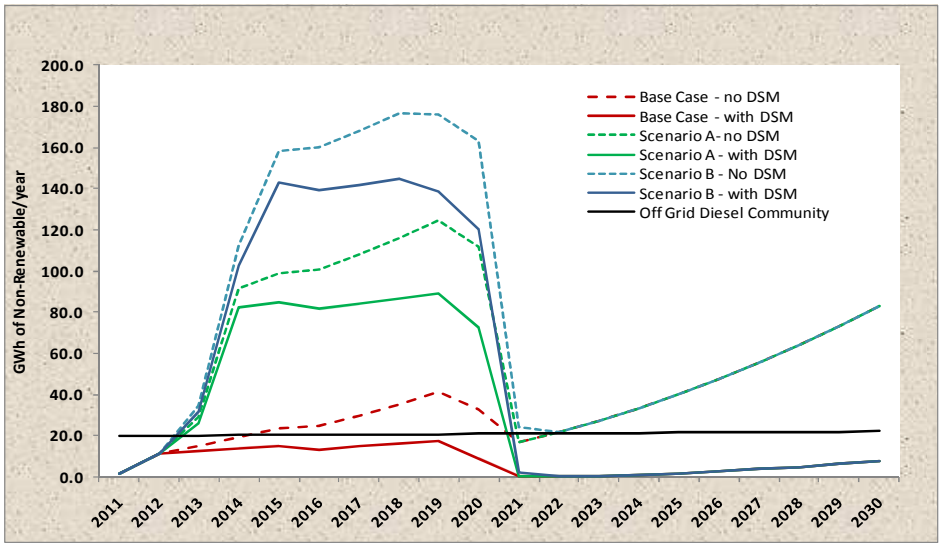
- **Base Case** – Includes non-industrial loads growing at recent rates (2.26%/year) and current connected mines (Minto and Alexco – forecasts assume these mines remain on the grid until around 2020).
- **Scenario A** – Adds Victoria Gold mine to the grid Base Case in late 2013 (based on then available information, forecast assumes on grid for about 7 years, i.e. until end of 2020).
- **Scenario B** – Adds the potential Carmacks Copper mine and Whitehorse Copper Tailings mine to the grid Scenario A (based on then available information, forecasts assume on grid until 2021).

[10] This range of potential diesel generation requirements is used to test the sensitivity of new supply options to potential DSM/SSE program impacts (DSM/SSE costs and programs are being addressed later in 2012 after completion of current studies and program development). DSM is also being addressed with industrial customers and is anticipated to provide some load reductions beyond those shown (potentially in the order of 10% of grid mine loads). Pending completion of current DSM/SSE studies, the 2011 Resource Plan assumes that DSM/SSE programs incur an average annual cost equal to 7.5c/kW.h (2010$) of assumed energy load reduction.

[11] Figure 5-1 also shows forecast off-grid utility diesel generation requirements. Forecast diesel generation fuel and O&M costs reflect approved 2009 incremental diesel generation costs by rate zone escalated at inflation (2% per year) after 2010. Incremental grid diesel generation costs for fuel and O&M (2010$) are assumed at 28c/kW.h (escalated at general inflation assumed at 2%/year), reflecting YEC's approved 2009 GRA fuel prices (e.g., 96 cents per litre at Whitehorse) and a 50/50 average of estimated costs for existing and new units (range of unit efficiencies and O&M cost). Diesel fuel prices in 2011 were generally higher than the approved 2009 fuel prices; however, based on October 2011 NYMEX futures, future diesel prices would be slightly lower than assumed in the Resource Plan (NYMEX futures based prices about 3% lower in 2012, 5% lower by 2015 and 6% lower by 2018).

[12] All loads (including mine loads) as forecast in 2011 based on then available information. Changes since the 2011 Resource Plan was prepared include: Minto load growth occurring later in 2012; somewhat lower Alexco loads and higher Whitehorse Copper Tailings mine loads by 2014; delay in connection of Victoria Gold load until start of 2015 and expectation that this load will peak in summer and extend for a longer life than the seven years assumed earlier. See Appendix A to this Overview for updates.

Figure 5-1: Diesel Energy Requirements (Grid & Off-Grid Utility)
Resource Plan Scenarios 2011 Resource Plan[1]



Diesel Energy Requirement	2011	2015	2020	2025	2030
Base Case (GWh)					
with DSM/SSE	1.5	15.2	8.7	1.8	7.5
without DSM/SSE	1.5	23.7	32.5	40.3	82.8
Scenario A (GWh)					
with DSM/SSE	1.5	84.9	72.5	1.8	7.5
without DSM/SSE	1.5	98.9	112.0	40.3	82.8
Scenario B (GWh)					
with DSM/SSE	1.5	142.9	120.6	1.8	7.5
without DSM/SSE	1.5	158.1	163.3	40.3	82.8
Off Grid Diesel Community (GWh)	19.9	20.4	20.9	21.5	22.1
Diesel Energy Cost (Fuel & O&M)					
Base Case ($ millions)					
with DSM/SSE	0.4	4.7	3.0	0.7	3.1
without DSM/SSE	0.4	7.3	11.1	15.2	34.5
Scenario A ($ millions)					
with DSM/SSE	0.4	26.3	24.8	0.7	3.1
without DSM/SSE	0.4	30.6	38.3	15.2	34.5
Scenario B ($ millions)					
with DSM/SSE	0.4	44.2	41.2	0.7	3.1
without DSM/SSE	0.4	48.9	55.8	15.2	34.5
Off Grid Community ($ millions)	5.9	6.6	7.5	8.6	9.9

[1] See Appendix A to this Overview for current updated diesel energy and other forecasts prepared since the 2011 Resource Plan.

Under each of the above grid scenarios, a robust and successful DSM/SSE program would see minimal diesel generation (and consequently minimal diesel cost impacts and diesel displacement opportunities) after shut down of connected mine loads (i.e., with assumed DSM/SSE and Scenario A or B assumed mine closures after 2020, there is less than 10 GW.h of required diesel generation annually over the period from 2021 to 2030). In contrast, no DSM/SSE program (or unsuccessful DSM/SSE programming over the period) would see much greater rate impacts and diesel displacement opportunities after 2020 (i.e., between 22 GW.h to 83 GW.h per year (2022-2030) under all "no DSM/SSE" scenarios that assume closure of connected mines after 2020-2021).

Grid Season Generation – Impacts on Diesel Generation

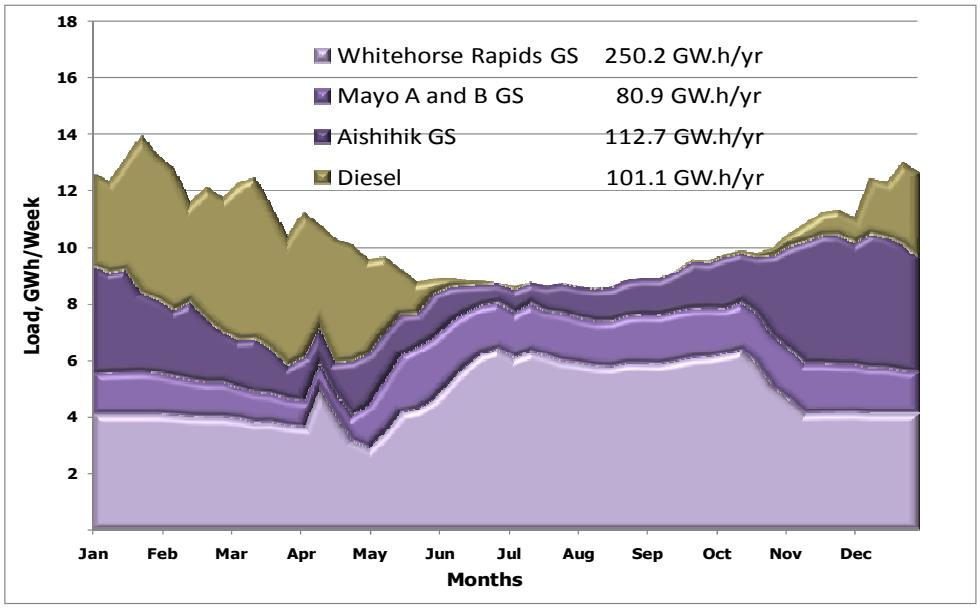
Diesel generation on the Yukon grid occurs in winter. As reviewed in Figure 5-2, with Scenario A 2015-2016 load and no DSM/SSE, 69% of annual near-term diesel generation forecast under average water conditions occurs in four winter months (December to March), and only 2% occurs in the five summer/fall months (June to October). Concentration of forecast diesel generation outside the summer/fall remains a key feature of the Yukon grid under a wide range of load and water conditions.

This concentration of grid diesel generation outside the summer/fall months reflects two factors: seasonal variation in grid loads (which are higher in winter than in summer) and seasonal variation in grid hydro generation for existing and committed facilities (hydro generation typically is higher in summer and fall as compared to winter/spring months). The seasonal concentration of grid diesel generation also reflects a key feature of Default Diesel, i.e., its flexibility to be utilized only when needed, reflecting both the technology (i.e., portable/storable fuel that is readily available) and its relatively low capital cost.

In contrast, Figure 5-3 shows seasonal generation at the Scenario A 2015-2016 load with a new 21 MW of wind generation providing 56 GW.h/year with year-round operation (reflects maximum near-term potential wind development at Ferry Hill). In an average water year, 88% of this new wind is used to displace diesel generation (this result is sensitive to assumed grid load and scale of wind generation):

- 49 GW.h of diesel displaced (70% directly displaced in winter, 30% through use of incremental stored hydro due to impact of wind's summer generation);
- 52 GW.h of diesel energy generation requirements remain on the grid under the assumed load and scale of wind capacity; and
- Unlike diesel, the 21 MW of new wind generation is dependent at all times on wind availability and therefore does not contribute to grid reliable capacity requirements (i.e., diesel or other new reliable capacity is needed to address diesel unit retirements plus added capacity requirements from growth).

Figure 5-2: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) at Scenario A 2015-16 Load without DSM/SSE Grid Load Net of Fish Lake and Wind

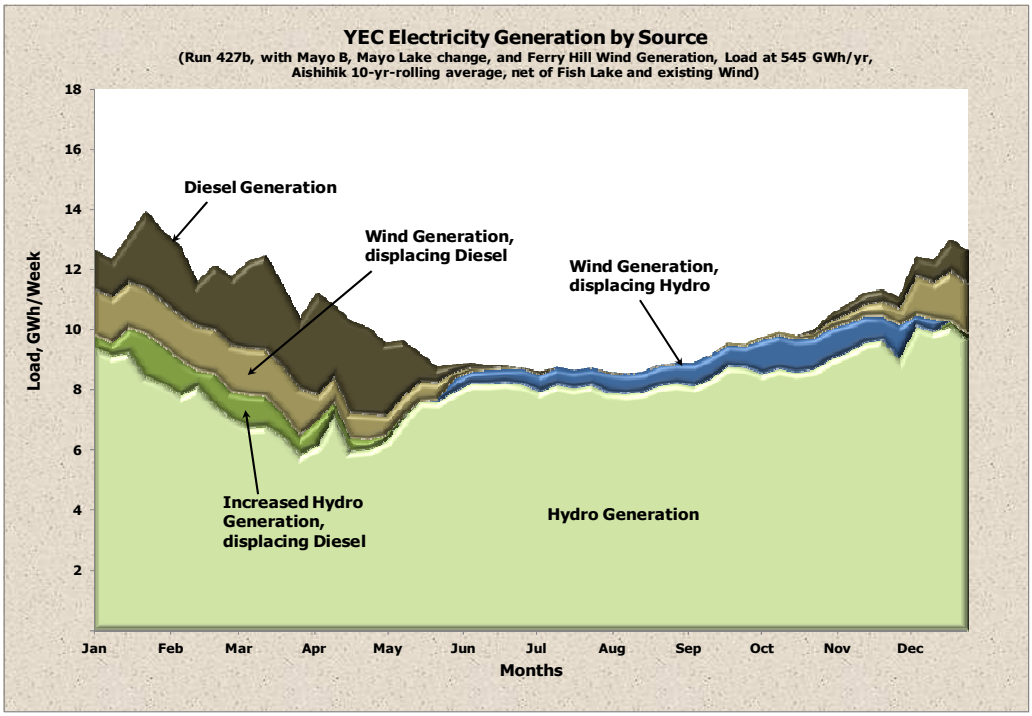


GW.h	Jan-Mar	April	May	June-Oct	Nov	Dec	Annual
	Wks 1-13	Wks 14-17	Wks 18-22	Wks 23-44	Wks 45-48	Wks 49-52	
Diesel Generation	59.9	17.2	9.1	1.9	3.2	9.8	101.1
	59%	*17%*	*9%*	*2%*	*3%*	*10%*	*100%*
Hydro Generation	100.5	25.3	37.1	199.0	41.3	40.6	443.9
	23%	*6%*	*8%*	*45%*	*9%*	*9%*	*100%*
Total Generation	160.4	42.5	46.2	201.0	44.5	50.4	545.0
	29%	*8%*	*8%*	*37%*	*8%*	*9%*	*100%*

Notes: Weekly grid generation by source in Figure 5-2 from January to December is based on long-term average water flows and the Scenario A grid 2015-2016 load without DSM/SSE (assumes yet-to-be approved Mayo Lake project with amended licence for one metre of enhanced bottom storage):

- Seasonal loads (peak in winter and are lowest in summer).
- Current hydro generation supply (tends to peak in summer/fall, constrained in winter/spring).
- Diesel energy generation for average year is concentrated in winter months (60% in four months of December to March), and only 2% in five summer/fall months (June to October).
- Diesel energy generation forecast for average year at 101 GW.h (reflects impact of potential load growth by 2015/16, i.e., much lower grid diesel generation today based on average year).
- Diesel provides critical reliable grid capacity requirements to meet peak winter loads and reserve when hydro capacity can be constrained on the current grid, e.g., reliable winter hydro capacity approximates 24 MW at Whitehorse (out of 40 MW installed) and 11 MW at Mayo (out of 15 MW installed).

Figure 5-3: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) with 21 MW Wind Project Displacing Diesel and Displacing Hydro at Scenario A 2015-16 Load Without DSM/SSE



Grid Generation at 545 GW/h load* (GW.	Without Wind Project	With 21 MW Wind Project	Change
Grid Load	545.0	545.0	
Grid Generation			
Hydro*	443.9	437.3	(6.6)
Diesel	101.1	51.9	(49.2)
Wind*	-	55.8	55.8
Total	545.0	545.0	

* Existing Wind and Fish Lake generation not included.

Breakdown of Wind Generation Impacts (GW.h/yr)	
Directly Displacing Diesel	34.6
Directly Displacing Hydro	
Stored Hydro Displacing Diesel	14.6
Spilled Hydro (not required)**	6.6
Total Wind Project Generation	55.8

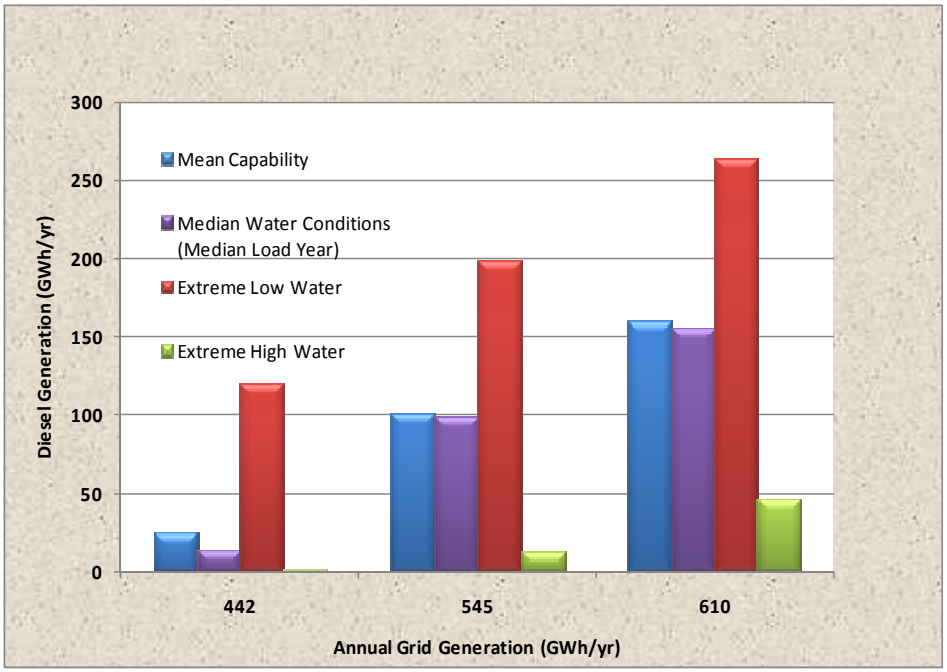
Total Displaced Diesel = 34.6 + 14.6 = 49.2 GW.h

**This figure provides an example that illustrates impacts this supply option would have on the existing generation system;
This does not suggest YEC would operate the system in a manner that results in hydro being displaced by other forms of more costly generation

Annual Diesel Variability Due to Annual Hydro Generation Fluctuations

Figure 5-4 demonstrates the high variability that exists on the current Yukon grid regarding annual diesel generation requirements at any assumed grid load level. By way of example, at the Scenario A 2015-2016 load without DSM/SSE assumed in Figures 5-2 and 5-3, diesel generation can potentially range in any year from 13 to 199 GW.h/year, depending on water flow impacts on grid hydro generation.

Figure 5-4: YEC Annual Grid Diesel Generation Variability at Different 2015-2016 Grid Loads (GW.h/yr)



Annual Diesel Generation (GW.h/yr)	Annual Grid Load (GW.h/yr)		
	442	545	610
Mean Capability	24.6	101.1	160.2
Median Water Conditions (Median Load Year)	13.6	98.6	155.7
Extreme Low Water	119.7	198.8	263.8
Extreme High Water	0.1	13.0	46.2

Notes:

- The range of annual grid loads reflects approximate forecast 2015-16 loads ranging from Base Case (442 GW.h - no new mines) to Scenario A (545 GW.h – connect Victoria Gold) and Scenario B (610 GW.h – connect Victoria Gold, Carmacks Copper and Whitehorse Copper Tailings).
- An "extreme" or "median" year reflects one year out of 364 cases (28 water years and 13 load years). "Averaged load year" (which not shown above) is average annual value for a water year calculated over all 13 load years. For the 545 GW.h/year grid load, the extreme low water diesel generation for Averaged Water Year would require 166.7 GW.h/year diesel generation (reflects 1996 water year of record), and the extreme high water diesel generation for Averaged Water Year would require 34.1 GW.h/year diesel generation (reflects 1992 water year of record).

Range of Possible Connected Mine Loads

The 2011 Resource Plan recognizes that a wide range of possible variations in connected mine loads may occur over the 20-year planning period, including delays in connection of specific loads, extensions in the

life of any connected loads, earlier-than-expected mine shutdowns, new connections not currently forecast and expansions or contractions in connected loads.

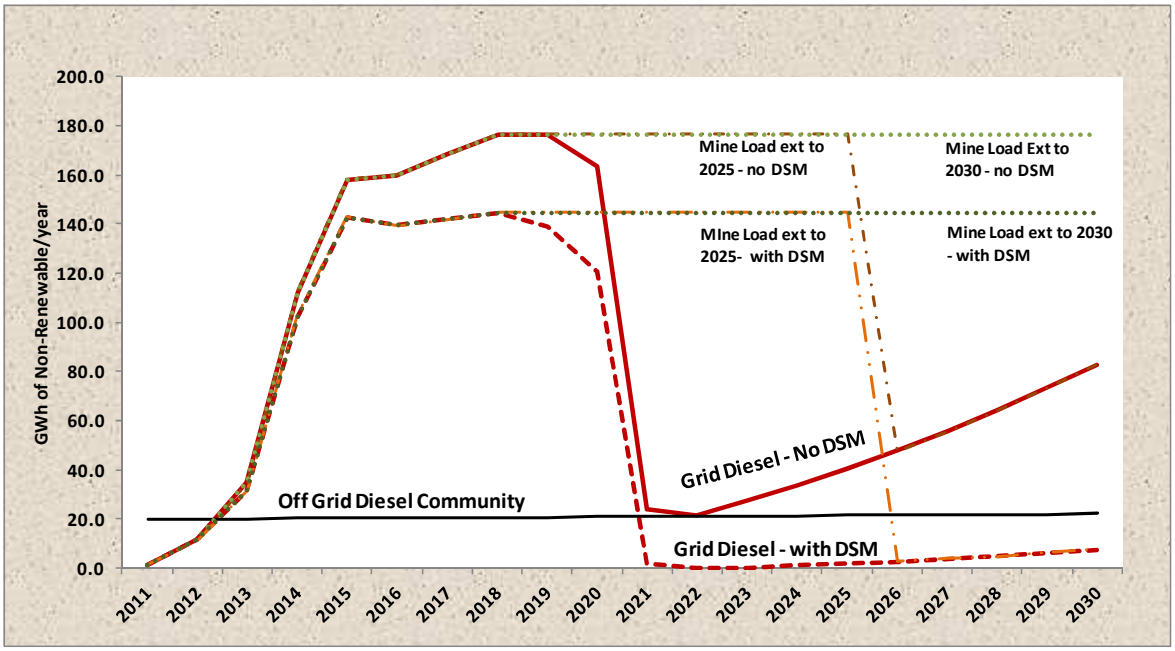
- Beyond looking at a range of near-term mine connections (e.g., Base Case, Scenario A and Scenario B loads), resource option sensitivity for displacing grid diesel generation is also tested for different potential extensions of connected mine loads beyond the 2020 date after which the forecasts show shut down of connected mine loads (sensitivity is tested separately as shown in Figure 5-5 for extensions of related grid diesel requirements to 2025 and 2030).

- The potential for connection to the grid of material new off-grid mine loads (beyond those included in Scenario A and B) has been forecast to be very limited:

    - Off-grid industrial diesel or other fossil fuel power generation at the Wolverine mine (37 GW.h/year) already exceeds utility diesel generation (grid and off-grid). This load is over 270 km from the grid, and connection was never considered to be a practical option given this distance and an expected 10 year mine life.
    - There are currently only a limited number of potential new mine opportunities located within 50-100 km of the 69-138 kV grid (e.g., potentially Brewery Creek, Rau Gold, and Ketza River); although none of these mine loads were included in the 2011 grid load forecasts, the developer of the Brewer Creek mine (Predator Mining Group Inc.) informed YEC that it would like to discuss connection to the grid potentially as soon as mid 2013 with a load of approximately 3.7 MW.

- Opportunities exist in the longer-term (i.e., commitments prior to 2021) to connect to the grid one or more of the major new off-grid mine loads that are driving potential off-grid diesel/LNG generation on a multi-decade basis as shown earlier in Figure 3-1. However, as noted, these mine loads are not being planned on the basis of any grid connection – and any potential grid connection in future will be contingent on new larger-scale renewable resources being developed that can supply a major share of the new off-grid power requirements on a timely and cost-effective basis. Looking at the largest of these potential off-grid mine loads (Casino), this opportunity translates into the challenge of developing new renewable resource options within the next decade that are less costly than the LNG (or natural gas fuelled generation if pipeline or Eagle Plain gas becomes available) that is currently planned to supply this load.

Figure 5-5: Diesel Energy Requirements - Sensitivity Tests re: Mine Load Extensions



Forecast Grid Diesel Requirements - Capacity

In addition to supplying energy requirements, diesel generating units are important for meeting grid capacity planning requirements, i.e., the required capacity to meet firm winter peak load requirements with adequate reserve. As reviewed in Table 5-1, over the 20-year planning period all of Yukon Energy's existing diesel generation capacity (37 MW) is forecast to be replaced due to expected retirements. The following highlights are noted from Table 5-1:

- There are no forecast new grid capacity requirements in 2011 under any of the resource planning scenarios.
- By 2015, with DSM/SSE, there is no new grid capacity required under the Base Case scenario, and between 9.6 MW to 17.6 MW of new capacity required under Scenario A and Scenario B loads respectively (at a diesel capacity replacement cost of approximately $15.7 million to $28.7 million)[13].
- By 2020, with DSM/SSE, 8.8 MW of new grid capacity is required under the Base Case scenario (at a diesel capacity replacement cost of $15.8 million). New capacity required under Scenario A

[13] Cumulative diesel capacity spending to date after 2010 to meet capacity planning requirements (escalated dollars – assumed cost of $1.5 million/MW [$2010]).

and Scenario B loads is 17.9 MW and 25.9 MW respectively (at a diesel capacity replacement cost of $30.6 million to meet Scenario A loads and $43.6 million to meet Scenario B loads).

- By 2025, with DSM/SSE, under all scenarios 27.6 MW of new capacity is required at a diesel capacity replacement cost of between $47.0 million and $52.1 million.
- By 2030, with DSM/SSE, under all scenarios 37.1 MW of new capacity is required at a diesel capacity replacement cost of between $67.0 million and $72.1 million.

Table 5-1: New Diesel Grid Capacity Requirements for Resource Plan Scenarios: 2011-30*

	2011	2015	2020	2025	2030
New Diesel Capacity Requirement (MW)					
With DSM/SSE					
N-1	0.0	0.0	8.8	27.6	37.1
Base Case	0.0	0.0	8.8	27.6	37.1
Scenario A	0.0	9.6	17.9	27.6	37.1
Scenario B	0.0	17.6	25.9	27.6	37.1
Without DSM/SSE					
N-1	0.0	2.8	18.0	43.5	60.4
Base Case	0.0	2.8	18.0	43.5	60.4
Scenario A	0.0	12.8	27.1	43.5	60.4
Scenario B	0.0	20.8	35.1	43.5	60.4
Diesel Capacity Additions ($Millions)[1]					
With DSM/SSE					
Base Case	0.0	0.0	15.8	52.1	72.1
Scenario A	0.0	15.7	30.6	50.0	70.0
Scenario B	0.0	28.7	43.6	47.0	67.0
Without DSM/SSE					
Base Case	0.0	4.7	31.7	81.0	116.9
Scenario A	0.0	21.0	46.4	78.8	114.7
Scenario B	0.0	34.0	59.4	76.3	112.2

1. Cumulative diesel capacity spending to date after 2010 to meet capacity planning requirements (escalated dollars - assumed cost of $1.5 million/MW [$2010]).

*See Appendix A to this Overview for current updated diesel grid capacity requirement forecasts prepared since the 2011 Resource Plan.

Forecast timing for new diesel capacity will be affected by diesel unit retirements and new capacity requirements during the 2013-2020 period related to different load scenarios[14]. This 2011 Resource Plan analysis assumes that the 25 km line L172 between Takhini and Whitehorse is appropriately reinforced within the next few years so as to provide no line constraint, i.e., absent such reinforcement, additional capacity would be required in Whitehorse.

Off-Grid Utility Diesel Generation Requirements

Off-grid utility community diesel energy power generation requirements are forecast to grow very slowly based on recent trends for the diesel rate zone communities served by Yukon Electrical (Watson Lake, three small diesel communities, and Old Crow). Off-grid utility community diesel generation exceeds grid diesel generation under the Base Case forecast with DSM/SSE. Off-grid utility community diesel capacity requirements are not addressed at this time.

Potential Off-Grid Mine Diesel Requirements

Potential off-grid mine diesel/LNG energy generation forecasts indicate that unprecedented potential off-grid industrial power load growth before 2020 could easily dwarf current projected utility gird and off-grid diesel generation (see earlier Figure 3-1). Current forecasts indicate that industrial off-grid diesel and/or LNG power generation could potentially exceed 330 GWh/year by 2015 and 1,545 GW.h/year by 2020, and remain above 1,300 GW.h per year beyond the planning period (2030); by comparison, total grid load served by hydro, wind and diesel generation as projected in 2020 under Scenario B with no DSM/SSE is 614 GW.h/year, i.e., about 36% of the potential off-grid industrial generation by that date.

The larger potential off-grid longer-life mines which constitute most of the potential projected off-grid industrial load over the planning period (e.g., Casino, Selwyn, Mactung and Northern Dancer) are not currently considering connection to the Yukon grid in order to meet load requirements. The largest of these potential industrial loads (Casino project) is planning to use LNG at costs well below the cost of diesel, and Northern Dancer is also looking at the LNG option.

[14] Forecast new default diesel capacity requirements by year on the grid for each load scenario reflect forecast peak loads under the grid load scenarios, forecast generation unit retirements, and Yukon Energy's grid capacity planning requirements to meet peak winter loads. During the 2015-2020 period connected mine loads as assumed in Scenarios A and B of the 2011 Resource Plan are expected to be sufficient potentially to affect capacity planning requirements (under updated assessments, this is assumed to occur under the Loss of Load Expectation [LOLE] planning requirements when industrial loads exceed 13 MW), while in other years the N-1 requirement (currently loss of the Whitehorse transmission connection to the Aishihik hydro plant) based on non-industrial loads is expected to determine new default diesel capacity requirements.

6.0 NEAR-TERM RESOURCE OPTIONS TO DEFAULT DIESEL

Portfolio options examine the extent to which alternative resource combinations could effectively reduce grid diesel generation under different forecast load scenarios. Diesel generation is assumed to be retained in each portfolio to supply all generation requirements not supplied by other resources.

Near-Term Resource Options to Default Diesel

Non-diesel resource options potentially available for in service by late 2014 that were selected for near-term portfolios include Marsh Lake Storage (6.4 GW.h/year potential), Wood Biomass Thermal (15 MW)[15], Waste to Energy (WTE) Thermal (2.2 MW)[16], Wind (21 MW)[17], and Liquid Natural Gas (LNG)[18]. In contrast, Gladstone Diversion (36.6 GW.h/year potential) likely cannot be committed before 2016 at the earliest, but could potentially constitute a resource for in-service by late 2017.

Each of these near-term options were assessed in the 2011 Resource Plan based on then available information – recognizing that further feasibility work is required in each case to confirm costs and supply capabilities, and also to determine whether or not the option is feasible to be committed by the dates currently assumed.

- LNG and Wood biomass are options where sourcing fuel supply remained a significant issue at the time of the 2011 Resource Plan analysis, and it was recognized that further pre-feasibility analysis is required prior to relying on either of these options for near-term supply[19]. Ongoing work by YEC is focusing on confirming least-cost options whereby LNG supplies can be secured as required by late 2014[20].

- Feasibility information for Marsh Lake Storage and Gladstone Diversion confirms the relatively low cost offered by each of these hydro enhancement options – however, each of these hydro

[15] Resource Plan analysis determined that any larger scale Wood Biomass plant would be more costly under forecast grid loads (the plant scale exceeds forecast grid requirements for a thermal plant running throughout the year). In contrast, a 10 MW plant might merit review under lower Scenario A loads. Wood Biomass plants smaller than 10 MW (e.g., 3 MW) are being examined as possible pilot projects (see Section 8 of this Overview).

[16] The 2.2 MW scale was assessed to be an optimum scale based on projected available municipal solid waste (MSW) resource supplies and potential access to low cost wood biomass "waste" supplies to supplement MSW supplies.

[17] A smaller 10.5 MW option was examined, but was slightly less cost-effective at forecast loads than the 21 MW option (the latter option reflected estimated wind resource that could be developed at Ferry Hill).

[18] LNG capacity is adapted as required to the specific assumed load forecast (assumes BC based LNG supply not limited).

[19] It was assumed that LNG and wood biomass options could likely be committed before 2015 if selected for development, subject to sufficient studies and planning being carried out in a timely manner to resolve various feedstock supply issues. The 2011 Resource Plan (Section 6.1) reviewed recent studies that YEC has participated in with the developer of the Casino mine project to confirm the feasibility of near-term LNG supply chain options to Yukon from Kitimat or Fort Nelson, B.C.

[20] See YEC web site for: (a) January 2012 LNG Workshop background paper and presentations; (b) December 2011 Biomass background study and presentations.

projects is subject to material timing uncertainties related to regulatory and permitting processes, and further Yukon Energy planning work on Gladstone Diversion is also subject to securing local First Nation support for the project. Gladstone Diversion is examined as potentially being in-service by late 2017 (it is expected that this option cannot be committed before 2015 – the assessment examined the potential impact of securing this option by the end of 2017).

- Feasibility information is also available for Wind and WTE options – however, further feasibility work is required on each of these projects before commitments could be made to proceed with permitting activities[21].

Energy and Capacity Supply Capabilities

Overall, only a few of the available non-diesel resource options offer large scale energy generation supply potential relative to forecast Yukon diesel generation loads. Figure 6-1 highlights the gross energy supply capabilities of the near-term options relative to each of the forecast 2015-2019 grid diesel requirement load scenarios with and without DSM/SSE (the table below this figure reviews reliable capacity capabilities and capital costs for each resource supply option):

- **LNG** – LNG supply is the only option that can potentially displace all diesel energy loads as well as all new diesel capacity requirements at any near-term load.

- **15 MW Wood Biomass** – Gross energy capability of a 15 MW wood biomass option exceeds all but Scenario B diesel energy loads; however, after seasonal diesel requirements and annual hydro variability impacts are considered, this option's net energy displacement of diesel is much lower than the gross energy capability, e.g., assuming Scenario A with DSM/SSE, net energy diesel displacement approximates only 72 GW.h of the 119.6 GW.h annual gross energy. This option can displace only a portion of new diesel capacity requirements (at this scale of plant, the only identified potentially feasible locations are either in Whitehorse or in the Minto burn area).

- **Other Near-Term Options** – Gross energy capability of other near-term options only displace portions of Scenario A diesel requirements, and net energy capability to displace diesel is lower than gross capability, e.g., approximately 80% to 88% of WTE or Wind gross generation displaces diesel with Scenario A load; minimal contributions from Marsh Lake hydro and WTE; wind provides minimal capacity contribution.

In summary, LNG can provide flexible amounts of supply up to any load levels likely to be required and Wood Biomass can also provide relatively large amounts of annual generation (119.6 GW.h/year for a 15

[21] See YEC web site for October 2011 Waste to Energy Workshop background study and presentations.

MW plant, of which 72 GW.h would displace diesel generation under Scenario A loads with DSM/SSE)[22]. In contrast, maximum potential levels of annual generation are limited from Marsh Lake (6.4 GW.h/year), 2.2 MW WTE (17.1 GW.h/year), Gladstone Diversion (36.6 GW.h/year), and Wind (55.6 GW.h/year).

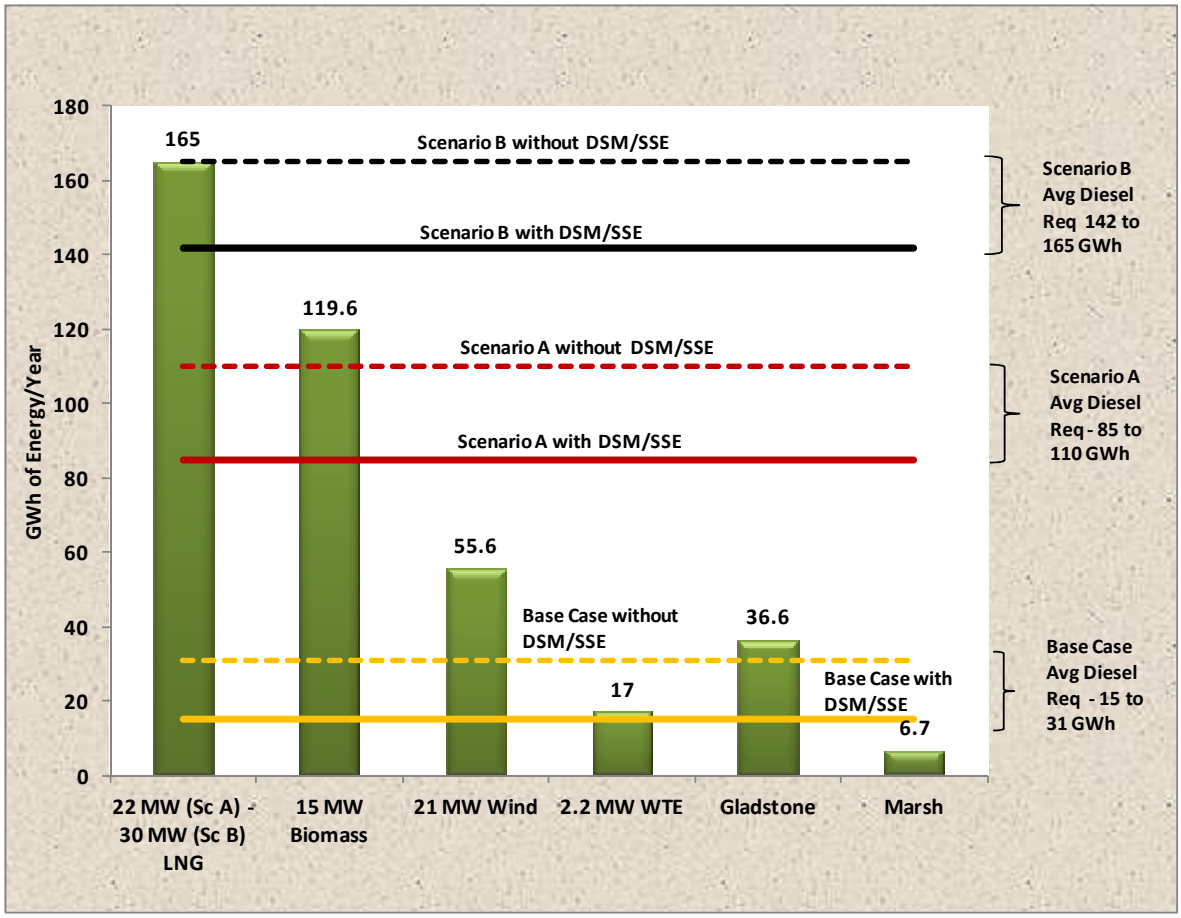
Ongoing studies are defining the economic potential for DSM and SSE as well as specific programs and costs. Pending completion of these studies, the 2011 Resource Plan assumes that a specific level of DSM/SSE will be implemented starting in 2013 for non-industrial grid loads[23] and tests the sensitivity of all non-diesel supply options to these potential DSM/SSE impacts. In summary, notwithstanding the materially higher diesel displacement opportunities and higher Default Diesel Portfolio costs with no DSM/SSE, comparative feasibility assessments of the different resource portfolio options under load scenarios with DSM/SSE were not generally changed by consideration of load scenarios with no DSM/SSE[24]. Accordingly, the following summary overview analysis of resource and portfolio options typically focuses solely on review of load scenarios with DSM/SSE.

[22] Studies suggest that a 25 MW plant scale located in Whitehorse might also be feasible, with annual generation approaching 200 GW.h/year; however, under Scenario A loads with DSM/SSE, less than 15% of the annual biomass energy over the project life would displace diesel generation (even during the 2015-19 period with mine loads connected, less than 100 GW.h/yr of the wood biomass generation would be used to displace diesel generation).

[23] Although the timing and level of future DSM/SSE remains uncertain, preliminary study results suggest that future DSM/SSE load reduction impacts over the period to 2030 may be within 50-75% of DSM/SSE assumed in the 2011 Resource Plan.

[24] Higher loads assuming no DSM/SSE tend to improve cost savings for all non-diesel portfolio options when compared with the Default Diesel Portfolio, and reduce somewhat the penalties faced by non-flexible options such as Wind when grid loads drop due to mine closures. Portfolios that include Gladstone Diversion tend in particular to show improved (lower) present value costs over the planning period with higher loads assuming no DSM/SSE. However, the overall cost ranking of LNG Transition Portfolio Options relative to Minimum GHG Portfolio Options or the Default Diesel Portfolio is not materially changed without DSM/SSE.

Figure 6-1: Gross Energy Supply Capabilities by Near-Term Option (GW.h/yr During 2015-2019) – Compared to Diesel Requirements by Load Scenario with and without DSM/SSE (Net Energy Displacement of Diesel may be less than Gross Energy)



Notes: Reliable Capacity capability (up to 37 MW new grid capacity needed by 2030 with Scenario A load with DSM/SSE):

- **Diesel, LNG** – Each can provide all of the firm capacity required (capital cost of $1.5 million/MW assumed; for LNG cost of $1.8 million/MW for combined cycle).
- **Wood Biomass** - Option assumes 15 MW of firm capacity (capital cost of $5.7 million/MW).
- **Waste-to-Energy (WTE)** - 2.2 MW of firm capacity (capital cost of $17.7 million/MW).
- **21 MW Wind** – Wind generation does not provide any reliable capacity; the option includes 5 MW of DRUPS (diesel rotary uninterruptible power) to enhance reliability, and this adds 5 MW to reliable capacity. Wind option capital cost of $3.6 million/MW for 26 MW (wind & DRUPS).
- **Gladstone and Marsh** – Gladstone Diversion hydro adds minimal or no reliable capacity (due to Aishihik Transmission line vulnerability); Marsh Lake hydro storage adds about 1 MW reliable capacity. Overall capital costs are estimated at $40 million for Gladstone and $10.5 million for Marsh Lake storage. Earliest potential in-service for Gladstone is late 2017.

2015-2020 Average Annual Costs per kW.h

New resource supply options display widely varying annual ratepayer cost impacts per kW.h during the 2015-2020 period with assumed connected mine loads (see Figure 6-2 for annual ratepayer costs per kW.h with Scenario A loads and DSM/SSE, assuming average annual hydro generation):

- **LNG and Hydro Enhancements (Marsh & Gladstone) are lowest cost** – LNG and hydro enhancements cost less than 20 c/kW.h each year relative to diesel fuel and O&M (new diesel units) at approximately 30 c/kW.h or higher (LNG fuel and O&M cost is lowest at 11 to 13 c/kW.h)[25].

- **Wind and WTE slightly lower cost than Diesel** – Wind and WTE cost typically between 25 and 30 c/KW.h[26]; these capital intensive options are sensitive to load decline that is forecast starting in 2020 (lower loads result in higher average costs per KW.h).

- **Wood Biomass costs more than Diesel** – Wood biomass costs at or slightly below 35 c/kW.h until 2020, when costs rise above 35 c/kW.h[27]; this is a capital intensive option that is sensitive to load decline as forecast starting in 2020 (lower loads result in higher average costs per kW.h).

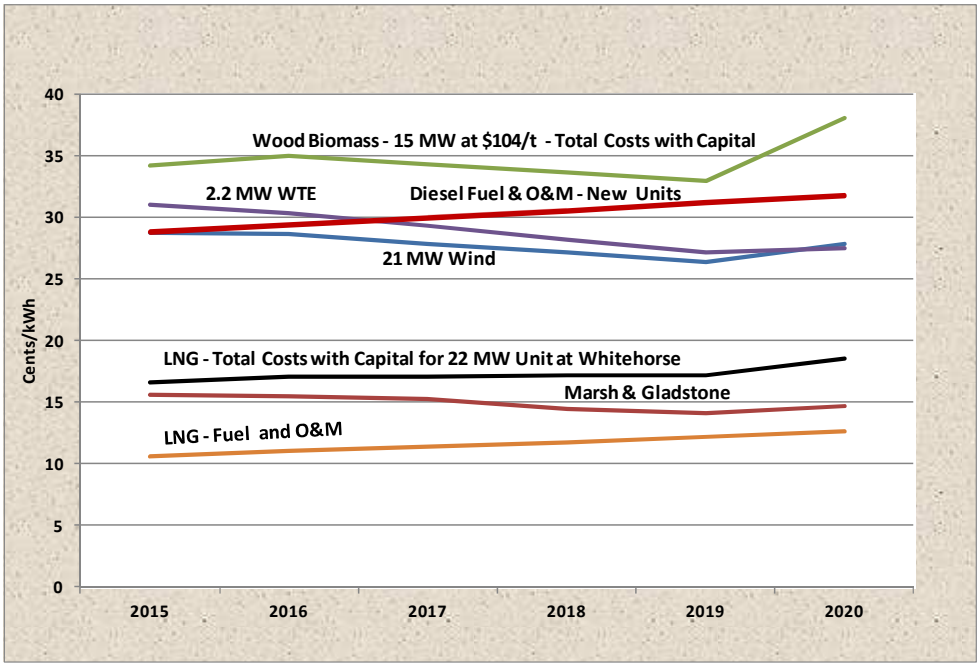
In summary, LNG is a flexible low capital cost option where unit fuel costs determine overall annual costs per kW.h. In contrast, higher capital costs per MW for other options result in costs per kW.h being sensitive to option scale and assumed grid loads.

[25] Forecasts assume diesel fuel and O&M cost escalation at 2% year (fuel price as approved by YUB in place in 2010). LNG costs assume 22 MW combined cycle generation units at Whitehorse (50% energy efficiency [6.562 Mcf/MW.h] and 44% average annual plant capacity factor) with LNG supplied by truck from Kitimat at cost of 2.7 cents per kW.h (2010$) for all LNG supply costs other than LNG fuel; cost of LNG fuel at assumed natural gas price in BC plus $3/MMBtu (2010$) to reflect conversion costs and impact of export pricing; assumed BC gas price at $5.5/MMBtu in 2015 ($6.07/MMBtu after inflation), $6.60/MMBtu in 2020 ($8.05/MMBtu after inflation) and $7.45/MMBtu in 2030 ($11.07/MMBtu after inflation). Although combined cycle provides opportunity for waste heat sales in Whitehorse, no waste heat revenue offsets assumed with LNG option in this analysis.

[26] Assumes use 25,000 ODT/year of MSW plus 3,800 ODT/year wood biomass at Whitehorse WTE plant, with district heat net revenues, tipping fees and other revenues of $3.3 million per year (2010$). See Figure 6-3.

[27] Wood Biomass plant assumed to be located adjacent to grid in Minto burn area with wood biomass requirement of 0.7 ODT/MW.h at an average cost (2010$) of $104/per ODT. Assume 2%/year inflation of costs.

Figure 6-2: Average Annual Costs per kW.h for Near-Term Resource Options – 2015-2020 (Scenario A Load with DSM/SSE – Cost Inflation at 2%/yr; higher for LNG)



Annual Cost (cents/kW.h)	2015	2016	2017	2018	2019	2020
Diesel Fuel & O&M - new units	29	29	30	31	31	32
Wood biomass 15 MW at $104/t						
Total Costs	34	35	34	34	33	38
Fuel + O&M	19	20	20	20	20	24
21 MW Wind	29	29	28	27	26	28
2.2 MW WTE	31	30	29	28	27	28
LNG - total costs with capital	17	17	17	17	17	19
LNG - fuel & O&M	11	11	11	12	12	13
Marsh & Gladstone	16	15	15	14	14	15

Note: Assumes 2%/yr inflation for 2010$ costs, except for LNG fuel cost which assumes specific real escalation of the 2010$ natural gas price as well as overall inflation at 2%/yr (per footnote 24 at page 28). All costs assume average annual hydro generation each year during the period.

Lifecycle Costs per kW.h (LCOE)

Resource options are more effective in displacing grid diesel generation to the extent that they can be focused in the priority diesel generation periods (winter/spring) and flexible to address relatively wide variability in annual hydro generation capability[28].

Figure 6-3 provides, by option, forecast lifecycle costs of energy (LCOE) per kW.h (2010$) of generation used to displace forecast diesel over the economic life of each option[29]. Separate LCOE forecasts for Scenario A load with DSM/SSE, for sensitivity tests for mine load diesel displacement extended to 2025 and 2030, and for full utilization of all generation to displace diesel are summarized below:

- **Forecast LCOE with no mine loads after 2021** – Only LNG and Marsh Lake & Gladstone have LCOE less than 30 c/kW.h (13.1 c/kW.h for Marsh/Gladstone and 18.4 c/kW.h for LNG); the highest LCOEs are Wind option (40 c/kW.h) and Wood Biomass (60.8 c/kW.h).

- **Forecast LCOEs decline as mine load diesel displacement is extended** – With mine loads extended to 2025, only LNG and Marsh Lake & Gladstone have LCOE less than 20 c/kW.h (10.1 c/kW.h for Marsh/Gladstone and 15.2 c/kW.h for LNG), and the highest LCOEs are Wind (26.5 c/kW.h) and Wood Biomass (37.1 c/kW.h) – with mine loads extended to 2030, further LCOE declines occur without changing the cost ranking of the options.

- **Full Utilization LCOE do not reflect forecast diesel displacement** – Forecast LCOEs with no mine loads after 2021 are much higher than Full Utilization LCOE which assume all generation can always be fully used to displace diesel, e.g., 53% higher for LNG (Forecast LCOE vs. Full Utilization LCOE), 111% higher for Marsh/Gladstone, 133% higher for WTE, 176% higher for Wind and 285% higher for 15 MW Wood Biomass.

  Figure 6-4 demonstrates how Full Utilization generation varies from Forecast net diesel displaced with Scenario A loads for a Wind option over a 25 year economic life (highlights the impact of mine shutdown when the resource has no flexibility to limit its ongoing generation or costs).

In summary, LNG and Hydro Enhancements (Marsh Lake & Gladstone Diversion) have the lowest LCOE, and Wood Biomass has the highest LCOE, under all Scenario A cases examined in Figure 6-3.

[28] This reality reflects the lack of grid connection in Yukon to external markets - and the resulting need to ensure where feasible that local generation matches the local grid load requirements (as surplus generation cannot otherwise be usefully used or sold). See Section 5 regarding grid hydro seasonal load and supply characteristics, as well as annual hydro supply variability. In the end, resource options for the grid in Yukon are valued based on ability to displace diesel generation, i.e., generation that is surplus to diesel displacement needs has little if any value to ratepayers.

[29] LCOE and present value cost assume discount rate of 6.56%/year for new generation assets based on YEC's 2009 GRA approved return on equity and cost of new long-term debt. Assumed project life varies by resource option, e.g., 20-years for LNG, 25 years for WTE and Wood Biomass and Wind, 65 years for Hydro enhancements.

Figure 6-3: Forecast Lifecycle Cost of Energy (LCOE - 2010$) by Near-Term Option - Scenario A Load with DSM/SSE

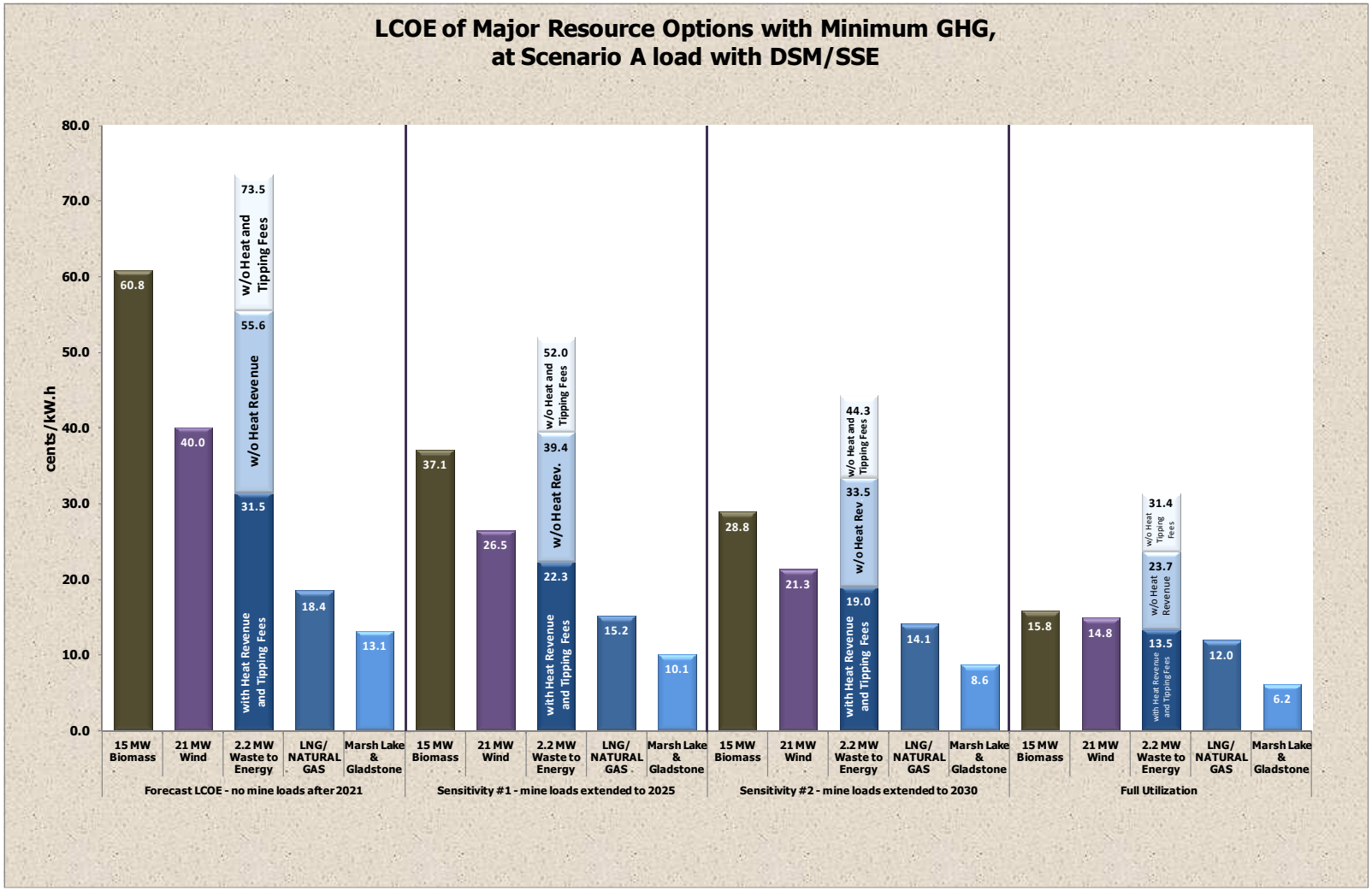
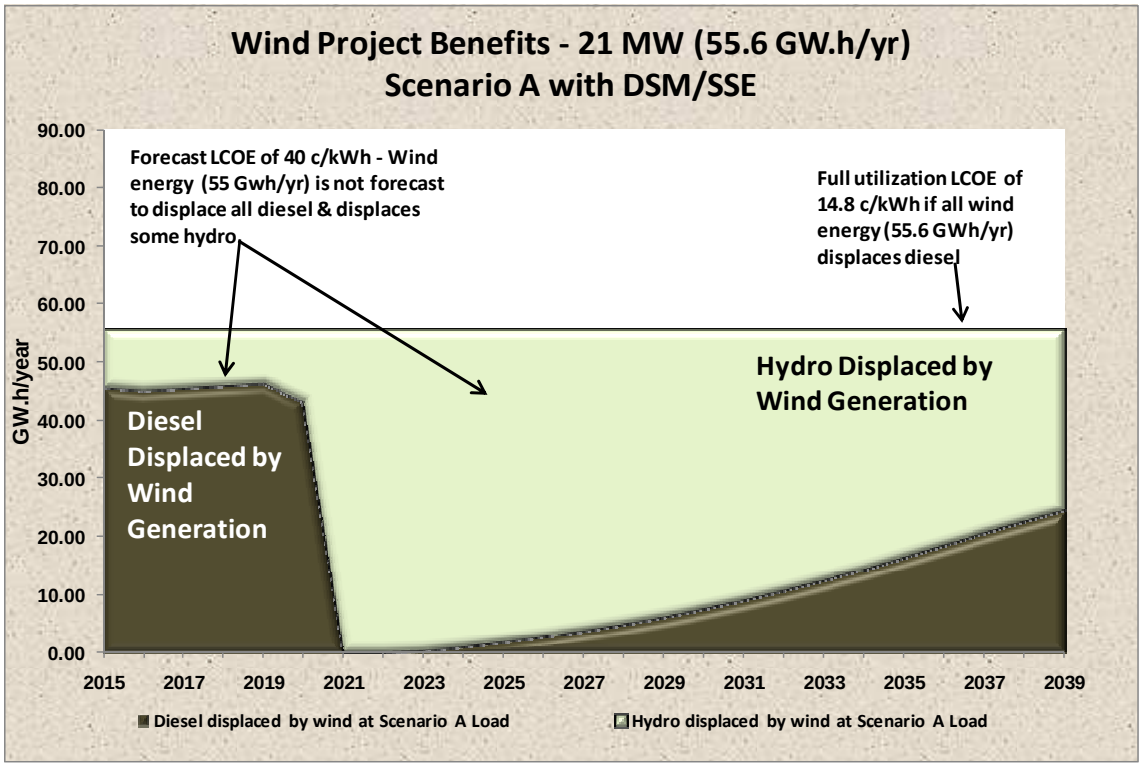


Figure 6-4: Wind Project: Displacing Diesel and Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021)



Near-Term Portfolio Options to Default Diesel

Alternative portfolios including each of the above near-term resource options have been reviewed considering grid economic impacts, Yukon greenhouse gas emissions impacts and long-term development considerations. Near-term cost and rate impacts vary significantly depending in large part on the capital intensive nature of each resource option and its flexibility relative to major forecast load reductions after 2020 under all resource plan forecast scenarios.

Table 6-1 provides an overview of different resource portfolio near-term options indentified in the 2011 Resource Plan (Scenario A grid loads with DSM/SSE are assumed for this table)[30].

[30] The same Resource Portfolio Options apply for Scenario B loads with DSM/SSE, and for Scenario A or B loads with no DSM/SSE, subject to the LNG plant being 30 MW capacity rather than 22 MW capacity. Base Case Portfolio Options are more limited due to smaller scale of the diesel displacement loads, e.g., with DSM/SSE the options are Marsh Lake Storage & 2.2 MW WTE for Minimum GHG Portfolio, and LNG 4 MW or Marsh Lake Storage & LNG 4 MW for LNG Transition Portfolio [if no DSM/SSE, LNG plant scale increased to 8 MW]; for Base Case loads, LNG options assume simple cycle power plant (40% energy efficiency) and reliance on LNG availability in Yukon to supply off-grid mine loads.

In addition to the Default Diesel Portfolio, the following Portfolio Options are identified (resource options assumed to be in operation by start of 2015, except for Gladstone Diversion [assumed in operation by start of 2018]):

1. Minimum GHG Portfolio Options:
    a. Marsh Lake Storage & 15 MW Wood Biomass (89-92% reduction of grid diesel GHG for 2015-2019 period)[31].
    b. Marsh Lake Storage, Gladstone Diversion & 21 MW Wind (60-61% reduction of grid diesel GHG for 2015-17 period and 84-85% for 2018-19 period [after Gladstone]).
    c. Marsh Lake Storage, 21 MW Wind & 2.2 MW Waste-to-Energy (WTE) (70-74% reduction of grid diesel GHG for 2015-2019 period).
2. LNG Transition Portfolio Options:
    a. Marsh Lake Storage & LNG (22 MW) (52% reduction of grid diesel GHG for 2015-2019 period).
    b. LNG (22 MW) (48% reduction of grid diesel GHG for 2015-2019 period).

Table 6-1 compares the present value (PV) incremental generation costs of each Portfolio option over the 20-year planning period and the Forecast LCOE (levelized cost of energy over project life)[32].

- LNG Transition Portfolios have a much lower PV cost and Forecast LCOE than Default Diesel.
    - LNG Portfolio PV costs at 65-66% of PV costs for Default Diesel Portfolio.
    - LNG Forecast LCOE at 47-51% of Default Diesel Portfolio Forecast LCOE (61-66% if compare only with diesel fuel and O&M costs).
- LNG Transition Portfolios have a much lower PV cost and Forecast LCOE than any of the Minimum GHG Portfolio Options.
    - Minimum GHG Portfolio PV costs 110-120% of PV costs for Default Diesel Portfolio.
    - Minimum GHG Portfolio Forecast LCOE at 80-109% of Default Diesel Portfolio Forecast LCOE (104-141% if compare only with diesel fuel and O&M costs).

[31] The Wood Biomass resource option is typically assumed to operate year round – however, it is assumed to be flexible enough to shut down when grid annual load drops to very low levels after 2020 (as a result, the material O&M cost of $72.8/MW.h (2010$) is saved, providing this option with PV cost savings relative to other Minimum GHG resource options which do not have this flexibility).
[32] PV cost and LCOE assume discount rate of 6.56%/year based on YEC's 2009 GRA approved return on equity and cost of new long-term debt. PV cost excludes assumed $35.4 million PV cost for DSM/SSE over this period, which is common to all Portfolio options. Forecast LCOE for a specific resource option is cents per kW.h of forecast diesel displaced [2010$] over the assumed economic life of that resource option and assuming forecast diesel generation under Scenario A with DSM/SSE.

Table 6-1: Overview of Resource Portfolio Near-Term Options Scenario A with DSM/SSE: 2011-2030

	PV Cost million[1]	Forecast LCOE[2]	Capital Cost (2010$)		O&M Cost (2010$)		Reliable Capacity	Total Capacity	Energy Capability	Diesel Required/ Displaced
	(2010$)	c/kWh	$/MW	$million	$/MW.h	$mill./ year	MW	MW	GW.h/year	2015-19 av. GW.h/yr
Default Diesel Portfolio										
Diesel Energy	133.9	28.0			280.3	-			292.0	85
Diesel Capacity	34.7	8.1	1.5	55.6			37.1	37.1		
Total Default Diesel	**168.6**	**36.1**								
Min GHG Portfolio Options										
Marsh & 15 MW Wood Biomass										
Marsh Lake Storage	7.0	**34.8**		10.5	-	0.1	1.0	1.0	6.7	6
Wood Biomass (15 MW)*	121.8		5.7	85.5	72.8	4.0	15.0	15.0	120.0	72
Diesel Energy	39.7				280.3				166.4	7
Diesel Capacity	16.5		1.5	31.6			21.1	21.1		
Total	**185.0**			127.6			37.1	37.1		
*No O&M after 2020										
Marsh, Gladstone & 21 MW Wind										
Marsh Lake Storage	7.0	**29.0**		10.5		0.1	1.0	1.0	6.7	6
Gladstone Diversion	20.8			40.0		0.2	-	-	36.6	NA
Wind (21 MW)*	88.4		3.6	93.4		2.1	5.0	26.0	55.6	45
Diesel Energy	57.1				280.3				245.3	NA
Diesel Capacity	27.3		1.5	46.6			31.1	31.1		
Total	**200.6**			190.5			37.1	58.1		
*Includes 5MW DRUPS										
Marsh, 21 MW Wind, & 2.2 MW WTE										
Marsh Lake Storage	7.0	**39.4**		10.5		0.1	1.0	1.0	6.4	6
Wind (21 MW)*	88.4		3.6	93.4		2.1	5.0	26.0	55.6	45
2.2 MW Waste to Energy (WTE)	25.9		17.7	39.0		(0.3)	2.2	2.2	17.1	14
Diesel Energy	56.7				280.3				228.0	20
Diesel Capacity	24.6		1.5	43.3			28.9	28.9		
Total	**202.6**			186.2			37.1	58.1		
*Includes 5MW DRUPS										
LNG Transition Portfolio Options										
Marsh & 22 MW LNG										
Marsh Lake Storage	7.0	**17.1**		10.5		0.1	1.0	1.0	6.4	6
LNG (22 MW)	65.4		1.8	40.3	95.6-107.9	0.1	22.0	22.0	173.4	79
Diesel Energy	29.2				280.3				111.2	-
Diesel Capacity	10.6		1.5	21.1			14.1	14.1		
Total	112.1			71.9			37.1	37.1		
LNG (22 MW)										
LNG (22 MW)	69.0	**18.4**	1.8	40.3	95.6-107.9	0.1	22.0	22.0	173.4	85
Diesel Energy	29.2				280.3				119.1	-
Diesel Capacity	11.4		1.5	22.6			15.1	15.1		
Total	109.6			62.9			37.1	37.1		

Notes: 1. PV = Present Value cost over 20-year planning period (2011-2030). Excludes $35.4 million PV cost for DSM/SSE.
2. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010$]) over project life.

The LNG resource option has much lower incremental capital costs than the wood biomass or wind resource options examined, and much lower capital costs per MW than each of the Minimum GHG resource options. LNG, WTE and Wood Biomass resource options each provide reliable capacity equal to their plant capacity – in contrast, Wind and Gladstone each provide little if any reliable capacity benefits.

Comparative Rate Impacts for Near-Term Portfolio Options

The Default Diesel Portfolio shows material increases in grid diesel energy requirements by 2015 under all load scenarios. Assuming DSM/SSE, diesel fuel and O&M cost increases from 2011 to 2015 are projected at $4.3 million with Base Case loads, $25.9 million with Scenario A loads and $43.8 million with Scenario B loads (see Figure 5-1 and accompanying table). Increased revenues from new loads will offset some, but not all, of these increased costs - resulting in upward pressure on rates.

Unlike the Default Diesel Portfolio, LNG portfolio options allow major new incremental loads to occur by 2015 under Scenario A or B without requiring material rate increase impacts. As reviewed in Figure 6-2, average annual costs in 2015 with Scenario A loads and DSM/SSE are projected at 17 cents/kW.h with LNG (including capital costs) as compared to 29 cents/kW.h with diesel (fuel and O&M costs, excluding capital costs).

The Minimum GHG Portfolio options show varying rate impacts during 2015-2020 depending on the assumed load scenario. Overall, however, costs for these options during 2015-2019 are at best only slightly lower than diesel - and in several instances are higher than diesel fuel and O&M costs (see Figure 6-2).

After 2020 with Scenario A or B and DSM/SSE, the assumed drop in grid loads (when mine loads are forecast not to be connected, based on the then available information) at the outset could slightly reduce Default Diesel Portfolio rate impacts, but ongoing load growth by 2030 would lead to renewed rate increase pressures[33]. After the loss of the mine loads, LNG Transition Portfolio Options would continue to have lower rate impacts than any of the other non-diesel portfolio options - however, until later in the period (close to 2030) the Default Diesel Portfolio with these greatly reduced loads could have slightly lower rate impacts than the LNG Transition Portfolio Options[34].

A sensitivity test assuming connected mine loads continue to 2030 at sufficient levels to prevent a drop in grid diesel generation under the Default Diesel Portfolio indicates that the least cost LNG Transition

[33] Loss of mine loads leads to loss of all revenues from these loads, as well as reduced diesel costs as shown in Figure 5-1. All Portfolio Options, including Default Diesel, include assumed costs for DSM/SSE as well as capacity installed that are not reduced by mine load reductions.

[34] In cases with no DSM/SSE, the LNG Transition Portfolio Options would have lower rate impacts than Default Diesel in all years of the planning period (as well as lower rate impacts than any of the Minimum GHG Portfolio Options).

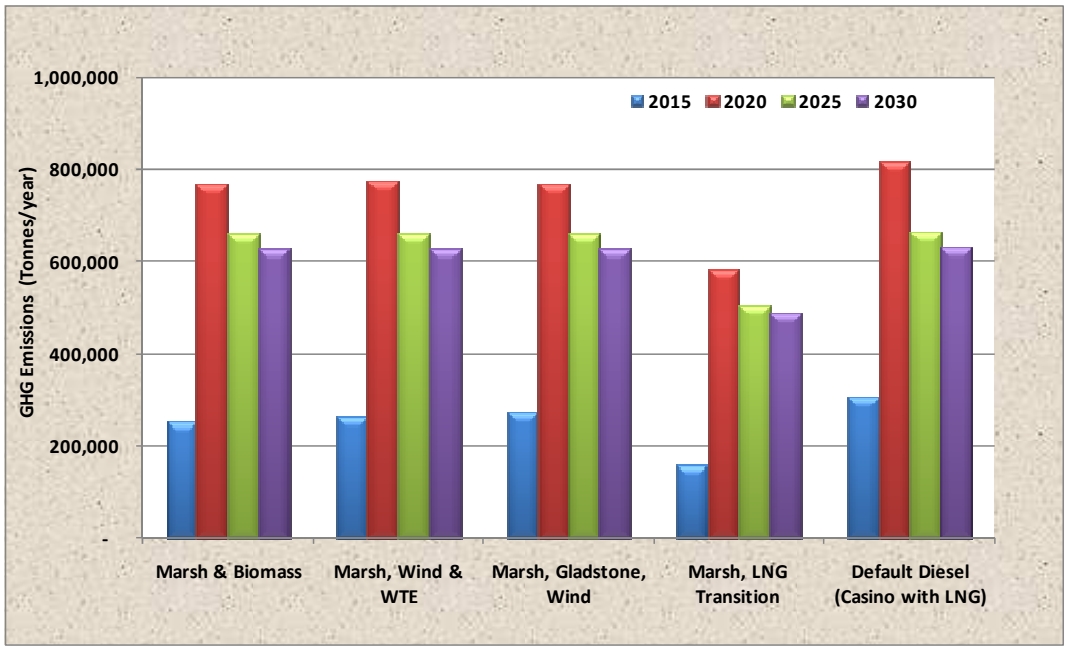
Portfolio Option continues through 2030 to show potential rate impacts that are materially lower than the potential rate impacts for all Minimum GHG Portfolio Options as well as the Default Diesel Portfolio.

Comparative GHG Emission Impacts for Near-Term Portfolio Options

LNG is the only non-diesel portfolio option examined for the near-term that can be used off-grid to reduce reliance on diesel (i.e., either off-grid communities or industrial customers).

Figure 6-5 demonstrates that when off-grid industrial and utility diesel community load opportunities are fully considered, near-term LNG supply development in Yukon as part of the LNG Transition approach has the potential to achieve far lower overall GHG emission levels from power generation in Yukon during the next 5-10 years than can be secured by grid-focused Minimum GHG Emissions Portfolio Options.

Figure 6-5: Portfolio Option Yukon GHG (tonnes/year) – 2015-2030
Grid Scenario A with DSM/SSE, Off-grid Diesel Community, & Off-Grid Mines



Total Yukon GHG Emissions (Tonnes/Year)[1]

	2015	2020	2025	2030
Marsh & Biomass	252,384	767,010	661,267	625,287
Marsh, Wind & WTE	263,266	775,226	661,267	625,287
Marsh, Gladstone, Wind	270,569	769,132	661,267	625,287
Marsh, LNG Transition[2]	158,844	582,266	505,355	488,089
Default Diesel (Casino with LNG)	306,067	815,235	662,522	630,560

1.Grid Scenario A with DSM/SSE, Off Grid Diesel Communities, & Off Grid Mines
2. Assumes LNG simple cycle at Watson Lake, LNG combined cycle at all mines.

The specified resource portfolios are examined in Figure 6-5, with any requirements not met by the specified resources assumed to be supplied by diesel generation under each portfolio. LNG is the only resource option other than diesel that can be applied in the near-term to off-grid as well as on grid requirements. The analysis excludes potential LNG impacts to reduce diesel and oil products in Yukon transportation and heating end uses (the largest GHG generating sectors in Yukon today).

- Yukon GHG emissions are materially lower in each time period with LNG than with any other resource option; reflects ability to apply LNG to off-grid diesel displacement.
- Overall LNG accessibility for all potential Yukon uses is facilitated by co-ordinated near-term planning and actions.

7.0 LONGER-TERM RESOURCE OPTIONS TO DEFAULT DIESEL

Greenfield Hydro Opportunities

A range of greenfield hydro resource project opportunities are potentially available to start construction before 2021, subject to appropriate planning and development of loads sufficient to fully utilize these resources[35]. These opportunities offer potential to establish sustainable lower cost electricity as well as low GHG emissions in a way similar to that secured by earlier legacy hydro developed in response to earlier major Yukon industrial mine developments.

Table 7-1 summarizes the available hydro sites by size of project, indicating key features as currently estimated (potential installed capacity, annual energy, capital cost and levelized lifecycle cost at full utilization)[36]. Total potential supply exceeds 6,800 GW.h/year at full utilization levelized cost (including transmission) below 15 cents per kW.h.

- **Hydro Options at less than 10 cents/kW.h** – Nine sites or schemes are identified with estimated Full Utilization LCOE's (2009$) below 10 cents per kW.h and over 4,390 GW.h per year of average annual sustainable energy (net of duplication among sites); four of these sites are Medium scale (11-60 MW) that could together provide over 850 GW.h/year; the other sites are Large scale (>60 MW).

- **Hydro Options at 10-15 cents/kW.h** – A further eight sites or schemes are identified with Full Utilization LCOE's between 10 and 15 cents per kW.h and over 2,000 GW.h of additional average annual sustainable energy; five of these sites are Medium scale (over 850 GW.h/year); the other sites are Large scale (>60 MW).

- **Other Medium Scale Hydro Options** – A further two Medium scale sites located north of the Watson Lake area are identified with Full Utilization LCOE's under 15 cents per kW.h if exceptionally high transmission cost estimates to connect to the existing grid are excluded from consideration. Together, these sites could provide over 375 GW.h per year of additional average annual sustainable energy.

[35] The geothermal option is identified in the 2011 Resource Plan as "other long-term options" in Yukon that might provide both low cost and low GHG emissions at some point during the planning period – however, beyond monitoring of related activities (e.g., geothermal exploration and confirmation drilling), the 2011 Resource Plan does not consider specific planning activities for the next five years. Similarly, monitoring of ongoing activities is all that is considered today with regard to potential development in the future of a natural gas pipeline, Eagle Plains gas, or transmission connection to the BC grid and/or Alaska.
[36] See Figure 1-2 for map showing the location of identified load and resource supply options.

Development of such longer-term renewable resource options is subject to connecting new grid loads that could fully utilize the specific resource options over 20-30 or more years.

- Potential off-grid mine developments prior to 2021 relying on fossil fuel generation are identified that could potentially exceed 1,500 GW.h/year and remain above 1,300 GW.h/year through 2045 in the event that three of these multi-decade off-grid mines are developed, i.e., the Casino Property west of the CSTP grid (940 GW.h/year), the Selwyn project located to the east of the WAF grid in the passes close to the border with NWT (147 GW.h/year), and the Northern Dancer project located near the Alaska Highway east of Teslin (200-300 GW.h/year).

- If the Alaska Highway Pipeline project proceeds, gas compressors for this project could potentially add 1,470 GW.h/year of additional equivalent energy requirements (six compressor stations) by approximately 2020/21 that would also be sustained over 25 years in the event that GHG emissions concerns support electrification initiatives.

Table 7-2 identifies potential off-grid mine loads and/or pipeline compressor loads that could radically change the electricity generation sector in Yukon during the next 5 to 10 years. These potential new loads offer the opportunity to plan for new legacy hydro development opportunities concurrent with actual development of new major mines or other major new loads. The following possible development packages are noted:

- **Develop Southern Lakes Grid Connection** – These are not low cost options; development of some of these options might be considered if Gladstone is not able to proceed and loads remain uncertain.

- **Develop Grid East of Ross River** – Potential options to consider in connection with Selwyn/Mactung mine loads, which offer 20+ years of load.

- **Develop Southern Grid to East Near Alaska Highway** – Potential options to consider in connection with Northern Dancer mine load and/or Alaska Highway Pipeline compression loads which offer 20+ years of load.

- **Develop Central & Western Yukon Grid** – Potential options to consider in connection with Casino and other mine loads south of Dawson City, which offer 20+ years of load.

Protecting the option to start construction for such projects before 2021 is contingent upon sustaining sufficient site specific planning processes as required throughout the next five year period through 2015. Figure 7-1 sets out proposed planning activities that would need to be pursued during the next five to ten years to protect the ability to start construction prior to 2021.

Coordination with LNG Transition Portfolio Option

The LNG Transition Portfolio Option is a near-term rather than a long-term legacy resource option for Yukon. The intent is to displace LNG use with appropriate renewable resource options when it is cost effective to do so, i.e., when sustained high utilization can be effectively achieved for renewable options so as to secure Forecast Utilization LCOEs that are equivalent to or less than LNG costs.

LNG Transition Portfolio Options are expected to show escalating costs as natural gas prices increase at a rate faster than general inflation. By 2020, the initial year costs for a new hydro development with a levelized cost (2010$) of 10 cents/kW.h might potentially correspond to the then current costs for LNG-supplied generation - in which case, subject to securing sufficient long-term load, the transition from LNG to new hydro could occur relatively smoothly[37].

At such time as new hydro develops, LNG grid generating unit capacity no longer needed for baseload energy generation can be retained for peaking, low water and emergency/grid reliability use. These units are flexible as to the range of such uses - and will likely be dual fuel in nature such that they can also use diesel fuel if so required. Furthermore, when new hydro is developed LNG supplies are expected to continue to be provided in Yukon to meet remaining off-grid power loads as well as other sector loads such as transportation[38]. Introduction of LNG/natural gas supplies in Yukon will also likely create longer-term development of natural gas use in the transportation and heating sectors.

[37] Figure 6-2 shows annual costs per kW.h during the period of forecast connected mine loads (2015-2020), indications that LNG annual costs (with capital) during this period remain well below annual costs for all renewable options other than the hydro enhancement options (Marsh Lake Storage and Gladstone Diversion) - by 2020, LNG costs in escalated dollars approximate 19 c/kW.h (13 cents for fuel and O&M only).

[38] These same considerations apply in the event that natural gas supplies come to be available directly in Yukon through the Alaska Highway Pipeline Project and/or Eagle Plain gas development. LNG liquefaction facilities may need to be moved to (or developed in) Yukon - but ongoing LNG requirements are anticipated to remain for off-grid power uses and other sectors.

Table 7-1: Summary of Potential Hydro Sites

		Installed Capacity (MW)	Annual Energy (GWh)	Capital Cost (Million $2009)	Levelized Cost (c/kWh)
Small Hydro Projects <10MW)					
20-23 c/kWh	Moon Lake	5.8	32.9	126.8*	19.9
	Tutshi River	4.2	30.3	135.5*	23.1
	Tutshi (Windy Arm)	5.9	39.4	164.9*	21.6
	Pine Creek at Atlin	3.5-8	23-52	NA	NA
Medium Hydro Projects (<60 MW)					
< 10 c/kWh	Hoole Canyon with Storage	40.4	275	460.1	8.6
	Granite Canyon Small	60.0	400	670.3	8.7
	Slate Rapids	41.6	266	505.6	9.8
	Finlayson	17.0	128.9	233.7**	9.4
10 to 15 c/kWh	Ross Canyon	30	181	495.0	14.1
	False Canyon	58	370	1,036.3**	14.5
	Two Mile Canyon	53.1	280	696.5	12.9
	Combined Slate Rapids[1] & Hoole	50.1	351.1	728.9	10.7
	Slate Rapids[1] (powerhouse at foot of dam	22.3	156.3	441.4	14.6
Other[2]	Middle Canyon	38.0	200	773.5***	20.0
	Upper Canyon	25.2	176.6	677.2***	19.8
Large Hydro Project (>60 mW)					
< 10 c/kWh	Granite Canyon High	254.0	1,783	1,680.7	4.9
	Fraser Falls Low	100.0	700	1,340.4	9.9
	Granite Canyon Low	80.0	600	934.8	7.3
	Fraser Falls High	300.0	2,100	2,540.6	6.3
	Combined Slate Rapids & Hoole	69.4	459	849.7*	9.6
10 to 15 c/kWh	Detour Canyon	65.0	435	1,057.0	12.6
	Detour Canyon w storage At Pelly Lakes	100.0	585	1,301.0	11.5
	Liard Canyon	93.5	659	1,554.6**	12.2

Notes:

1. Powerhouse at foot of dam

2. Excluding exceptionally high transmission costs to connect to existing grid, these sites would be under 15 cents per kW.h.

* Transmission costs to connect to grid are 18% of cost for Tutshi (Windy Arm), 21% of cost for Combined Slate Rapids & Hoole Canyon, and 26-27% of cost for Moon Lake & Tutshi River.

** Transmission costs are 33% of cost for Liard Canyon, 36% of cost for Finlayson, and 38% of cost for False Canyon.

*** Transmission costs to connect to existing grid are estimated at 54-55% of cost for these sites.

Table 7-2: Yukon Industrial Load Opportunities and Potential Hydro Sites

POTENTIAL INDUSTRIAL LOAD OPPORTUNITIES

Developing low cost/low emission hydro options depends on connecting new grid loads that could adequately utilize the resource for 20-30 years

DEVELOP SOUTHERN LAKES GRID CONNECTIONS

Timing for development of these projects in the next decade will depend on whether or not Gladstone is developed, future grid loads and definition of distinct hydro project opportunities

DEVELOP GRID TO EAST OF ROSS RIVER

SELWYN (147 GWh/yr) **& MACTUNG**
30+ year load in service 2014/15 - A medium hydro project in the 17-30 MW range (129 to 181 GWh/yr) to the east of the northern WAF grid could match all or most of the Selwyn load

DEVELOP SOUTHERN GRID TO EAST NEAR ALASKA HWY

NORTHERN DANCER (200-300 GWh/yr) - a 30 year load in service in 2017 to east of Teslin. A medium hydro project to serve this load could provide basis for extension of grid in south-east portion of Yukon

PIPELINE COMPRESSOR - Marsh Lake - 245 GWh/yr load per compressor in service in 2020/21 - Could provide anchor load for a medium hydro project in 266-280 GWh range (25 year load)

PIPELINE COMPRESSOR - Alaska Hwy - 245 GWh/yr load per compressor in service in 2020/21; May provide an opportunity to develop sites and transmission in east Yukon such as Liard Canyon (25 year load); Liard Canyon may also support develpment of NORTHERN DANCER

DEVELOP CENTRAL & WESTERN YUKON GRID

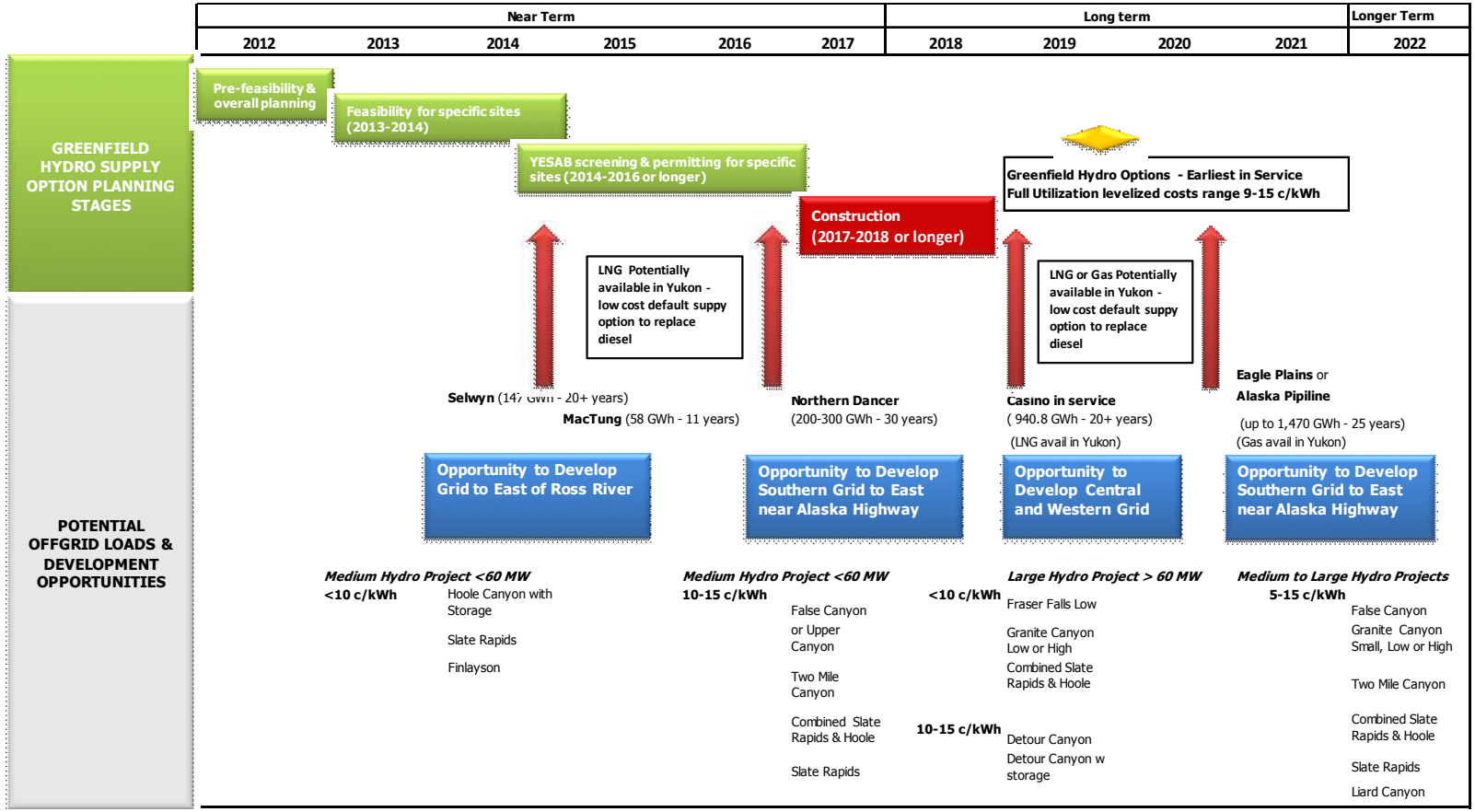
CASINO MINE (940.8 GWh/yr)
20-30 year load in service in 2018-19 - A large hydro project in the 69-100 MW range (450-700 GWh/yr) reasonably near the CSTP grid could match a large share of the Casino Load

POTENTIAL HYDRO DEVELOPMENT OPPORTUNITIES

		Installed Capacity (MW)	Annual Energy (GWh)	Levelized Cost (c/kWh)
Small Hydro Projects (<10MW)				
	Southern Lakes Projects			
20-23 c/kWh	Moon Lake	5.8	32.9	19.9
	Tutshi River	4.2	30.3	23.1
	Tutshi (Windy Arm)	5.9	39.4	21.6
	Pine Creek at Atlin	3.5 to 8	23-52	N/A
Medium Hydro Projects (<60 MW)				
< 10 c/kWh	Hoole Canyon with Storage	40.4	275	8.6
	Slate Rapids	41.6	266	9.8
	Finlayson	17	128.9	9.4
10-15 c/kWh	Ross Canyon	30	181	14.1
Medium Hydro Projects (<60 MW)				
10 to 15 c/kWh	False Canyon	58	370	14.5
	Middle Canyon*	38	200	20.0
	Upper Canyon*	25.2	176.6	19.8
	Two Mile Canyon	53.1	280	12.9
8.7 10 to 15 c/kWh	Combined Slate Rapids & Hoole	50.1	351.1	10.7
	Granite Canyon Small	60	400	8.7
	Slate Rapids	22.3	156.3	14.6
Large Hydro Project (> 60 MW)				
10-15 c/kWh	Liard Canyon	93.5	659	12.2
Large Hydro Project (> 60 MW)				
< 10 c/kWh	Granite Canyon Low	80	600	7.3
	Fraser Falls Low	100	700	9.9
	Granite Canyon High	254	1783	4.9
	Fraser Falls High	300	2100	6.3
	Combined Slate Rapids & Hoole	69.4	459	9.6
10 to 15 c/kWh	Detour Canyon	65	435	12.6
	Detour Canyon w storage	100	585	11.5

*Transmission costs to connect to existng grid are 54-55% of levelized cost.

Figure 7-1: Overview of Planning Activities for Greenfield Hydro Supply Option Development - 2011-2021



8.0 SUMMARY CONCLUSIONS & RECOMMENDED PLANS

Overview of Options

Figure 8-1 summarizes near-term options examined in the 2011 Resource Plan in the context of Yukon Energy's four key planning principles. Conservation/efficiencies (DSM/SSE) programs are being developed as an option to be pursued in combination with other selected resource options.

Figure 8-1: Near-Term Resource Supply Options[39]

OPTIONS	**Reliability** Winter Peak Capacity; Development Timing & Cost	**Affordability** Potential lifecycle cost per kWh if fully used	**Flexibility** Ratepayer Risk re: Mine Load Reductions	**Environmental Responsibility** Env. Mitigation; GHG Emission Reduction
Southern Lakes (Marsh Lake) Hydro Enhancement	**Medium**	**High**	**Medium**	**High**
Gladstone Diversion Hydro Enhancement	**Medium**	**High**	**Medium**	**High**
Conservation / Efficiencies	**Medium**	**High**	**Medium**	**High**
Biomass	**High**	**Medium**	**Low**	**High**
Liquefied Natural Gas	**High**	**Medium / High**	**High**	**Medium**
Wind	**Low**	**Low**	**Low**	**High**
Diesel	**High**	**Low**	**High**	**Low**

Table 8-1 provides an overview of the near-term resource options identified for potential construction start on the grid before 2015 (including a 3 MW wood biomass pilot plant option[40]), and the longer term resource options identified for potential construction start before 2021. The Gladstone Diversion project is excluded from the near-term options on the basis that construction start is not feasible before 2015, and

[39] See Table 4-1 for more detail.

[40] The 2011 Resource Plan examined various wood biomass plant options, ranging from 10 MW to 25 MW and at different locations to accommodate potential wood biomass supply (e.g., Whitehorse for 25 MW plant; 10 to 15 MW plant in Minto burn area option). Based on feedback from the workshop held on wood biomass, this option has been scaled back to a 2-3 MW wood biomass pilot plant option. Yukon Energy is currently developing a partnership with the Champagne and Aishihik First Nations and Dakwakada Development Corporation to examine opportunities for a small-scale (2-3 MW) wood biomass pilot project, potentially with existing wood operations at Haines Junction, and to seek funding support for this pilot plant.

earliest in-service is in late 2017. Table 8-2 provides a more detailed overview of the near-term resource option capabilities and costs under both Scenario A and B grid loads with DSM/SSE.

In the near-term, LNG is identified in the 2011 Resource Plan as the only near-term option that can totally displace Default Diesel on the grid during 2015-2019 with forecast Scenario A or B loads (e.g., with forecast diesel generation ranging from 85 to 143 GW.h/year with DSM/SSE). Excluding the relatively small energy impact Marsh Lake Storage hydro enhancement option (approximately 6 GW.h/year), LNG is also the lowest cost near-term option, with costs per kW.h of diesel displaced less than half the cost of diesel. Wood Biomass ranks second behind LNG in diesel displacement capability, but is the highest cost near-term option (with costs per kW.h of diesel displaced higher than the cost of diesel). The only other near-term option with potential ability to displace more than 50% of Scenario A diesel generation requirements (i.e., Wind) has 2015-2019 costs per KWh only slightly lower than diesel, and forecast LCOE costs that are higher than diesel under Scenario A or B loads with the assumed DSM/SSE.

In contrast to the near-term options, longer term hydro options are identified in the 2011 Resource Plan that offer a wide range of annual energy capability (e.g., options in Table 8-1 range from 33 to over 450 GW.h/year), with several options also having estimated Full Utilization LCOE at less than 10 cents/kW.h. The 2011 Resource Plan outlines the requirements for successful development of these longer term options, including securing appropriate long-term loads as required to adequately utilize such options over 20-30 or more years and sustaining sufficient and successful site specific planning processes over the next five years to protect the ability for potential construction start before 2021.

Tables 8-1 and 8-2 also show the extent to which each near-term resource option's economic feasibility (i.e., comparative LCOE) is affected by the option's flexibility to adapt to Yukon's isolated grid and the expected range of load and hydro generation conditions on this grid.

- LNG, Wood, Wind and Waste-to-Energy options, for example, show minimal variation in estimated LCOE when full utilization is simply assumed of all electricity generated for each option, e.g., LCOEs (2010$) for these options range from 12 c/kW.h for LNG to 17 c/kW.h for the 3 MW Wood Pilot.

- However, when Scenario A forecast loads (which are well in excess of Base Case loads) and expected hydro conditions on Yukon's isolated grid are considered, LNG is the only option with an LCOE at less than 20 c/kW.h for diesel displaced, and the 3 MW Wood Pilot is the only other option with an LCOE less than diesel fuel and O&M cost at 28 c/kW.h. Higher LCOEs for Wind, 15 MW Wood Biomass and 2.2 MW Waste-to-Energy options in this instance reflect relative

inflexibility to adapt to an assumed sharp drop in mine loads on the grid after 2020 as well as seasonal and annual variability in hydro generation on the grid.

LNG Transition Option Near-Term Benefits

In summary, the 2011 Resource Plan indicates that the LNG Transition Portfolio option provides a range of potential benefits relative to the other near-term grid generation options available for potential commitment before 2015:

- LNG is superior to diesel in terms of cost (affordability) and emissions (environmental responsibility); relative to near-term renewable resource options, LNG is less costly while also providing high reliability, flexibility and diversity of potential Yukon uses on and off-grid.
- Where established, LNG would displace diesel as the default option in Yukon (although dual fuel units could also cost effectively retain flexibility to use diesel if and when advantageous). Lower cost LNG fuel would affect the assessment of future resource choices and also incremental pricing and rate setting in the rate zones where it is utilized, i.e., run out rates for higher use levels could be set based on LNG costs rather than diesel fuel costs.
- Other potential development benefits include:
    - LNG is the only option to offer material reductions in near-term rate increase impacts relative to diesel under Scenario A or B loads, as well as the non-diesel option with the lowest rate impacts in the event that currently assumed mine closures reduce grid loads after 2020.
    - LNG provides a cost effective contribution to grid capacity planning requirements, and the planned retirements of all of YEC's diesel plant over the 20-year planning period.
    - As a result of the above impacts, LNG is the only option to offer opportunity to reduce present value diesel costs during the planning period under Scenarios A and B (projected reductions at 35% under Scenario A and 41% under Scenario B).
    - Overall, LNG offers high flexibility with ability to be turned off and ability to accommodate load changes; it can provide cost effective baseload generation and backup capacity, and can be cost effectively developed concurrently with hydro enhancements such as Marsh Lake Storage and Gladstone Diversion.
    - The LNG Transition Option can accommodate optimum timing for Gladstone diversion, other potential hydro enhancements or greenfield developments, and wind development

in response to confirmation of longer-term grid loads needed to secure reduced Forecast LCOE for these various renewable resource options.

- LNG is the only portfolio option that can be used off-grid to reduce reliance on diesel (i.e., off-grid communities such as Watson Lake and mines at various off-grid locations). This option can also be used to reduce GHG emissions in other sectors where GHG emissions impacts are more significant (e.g., transportation).

In order to pursue the LNG option for near-term development for power generation in Yukon by late 2014, Yukon Energy is pursuing further feasibility work to determine the optimum way to secure the LNG, the required timing and all related costs (including assessment of potential options for LNG supply chain development jointly with other interests to meet broader near and longer term Yukon opportunities). Feasibility work is also being pursued to optimize the specific Yukon Energy generation capacity and technology for power generation using LNG (including assessment of the optimum combination of combined cycle and simple cycle units in response to different potential load scenarios).

Resource Portfolios - Combining Options

Combining projects on the Yukon grid can dilute the benefits and raise LCOEs relative to what is shown for individual options.

For example, the Scenario A (with DSM/SSE) LCOE is 11.4 c/kW.h for Marsh Lake storage on its own and 8.0 c/kW.h for Gladstone Diversion on its own (see Table 8-1) - however, combining these two hydro enhancement projects results in a higher overall LCOE at 13.1 c/kW.h for the combined projects.

Similarly, LCOEs (2010$)per kW.h of displaced diesel generation for various renewable resource options under Scenario A loads are significantly higher when combined with the assumed DSM/SSE than when assessed without DSM/SSE[41]:

- Marsh Lake Storage LCOE: 11.4 c/kW.h with DSM/SSE, 8.6 c/kW,h without DSM/SSE.
- Gladstone Diversion LCOE: 12.0 c/kW.h with DSM/SSE, 6.5 c/kW,h without DSM/SSE.
- 2.2 MW Waste to Energy: 31.5 c/kW.h with DSM/SSE, 17.6 c/kW,h without DSM/SSE.
- 3 MW Wood Pilot: 35.4 c/kW.h with DSM/SSE (with assumed shut down in 2020), 22.7 c/kW,h without DSM/SSE (no shut down).
- 15 MW Wood Biomass LCOE (with assumed shut down after 2020): 40.1 c/kW.h with DSM/SSE, 17.8 c/kW,h without DSM/SSE.

[41] LNG LCOE for Scenario A also slightly reduced (18.4 c/kW.h with DSM/SSE, 14.0 c/kW.h without DSM/SSE).

- 21 MW Wind with 5 MW DRUPS: 40.0 c/kW.h with DSM/SSE, 19.6 c/kW.h without DSM/SSE.

In summary, dilution of benefits and higher LCOEs that result from combining projects highlight once again the extent to which load and hydro conditions on the isolated Yukon grid can critically affect economic assessment of resource option portfolios.

Table 8-1: Overview of Resource Options - Capabilities and Costs

	Capital (2010$ million)	Capacity (MW)	Energy Capability (Average GWh/yr)	2015-2019 Diesel Required/ Displaced (GWh/yr)	2015-2019 Annual Costs (cents/kW.h diesel displaced)	LCOE (2010 c/kWh) Scenario A	LCOE (2010 c/kWh) Extend 2019 load to 2030	LCOE (2010 c/kWh) Full Utilization
Near Term Options (able to start construction before 2015) with Scenario A Loads and DSM/SSE - Default Diesel is new capacity needed by 2030								
Default Diesel Requirement	56	37	292	85	29-31 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)
Waste to Energy	39	2.2	17	14	27-31	31.5	19.0	13.5
Wind with 5 MW DRUPS	93	26*	56	45	26-29	40.0	21.3	14.8
		*21 MW wind not firm						
		10.5 MW wind option was slightly less cost-effective at forecast loads.						
Marsh Lake Storage	10	NA	6.7	6.4	15-16	11.4	8.8	8.5
25 MW Wood Biomass	114	25	199	85	48-51	55.4*	42.8	16.6
15 MW Wood Biomass	86	15	120	72	33-35	40.1*	28.8	15.8
3 MW Wood Pilot (Haines J.)	19	3	24	18	28-29	35.4*	24.7	17
						*shut down after 2020		
LNG Transition	40	22	173	85	17	18.4	14.1	12
Long Term Options (Potential start construction before 2021)								
Gladstone Diversion	40	NA	36.6	29	14	12.03	8.0	5.7
Greenfield Hydro (examples)								
Moon Lake	127*	5.8	32.9	NA	NA	NA	NA	19.9*
Hoole Canyon (w storage)	460*	40.4	275	NA	NA	NA	NA	8.6*
Slate Rapids	506*	41.6	266	NA	NA	NA	NA	9.8*
Finlayson	234*	17.0	129	NA	NA	NA	NA	9.4*
Combined Slate & Hoole	850*	69.4	459	NA	NA	NA	NA	9.6*
	*Inc. Transmission to grid							*Inc. Transmission to grid

Table 8-2: Overview of Near-Term Resource Options - Capabilities and Costs: Scenario A Loads with DSM/SSE (options that could start construction before 2015 – Default Diesel Capacity is new grid capacity required before 2030)

	37 MW Default Diesel	22-30 MW LNG	15 MW Wood Biomass	3 MW Wood Pilot (Haines Junction)	21 MW Wind and 5 MW DRUPS[1]	2.2 MW Waste-to-Energy	Marsh Lake Storage
		Sc. A vs. Sc.B)					
Capital Cost (2010$ million)	56	40-55	86	19	93	39	10
Reliable Peak Winter Capacity Contribution (MW)	37	22-30	15	0	5	2.2	1
Annual Energy Supply (GW.h/year)							
Annual Energy Capability	292	173 - 236	120	24	56	17	6.7
2015-19 Average Diesel Energy Required/Displaced							
Scenario A Load with DSM/SSE	85	85	72	18	45	14	6.4
Scenario B Load with DSM/SSE	143	143	93	22	51	16	6.6
Near term supply Issues/risks	NA	LNG supply BC/Alta	Wood Supply Regime	NA	NA	NA	Regulator approval timing
2015-19 Annual Costs (cents/kW.h diesel displaced)	(fuel+O&M)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)
Scenario A Load with DSM/SSE	29-31	17	33-35	28-29	26-29	27-31	15-16
Scenario B Load with DSM/SSE	29-31	16-17	27	24-25	24-26	24-27	14-15
2015-19 Cost Savings (% of Diesel Fuel and O&M)							
Scenario A Load with DSM/SSE	NA	43%	-11%	1%	4%	1%	4%
Lifecycle Cost of Energy (2010 cents/kWh diesel displaced)	(fuel+O&M)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)
Scenario A Load with DSM/SSE	28.0	18.4	40.1*	35.4*	40.0	31.5	11.4
Scenario B Load with DSM/SSE	28.0	17.0	31.6*	30.0*	36.5	28.8	11.1
Extend Scenario A 2019 load to 2030	28.0	14.1	28.8	24.7	21.3	19.0	8.8
Full Utilization of all energy in each year	28.0	12	15.8	17	14.8	13.5	8.5
Ability to adjust to load changes	Flexible	Flexible	Semi-flexible	Semi-flexible	Not flexible	Not flexible	Semi-flexible

* Shut down after 2020

Note #1: 10.5 MW wind option was slightly less cost-effective at forecast loads.

Graphic Comparisons of Near-Term Options

Figures 8-2, 8-3 and 8-4 compare key features of the near-term options and Gladstone Diversion under Scenario A loads with DSM/SSE, highlighting each option's comparative diesel displacement capability (GW.h/year) during 2015-2019. DSM/SSE (conservation/efficiency) option impacts as assumed in the 2011 Resource Plan are also included for broad comparison[42].

Figures 8-2 and 8-3 compare lifecycle costs per kW.h (LCOE) and capital cost for each option, with Figure 8-3 showing the extent to which LCOE is reduced for each option under Scenario A if the 2019 grid loads are extended to 2030.

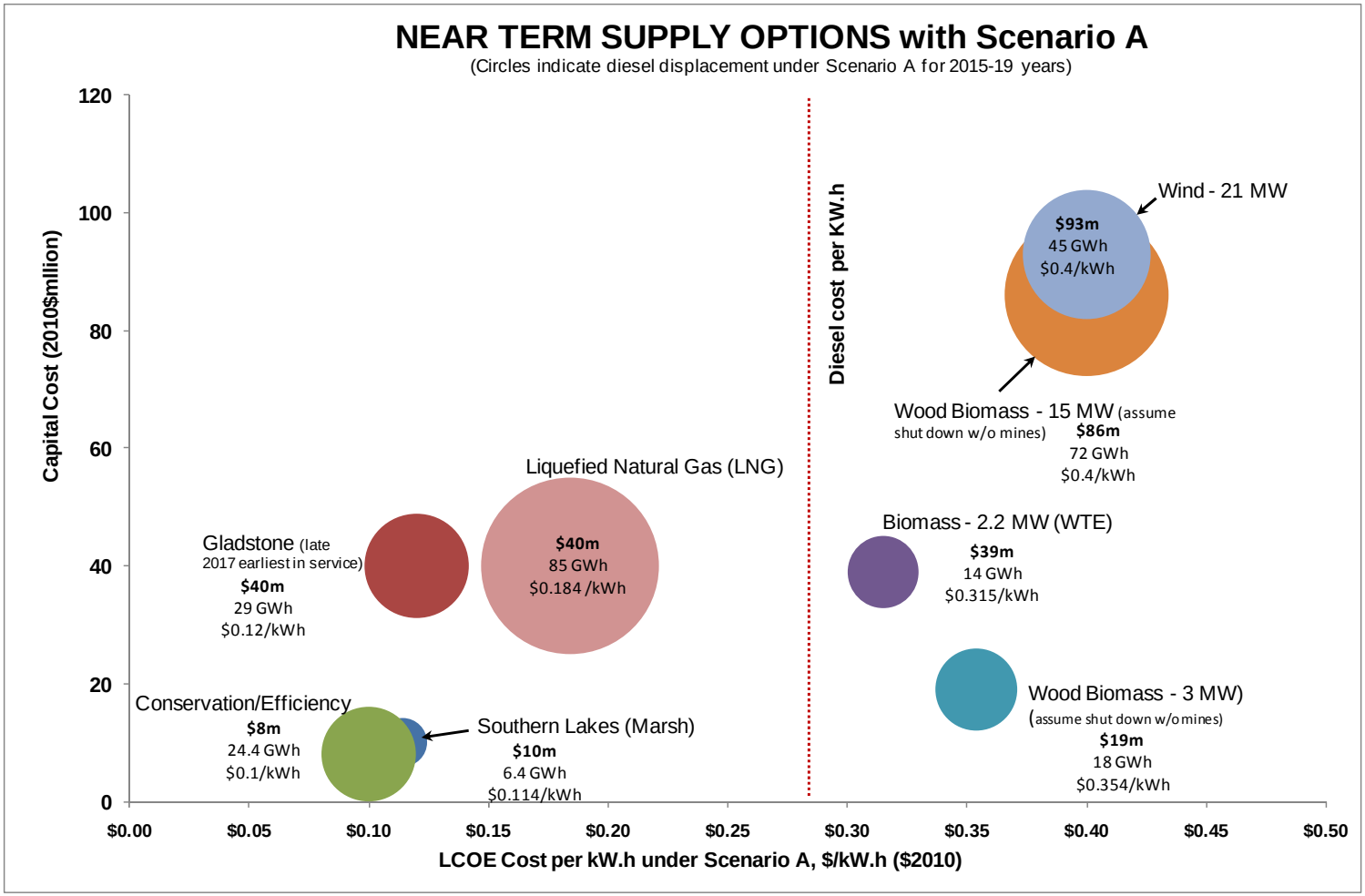
- Based on total capital costs ($2010) as shown in Figures 8-2 and 8-3, the wind and large scale biomass options require considerably higher capital costs than other near-term options, and LNG provides far greater diesel displacement than any other option requiring similar capital costs.
- Based on LCOE (2010$) for Scenario A loads with DSM/SSE as shown in Figure 8-2, near-term options with forecast lifecycle costs that are less the diesel include conservation/efficiency, hydro enhancements (Marsh Lake and Gladstone Diversion) and LNG; near-term option options with forecast lifecycle costs that are more than diesel include the biomass and wind options.
- Comparison of Figure 8-2 and 8-3 LCOE for any option highlights sensitivity to major changes in grid loads over the planning period, e.g., the wind and biomass options show significantly lower LCOE's if the 2019 grid loads are assumed to be extended to 2030.

Figure 8-4 focuses on impacts in the 2015-2019 period, comparing costs per kW.h and percentage savings in diesel fuel and O&M costs for each option.

- Differences in cost per kW.h of diesel displaced for the first few years of operation (2015-19) reflect normal utility costing (e.g., capital costs charged per year decline over the project life).
- Comparative near-term diesel fuel and O&M cost savings for ratepayers reflect diesel displacement capability as well as near-term cost saving capability per kW.h relative to diesel generation for each option, and highlight LNG's overall cost saving benefits relative to other near-term options.

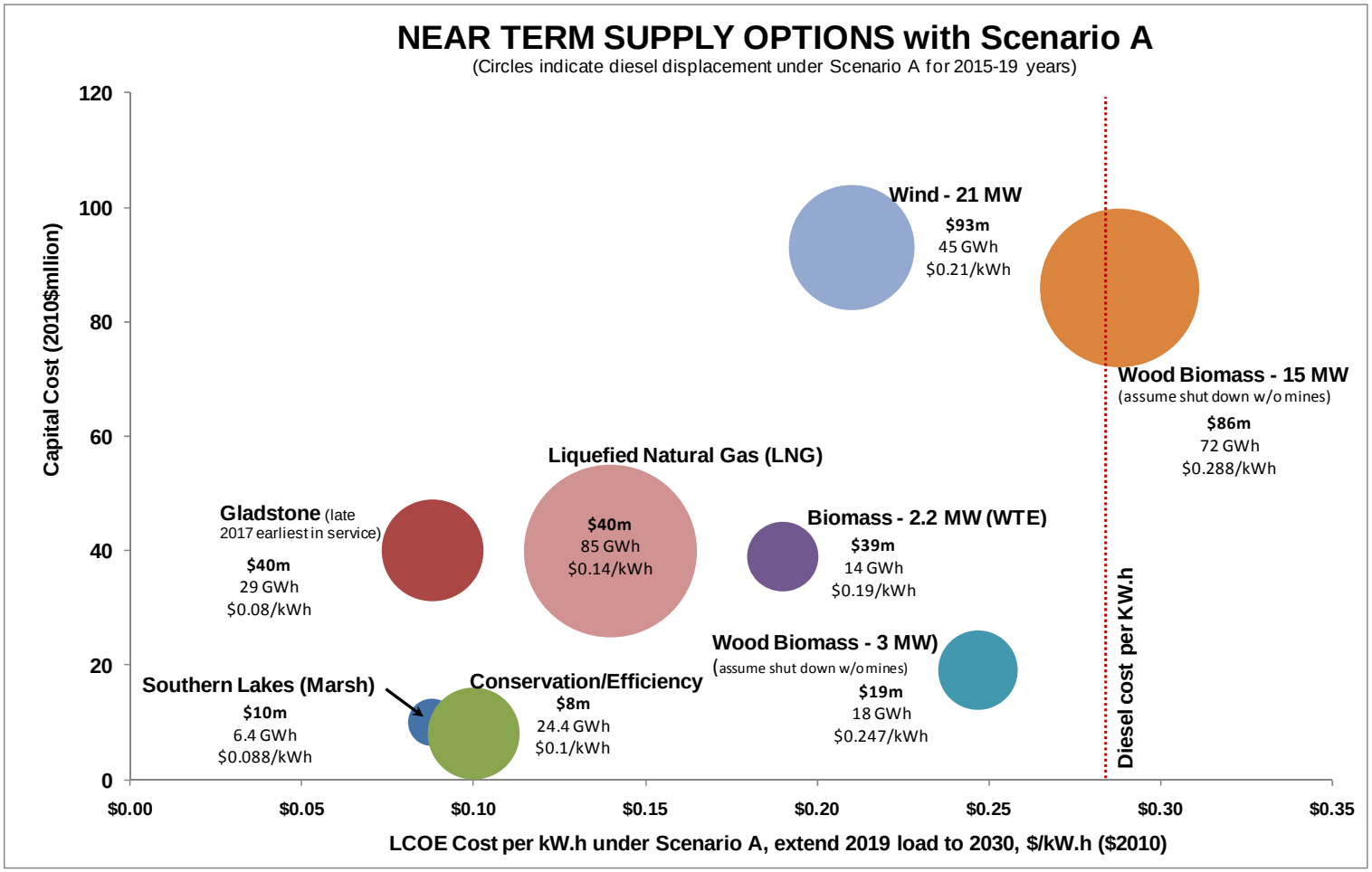
[42] These figures show the maximum potential DSM/SSE (conservation/efficiency) diesel displacement impacts assumed in the 2011 Resource Plan for non-industrial load reduction during the 2015-2019 time period. As noted in Appendix A, pending completion of current DSM/SSE planning, it is considered that likely DSM/SSE over the period to 2030 will be 50% of this maximum. In the near-term period from 2015 to 2019, DSM/SSE will be in an initial implementation phase and accordingly may be less (relative to the 2011 Resource Plan maximums) than levels expected to be achieved by 2030.

Figure 8-2: Overview of Near-Term Resource Options with Scenario A Loads (LCOE, Capital Cost & Diesel Displacement)



Source: Table 8-2 and Table 8-1.

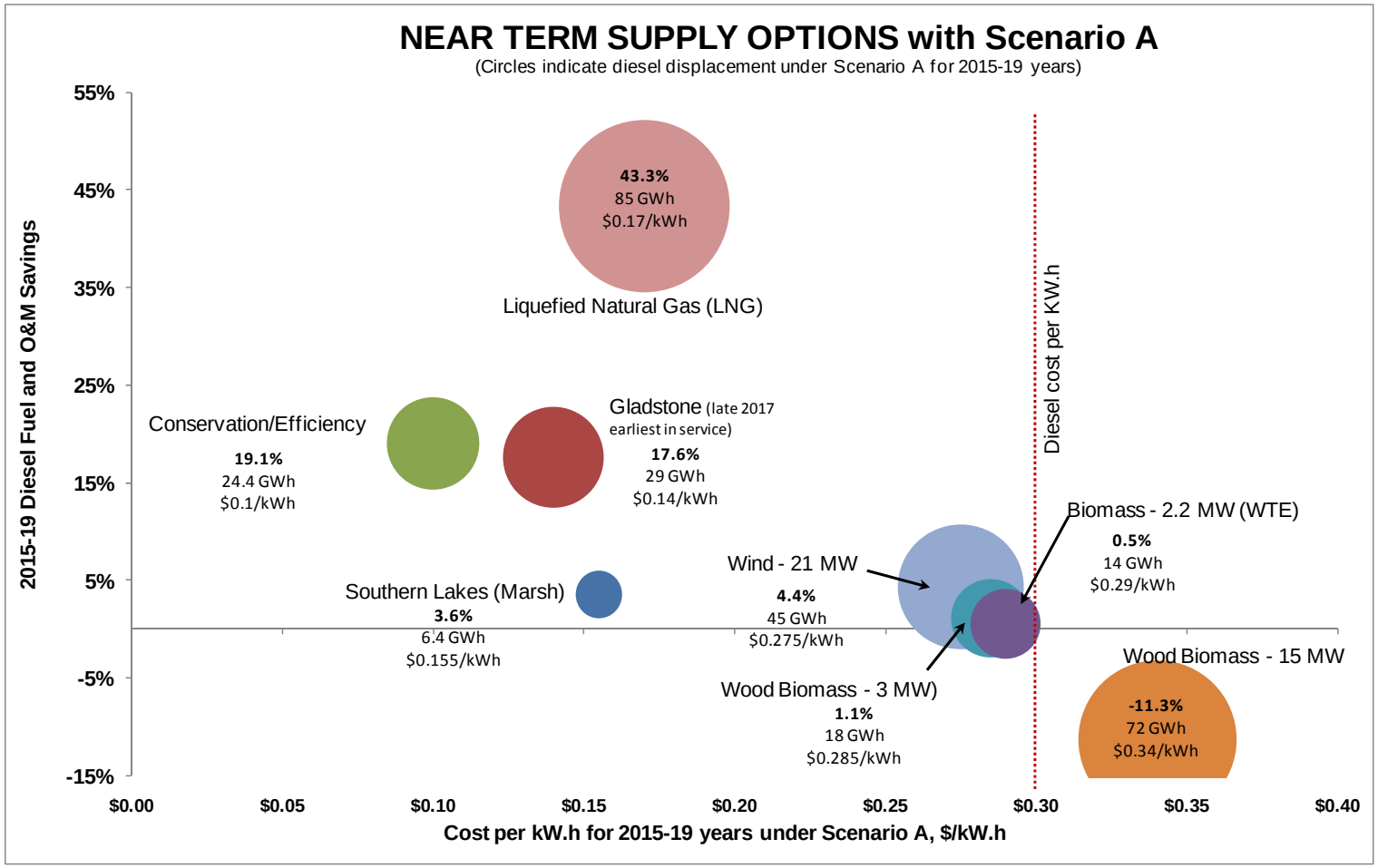
Figure 8-3: Overview of Near-Term Resource Options with Scenario A Loads
(LCOE with 2019 load extended to 2030, Capital Cost & Diesel Displacement)



Source: Table 8-2 and Table 8-1.

Figure 8-4: Overview of Near-Term Resource Options with Scenario A Loads 2015-2019

(Cost per kW.h, Diesel Fuel and O&M Savings, & Diesel Displacement)



Source: Table 8-2 and Table 8-1.

Recommended Plans

Based on the 2011 Resource Plan, Yukon Energy's recommended plans for the period prior to 2015 include the following (in addition to implementing cost-effective DSM/SSE pursuant to the separate ongoing planning process currently underway with other parties):

1. **LNG Transition Option:** Subject to successful completion of current assessments, determine whether Yukon Energy is able to establish LNG generating capability in Whitehorse prior to 2015 with sufficient capacity to displace grid diesel generation under current Base Case grid load forecasts, and determine the feasibility of utilizing LNG in the event that material additional near-term grid loads occur such as those assessed in Scenarios A and B. This action is being undertaken to implement LNG as a transition option that is able to meet current forecast loads with the least cost option available for near-term implementation, i.e., prior to 2015, and with reduced GHG and other emissions relative to diesel generation.

2. **Near-term Hydro Enhancements:**

    a. Complete the required environmental, engineering and remediation studies related to the Marsh Lake Storage hydro enhancement project and make a determination whether it is feasible and cost effective to proceed once this information is available.

    b. Plan within the next 6 to 12 months to reach a final determination regarding whether Gladstone Diversion is feasible to pursue further at this time, based on discussions with local First Nations and regulators.

3. **Future Development:**

    a. **Wind:** Finish current Ferry Hill wind monitoring in order to have this project shelf-ready to pursue through regulatory submissions and other development activity at such time as grid loads and other relevant conditions indicate that this project would be cost-effective to implement. Continue to examine for initial development the feasibility of smaller wind projects in the range of 10 MW to meet suitable grid loads.

    b. **Greenfield Hydro Sites:** Continue to carry out planning studies to identify and plan priority longer-term greenfield hydro development opportunities as recommended in the 2011 Resource Plan, including Hoole and Finlayson sites, and seek funding support for these activities.

4. Other Longer-Term Resource Planning:

a. **Geothermal:** Carry out scaled down geothermal investigations and look for funding support for geothermal exploration and studies, and seek funding support for these activities.

b. **Grid Extensions:** Continue to explore opportunities to extend the grid within Yukon, and to connect the Yukon grid to British Columbia and/or Alaska (including Skagway). A watching brief with regard to grid extensions to BC or Alaska and other potential longer-term resource options.

c. **Wood Biomass:** Identify and pursue opportunities for a small scale (e.g., 2 to 3 MW) wood biomass pilot project, potentially in association with existing wood operations at Haines Junction, and seek funding support for this pilot project.

d. **Other Options:** Continue watching briefs with regard to other resource options, including:
   i. Solar (cost-effective proven technology development suited to Yukon market conditions); and
   ii. Pipeline/natural gas (commitments by others regarding Alaska Highway Pipeline and/or potential Eagle Plain or other Yukon natural gas development).

APPENDIX A: UPDATED NEAR-TERM GRID LOAD SCENARIOS

The 2011 Resource Plan grid load scenarios are updated on an ongoing basis. As at spring 2012, four load scenarios are currently applicable for Yukon Energy grid generation and capacity planning (see Table A-1):

1. Load scenarios without connection of major new mines:

    a. **Base Case:**[43]

        i. GRA forecast loads for 2012 and 2013;
        ii. non-industrial growth after 2013 at 2.26%/year less 50% of DSM/SSE assumed in 2011 Resource Plan;
        iii. Minto generation load at 46.7 GW.h/yr (same as 2013) until 2019, and 23.4 GW.h in 2020 until mid-year (no load thereafter);
        iv. Alexco generation load at 21.7 GW.h/year 2014-16 (as compared to 15.9 GW.h/yr forecast in 2013); 15.0 GW.h/yr assumed 2017-2020 (no load thereafter); and
        v. Whitehorse Copper Tailings (WHCT) at 9.3 GW.h/yr 2014-2018 (as compared to 5.2 GW.h/yr in 2013) and 4.1 GW.h in 2019 (no load thereafter).

    b. **Base Case with Brewery Creek:** Base Case with the added connection, starting January 2014, of Brewery Creek mine with generation load assumed of 20.5 GW.h/yr in 2014 and 33.88 GW.h/yr thereafter until the end of 2023[44].

2. Load scenarios with connection of major new mines:

    a. **Scenario A:** Base Case with Brewery Creek and Victoria Gold mine, starting January 1, 2015 with generation load of 103.3 GW.h/yr that continues until the end of 2024 (no load thereafter)[45].

[43] The Base Case loads are expected to be reviewed in future to consider higher near-term non-industrial load growth (related to increased use of electric heat, consideration of Whistle Bend subdivision development impacts, and expected DSM/SSE timing which may indicate lower DSM/SSE impacts in near-term), and more recent information on Minto, Alexco and WHCT loads. The current Base Case does not consider Capstone's June 2012 announcement of Phase VI Pre-feasibility study results that extend Minto mine life to 2022. PPA negotiation for WHCT has not yet commenced.

[44] Negotiation of a PPA with Brewery Creek has not yet commenced. The load forecast includes expansion as provided by WHCT plans. This mine has expressed interest in connection in second half of 2013.

[45] PPA negotiations are ongoing with Victoria Gold (an earlier LOI set out principles for connection to the grid). It is assumed that Victoria Gold will pay all costs required for grid connection, plus upgrade of the Mayo-Keno line. The timing for connection of this mine remains uncertain (but will not be earlier than the Q1 2015 assumed in Scenario A).

b. **Scenario B:** Base Case with Brewery Creek, Victoria Gold and Carmacks Copper mine, starting January 1, 2015 with generation load of 56.5 GW.h/yr that continues until the end of 2020 (no load thereafter)[46].

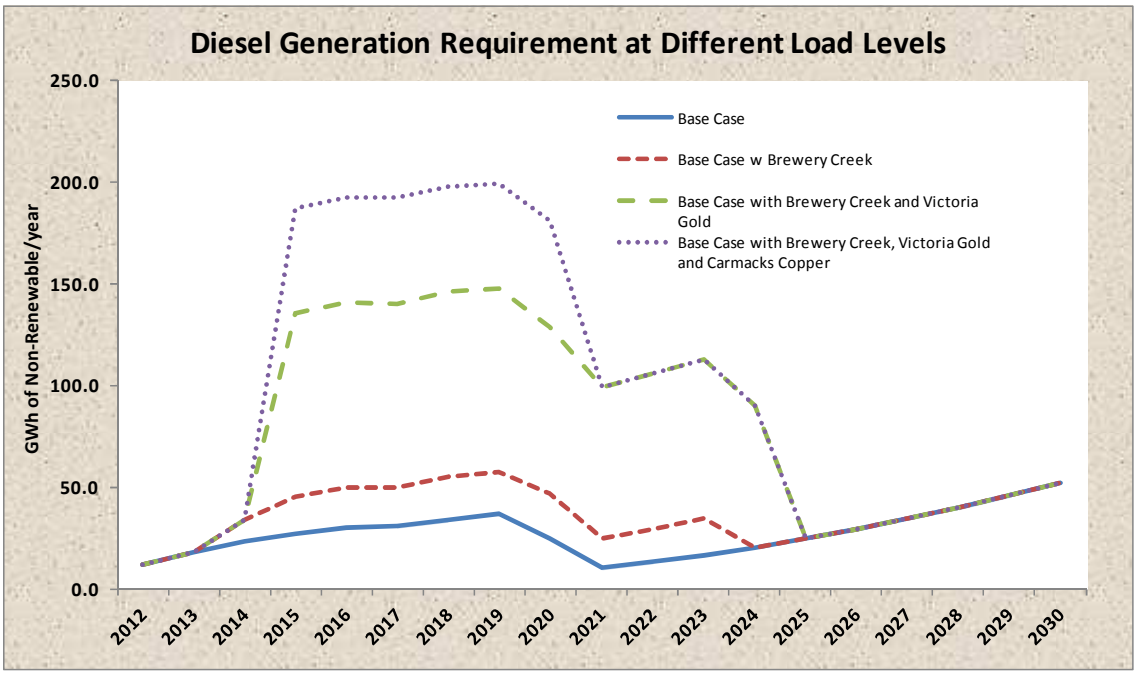
[46] Carmacks Copper has recently re-started its regulatory review processes, with an announced filing of a revised application planned this fall with YESAB, followed shortly thereafter with revised filing with the YWB. PPA discussions occurred in the past, and have been restarted – Carmacks Copper will be required to pay all costs required for grid connection plus a contribution to CSTP capital costs. The timing for connection of this mine remains uncertain, but could potentially occur during 2015 or (perhaps more likely) during 2016.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030 **July 2012**

Table A-1: Updated Grid Load Scenarios

Forecast Years	Base Case			Base Case w Brewery Creek			Base Case with Brewery Creek and Victoria Gold			Base Case with Brewery Creek, Victoria Gold and Carmacks Copper		
	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)
2012	359.0	56.9	415.9	359.0	56.9	415.9	359.0	56.9	415.9	359.0	56.9	415.9
2013	362.6	67.8	430.4	362.6	67.8	430.4	362.6	67.8	430.4	362.6	67.8	430.4
2014	365.5	77.8	443.3	365.5	98.4	463.9	365.5	98.4	463.9	365.5	98.4	463.9
2015	371.3	77.8	449.1	371.3	111.7	483.0	371.3	215.0	586.2	371.3	271.5	642.8
2016	377.2	77.8	455.0	377.2	111.7	488.9	377.2	215.0	592.1	377.2	271.5	648.7
2017	383.2	71.1	454.3	383.2	104.9	488.2	383.2	208.2	591.4	383.2	264.7	648.0
2018	389.4	71.1	460.5	389.4	104.9	494.4	389.4	208.2	597.6	389.4	264.7	654.1
2019	395.7	65.9	461.6	395.7	99.8	495.5	395.7	203.0	598.8	395.7	259.6	655.3
2020	402.2	38.4	440.5	402.2	72.3	474.4	402.2	175.5	577.7	402.2	232.0	634.2
2021	408.8		408.8	408.8	33.9	442.7	408.8	137.1	545.9	408.8	137.1	545.9
2022	415.5		415.5	415.5	33.9	449.4	415.5	137.1	552.7	415.5	137.1	552.7
2023	422.4		422.4	422.4	33.9	456.3	422.4	137.1	559.6	422.4	137.1	559.6
2024	429.5		429.5	429.5		429.5	429.5	103.3	532.8	429.5	103.3	532.8
2025	436.7		436.7	436.7		436.7	436.7		436.7	436.7		436.7
2026	444.1		444.1	444.1		444.1	444.1		444.1	444.1		444.1
2027	451.7		451.7	451.7		451.7	451.7		451.7	451.7		451.7
2028	459.4		459.4	459.4		459.4	459.4		459.4	459.4		459.4
2029	467.3		467.3	467.3		467.3	467.3		467.3	467.3		467.3
2030	475.3		475.3	475.3		475.3	475.3		475.3	475.3		475.3

Figure A-1: Diesel Generation Requirements at Different Forecast Loads: 2012-2030



Diesel Energy Requirement (GWh)	2012	2015	2020	2025	2030
Base Case	11.5	27.0	24.4	24.5	51.9
Base Case with Brewery Creek	11.5	45.5	47.1	24.5	51.9
Base Case with Brewery Creek and Victoria Gold	11.5	135.2	128.8	24.5	51.9
Base Case with Brewery Creek, Victoria Gold and Carmacks Copper	11.5	187.1	181.0	24.5	51.9

Figure A-1 and table provide the forecast diesel generation requirement during the 20-year planning period for each of the load scenarios.

1. The numbers are based on updated load for 2012-2030.
2. Diesel requirement numbers are long-term average diesel.
3. Model run with Aishihik 10-year rolling average rule, Mayo Lake assumed in-service by winter 2013/14 (more recent information suggests earliest in-service is now winter 2014/15).

Diesel generation forecasts for each load scenario reflect long-term average hydro generation, i.e., the average hydro generation over 28 recorded water year conditions at the assumed load, as estimated by the power benefits model used by YEC for grid generation planning. Table A-2 and the Figure A-2 below it provide a detailed review of potential diesel generation variability for the year 2015 under each load scenario for each of the 28 water years (the figure shows the annual load duration curve for diesel for each load scenario).

Table A-2: Forecast Diesel Generation Variability (GW.h) Depending on Water Year Conditions - Load Scenarios for 2015 and 28 Water Years of Record

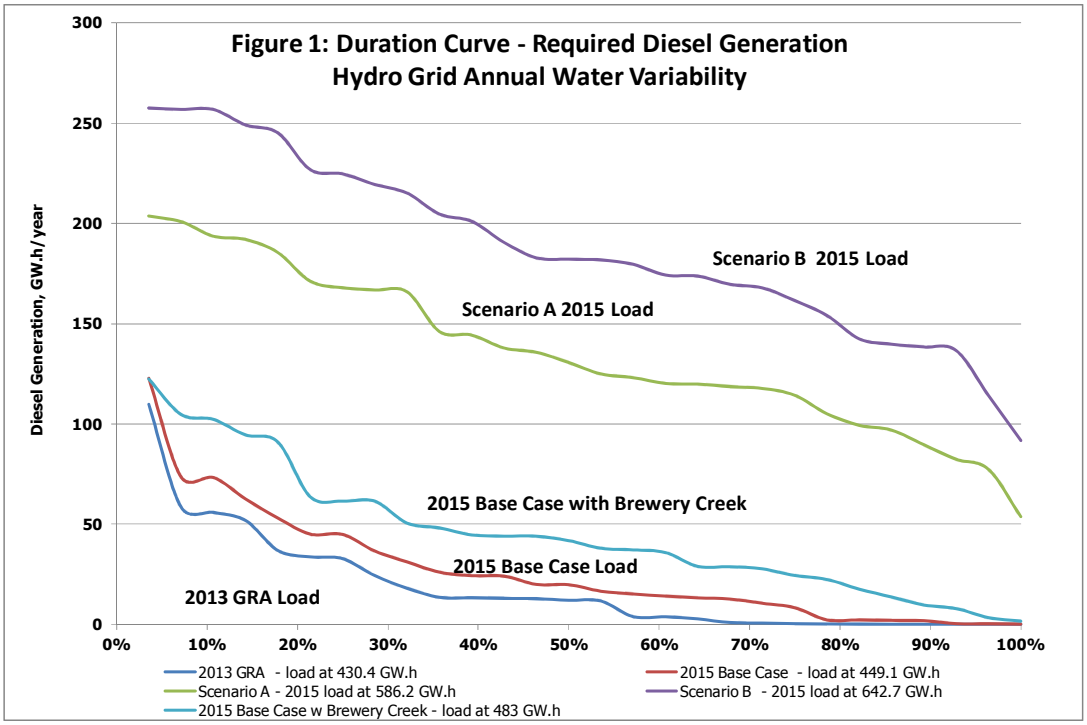
Average Annual Diesel Generation (Averaged Load Years for 28 Water Years)

Water Year	2013 GRA - load at 430.4 GW.h	2015 Base Case - load at 449.1 GW.h	2015 Base Case w Brewery Creek - load at 483 GW.h	Average diesel generation required (GW.h) Scenario A - 2015 load at 586.2 GW.h	Scenario B - 2015 load at 642.7 GW.h
1981	0.6	2.2	9.8	114.3	182.2
1982	2.6	10.5	48.2	135.7	181.8
1983	3.8	8.3	38.1	118.6	173.8
1984	11.6	19.9	63.7	168.0	226.8
1985	3.7	24.2	44.7	146.1	201.0
1986	0.9	16.5	44.1	125.0	169.6
1987	0.1	12.6	24.5	117.7	179.6
1988	0.0	14.1	27.8	105.1	142.5
1989	0.0	2.2	8.0	89.6	154.1
1990	0.1	1.8	17.7	123.1	174.3
1991	0.0	1.9	13.8	96.9	138.5
1992	0.0	0.3	1.8	53.8	91.9
1993	0.3	0.1	3.5	82.4	136.7
1994	0.0	0.3	22.5	185.5	249.0
1995	12.9	31.1	94.5	201.0	257.4
1996	51.8	62.5	104.8	203.7	256.7
1997	58.5	73.5	102.3	171.3	215.1
1998	36.8	44.8	90.9	193.7	256.8
1999	109.9	122.7	122.4	192.0	245.0
2000	55.9	73.2	61.5	130.7	167.9
2001	32.8	45.0	28.9	77.4	114.3
2002	24.3	36.5	35.9	120.2	182.9
2003	13.3	26.0	50.6	166.9	224.7
2004	33.6	52.9	61.5	165.9	219.4
2005	18.0	19.7	44.1	137.9	190.5
2006	12.8	15.1	37.3	144.3	204.7
2007	12.0	24.0	41.9	119.8	161.6
2008	13.5	13.2	29.1	99.3	139.9
Average	18.2	27.0	45.5	135.2	187.1

Distribution of Annual Water Year Loads (Figure 1)

	% of Years not less than	2013 GRA - load at 430.4 GW.h	2015 Base Case - load at 449.1 GW.h	2015 Base Case w Brewery Creek - load at 483 GW.h	Scenario A - 2015 load at 586.2 GW.h	Scenario B - 2015 load at 642.7 GW.h
1	4%	109.9	122.7	122.4	203.7	257.4
2	7%	58.5	73.5	104.8	201.0	256.8
3	11%	55.9	73.2	102.3	193.7	256.7
4	14%	51.8	62.5	94.5	192.0	249.0
5	18%	36.8	52.9	90.9	185.5	245.0
6	21%	33.6	45.0	63.7	171.3	226.8
7	25%	32.8	44.8	61.5	168.0	224.7
8	29%	24.3	36.5	61.5	166.9	219.4
9	32%	18.0	31.1	50.6	165.9	215.1
10	36%	13.5	26.0	48.2	146.1	204.7
11	39%	13.3	24.2	44.7	144.3	201.0
12	43%	12.9	24.0	44.1	137.9	190.5
13	46%	12.8	19.9	44.1	135.7	182.9
14	50%	12.0	19.7	41.9	130.7	182.2
15	54%	11.6	16.5	38.1	125.0	181.8
16	57%	3.8	15.1	37.3	123.1	179.6
17	61%	3.7	14.1	35.9	120.2	174.3
18	64%	2.6	13.2	29.1	119.8	173.8
19	68%	0.9	12.6	28.9	118.6	169.6
20	71%	0.6	10.5	27.8	117.7	167.9
21	75%	0.3	8.3	24.5	114.3	161.6
22	79%	0.1	2.2	22.5	105.1	154.1
23	82%	0.1	2.2	17.7	99.3	142.5
24	86%	0.0	1.9	13.8	96.9	139.9
25	89%	0.0	1.8	9.8	89.6	138.5
26	93%	0.0	0.3	8.0	82.4	136.7
27	96%	0.0	0.3	3.5	77.4	114.3
28	100%	0.0	0.1	1.8	53.8	91.9
		18.2	27.0	45.5	135.2	187.1

Figure A-2: Duration Curve – Required Diesel Generation Hydro Grid Annual Water Variability



Projected annual grid capacity MW surplus (shortfall) under each load scenario is provided in Table A-3, assuming existing plant and planned diesel unit retirements and applying YEC's approved N-1 and LOLE capacity planning criteria. These shortfalls assume that L172 is re-enforced (with by twinning or by provision for the 35 kV system to be able to by-pass this line between Takhini and McIntyre substations).

The following are noted regarding assumed diesel unit retirements, using projected shortfalls under the Base Case to demonstrate the impact of assumed retirements:

- 2015 Base Case shortfall of 3.3 MW: reflects following 8 MW of diesel unit retirements:
    - Mirrlees WD#1 and WD#2 retired in 2014/2015 (2011 Resource Plan rating of 3.50 and 4.5 MW=8 MW total).
    - Replacing one of these units with at least the same capacity would totally resolve the 2015 shortfall.
- 2020 Base Case shortfall of 15.7 MW: reflects following 13.11 MW of diesel unit retirements:
    - The above Mirrlees retirements (8 MW) plus.
    - Dawson retirement of 3 units (total 2.56 MW retired in 2017, 2018 and 2020).
    - Mayo retirement of 2 units (total 1.7 MW in 2019).
    - Faro retirement of 1 unit (0.85 MW in 2019).
- 2025 Base Case shortfall of 38.1 MW: reflects following 28.61 MW of diesel unit retirements:
    - The above 13.11 MW retired by 2020 plus.
    - Whitehorse retirement of 4 units (total 11.5 MW - last Mirrlees (4.5 MW) and 3 EMDs).
    - Faro Mirrlees unit (4.0 MW in 2021).
- 2030 Base Case shortfall of 51.5 MW: reflects following 34.41 MW of diesel unit retirements:
    - The above 28.61 MW retired by 2025 plus.
    - Whitehorse CAT (3.0 MW in 2026).
    - Faro CAT (2.8 MW in 2027).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030 **July 2012**

Table A-3: Grid Capacity Planning - Forecast MW Surplus (Shortfall) by Load Scenario: 2012-2030

Comparison of Peak, N-1 and LOLE requirements

Forecast Years	Base Case			Base Case w Brewery Creek			Base Case with Brewery Creek and Victoria Gold			Base Case with Brewery Creek, Victoria Gold and Carmacks Copper		
	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)
2012	80.1	7.2	7.2	80.1	7.2	7.2	80.1	7.2	7.2	80.1	7.2	7.2
2013	81.1	6.5	6.5	81.1	6.5	6.5	81.1	6.5	6.5	81.1	6.5	6.5
2014	82.6	2.4	2.4	83.8	2.4	2.4	83.8	2.4	2.4	83.8	2.4	2.4
2015	83.7	-3.3	-3.3	86.9	-3.3	-3.5	99.9	-3.3	-16.5	107.9	-3.3	-24.5
2016	84.9	-4.4	-4.4	88.1	-4.4	-4.6	101.1	-4.4	-17.6	109.1	-4.4	-25.6
2017	85.2	-6.5	-6.5	88.4	-6.5	-6.5	101.4	-6.5	-18.8	109.4	-6.5	-26.8
2018	86.4	-8.5	-8.5	89.6	-8.5	-8.5	102.6	-8.5	-20.8	110.6	-8.5	-28.8
2019	87.7	-12.3	-12.3	90.9	-12.3	-12.3	103.9	-12.3	-24.6	111.9	-12.3	-32.6
2020	89.0	-15.7	-15.7	92.2	-15.7	-15.7	105.2	-15.7	-28.0	113.2	-15.7	-36.0
2021	81.2	-25.5	-25.5	84.4	-25.5	-25.5	97.4	-25.5	-28.7	97.4	-25.5	-28.7
2022	82.5	-26.8	-26.8	85.7	-26.8	-26.8	98.7	-26.8	-30.0	98.7	-26.8	-30.0
2023	83.9	-28.2	-28.2	87.1	-28.2	-28.2	100.1	-28.2	-31.4	100.1	-28.2	-31.4
2024	85.3	-29.6	-29.6	85.3	-29.6	-29.6	98.3	-29.6	-29.6	98.3	-29.6	-29.6
2025	86.7	-38.1	-38.1	86.7	-38.1	-38.1	86.7	-38.1	-38.1	86.7	-38.1	-38.1
2026	88.2	-42.5	-42.5	88.2	-42.5	-42.5	88.2	-42.5	-42.5	88.2	-42.5	-42.5
2027	89.7	-46.8	-46.8	89.7	-46.8	-46.8	89.7	-46.8	-46.8	89.7	-46.8	-46.8
2028	91.2	-48.4	-48.4	91.2	-48.4	-48.4	91.2	-48.4	-48.4	91.2	-48.4	-48.4
2029	92.8	-49.9	-49.9	92.8	-49.9	-49.9	92.8	-49.9	-49.9	92.8	-49.9	-49.9
2030	94.4	-51.5	-51.5	94.4	-51.5	-51.5	94.4	-51.5	-51.5	94.4	-51.5	-51.5

2016 Resource Plan Appendices

Appendix 3.1
Electricity Values Survey Report
(Yukon Bureau of Statistics 2016)

Yukon Electricity Values Survey 2016 Report

Prepared by
Yukon Bureau of Statistics
for
Yukon Energy Corporation

July 2016

Table of Contents

Executive Summary ..... **i**

Introduction **1**

Part 1: Understanding the Public's Values Regarding YEC Initiatives **2**

Factors to be Considered for YEC's Future Projects 2

Figure 1. Ranking of factors that respondents would like YEC to consider in deciding on future projects. 2

Environmental Protection 3

Figure 2. Ranking of preference for environmental protection in respondents' order of importance. 4

Electricity Affordability, Reasonability of Rates, and Conservation Efforts 4

Figure 3. The affordability of electricity bills, the reasonability of current electricity rates, and efforts to reduce energy use. 4

Support for YEC Initiatives 5

Figure 4. Extent of support to YEC initiatives even with a potential increase in electricity rates. 5

Power outages and Back-up Heating 6

Figure 5. Respondents' experience of power outages in 2015 6

Figure 6. Necessity of back-up heating and/or a generator in case of a power outage. 6

Social Responsibility 7

Figure 7. Ranking of statements relating to social responsibility in order of importance 7

Preferred Future Energy Source for Yukon 7

Figure 8. Ranking of energy sources for Yukon's future in order of preference. 8

Energy Efficiency 8

Figure 9. Frequency of checking energy efficiency rating before purchasing a new appliance or electronic device. 8

Home Heating Sources 9

Figure 10a. Primary home heating sources as listed on home insurance. 9

Figure 10b. Additional home heating sources (Note: respondents were allowed to choose multiple responses and percentages are derived from the sum of all reported additional home heating sources). 10

Figure 11. Respondents' consideration of switching to electric heat. 10

Home Heating Selection 11

Figure 12. Ranking of factors that influence respondents' home heating system selection 11

Part 2: Focus on Understanding the Support for YEC Initiatives **11**

Yukon's Future Back-up Generation Fossil Fuel Choice 11

Figure 13. Respondents' preference of fossil fuel if YEC is required to choose a fossil fuel for future back-up generation. 12
Confidence in YEC to Plan and Develop Sustainable Energy Sources 12
Figure 14. Respondents' confidence in YEC's ability to plan and develop sustainable energy sources to meet future needs. 12
Part 3: Demographics of the Respondents 13
Respondents' Age Groups 13
Figure 15. Age groups of the respondents. 13
Respondents' Education Levels 13
Figure 16. Levels of education of the respondents. 14
Income Groups of Responding Households 14
Figure 17. Responding households by annual gross household income. 14
Response by Aboriginal Groups 15
Figure 18. Respondents who identified themselves as Aboriginal. 15
Response by Community 15
Conclusion 16
APPENDIX A – Summary Tables 17
APPENDIX B – Yukon Electricity Values Survey 22

EXECUTIVE SUMMARY

The Yukon Bureau of Statistics conducted the Electricity Values Survey in the spring of 2016 on behalf on the Yukon Energy Corporation (YEC). The purpose of the survey was to generate information on Yukon residents' preference for factors that would be affected by future electricity generation in Yukon. The survey also aimed at understanding Yukon residents' preferences and values relating to energy use.

A stratified random sample representing one-third of total eligible Yukon households was selected to complete the phone survey. The overall response rate for the survey was 63.2%, indicating the results are a good representation of all Yukon households.

Respondents ranked four major factors in order of importance to YEC's future projects. Environmental Protection was ranked first by 44% of respondents, followed by Cost (23%), Reliability (21%), and Social Responsibility (8%).

In contrast to the importance given to YEC's projects, when respondents were asked to rank five factors that influence their own home heating system selection, cost was the most important factor (chosen first by 45% of respondents) to influence a respondent's home heating selection. Respondents' selection of home heating system was more influenced by cost than all four other factors (safety, environmental concerns, comfort, and ease of maintenance) combined.

Respondents ranked statements on Environmental Protection in order of importance. 'Reduce pollution to land, water, and air, other than greenhouse gas emissions' was ranked first by 30% of households, followed by 'Reduce impacts on species' habitats and wildlife populations at risk' (24%), and 'Reduce impacts on Earth's atmosphere' (23%). 'Minimize the amount of land affected by a new energy project' was ranked last (12%).

While Social Responsibility was the factor least ranked first of the four major factors, a question asking respondents to rank statements relating to social responsibility revealed that one-third of Yukon households ranked 'Enhancing economic growth and creating jobs' as the most important social responsibility.

When asked if they would support specific Yukon Energy initiatives even if it meant a potential increase in electricity rates, respondents answered 'Yes' at the following percentages:

- An effort to reduce impact on species' habitats and wildlife populations at risk (81%)
- An effort to reduce GHG emissions in energy production (78%)
- An effort to create local jobs (73%)
- An effort to maintain access to wilderness recreation (73%)
- An effort to reduce power outages in your area (71%)
- An effort to not compromise traditional pursuits as a way of life (69%)
- An effort to enhance economic growth for Yukon (57%)
- A decision to supply electricity to mines (46%)

In ranking three energy sources in order of preference for Yukon's future, 59% of the responding households chose renewable energy as their preferred future energy source. About one-third (31%) preferred energy conservation as a future energy source, while only 5% preferred fossil fuels as a future energy source.

If YEC is required to choose a fossil fuel for future back-up generation, slightly over half of Yukon households (51%) would prefer the use of natural gas. Only 14% would prefer diesel fuel.

At 47%, fuel oil is the most prevalent primary home heating source in Yukon. Electricity (baseboard, furnace or boiler) is the second most prevalent primary home heating source and is used by a quarter (25%) of households. Of those who did not already use electricity as a primary or additional home heating source, only 18% had considered switching to electric heat.

Most households (41%) did not have an additional home heating source. Of households that did have additional home heating sources (59%), wood was the most common (36%) additional home heating source followed by electricity (31%). While fuel oil was the most commonly used primary source of heat, it was not commonly used (13%) as an additional home heating source.

A little over three-quarters of the respondents (76%) said their electricity bills are affordable, while 55% thought Yukon's current electricity rates are reasonable. Almost all respondents (97%) claimed they make efforts to reduce their energy use; however, a little over three-quarters (77%) of respondents said they 'always' or 'frequently' check the energy efficiency rating when purchasing a new appliance or electronic device.

Eighty-five percent of all households experienced at least one power outage in 2015. About two-thirds of the households felt it necessary to have back-up heating and/or a generator in case of power outages.

Most (61%) respondents were confident that YEC is able to plan and develop sustainable energy sources to meet future needs. About a fifth (19%) of the respondents said that that they do not have confidence in YEC's ability.

INTRODUCTION

The Electricity Values Survey 2016 was conducted by the Yukon Bureau of Statistics (YBS) on behalf of the Yukon Energy Corporation (YEC). The objective of the survey was to generate information on Yukon residents' perspectives on factors that need to be considered in planning for Yukon's future electricity needs. The results of the survey will be used in YEC's 2016 Resource Plan – a document that outlines how to meet Yukon's electricity needs for the next 20 years (2016 to 2035).

The Electricity Values Survey 2016 was designed to collect information primarily on Yukon residents' preference for factors that can potentially be affected by Yukon's future electricity generation. For instance, how would Yukon residents balance their preference between environmental protection, cost, reliability, and social responsibility, knowing that choosing any energy option requires trade-off? The survey questionnaire also included modules aimed to understand Yukon residents' interests and values relating to energy use so that they can be reflected in YEC's 2016 Resource Plan.

YBS conducted the survey using a Computer Assisted Telephone Interviewing (CATI) system. A stratified random sample[1] of 4,534 households representing one-third of the total eligible Yukon households (13,591) was selected to complete the CATI survey[2]. Only one person per household could complete the survey and the respondent was selected with a regressive eligibility criterion[3] based on their availability during the call. The overall weighted[4] response rate for the survey was 63.2% indicating that the results are a good representation of Yukon households.

The results of a survey with a response rate of 70% or greater are considered excellent, while those derived from a survey with a response rate between 60% and 70% are considered of good quality. Results from a survey below 60% response rate tend to have high margins of error. However, for highly important public opinion research involving key policy or resource allocation decisions, Canada's federal government departments target a response rate of 40% to 60%[5].

Appendices to this report contain the following information:

Appendix A: Results and summary tables of survey responses,
Appendix B: Survey response rates and survey delivery details, and
Appendix C: Survey questions.

The following analyses[6] provide a summary of results by survey question (or group of related questions). The results of the ranking questions are presented as percentages of first ranking as well as weighted averages of all rankings[7].

---

[1] All Yukon households were stratified by geography and household size (i.e., the number of household members) and random sample was drawn from each stratum. Smaller communities were allocated with a relatively bigger proportion of samples.

[2] The distribution of the valid sample was checked against that of the initial sample and the survey universe by stratum to ensure randomness of the sample with valid contact information.

[3] The most senior person, or the next senior person, or in their absence, an adult who is at least 18 years old.

[4] The distribution of the responses was checked against that of the sample by stratum, and the sample weights were calibrated to adjust for non-response.

[5] http://www.tpsgc-pwgsc.gc.ca/rop-por/rapports-reports/comitephone-panelphone/page-06-eng.html

[6] All graph values are represented as percentages of the sum of respondents based on weighted frequencies.

[7] Geometrically declining weights are applied to progressively reducing preferences to calculate weighted averages.

PART 1: UNDERSTANDING THE PUBLIC'S VALUES REGARDING YEC INITIATIVES

A critical part of YEC's resource planning work is to gather input from Yukoners so that the Corporation can create a plan reflecting Yukoners' values in terms of the territory's energy future. Since all energy options have impacts on often competing preferences and require trade-offs, YEC wanted to understand how the public would rank various factors in terms of their importance. Four broad categories of factors included Environmental Protection, Cost, Reliability, and Social Responsibility. Each survey question in this section is related to one or more factors in these categories.

FACTORS TO BE CONSIDERED FOR YEC'S FUTURE PROJECTS

Respondents were asked to rank four factors in order of importance for YEC's future projects. As shown in Figure 1, the four factors were ranked in order of importance as follows:

- Environmental Protection: 44.4% ranked first (weighted average of all rankings: 34.3%);
- Cost: 22.7% ranked first (weighted average of all rankings: 24.1%);
- Reliability: 21.0% ranked first (weighted average of all rankings: 22.5%), and
- Social Responsibility: 7.7% ranked first (weighted average of all rankings: 14.6%).

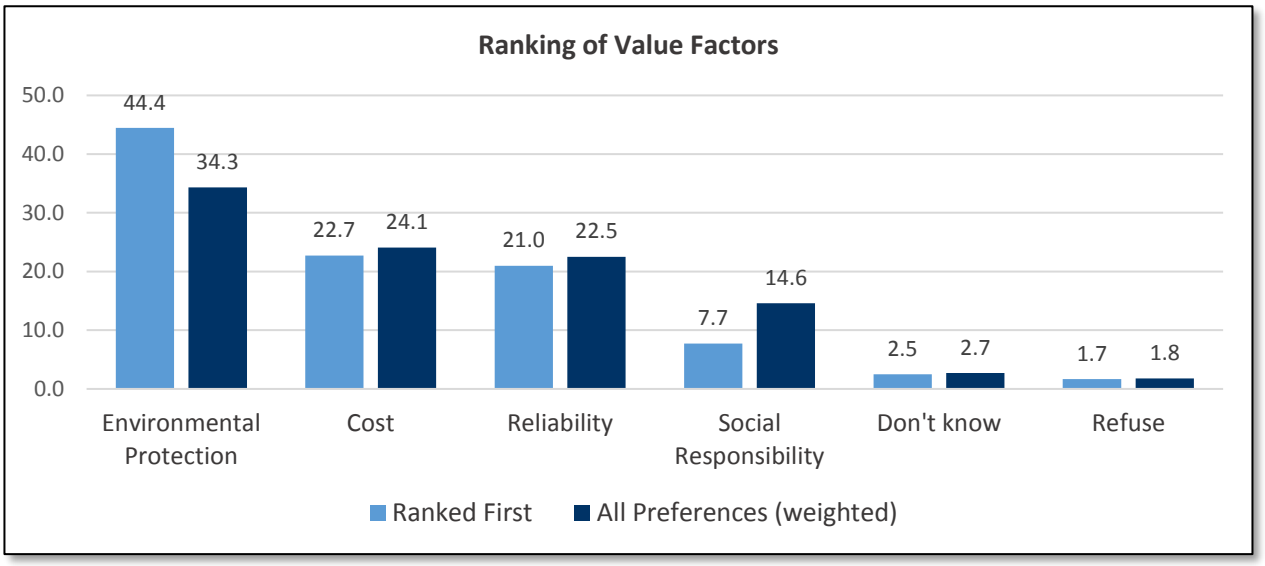


Figure 1. Ranking of factors that respondents would like YEC to consider in deciding on future projects.

Of those Yukon households that value *Environmental Protection* as the most important factor, 32.5% ranked the reduction of risk of pollution to land, water and air other than greenhouse gases as the most important form of environmental protection, followed closely by reduction of impacts on Earth's atmosphere (30.5%). Even with a potential increase in electricity rates, 71.0% households of this group would support YEC's effort to create local jobs. However, only 52.5% households would support YEC's effort to enhance economic growth. While ranking statements on *Social Responsibility*, 27.1% of this group ranked maintaining traditional pursuits as the most important *Social Responsibility*, and 23.9% chose economic growth and job creation as the most important. This group was split almost evenly between Yes (40.9%) and No (41.5%) when asked if they would support YEC's decision to supply

electricity to mines even with a potential increase to electricity rates. In addition, 57.0% of this group preferred renewable energy as the most important type of future energy source for Yukon. For 38.4% of this group, *cost* was the most important factor that influences their home heating selection, while only 18.7% identified *environmental concerns* as the most important factor.

Of households that value *Cost* as the most important factor, 31.2% ranked the reduction of pollution to land, water and air other than greenhouse gases as the most important form of environmental protection. Even with an increase in electricity rates, 76.4% of this group would support an effort to reduce impact on species' habitats and wildlife populations at risk, 75.8% would favour creation of local jobs, and 52.5% would support YEC's decision to supply electricity to mines. Most households (43.8%) in this group chose economic growth and job creation as the most important *Social Responsibility*. Further, 64.1% of this group preferred renewable energy as future energy source for Yukon and for 59.9%, *cost* was the most important factor that influences their home heating selection.

Of households that value *Reliability* as the most important factor, 32.4% ranked the reduction of pollution to land, water and air other than greenhouse gases as the most important form of environmental protection. Even with an increase in electricity rates, 77.2% of the respondents in this group would support efforts to reduce power outages in their areas and 75.8% would favour creation of local jobs. Majority of the households in this group (44.6%) ranked economic growth and job creation as the most important *Social Responsibility*. In addition, 61.4% of this group ranked renewable energy as the most important type of future energy source for Yukon and 51.4% said *cost* was the most important factor that influences their home heating selection.

Of households that value *Social Responsibility* as the most important attribute, 31.7% ranked the reduction of impacts on species' habitats and wildlife populations at risk as the most important form of environmental protection. Even with an increase in electricity rates, 84.9% of this group would support an effort to reduce impact on species' habitats and wildlife populations at risk, and 79.7% would favour an effort to reduce greenhouse gas emissions in energy production. Of this group, 34.4% ranked economic growth and job creation as the most important *Social Responsibility*. Further, 57.7% of this group ranked renewable energy as the most important type of future energy source for Yukon and for 31.7%, *cost* was the most important factor that influences their home heating selection.

ENVIRONMENTAL PROTECTION

Respondents were asked to rank statements on *Environmental Protection* in order of their importance. The statement 'reduce pollution to land, water and air, other than GHG emissions' was ranked first by 29.5% (weighted average of all rankings: 26.7%) of households (Figure 2). This was followed by 'reduce impacts on species' habitats and wildlife populations at risk' (23.7%; weighted average: 24.3%) and 'reduce impacts on earth's atmosphere specifically relating to GHG emissions' (22.6%; weighted average: 20.9%). 'Minimize the amount of land affected by a new energy project' was the least important to households at 12.1% (weighted average: 15.1%).

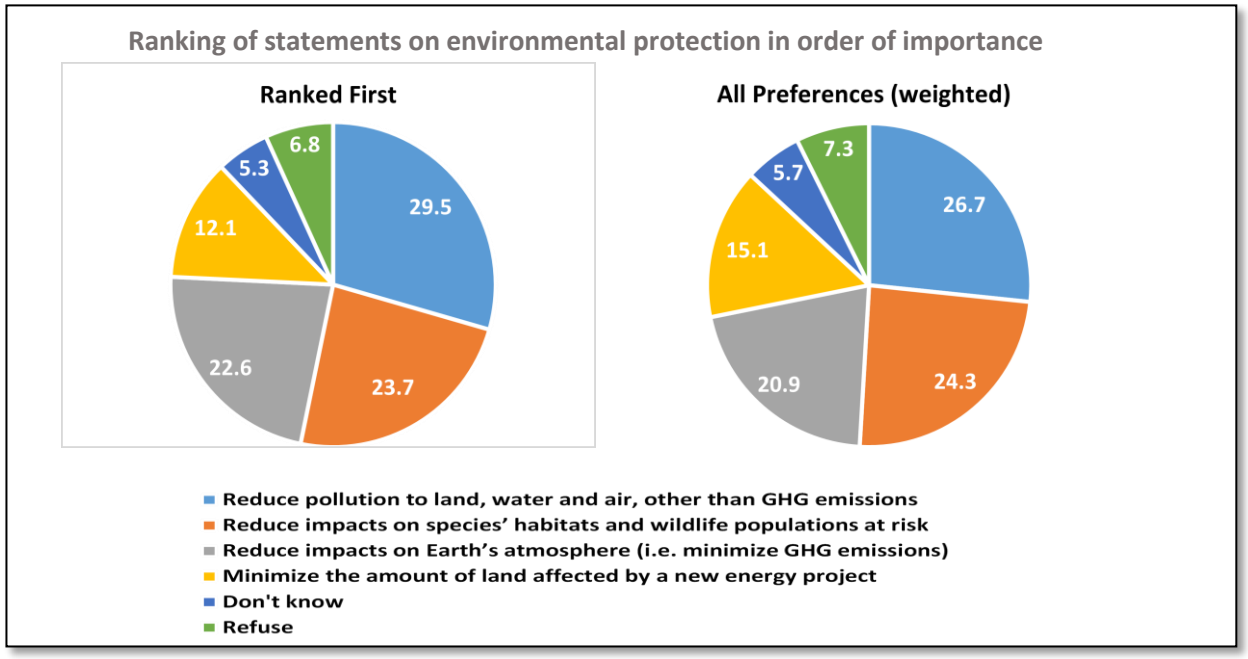


Figure 2. Ranking of preference for environmental protection in respondents' order of importance.

ELECTRICITY AFFORDABILITY, REASONABILITY OF RATES, AND CONSERVATION EFFORTS

Respondents were asked simple questions on the affordability of their electricity bills, the reasonability of the electricity rate, and their efforts to reduce enrgy use. While a little over three-quarters of the respondents (76.4%) said that their electricity bills are affordable, 54.7% thought that Yukon's current electricity rates are reasonable (Figure 3). Almost all respondents (96.9%) claimed that they make efforts to reduce their energy use.

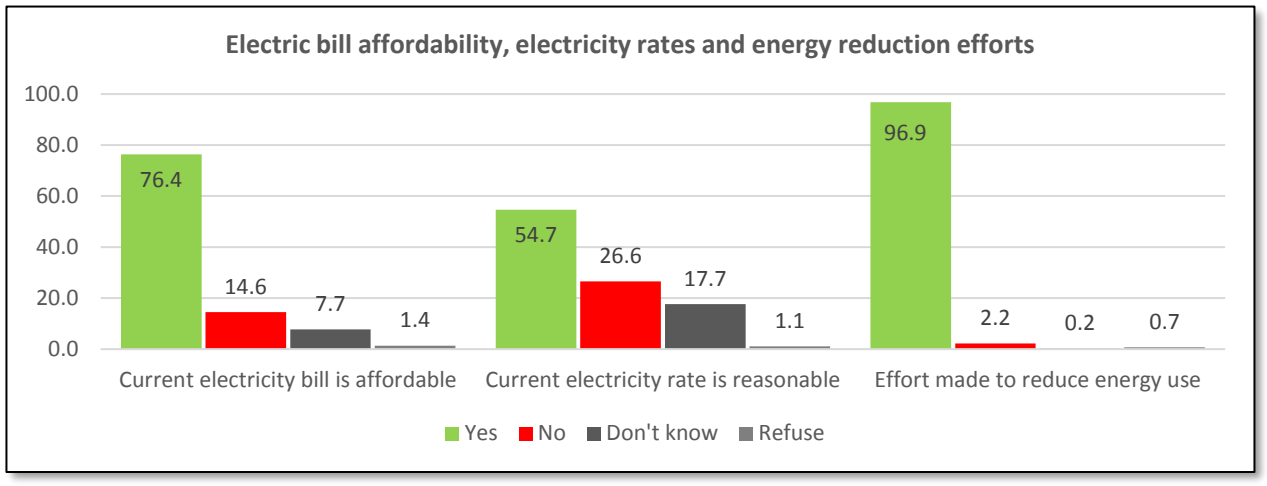


Figure 3. The affordability of electricity bills, the reasonability of current electricity rates, and efforts to reduce energy use.

SUPPORT FOR YEC INITIATIVES

Respondents were asked, even with a potential increase in electricity rates, whether they would support YEC's initiatives to protect environment, maintain social responsibility, and enhance reliability in project planning. The results are presented in Figure 4.

As shown in the figure, 80.7% Yukon households would support YEC's efforts to protect environment, even with a potential increase in electricity rates. While 73.4% households would support initiatives that would create local jobs, only 57.1% would favour initiatives to enhance economic growth. About three-quarters of households (73.1%) would support initiatives to maintain access to wilderness recreation, about two-thirds (68.6%) would support initiatives not to compromise traditional pursuits, and 71.0% would support initiatives to reduce power outages. The support for YEC's decision to supply electricity to mines was the lowest at 46.0%.

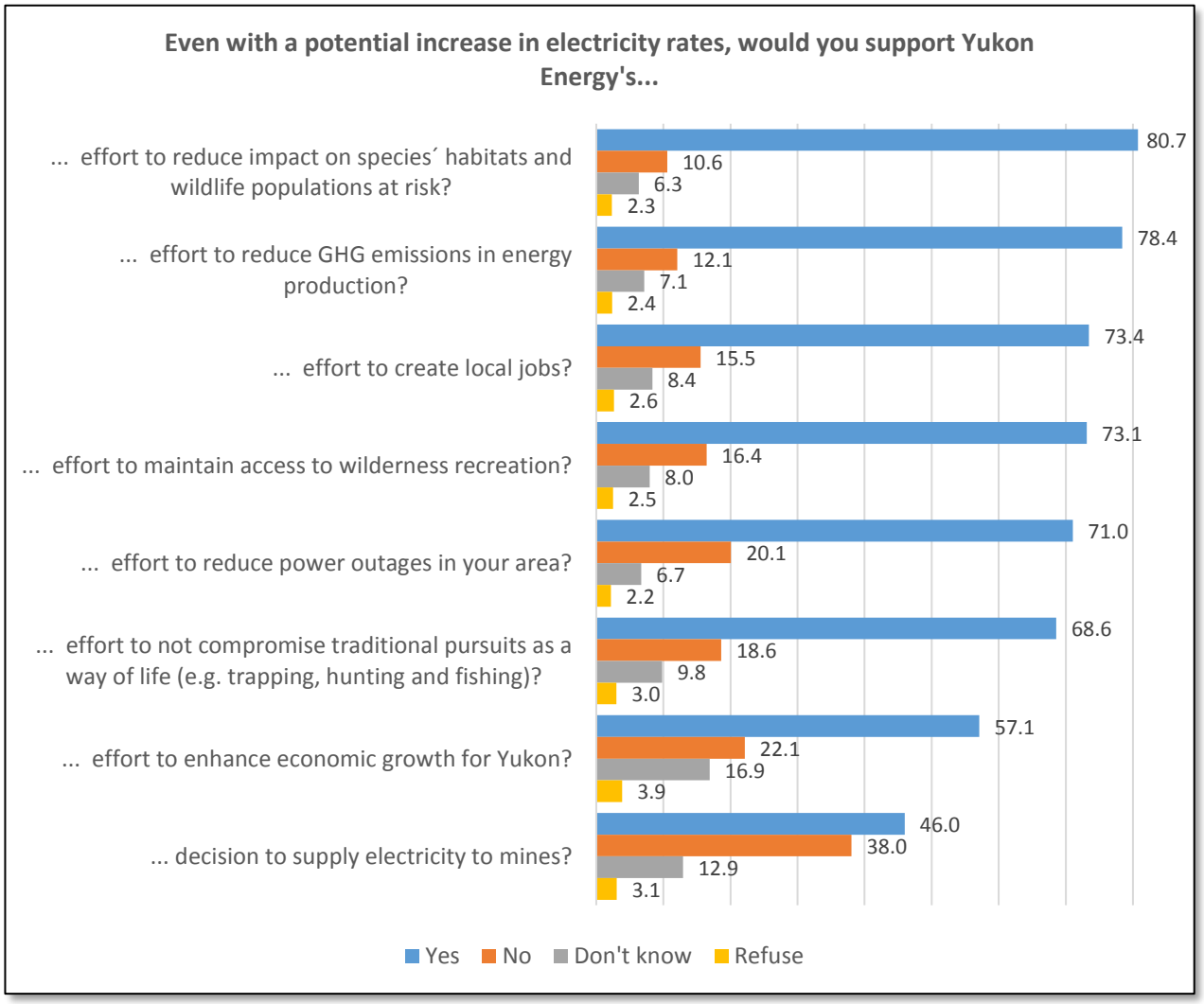


Figure 4. Extent of support to YEC initiatives even with a potential increase in electricity rates.

POWER OUTAGES AND BACK-UP HEATING

Respondents were asked if they had experienced power outages in 2015. While 84.5% of all households experienced at least one power outages in 2015, 64.6% of those households experienced at least one outage that lasted more than an hour (Figure 5). About two-thirds of the households (67.2%) felt it necessary to have back-up heating and/or a generator in case of power outages (Figure 6).

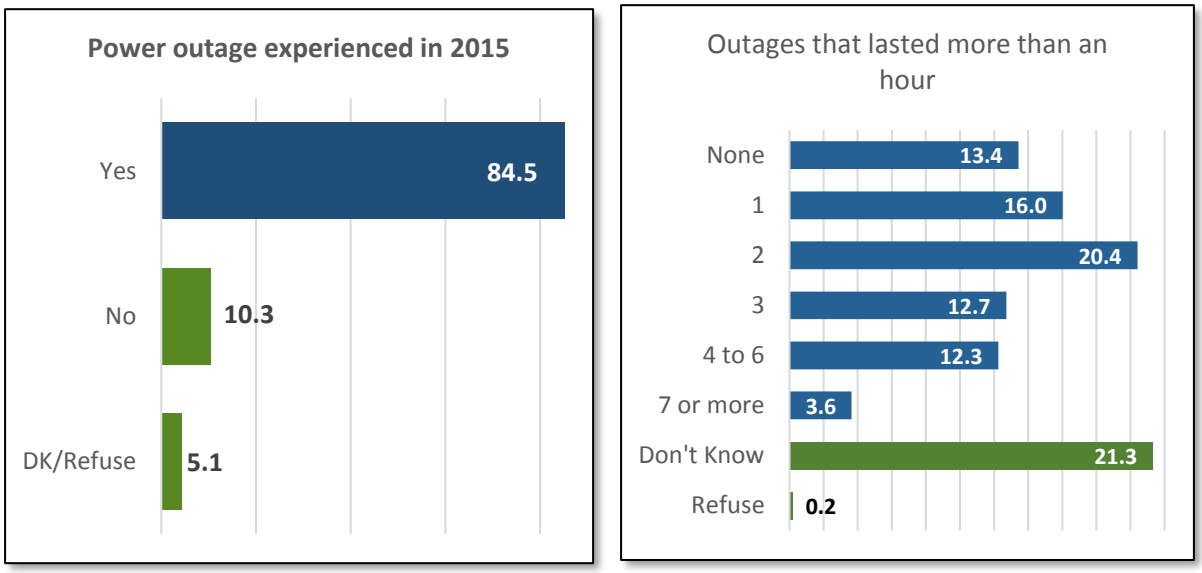


Figure 5. Respondents' experience of power outages in 2015.

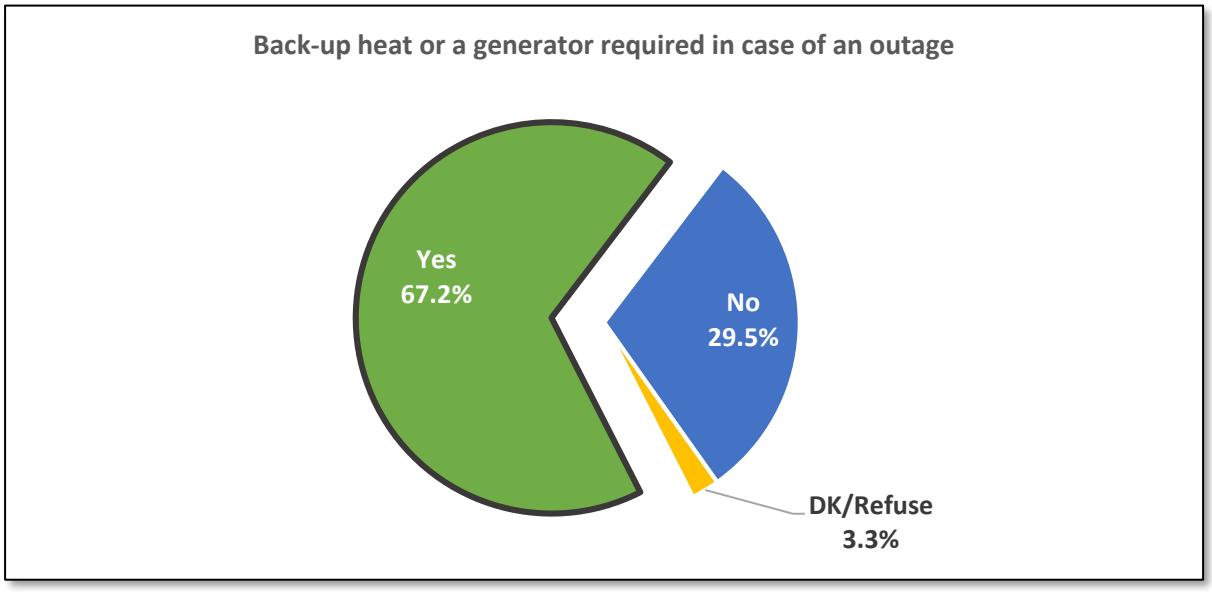


Figure 6. Necessity of back-up heating and/or a generator in case of a power outage.

SOCIAL RESPONSIBILITY

The survey asked the respondents to rank the following statements concerning social responsibility in order of importance:

- Enhance economic growth and create jobs;
- Do not compromise traditional pursuits (e.g. trapping, hunting and fishing);
- Maintain access to wilderness recreation; and
- Conservation of historical sites to protect Yukon culture.

Based on the responses, one-third of Yukon households (33.3%; weighted average of all rankings: 25.2%) ranked 'enhance economic growth and create jobs' as the most important *Social Responsibility*, while about one-fifth (20.2%; weighted average: 21.0%), ranked 'do not compromise traditional pursuits' as the most important (Figure 7). The next in order were maintaining access to wilderness recreation (16.7%; weighted average: 20.0%), and conservation of historical sites to protect Yukon culture (14.8%; weighted average of all rankings: 17.5%).

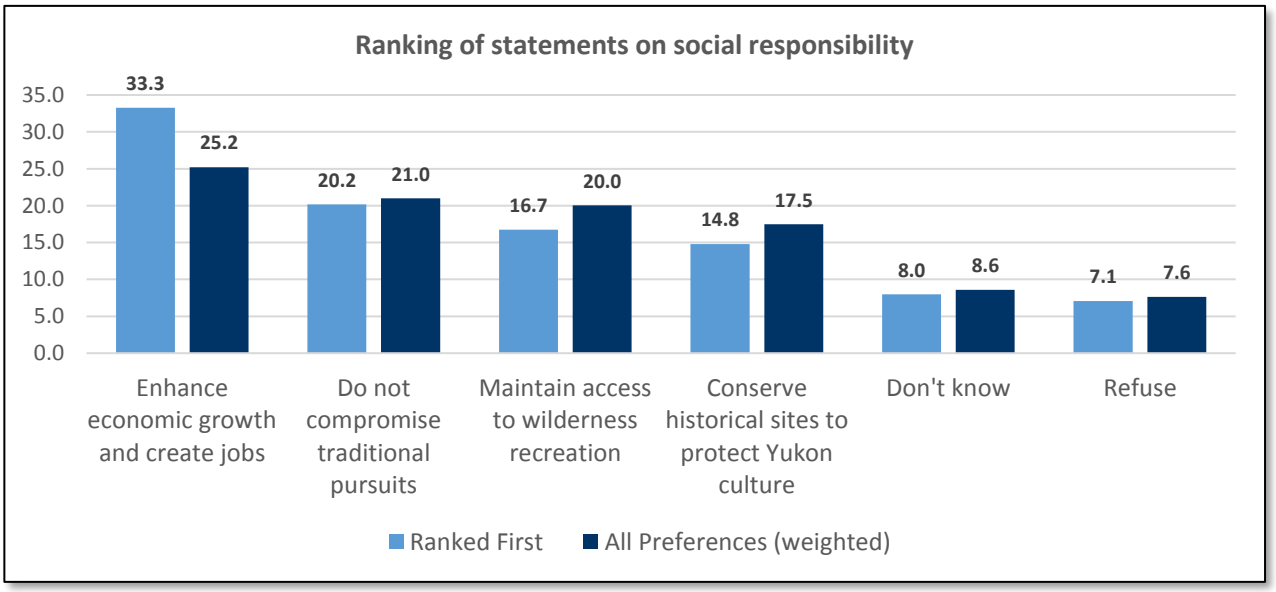


Figure 7. Ranking of statements relating to social responsibility in order of importance.

PREFERRED FUTURE ENERGY SOURCE FOR YUKON

When asked to rank three energy sources (fossil fuels, renewable energy and energy conservation) in order of preference, 59.2% (weighted average of all rankings: 44.1%) of the responding households chose renewable energy as their preferred future energy source (Figure 8). About one-third (31.0%; weighted average: 34.2%) preferred energy conservation as a future energy source, while only 4.6% (weighted average of all rankings: 16.3%) preferred fossil fuels as a future energy source.

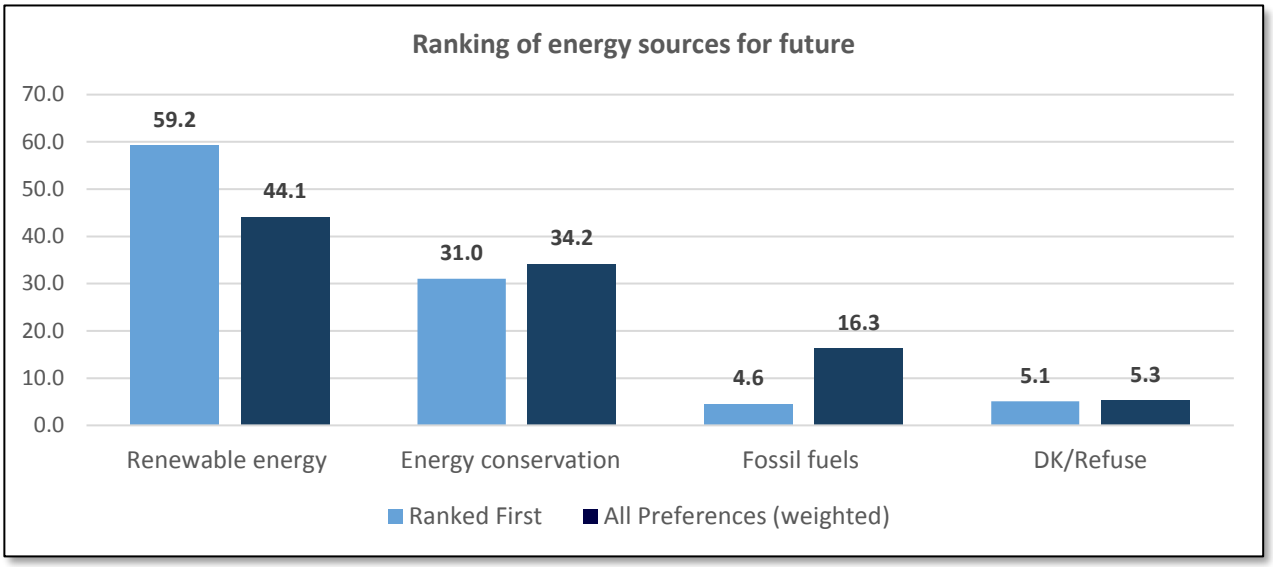


Figure 8. Ranking of energy sources for Yukon's future in order of preference.

ENERGY EFFICIENCY

Respondents were asked how often they consider the item´s energy efficiency rating when purchasing a new appliance or electronic device. A little over three-quarters (76.8%) of the respondents said they always or frequently check energy efficiency rating when purchasing a new appliance or electronic device, while 10.0% of the respondents never or rarely check (Figure 9).

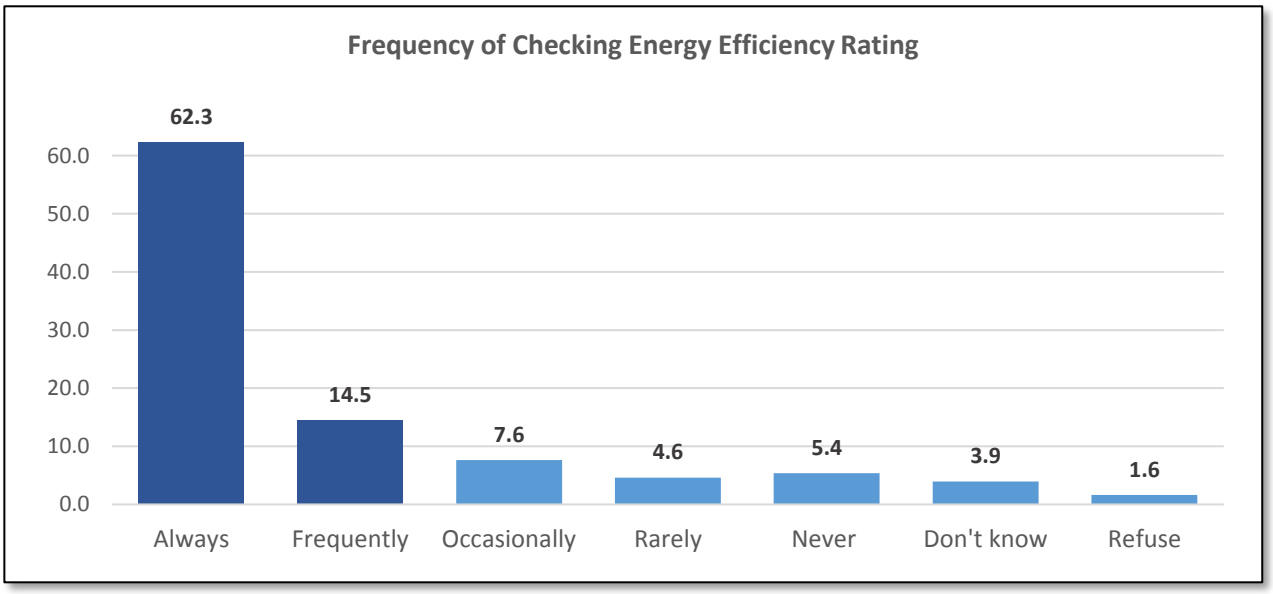


Figure 9. Frequency of checking energy efficiency rating before purchasing a new appliance or electronic device.

HOME HEATING SOURCES

Respondents were asked about their primary home heating sources as listed on their home insurance. At 46.5%, fuel oil is the most prevalent primary home heating source in Yukon. Electricity (baseboard, furnace or boiler) is the second most prevalent primary home heating source used by almost a quarter (24.5%) of the households (Figure 10a). Other primary sources, not listed in the question, included diesel, pellet stove, solar, forced air, kerosene heater, propane hot water heat, heat pump and exchange, Toyostove, pellet boiler, radiant heat, electro-thermal storage unit, and external wood boiler.

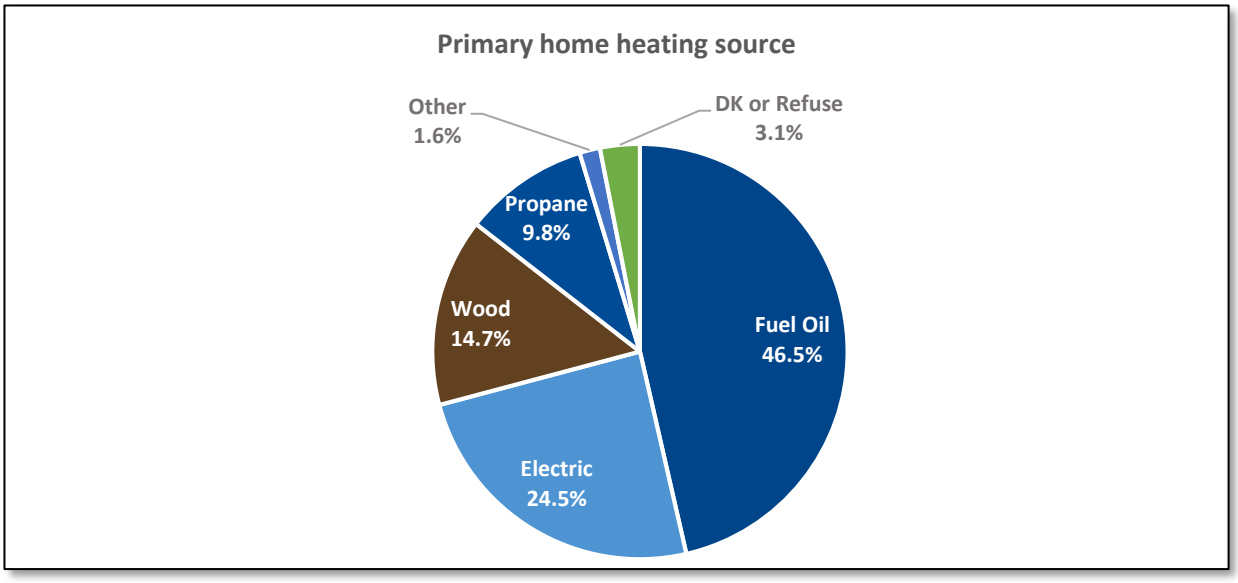


Figure 10a. Primary home heating sources as listed on home insurance.

In response to the question about additional home heating sources, most respondents (41.2%) said they did not have an additional home heating source. Of households that had additional home heating sources (58.9%), wood was the most common (35.5%) additonal home heating source followed by electricity (30.6%), as shown in Figure 10b. While fuel oil was the most commonly used (46.5%) primary source of heat, it was not so commonly used (12.9%) as an additional home heating source. Other additional home heating sources (3.3%) included pellet stove, fireplace, solar, diesel, generator, kerosene heater, Toyostove, oil, infrared heater, propane system, hot water heat, sauna, forced air, boiler system, candles, monitor, portable electrical heater, and hydronic.

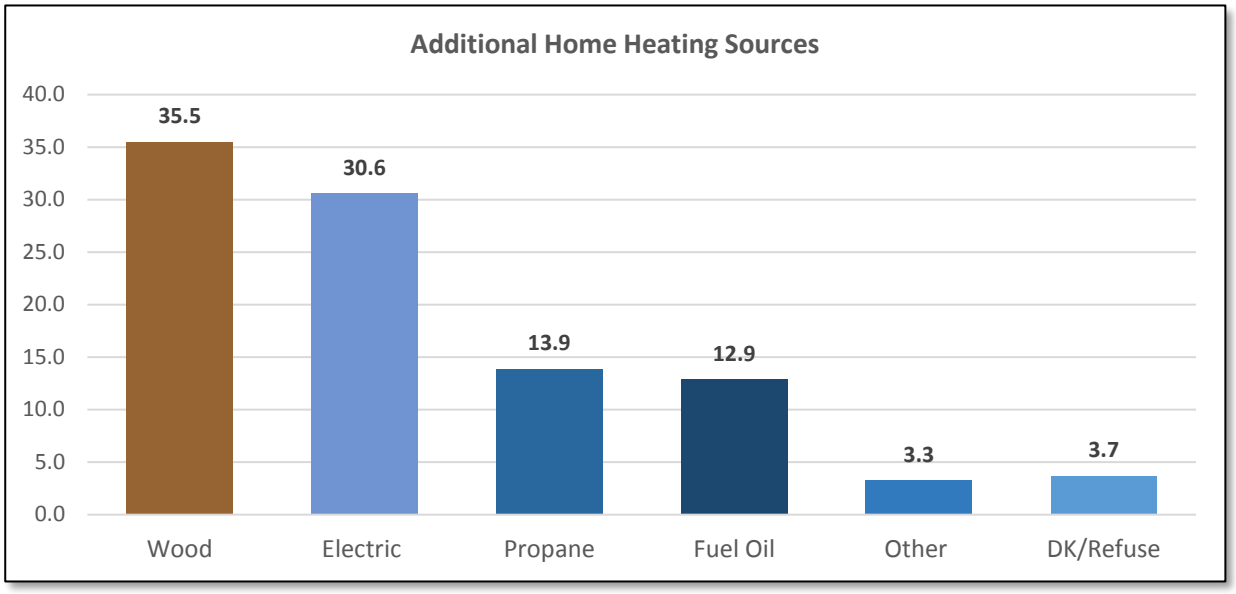


Figure 10b. Additional home heating sources (Note: respondents were allowed to choose multiple responses and percentages are derived from the sum of all reported additional home heating sources).

Responding households with oil or propane as a home heating source were asked if they have considered switching to electric heat. Of those who did not already use electricity as a primary or additional home heating source, 73.4% had not considered switching to electric heat, while 18.1% had (Figure 11).

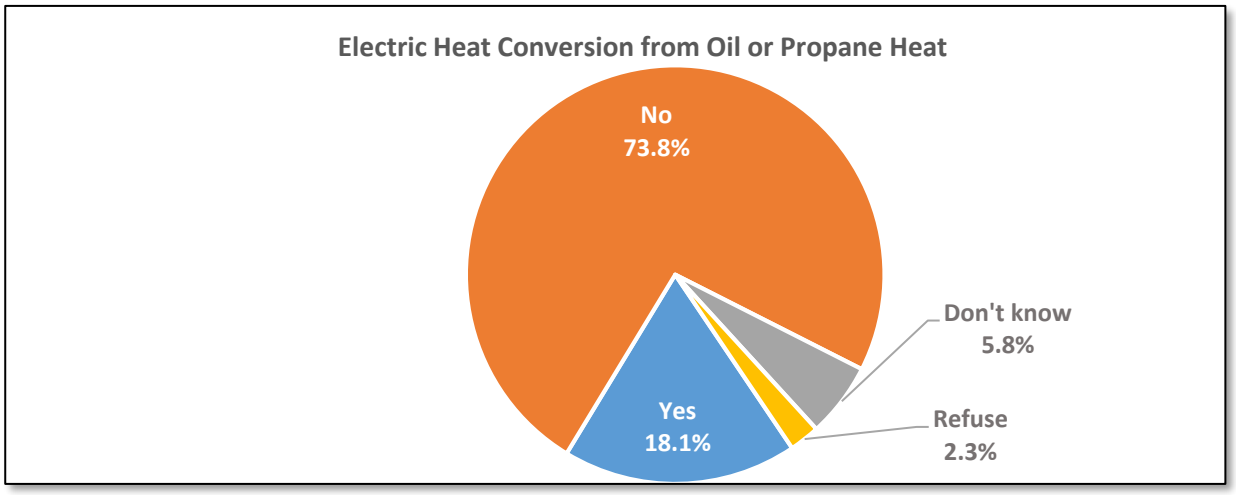


Figure 11. Respondents' consideration of switching to electric heat.

HOME HEATING SELECTION

Respondents were asked to rank five factors that influence their home heating system selection. Of the five given factors, cost was the most important (45.1%; weighted average of all rankings: 31.0%) to influence a respondent's home heating selection, distantly followed by safety (15.2%; weighted average: 16.7%), environmental concerns (11.2%; weighted average: 13.5%), comfort (9.5%; weighted average: 13.9%) and ease of maintenance (6.7%; weighted average of all rankings: 11.9%). In terms of first ranking (light blue bars in the chart below), respondents' selection of home heating system is more influenced by cost than all four other factors combined (Figure 12).

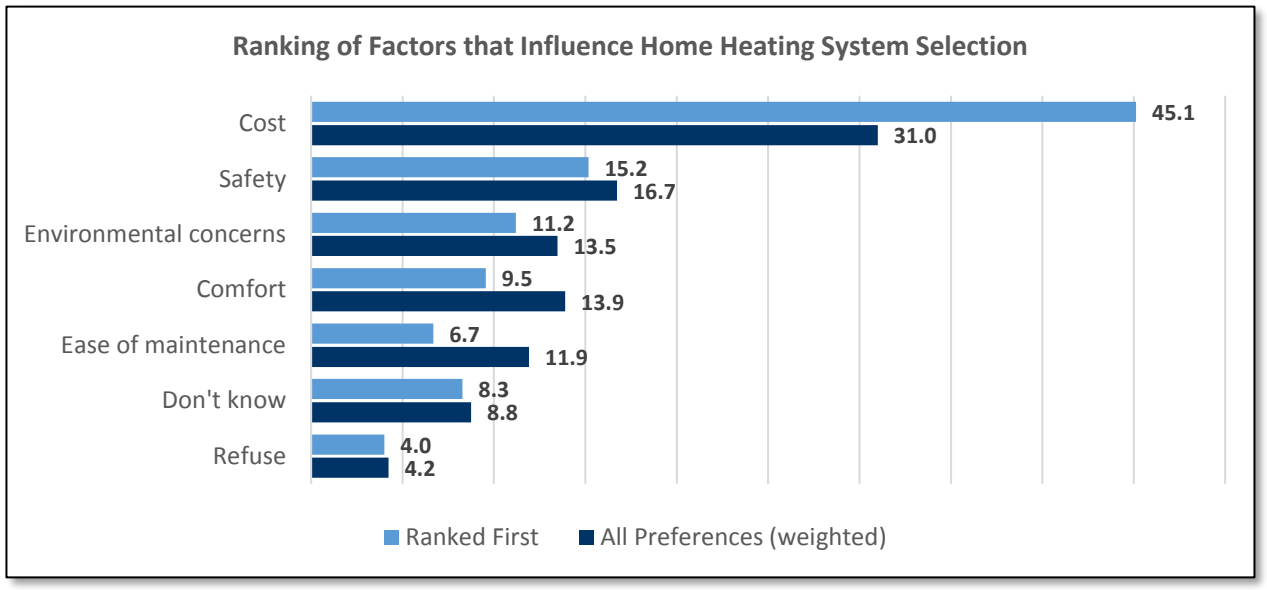


Figure 12. Ranking of factors that influence respondents' home heating system selection.

PART 2: FOCUS ON UNDERSTANDING THE SUPPORT FOR YEC INITIATIVES

This section of the survey generated information on two topics: to understand the Yukoners' preference for the type of fossil fuel for future back-up generation and to find if Yukoners have confidence in YEC's ability to plan and develop sustainable energy sources to meet future needs.

YUKON'S FUTURE BACK-UP GENERATION FOSSIL FUEL CHOICE

Respondents were asked about their preference of fossil fuel if YEC is required to choose a fossil fuel for future back-up generation. Slightly over half of Yukon households (50.7%) would prefer the use of natural gas if YEC is required to choose a fossil fuel for future back-up generation (Figure 13). Only 14.0% would prefer diesel fuel. About a quarter of the responding households did not know how to respond to this question, while 10.6% refused to provide a response.

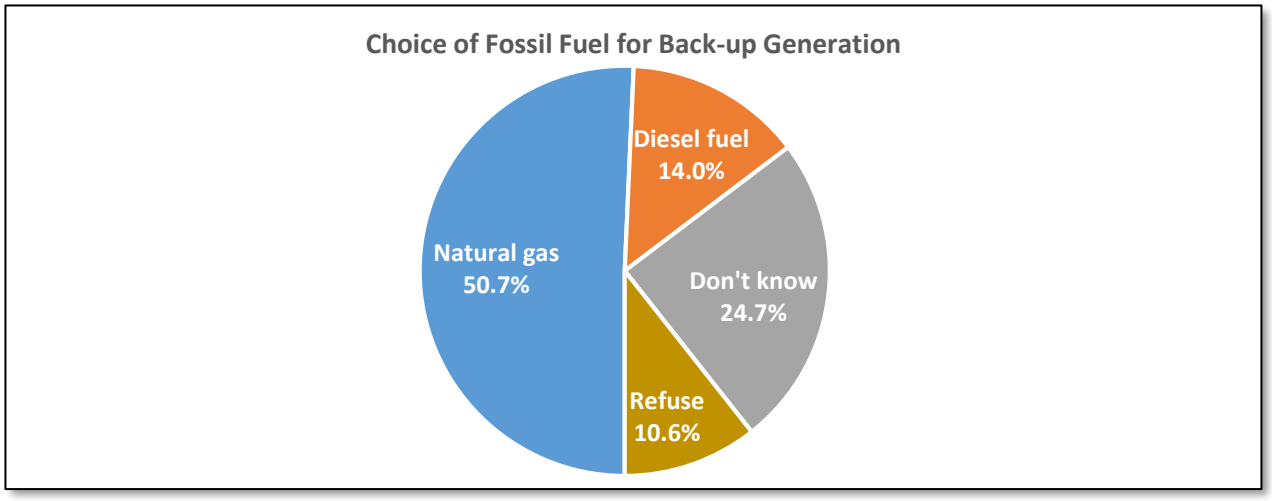


Figure 13. Respondents' preference of fossil fuel if YEC is required to choose a fossil fuel for future back-up generation.

CONFIDENCE IN YEC TO PLAN AND DEVELOP SUSTAINABLE ENERGY SOURCES

Respondents were asked if they have confidence in YEC to plan and develop sustainable energy sources to meet future needs. Most (61.2%) respondents were confident that YEC is able to plan and develop sustainable energy sources to meet future needs (Figure 14). About a fifth (19.2%) of the respondents said that that they do not have confidence in YEC's ability, while 17.2% either did not know or refused.

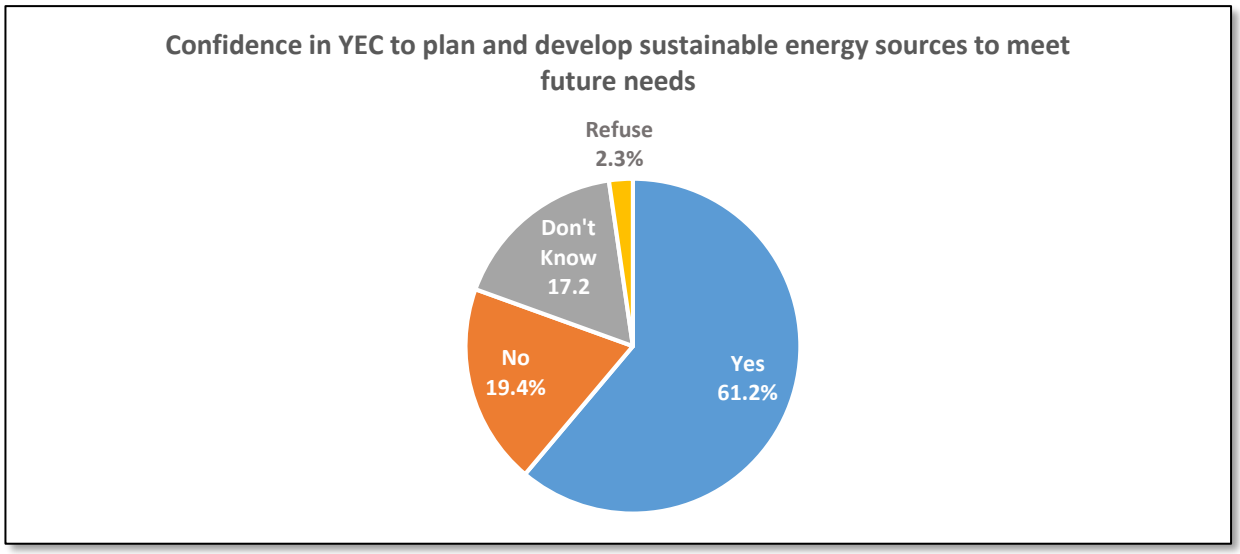


Figure 14. Respondents' confidence in YEC's ability to plan and develop sustainable energy sources to meet future needs.

PART 3: DEMOGRAPHICS OF THE RESPONDENTS

The survey was a household survey designed to collect responses primarily from head of the household or the next senior person in the household. Therefore, the demographic characteristics of the respondents of this survey may not match those of Yukon's total population.

RESPONDENTS' AGE GROUPS

More female (55.1%) than male respondents (42.7%) completed the survey. The largest proportion (28.0%) of the respondents were in the age group of 60 years or more, followed by the 30-39 years age group at 21.1% and the 50-59 years age group at 20.8% (Figure 15). As expected, the smallest respresented age group was 18-29 years.

Since the survey was designed to collect responses primarily from household heads or the next senior person, the age distribution of the respondents is not expected to match that of the population, especially those in the 18-29 years and the 60+ years age groups. However, the percentages of respondents in the age groups 30-39 years (21.1%), 40-49 years (17.6%) and 50-59 years (20.8%), are roughly comparable to the relevant population percentages (19.7%, 17.2% and 20.3%, respectively).

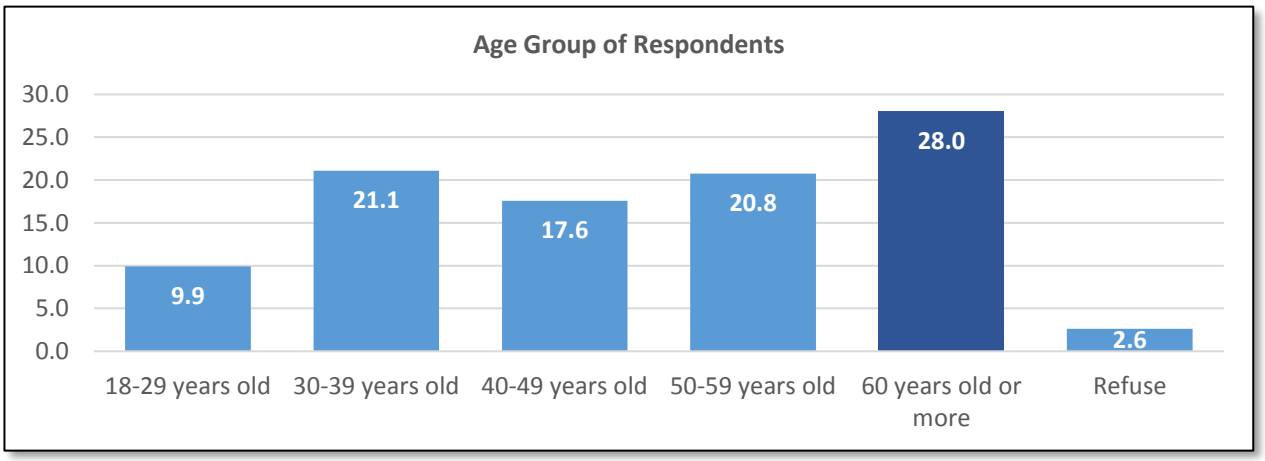


Figure 15. Age groups of the respondents.

RESPONDENTS' EDUCATION LEVELS

Nearly all respondents had at least a high school (or general education) diploma (Figure 16). About a quarter (24.2%) of the respondents had a bachelor's degree, while 11.8% had a graduate degree.

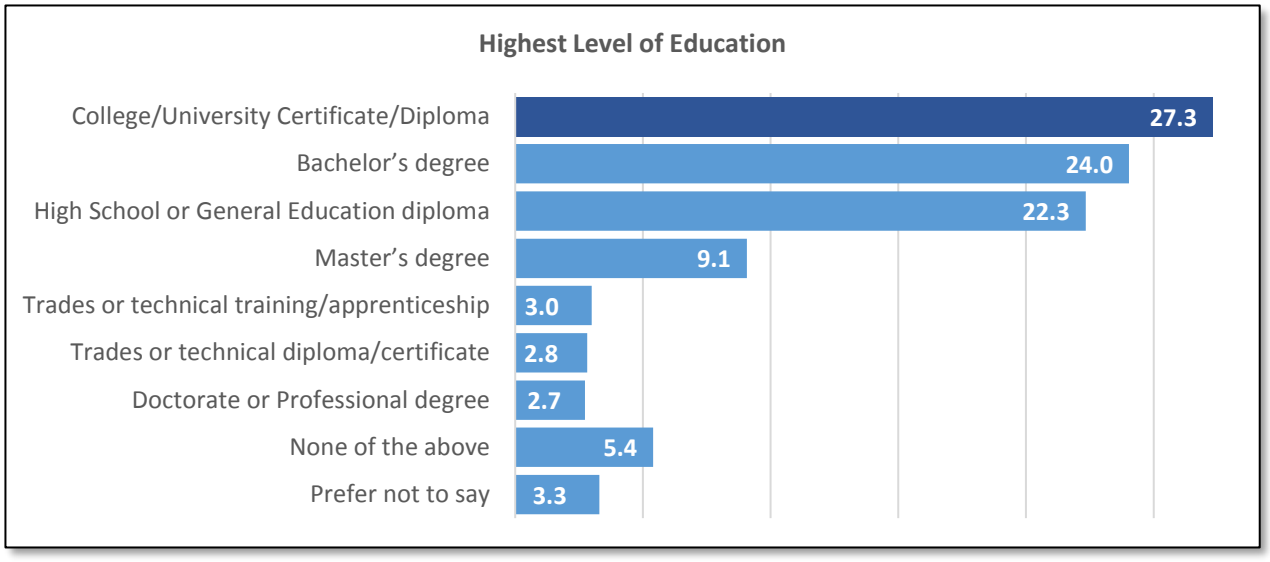


Figure 16. Levels of education of the respondents.

INCOME GROUPS OF RESPONDING HOUSEHOLDS

Almost 60% of respondents had an annual gross household income of greater than $50,000; about half of them had a household income of more than $100,000 (Figure 17). Of the demographic questions, this question had the highest refusal rate at 16.0%.

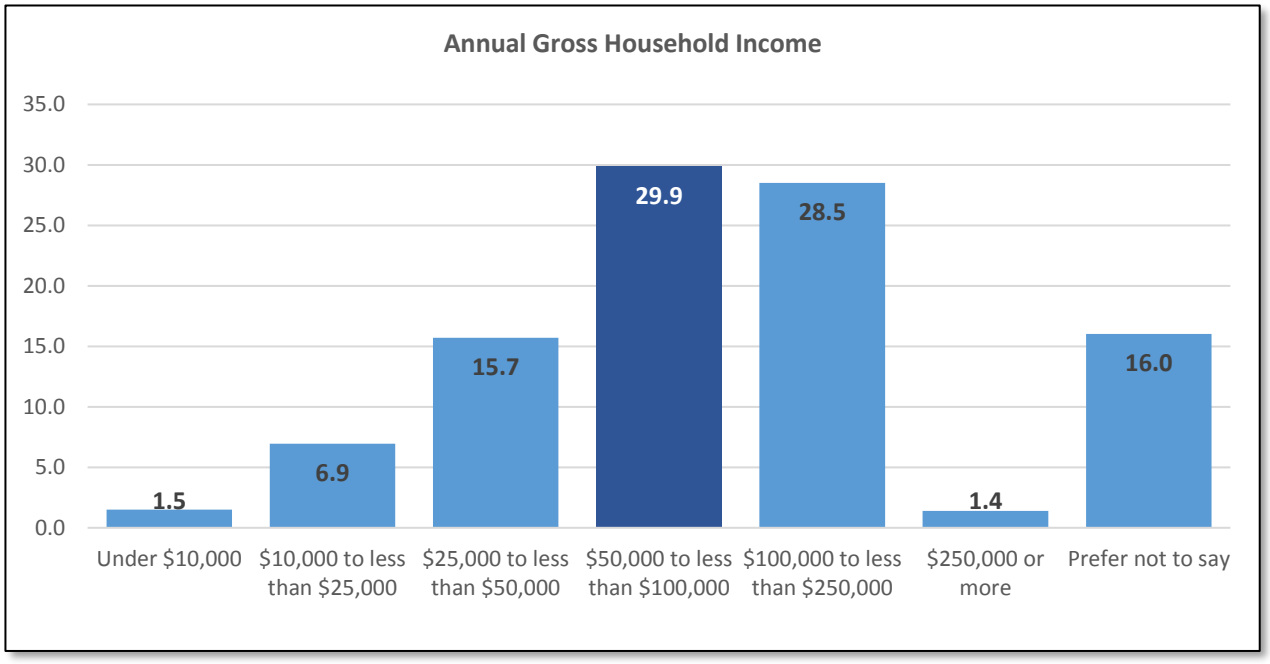


Figure 17. Responding households by annual gross household income.

RESPONSE BY ABORIGINAL GROUPS

Of the 14.5% of respondents who identified themselves as Aboriginal, 22.5% identified themselves as non-Yukon First Nations and 14.1% identified themselves as Metis (Figure 18). The ratio of Aboriginal respondents is less than the proportion of Aboriginal population in Yukon (23.1%). However, a comparison of the results of Aboriginal respondents to those of non-Aboginal respondents did not reveal any significant difference except the ranking order of the statements on social responsibility. Compared to non-Aboriginal respondents, Aboriginal respondents ranked 'do not compromise traditional pursuits' first at a higher rate (34.2% compared to 17.7%), and ranked 'enhance economic growth and create jobs' first at a lower rate (23.9% compared to 34.8%).

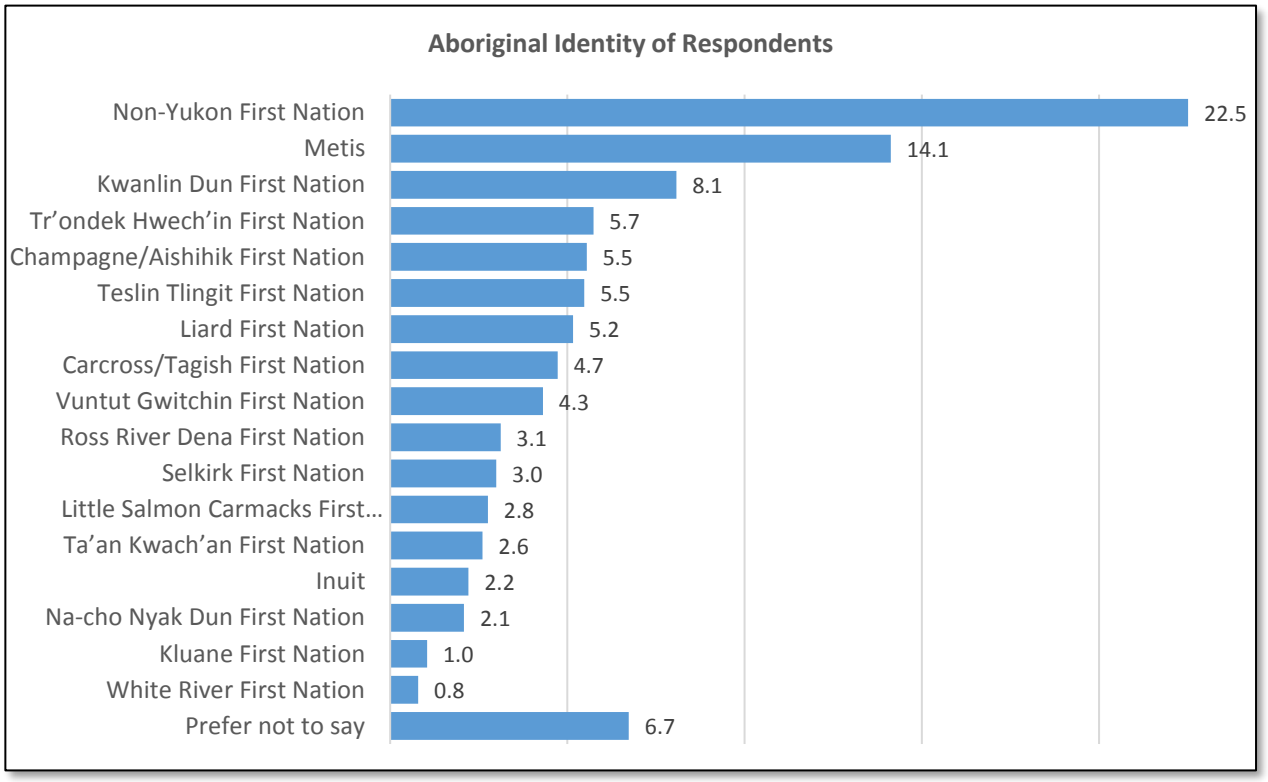


Figure 18. Respondents who identified themselves as Aboriginal.

RESPONSE BY COMMUNITY

Most respondents (76.4%) lived in Whitehorse and 22.8% of Yukon respondents lived in other Yukon communities. Less than 1% of respondents lived outside of Yukon or refused to reveal their Yukon community. A comparison of the results for Whitehorse and the rest of Yukon communities did not reveal any significant difference.

CONCLUSION

Through this survey, Yukoners ranked environmental protection as the most important factor for YEC's future project management goals, followed in order by cost, reliability, and social responsibility. However, personal home heating selection was influenced largely by cost (45.5%), followed by safety (15.2%), environmental concerns (11.2%), comfort (9.5%), and ease of maintenance (6.7%).When considering environmental protection, reducing the risk of pollution to land, water and air, other than greenhouse gases was of the most concern (29.5%).

Overall, respondents' current electricity bills were reported to be affordable (76.4%). However, when asked if current electricity rates were reasonable, there was more uncertainty; 54.7% thought rates were reasonable and 17.7% did not know. Most responding households (84.5) experienced a power outage in 2015, 65.1% of them reported one or more outages lasting more than an hour. In turn, 67.9% of the responding households felt it was necessary to have back-up heat source in case of an outage.

Based on the responses to this survey, Yukoners would generally support YEC's efforts to protect environment, enhance reliability, not compromise traditional pursuits, maintain access to wilderness, and create local jobs, even with a potential increase in electricity rates. However, respondents' support for YEC's efforts to economic growth was not overwhelming and they were divided on the issue of supplying electricity to mines if it leads to an increase in electricity rates.

For 56.3% Yukon households, the primary home heating source was fuel oil, followed by electricity for about a quarter of them. Most additional home heating sources were wood and electricity. Of households that did not have electric heating, 18.1% had considered switching to electric heat.

Most responding households (59.2%) selected renewable energy sources as the most preferred energy sources for Yukon's future, while 31.0% of them preferred energy conservation over new energy production. A little over half of the responding households would prefer natural gas, if YEC is required to use a fossil fuel for future back-up generation. Many of the respondents (61.2%) expressed their confidence in YEC's ability to plan and develop sustainable energy sources for the future.

APPENDIX A – SUMMARY TABLES

Q1. To help Yukon Energy choose new projects, please rank the following four factors in order of importance.	Percent			
	1st	2nd	3rd	4th
Environmental Protection	44.4	23.9	19.0	6.7
Cost	22.7	28.4	21.9	23.3
Reliability	21.0	21.8	33.8	18.5
Social Responsibility	7.7	21.1	20.0	46.1
Don't know	2.5	2.9	3.2	3.2
Refuse	1.7	1.9	2.1	2.1

Q2. For environmental protection, please rank which statement you consider more important.	Percent			
	1st	2nd	3rd	4th
Reduce impacts on Earth's atmosphere	22.6	16.3	22.1	21.8
Reduce risk of pollution to land, water and air, other than greenhouse	29.5	27.3	18.3	12.1
Reduce impact on species' habitats and wildlife populations at risk	23.7	28.6	26.3	6.7
Minimize the amount of land affected by a new energy project	12.1	13.9	18.2	44.2
Don't know	5.3	6.1	6.6	6.7
Refuse	6.8	7.8	8.5	8.6

Q3 Is your current electricity bill affordable?	Percent
Yes	76.4
No	14.6
DK	7.7
Refuse	1.4

Q4 Do you think that the current electricity rate in Yukon is reasonable?	Percent
Yes	54.7
No	26.6
DK	17.7
Refuse	1.1

Q5 Do you make efforts to reduce your energy use?	Percent
Yes	96.9
No	2.2
DK	0.2
Refuse	0.7

Q6 Even with a potential increase to electricity rates, would you support Yukon Energy's ...	Percent			
	Yes	No	DK	Refuse
... effort to enhance economic growth for Yukon?	57.1	22.1	16.9	3.9
... effort to create local jobs?	73.4	15.5	8.4	2.6
... effort to reduce power outages in your area?	71.0	20.1	6.7	2.2
... effort to reduce GHG emissions in energy production?	78.4	12.1	7.1	2.4
... effort to reduce impact on species´ habitats and wildlife populations at risk?	80.7	10.6	6.3	2.3
... effort to not compromise traditional pursuits as a way of life (e.g. trapping, hunting and fishing)?	68.6	18.6	9.8	3.0
... effort to maintain access to wilderness recreation?	73.1	16.4	8.0	2.5
... decision to supply electricity to mines?	46.0	38.0	12.9	3.1

Q7 Did you experience power outages in 2015?	Percent
Yes	84.5
No	10.3
DK	4.3
Refuse	0.9

Q8 Approximately how many power outages did you experience in 2015 that lasted more than one hour?	Percent
Less than an hour	13.4
1	16.0
2	20.4
3	12.7
4	5.3
5	3.9
6	3.1
7 or more	3.7
DK	21.3
Refuse	0.2

Q9 Do you feel it is necessary to have back-up heating and/or a generator at your home in case of power	Percent
Yes	67.2
No	29.5
DK	2.3
Refuse	1.0

Q10. With respect to social responsibility, please rank the statements in order of importance.	Percent			
	1st	2nd	3rd	4th
Enhance economic growth and create jobs	33.3	11.7	15.0	23.8
Do not compromise traditional pursuits as a way of life	20.2	24.2	20.4	16.8
Maintain access to wilderness recreation	16.7	27.3	23.8	14.5
Conservation of historical sites to protect Yukon culture	14.8	19.5	22.2	26.1
Don't know	8.0	9.2	9.8	10.0
Refuse	7.1	8.2	8.7	8.9

Q11. Please rank the next three energy sources for Yukon's future in terms of preference.	Percent		
	1st	2nd	3rd
Fossil fuels	4.6	11.9	78.1
Renewable energy	59.2	30.2	4.9
Energy conservation	31.0	52.3	11.2
Don't know	2.8	3.1	3.2
Refuse	2.3	2.5	2.6

Q12 When purchasing a new appliance/electronic device, how often do you consider the item´s energy	Percent
Always	62.3
Frequently	14.5
Occasionally	7.6
Rarely	4.6
Never	5.4
Don't know	3.9
Refuse	1.6

Q13 What is the primary heating source in your home as listed on your home insurance?	Percent
Electric (Baseboard, furnace or boiler)	24.5
Fuel Oil	46.5
Propane	9.8
Wood	14.7
Other (specify):	1.6
Don't Know	1.8
Refuse	1.3

Q13_O What other primary heating sources are in your home as listed on your home insurance? (n=133)	Percent
Diesel	24.4
Electro Thermal Storage Unit	2.4
External Wood Boiler	2.4
Forced Air	7.3
Heat Pump	4.8
Heat exchange	2.4
Hot Water Heat	2.4
Kerosene Heater	7.3
Oil and Wood Furnace Combo	7.2
Pellet Boiler	2.4
Pellet Stove	15.1
Propane Hot Water	2.4
Radiant Heat	2.4
Solar	7.3
Toyo Stove	4.8
Water	2.4
Wood And Propane Combo	2.4

Q14 What additional heating sources exist in your home? (Check all that apply.)	Percent
Electric (Baseboard, furnace or boiler)	20.7
Fuel Oil	8.7
No secondary	41.2
Propane	9.4
Wood	24.0
Other (specify):	2.3
Don't Know	1.2
Refuse	1.3

Q14 (Other) What other additional heating sources exist in your home? (Check all that apply.)	Percent
Boiler System/Hot Water Heat/Hydronic	6.6
Candles	1.7
Diesel	7.9
Fireplace	10.0
Forced Air	1.7
Generator	6.7
Kerosene Heater	5.0
Monitor/Toyo Stove	6.7
Oil	3.4
Pellet Stove	29.5
Portable Electrical Heater/Infrared Heater	5.0
Propane System	3.3
Sauna	3.3
Solar	9.2

Q15 Have you considered switching to electric heat?	Percent
Yes	18.1
No	73.8
DK	5.8
Refuse	2.3

Q16. Please rank how the following five factors influence your home heating system selection.	Percent				
	1st	2nd	3rd	4th	5th
Cost	45.1	17.4	11.6	6.6	7.8
Comfort	9.5	20.0	17.6	17.7	20.8
Safety	15.2	17.9	21.6	20.1	9.4
Environmental concerns	11.2	13.9	17.4	21.9	21.0
Ease of maintenance	6.7	17.6	17.5	18.7	25.8
Don't know	8.3	8.9	9.7	10.1	10.2
Refuse	4.0	4.3	4.7	4.9	4.9

Q17 If Yukon Energy is required to choose a fossil fuel for future back-up generation, which fuel do you prefer?	Percent
Natural gas	50.7
Diesel fuel	14.0
DK	24.7
Refuse	10.6

Q18 Do you have confidence in Yukon Energy to plan and develop sustainable energy sources to meet future	Percent
Yes	61.2
No	19.4
DK	17.2
Refuse	2.3

Q19 You identify yourself as a:	Percent
Male	42.7
Female	55.1
Other	0.4
Prefer not to say	1.7

Q20 Is your age between:	Percent
18-29 years old	9.9
30-39 years old	21.1
40-49 years old	17.6
50-59 years old	20.8
60 years old or more	28.0
Refuse	2.6

Q21 What is your highest level of education?	Percent
High School diploma or certificate	20.7
GED (General Education Diploma)	0.9
College/University Certificate/Diploma	27.6
Trades or technical training/apprenticeship	3.0
Trades or technical diploma/certificate	2.9
Bachelor's degree	24.3
Master's degree	9.2
Doctorate	1.2
Professional degree (medicine, law)	1.6
None of the above	5.5
Prefer not to say	3.3

Q22 What is your annual household income range before tax?	Percent
Under $10,000	1.5
$10,000 to less than $25,000	7.0
$25,000 to less than $50,000	15.7
$50,000 to less than $100,000	29.9
$100,000 to less than $250,000	28.5
$250,000 or more	1.4
Prefer not to say	16.0

Q23 Do you identify yourself as an Aboriginal person (First Nations, Metis or Inuit)?	Percent
Yes	14.5
No	83.3
Refuse	2.2

Q24 In which Aboriginal group do you associate?	Percent
Carcross/Tagish First Nation	4.7
Champagne/Aishihik First Nation	5.5
Kluane First Nation	1.0
Kwanlin Dun First Nation	8.1
Liard First Nation	5.2
Little Salmon Carmacks First Nation	2.8
Na-cho Nyak Dun First Nation	2.1
Ross River Dena First Nation	3.1
Selkirk First Nation	3.0
Ta'an Kwach'an First Nation	2.6
Teslin Tlingit First Nation	5.5
Tr'ondek Hwech'in First Nation	5.7
Vuntut Gwitchin First Nation	4.3
White River First Nation	0.8
Non-Yukon First Nation	22.5
Metis	14.1
Inuit	2.2
Prefer not to say	6.7

Q25 In which Yukon community do you live?	Percent
Beaver Creek	0.3
Burwash Landing	0.3
Carmacks	0.9
Carcross	0.9
Dawson City	4.3
Destruction Bay	0.3
Faro	1.3
Haines Junction	2.5
Keno	0.1
Marsh Lake	2.2
Mayo	1.0
Old Crow	0.4
Pelly Crossing	0.5
Ross River	0.6
Stewart Crossing	0.1
Tagish	1.2
Teslin	1.1
Watson Lake	2.7
Whitehorse	76.3
Other (specify)	3.1
I don't live in Yukon	0.0

Q25 In which other Yukon community do you live?	Percent
O_Q25m1	Percent
Between Whitehorse And Carmacks	1.3
Braeburn	1.3
Carcross Road	1.3
Carmacks And Whitehorse	1.3
Champagne	1.3
Fox Lake	2.6
Golden Horn	3.9
Hootalinqua	2.6
Ibex Valley	5.2
Iron Creek	1.3
Lake Laberge	6.5
Mayo Road	2.6
Mendan Hall	5.2
Mount Lorne	14.2
Mountain	1.3
Near Johnson's Crossing	1.3
Outside City Limits	2.6
Silver City	1.3
South Mcclintock Subdivision	1.3
Spruce Hill	1.3
Swift River	1.3
Takhini Hot Springs Road	7.8
Upper Liard	1.3
Wolf Creek	1.9
Refuse	28.4

APPENDIX B – YUKON ELECTRICITY VALUES SURVEY

YEC Electricity Values Survey 2016

Hello. May I speak to… [*read contact name(s) from label*…]?

- ❑ Yes → [*continue with introduction*]
- ❑ No → We are conducting the Electricity Values Survey.
  When would be a good time to call back? _____

My name is _____ and I am calling from Yukon Bureau of Statistics in Whitehorse. We are conducting the Electricity Values Survey on behalf of the Yukon Energy Corporation. The purpose of this survey is to collect your input on how to meet Yukon's future electricity needs. Your responses will be used in YEC's project planning.

Your household has been randomly selected to complete the survey. Participation in this survey is voluntary and your responses are confidential. Information collected through this survey is protected in accordance with the Statistics Act.

Questionnaire

Q1. To help Yukon Energy choose new projects, please rank the following four factors in order of importance.
[Interviewer: please read all factors, then ask respondent for 1st, 2nd, 3rd and 4th]

Factor	Ranking
a. Environmental Protection (i.e. healthy planet and environment)	
b. Cost (i.e. affordable bills, rates and fees)	
c. Reliability (i.e. uninterrupted power supply, reduced power outages)	
d. Social Responsibility (i.e. healthy communities, strong economy)	

☐ Don't know ☐ Refuse

Q2. For environmental protection, please rank which statement you consider more important.
[Interviewer: please restate the agreement scale after each statement]

Statement	Ranking
a. Reduce impacts on Earth's atmosphere (i.e. minimize greenhouse gas emissions)	
b. Reduce risk of pollution to land, water and air, other than greenhouse gas emissions	
c. Reduce impact on species' habitats and wildlife populations at risk (e.g. Chinook salmon)	
d. Minimize the amount of land affected by a new energy project (i.e. smaller projects have a lower footprint)	

☐ Don't know ☐ Refuse

Q3. Is your current electricity bill affordable?
☐ Yes ☐ No ☐ Don't know ☐ Refuse

Q4. Do you think that the current electricity rate in Yukon is reasonable?
☐ Yes ☐ No ☐ Don't know ☐ Refuse

Q5. Do you make efforts to reduce your energy use?
☐ Yes ☐ No ☐ Don't know ☐ Refuse

Q6. Any new project initiative of Yukon Energy would likely involve costs and therefore, may affect electricity rates. Even with a potential increase to electricity rates, would you support:
[Interviewer: please ask respondent yes or no after each question]

Question	Yes	No	Don't Know	Refuse
a. Yukon Energy's effort to enhance economic growth for Yukon?	◯	◯	◯	◯
b. Yukon Energy's effort to create local jobs?	◯	◯	◯	◯
c. Yukon Energy's effort to reduce power outages in your area?	◯	◯	◯	◯
d. Yukon Energy's effort to reduce GHG emissions in energy production?	◯	◯	◯	◯
e. Yukon Energy's effort to reduce impact on species' habitats and wildlife populations at risk?	◯	◯	◯	◯
f. Yukon Energy's effort to not compromise traditional pursuits (e.g. trapping, hunting and fishing)?	◯	◯	◯	◯
g. Yukon Energy's effort to maintain access to wilderness recreation?	◯	◯	◯	◯
h. Yukon Energy's effort to conserve historical sites to protect Yukon culture?	◯	◯	◯	◯
i. Yukon Energy's decision to supply electricity to mines?	◯	◯	◯	◯

Q7. Did you experience power outages in 2015?
☐ Yes ☐ No → Go to Q9 ☐ Don't know → Go to Q9
☐ Refuse → Go to Q9

Q8. Approximately how many power outages did you experience in 2015 that lasted more than one hour?
_____ outages in 2015
☐ Don't Know ☐ Refuse

Q9. Do you feel it is necessary to have back-up heating and/or a generator at your home in case of power outages?
☐ Yes ☐ No ☐ Don't know ☐ Refuse

Q10. With respect to social responsibility, please rank the statements in order of importance.
[Interviewer: please read all types, then ask respondent for 1st, 2nd, 3rd and 4th choice]

Statement	Ranking
a. Enhance economic growth and create jobs	
b. Do not compromise traditional pursuits (e.g. trapping, hunting and fishing)	
c. Maintain access to wilderness recreation	
d. Conservation of historical sites to protect Yukon culture	

☐ Don't know ☐ Refuse

Q11. Please rank the next three energy sources for Yukon's future in terms of preference.
[Interviewer: please read all types, then ask respondent for 1st, 2nd and 3rd choice]

Energy source	Ranking
a. Fossil fuels (such as diesel, natural gas).	
b. Renewable energy (such as hydro, wind, solar).	
c. Energy conservation (such as savings measures, efficiency) preferred over new energy production.	

☐ Don't know ☐ Refuse

Q12. When you purchase a new appliance or electronic device, how often do you consider the product's energy efficiency rating?

☐ Always
☐ Frequently
☐ Occasionally
☐ Rarely
☐ Never
☐ Don't Know ☐ Refuse

Q13. What is the primary heating source in your home as listed on your home insurance?
[Interviewer: check only one]

☐ Electric (Baseboard, furnace or boiler)
☐ Fuel Oil
☐ Propane
☐ Wood
☐ Other (specify): _____
☐ Don't Know ☐ Refuse

Q14. What additional heating sources exist in your home? [Interviewer: check all that apply]

☐ Electric (Baseboard, furnace or boiler)
☐ Fuel Oil
☐ Propane
☐ Wood
☐ Other (specify): _____
☐ Don't Know ☐ Refuse

Q15. If you heat with oil or propane, have you considered switching to electric heat?

☐ Yes ☐ No ☐ Don't know ☐ Refuse

Q16. Please rank how the following five factors influence your home heating system selection. [Interviewer: please read all factors, then ask respondent to choose 1st, 2nd, etc. choice]

Factor	Ranking
a. Cost	
b. Comfort (such as dampness, perception of warmth, ease of controlling temperature)	
c. Safety (such as carbon monoxide, oil/gas tank placement)	
d. Environmental concerns (such as greenhouse gas emissions, fuel spills)	
e. Ease of maintenance	

Q17. If Yukon Energy is required to choose a fossil fuel for future back-up generation, which fuel do you prefer?

☐ Natural Gas ☐ Diesel Fuel ☐ Don't know ☐ Refuse

Q18. Do you have confidence in Yukon Energy to plan and develop sustainable energy sources to meet future needs?

☐ Yes ☐ No ☐ Don't know ☐ Refuse

Q19. You identify yourself as a:

- ☐ Male
- ☐ Female
- ☐ Other
- ☐ Prefer not to say

Q20. Is your age between:

- ☐ 18-29 years old
- ☐ 30-39 years old
- ☐ 40-49 years old
- ☐ 50-59 years old
- ☐ 60 years old or more
- ☐ Prefer not to say

Q21. What is your highest level of education?

- ☐ High School diploma or certificate
- ☐ GED (General Education Diploma)
- ☐ College/University Certificate/Diploma
- ☐ Trades or technical training/apprenticeship
- ☐ Trades or technical diploma/certificate
- ☐ Bachelor's degree
- ☐ Master's degree
- ☐ Doctorate
- ☐ Professional degree (medicine, law)
- ☐ None of the above
- ☐ Prefer not to say

Q22. What is your annual household income range before tax?

- ☐ Under $10,000
- ☐ $10,000 to less than $25,000
- ☐ $25,000 to less than $50,000
- ☐ $50,000 to less than $100,000
- ☐ $100,000 to less than $250,000
- ☐ $250,000 or more
- ☐ Prefer not to say

Q23. Do you identify yourself as an Aboriginal person (First Nations, Metis or Inuit)?

☐ Yes →Go to Q24 ☐ No →Go to Q25 ☐ Prefer not to say →Go to Q25

Q24. In which Aboriginal group do you associate?

- ☐ Carcross/Tagish First Nation
- ☐ Champagne/Aishihik First Nation
- ☐ Kluane First Nation
- ☐ Kwanlin Dun First Nation
- ☐ Liard First Nation
- ☐ Little Salmon Carmacks First Nation
- ☐ Na-cho Nyak Dun First Nation
- ☐ Ross River Dena First Nation
- ☐ Selkirk First Nation
- ☐ Ta'an Kwach'an First Nation
- ☐ Teslin Tlingit First Nation
- ☐ Tr'ondek Hwech'in First Nation
- ☐ Vuntut Gwitchin First Nation
- ☐ White River First Nation
- ☐ Non-Yukon First Nation
- ☐ Metis
- ☐ Inuit
- ☐ Prefer not to say

Q25. In which Yukon community do you live?

- ☐ Beaver Creek
- ☐ Burwash
- ☐ Carmacks
- ☐ Carcross
- ☐ Dawson City
- ☐ Destruction Bay
- ☐ Faro
- ☐ Haines Junction
- ☐ Keno
- ☐ Marsh Lake
- ☐ Mayo
- ☐ Old Crow
- ☐ Pelly Crossing
- ☐ Ross River
- ☐ Tagish
- ☐ Teslin
- ☐ Watson Lake
- ☐ Whitehorse
- ☐ Other (specify): _____
- ☐ I don't live in Yukon
- ☐ Prefer not to say

"Thank you for your time!"

Appendix 3.2. Communication Methods and Materials

Pre-Round	Timing	Goal	Notes
Meeting with Grand Chief of the Council of Yukon First Nations and several other Yukon First Nation Chiefs	Sep 2015	Engagement: to seek advice on engagement with FNs throughout the resource planning process.	• Yukon Energy received feedback that First Nations should be engaged as governments, and as potential business partners/investors, and as members of the Yukon public.
Information sheet	Sep 2015	Electricity literacy: to provide a summary of what a resource plan is and the steps that Yukon Energy expected to follow to complete the plan.	• This backgrounder was shared with Yukon First Nation governments and Development Corporations, along with stakeholders and members of the Yukon public.
Technical Advisory Committee meeting #1	Sep 2015	Engagement	• A summary of this meeting is posted on Yukon Energy's resource planning website.
Yukon-wide mailer #1	Oct 2015	Electricity literacy: to increase general understanding of utility issues.	• Mailer provided summaries of several "Electricity 101" information sheets, with links to the resource planning website where people could read full text. • Copies of mailer provided to First Nations as well as the Yukon general public.
Yukon News/l'Aurore boreale newspaper infomercials	Late 2015/early 2016	Electricity literacy: to increase general understanding of utility issues.	• Eight Electricity 101 information sheets were created both in English and French. • Each of the 8 sheets ran twice in the Yukon News and once in the French newspaper. • Sheets were provided to First Nations and electronic copies were posted on Yukon Energy's resource planning website.
RFP ads	Nov. 2015	Information: advising local contractors of employment opportunities and informing local First Nations of research that would be completed in their traditional territories.	• RFP ads were placed in both local newspapers and on Yukon Energy's website. • Copies of the ads were provided to First Nations on whose traditional territory the research would be carried out.
Media coverage	Fall 2015	Information	• Coverage by local radio, TV, and newspaper media regarding the resource planning process.

Round 1	Timing	Goal	Notes
Yukon-wide mailer #2	Jan. 2016	Information and electricity literacy	• Explanation of the resource planning process, how people can be involved, and a summary of the meaning of a load forecast. • Copies were provided to First Nations.
"News from the Future" worksheet/discussion paper	Feb. 2016	Engagement and electricity literacy	• Used with six classes of F. H. Collins High School students to introduce the idea of resource planning.
Technical Advisory Committee meeting #2	Feb. 2016	Engagement	• A summary of this meeting is posted on Yukon Energy's resource planning website.
Radio ads for public meetings	Feb. – Mar. 2016	Information and engagement	• Ads notifying Yukoners about the first round of public meetings.
Newspaper ads for public meetings	Feb. 2016	Information and engagement	• Placements in Yukon News, Whitehorse Star, and What's Up Yukon notifying Yukoners about first round of public meetings.
Posters	Feb. and early March 2016	Information and engagement	• Posted at various public locations in Dawson, Mayo, Haines Junction, Carcross, and Teslin notifying Yukoners about first round of public meetings.
E-invites	Feb. and early March 2016	Information and engagement	• Notification to Yukoners, including First Nations, about first round of public meetings.
Social media (Yukon Energy blog, Facebook, Twitter, and LinkedIn)	Feb. 2016	Information and engagement	• Notification to Yukoners about first round of public meetings.
Media coverage	Feb. – March 2016	Information	• Local media coverage (radio and newspaper) of first round of public meetings.
Resource Planning website	Late 2015 and throughout 2016	Information and engagement	• Regular updates on resource planning work, notification of public meetings, and two-way conversation with Yukoners sharing information, ideas and opinions.
Electricity 101 information sheets (both English and French)	Feb. 2016	Increase electricity literacy	• Shared at all public meetings and posted on the Resource Plan website.
Public meetings	Feb. 29 – Mar. 17, 2016	Information and engagement	• Meetings in downtown Whitehorse, Whitehorse campus of Yukon College, Haines Junction, Carcross, Teslin, Dawson City, and Mayo.

Round 1	Timing	Goal	Notes
PowerPoint	Feb. 29 – Mar. 17, 2016	Information and engagement	• PowerPoint presentation for public meetings. Presentation was recorded and posted on Yukon Energy's resource planning website and YouTube channel.
Values survey	May – June 2016	Gather information about what Yukoners value when considering effects of future electricity projects.	• One-third of Yukoners from throughout the territory selected for survey. • Survey results posted on the resource plan website and shared at public meetings.
Technical Advisory Committee meeting #3	Aug. 2016	Engagement	• A summary of this meeting is posted on Yukon Energy's resource planning website.

Round 2	Timing	Goal	Notes
Technical Advisory Committee meeting #4	Sept. 2016	Information and engagement	• Summary notes of the meeting are posted on Yukon Energy's resource planning website.
Maps	Nov. 2016	Information and engagement	• Maps were provided to Yukon First Nations showing potential energy projects by traditional territory.
Newspaper ads	Nov. 2016	Information and engagement	• Placements in Whitehorse Star and Yukon News notifying Yukoners about Round 2 public meetings.
Facebook and Google ads/boosted Facebook posts	Nov. 2016	Information and engagement	• Ads ran two weeks ahead of public meetings to notify Yukoners about Round 2 sessions.
Radio ads	Nov. 2016	Information and engagement	• Ads notifying Yukoners about Round 2 public meetings
Social media (Yukon Energy blog, Facebook, twitter, LinkedIn)	Nov. 2016	Information and engagement	• Notification of Round 2 public meetings
Posters	Nov. 2016	Information and engagement	• Posted at various public locations in Dawson, Mayo, Haines Junction, Carcross, and Teslin notifying Yukoners about Round 2 public meetings.
E-invites	Nov. 2016	Information and engagement	• Notification to Yukoners, including First Nations, about Round 2 public meetings.

Round 2	Timing	Goal	Notes
Information sheets/poster boards	Nov. – Dec. 2016	Information and engagement	• Fourteen information sheets and poster boards outlining each of the energy options we considered. • Sheets were available at all of the public meetings and were posted on the resource planning website.
Public meetings	Nov. 22 – Dec. 1, 2016	Information and engagement	• Meetings at Mount McIntyre in Whitehorse, in Dawson City, Mayo, Haines Junction, Carcross and Teslin
PowerPoint	Nov. 22 – Dec. 1, 2016	Information and engagement	• PowerPoint presentation for public meetings
Yukon-wide mailer #3	Dec. 2016	Information and engagement	• Summaries of all the energy options considered with link to the resource planning website for more information.
Resource Planning website	Late 2015 and throughout 2016	Information and engagement	• Regular updates on resource planning work, notification of public meetings, and two-way conversations with Yukoners sharing information, ideas and opinions.
Media coverage	Nov. 2016	Information	• Media coverage of second round of public engagement on resource plan.

Round 3	Timing	Goal	Notes
Technical Advisory Committee #5	Jan. 13, 2017	Information and engagement	• Summary of the meeting minutes was posted on Yukon Energy's resource planning website.
Newspaper ads	Jan. 2017	Information and engagement	• Ads ran in Yukon News and Whitehorse Star advising the public about the third round of public meetings.
Radio ads	Jan. 2017	Information and engagement	• Ads advising the public about the third round of public meetings.
Online ads	Jan. 2017	Information and engagement	• Facebook ads advising the public about the third round of public meetings.
Social media	Jan. 2017	Information and engagement	• Posts on Yukon Energy's Facebook, Twitter, and LinkedIn pages, advising the public about the third round of public meetings.

Round 3	Timing	Goal	Notes
Posters	Jan. 2017	Information and engagement	• Posted at various locations in Haines Junction, Carcross, Mayo, Dawson City, Teslin and Faro informing people about the third round of public meetings.
E-invites	Jan. 2017	Information and engagement	• Notification to Yukoners, including First Nations, about the third round of public meetings.
First Nation meetings	Jan. – Feb. 2017	Information and engagement	• Yukon Energy President and Vice-President met with several First Nations, including Carcross-Tagish First Nation, Kwanlin Dun First Nation, and Little Salmon/Carmacks First Nation.
NDP briefing	Feb. 16, 2017	Information	• Yukon Energy President and vice-President met with the NDP MLAs to provide a briefing on the resource planning process and proposed action plan.
Information sheet	Jan. – Feb. 2017	Information	• Summary sheet of presentation given at public meetings. It was provided to First Nations, given out at public meetings, and posted on Yukon Energy's resource planning website.
PowerPoint	Jan. – Feb. 2017	Information	• Presentation given at public and First Nation meetings.
Media coverage	Jan. – Feb. 2017	Information	• Media coverage (newspaper and radio) on third round of public engagement on the resource plan.

Draft Plan	Timing	Goal	Notes
Draft of 2016 Resource Plan	Late Feb. 2017	Information and engagement	• Draft posted on Yukon Energy's resource planning website.
E-mails	Late Feb. 2017	Information and engagement	• Yukoners who had indicated they wanted to be kept up to date on the resource planning process and who had provided Yukon Energy with their email address received notification that the draft plan was available for review.
Social media/website	Late Feb. 2017	Information and engagement	• Posts on Yukon Energy's Facebook, Twitter, and LinkedIn pages, along with the Corporation's website, inviting people to provide

Draft Plan	Timing	Goal	Notes
			comments on the draft resource plan.

Table A-1: Very Low Industrial Activity Scenario

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.4	165.5	42.0	0.1	384.0	33.8	417.8	83.8	0.0	6.5	90.3
F2018	177.6	168.8	0.0	0.1	346.5	30.5	377.0	85.8	0.0	0.0	85.8
F2019	179.2	172.4	0.0	0.1	351.7	31.0	382.7	87.9	0.1	0.0	88.0
F2020	180.3	176.2	0.0	0.2	356.7	31.4	388.1	90.3	0.1	0.0	90.4
F2021	180.9	178.3	0.0	0.3	359.6	31.6	391.2	92.0	0.1	0.0	92.2
F2022	181.7	181.1	0.0	0.4	363.2	32.0	395.1	94.0	0.2	0.0	94.2
F2023	182.4	183.6	0.0	0.6	366.6	32.3	398.9	95.9	0.3	0.0	96.1
F2024	183.4	186.7	0.0	0.8	370.9	32.6	403.6	97.9	0.4	0.0	98.2
F2025	184.3	188.6	0.0	1.1	373.9	32.9	406.9	99.2	0.5	0.0	99.7
F2026	185.1	191.0	0.0	1.5	377.7	33.2	410.9	100.5	0.6	0.0	101.1
F2027	186.3	194.1	0.0	1.9	382.4	33.6	416.0	101.9	0.8	0.0	102.7
F2028	187.8	198.2	0.0	2.4	388.4	34.2	422.6	103.7	1.0	0.0	104.7
F2029	189.0	200.7	0.0	3.0	392.7	34.6	427.3	104.6	1.2	0.0	105.8
F2030	189.5	203.2	0.0	3.6	396.3	34.9	431.1	105.2	1.5	0.0	106.7
F2031	189.2	204.2	0.0	4.3	397.8	35.0	432.8	105.2	1.8	0.0	107.0
F2032	188.6	204.6	0.0	5.1	398.3	35.0	433.3	105.1	2.1	0.0	107.2
F2033	187.1	202.8	0.0	5.9	395.8	34.8	430.6	104.1	2.4	0.0	106.5
F2034	185.2	201.2	0.0	6.8	393.2	34.6	427.8	103.1	2.7	0.0	105.8
F2035	182.9	199.3	0.0	7.7	389.9	34.3	424.3	101.9	3.1	0.0	105.0
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	-0.1%	1.7%	2.6%	88.4%	-1.2%	-3.2%	-1.4%	3.0%	81.4%	11.7%	2.0%
10 years: F2015 to F2025	0.2%	1.5%	1.3%	63.8%	-0.1%	-1.1%	-0.2%	2.4%	60.0%	5.9%	2.0%
20 years: F2015 to F2035	0.0%	1.0%	0.6%	42.6%	0.1%	-0.4%	0.1%	1.4%	40.4%	2.9%	1.3%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-2: Low Industrial Activity Scenario

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.5	165.5	42.0	0.1	384.0	33.8	417.8	83.8	0.0	6.5	90.3
F2018	177.7	168.9	42.0	0.1	388.8	34.2	423.0	85.8	0.0	6.5	92.4
F2019	179.4	172.7	42.0	0.1	394.3	34.7	429.0	88.0	0.1	6.5	94.6
F2020	180.5	176.7	42.0	0.2	399.4	35.2	434.6	90.4	0.1	6.5	97.0
F2021	181.2	178.9	42.0	0.3	402.4	35.4	437.8	92.2	0.1	6.5	98.8
F2022	181.9	181.6	21.0	0.4	385.0	33.9	418.9	94.1	0.2	6.5	100.8
F2023	182.8	184.1	0.0	0.6	367.5	32.3	399.9	96.0	0.3	0.0	96.3
F2024	184.0	187.3	0.0	0.8	372.1	32.7	404.8	98.1	0.4	0.0	98.4
F2025	184.9	189.7	0.0	1.1	375.7	33.1	408.8	99.5	0.5	0.0	99.9
F2026	186.0	192.9	0.0	1.5	380.5	33.5	413.9	100.9	0.6	0.0	101.6
F2027	187.4	196.3	0.0	1.9	385.6	33.9	419.6	102.5	0.8	0.0	103.3
F2028	188.9	200.5	0.0	2.4	391.9	34.5	426.3	104.2	1.0	0.0	105.2
F2029	190.1	202.9	0.0	3.0	396.0	34.8	430.8	105.1	1.2	0.0	106.3
F2030	190.4	205.0	0.0	3.6	399.0	35.1	434.2	105.7	1.5	0.0	107.2
F2031	189.9	205.5	0.0	4.3	399.7	35.2	434.9	105.5	1.8	0.0	107.3
F2032	189.0	205.5	0.0	5.1	399.5	35.2	434.6	105.2	2.1	0.0	107.3
F2033	187.2	203.4	0.0	5.9	396.4	34.9	431.3	104.0	2.4	0.0	106.4
F2034	185.0	201.5	0.0	6.8	393.2	34.6	427.8	102.9	2.7	0.0	105.7
F2035	182.6	199.4	0.0	7.7	389.7	34.3	424.0	101.7	3.1	0.0	104.8
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	-0.1%	1.7%	2.6%	88.4%	1.0%	-1.1%	0.8%	3.0%	81.4%	11.7%	3.4%
10 years: F2015 to F2025	0.2%	1.6%	1.3%	63.8%	-0.1%	-1.1%	-0.2%	2.5%	60.0%	5.9%	2.0%
20 years: F2015 to F2035	0.0%	1.0%	0.6%	42.6%	0.1%	-0.4%	0.1%	1.4%	40.4%	2.9%	1.3%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-3: Medium Industrial Activity Scenario

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.8	163.1	42.0	0.0	380.9	33.5	414.5	82.2	0.0	6.5	88.8
F2017	176.7	165.5	42.0	0.1	384.2	33.8	418.0	83.8	0.0	6.5	90.4
F2018	178.1	169.0	42.0	0.1	389.1	34.2	423.4	85.9	0.0	6.5	92.5
F2019	180.3	173.0	54.0	0.1	407.4	35.9	443.3	88.2	0.1	8.3	96.6
F2020	181.9	177.5	109.9	0.2	469.6	41.3	510.9	78.0	0.1	26.3	104.4
F2021	182.9	181.0	156.8	0.3	521.0	45.8	566.8	92.8	0.1	15.2	108.1
F2022	184.6	185.3	135.8	0.4	506.0	44.5	550.6	95.2	0.2	15.2	110.5
F2023	186.2	189.4	114.8	0.6	491.0	43.2	534.2	97.4	0.3	8.7	106.3
F2024	187.9	193.9	114.8	0.8	497.4	43.8	541.2	99.8	0.4	8.7	108.8
F2025	189.1	196.4	114.8	1.1	501.3	44.1	545.4	101.2	0.5	8.7	110.3
F2026	190.0	198.7	114.8	1.5	505.0	44.4	549.4	102.5	0.6	8.7	111.8
F2027	191.0	201.2	114.8	1.9	508.9	44.8	553.7	103.8	0.8	8.7	113.2
F2028	192.0	204.1	114.8	2.4	513.3	45.2	558.5	105.2	1.0	8.7	114.9
F2029	192.6	205.0	114.8	3.0	515.4	45.4	560.7	105.8	1.2	8.7	115.7
F2030	192.4	205.8	76.8	3.6	478.7	42.1	520.8	106.1	1.5	8.7	116.3
F2031	191.6	205.6	48.0	4.3	449.5	39.6	489.0	105.8	1.8	7.1	114.7
F2032	190.7	205.6	48.0	5.1	449.4	39.5	488.9	105.6	2.1	7.1	114.8
F2033	189.2	203.9	48.0	5.9	446.9	39.3	486.2	104.6	2.4	7.1	114.1
F2034	187.5	202.5	48.0	6.8	444.8	39.1	483.9	103.7	2.7	7.1	113.6
F2035	185.6	201.1	24.0	7.7	418.4	36.8	455.3	102.8	3.1	7.1	113.0
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.1%	1.8%	29.0%	88.4%	4.4%	2.4%	4.2%	0.2%	81.4%	60.6%	5.0%
10 years: F2015 to F2025	0.4%	1.9%	15.9%	63.8%	2.9%	1.9%	2.8%	2.9%	60.0%	21.8%	3.1%
20 years: F2015 to F2035	0.1%	1.1%	1.9%	42.6%	0.6%	0.1%	0.6%	1.5%	40.4%	10.0%	1.7%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-4: High Industrial Activity Scenario

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.5	165.2	54.0	0.1	395.8	34.8	430.6	83.7	0.0	8.3	92.1
F2018	178.3	168.8	109.9	0.1	457.1	40.2	497.4	74.5	0.1	26.3	100.9
F2019	181.1	173.7	156.8	0.2	511.7	45.0	556.7	88.5	0.1	15.2	103.8
F2020	183.9	180.2	178.4	0.3	542.7	47.8	590.5	91.6	0.1	19.6	111.3
F2021	186.2	186.6	272.9	0.4	646.1	56.9	702.9	94.3	0.2	36.2	130.7
F2022	189.2	196.2	251.9	0.5	637.7	56.1	693.9	97.8	0.2	36.2	134.2
F2023	192.4	204.7	225.9	0.7	623.7	54.9	678.6	100.9	0.3	28.7	129.9
F2024	195.6	212.2	225.9	1.0	634.6	55.8	690.4	103.8	0.4	28.7	132.9
F2025	197.7	216.8	225.9	1.3	641.7	56.5	698.2	105.7	0.6	28.7	134.9
F2026	198.9	220.0	225.9	1.8	646.5	56.9	703.4	107.1	0.8	28.7	136.5
F2027	199.6	222.2	210.9	2.3	635.0	55.9	690.9	108.3	1.0	25.9	135.2
F2028	199.7	223.1	172.9	2.9	598.7	52.7	651.4	109.4	1.2	25.9	136.4
F2029	198.8	220.6	144.1	3.5	567.0	49.9	616.9	109.1	1.5	24.3	134.9
F2030	196.8	218.9	120.6	4.2	540.6	47.6	588.2	108.6	1.8	22.3	132.8
F2031	194.3	216.7	50.4	5.0	466.3	41.0	507.4	107.4	2.1	7.7	117.2
F2032	191.9	215.2	50.4	5.9	463.3	40.8	504.1	106.5	2.5	7.7	116.6
F2033	189.4	212.4	24.0	6.8	432.6	38.1	470.7	105.0	2.9	7.1	115.0
F2034	187.2	210.7	0.0	7.8	405.7	35.7	441.4	103.9	3.3	0.0	107.2
F2035	185.5	209.4	0.0	8.9	403.8	35.5	439.4	103.1	3.7	0.0	106.8
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.3%	2.1%	40.3%	82.3%	7.5%	5.4%	7.3%	3.7%	76.8%	57.9%	6.3%
10 years: F2015 to F2025	0.9%	3.0%	23.6%	60.5%	5.6%	4.6%	5.5%	3.3%	57.5%	35.4%	5.2%
20 years: F2015 to F2035	0.1%	1.3%	-1.6%	40.7%	0.6%	0.1%	0.5%	1.5%	38.9%	7.8%	1.5%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-5: Low Industrial Activity Scenario with Sensitivity on Government Spending

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.5	165.5	42.0	0.1	384.0	33.8	417.8	83.8	0.0	6.5	90.3
F2018	177.7	168.9	42.0	0.1	388.8	34.2	423.0	85.8	0.0	6.5	92.4
F2019	179.4	172.7	42.0	0.1	394.2	34.7	428.9	88.0	0.1	6.5	94.6
F2020	180.4	176.6	42.0	0.2	399.2	35.1	434.3	90.3	0.1	6.5	97.0
F2021	180.9	178.4	42.0	0.3	401.6	35.3	436.9	92.0	0.1	6.5	98.7
F2022	181.3	180.5	21.0	0.4	383.2	33.7	416.9	93.8	0.2	6.5	100.5
F2023	181.7	181.9	0.0	0.6	364.2	32.0	396.2	95.4	0.3	0.0	95.7
F2024	182.2	183.7	0.0	0.8	366.7	32.3	398.9	97.2	0.4	0.0	97.6
F2025	182.3	184.2	0.0	1.1	367.6	32.3	400.0	98.2	0.5	0.0	98.6
F2026	182.4	185.3	0.0	1.5	369.2	32.5	401.7	99.1	0.6	0.0	99.8
F2027	182.7	186.4	0.0	1.9	371.0	32.7	403.7	100.1	0.8	0.0	100.9
F2028	183.2	188.2	0.0	2.4	373.8	32.9	406.7	101.3	1.0	0.0	102.3
F2029	183.3	188.5	0.0	3.0	374.7	33.0	407.7	101.6	1.2	0.0	102.9
F2030	182.7	188.6	0.0	3.6	374.9	33.0	407.9	101.8	1.5	0.0	103.3
F2031	181.4	187.7	0.0	4.3	373.4	32.9	406.3	101.2	1.8	0.0	103.0
F2032	179.8	186.9	0.0	5.1	371.7	32.7	404.5	100.6	2.1	0.0	102.7
F2033	177.4	184.3	0.0	5.9	367.6	32.3	399.9	99.1	2.4	0.0	101.5
F2034	174.7	182.0	0.0	6.8	363.4	32.0	395.4	97.7	2.7	0.0	100.5
F2035	171.8	179.5	0.0	7.7	359.0	31.6	390.6	96.2	3.1	0.0	99.4
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	-0.1%	1.7%	2.6%	88.4%	1.0%	-1.1%	0.8%	3.0%	51.6%	11.7%	3.4%
10 years: F2015 to F2025	0.1%	1.3%	1.3%	63.8%	-0.3%	-1.3%	-0.4%	2.3%	45.1%	5.9%	1.9%
20 years: F2015 to F2035	-0.3%	0.5%	0.6%	42.6%	-0.3%	-0.8%	-0.3%	1.1%	32.9%	2.9%	1.0%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-6: Medium Industrial Activity Scenario with Sensitivity on Government Spending

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.5	165.5	42.0	0.1	384.0	33.8	417.8	83.8	0.0	6.5	90.3
F2018	177.8	169.0	42.0	0.1	388.8	34.2	423.0	85.8	0.0	6.5	92.4
F2019	179.7	173.0	54.0	0.1	406.8	35.8	442.6	88.1	0.1	8.3	96.5
F2020	181.1	177.4	109.9	0.2	468.6	41.2	509.9	77.8	0.1	26.3	104.3
F2021	181.9	180.5	156.8	0.3	519.4	45.7	565.1	92.5	0.1	15.2	107.8
F2022	183.1	184.2	135.8	0.4	503.4	44.3	547.7	94.7	0.2	15.2	110.1
F2023	184.1	187.1	114.8	0.6	486.5	42.8	529.3	96.6	0.3	8.7	105.6
F2024	184.9	190.0	114.8	0.8	490.4	43.2	533.6	98.6	0.4	8.7	107.6
F2025	185.0	190.4	114.8	1.1	491.3	43.2	534.5	99.5	0.5	8.7	108.7
F2026	184.8	190.4	114.8	1.5	491.5	43.3	534.8	100.2	0.6	8.7	109.5
F2027	184.7	190.6	114.8	1.9	491.9	43.3	535.2	101.0	0.8	8.7	110.5
F2028	184.6	191.2	114.8	2.4	493.0	43.4	536.4	101.9	1.0	8.7	111.6
F2029	184.2	190.3	114.8	3.0	492.2	43.3	535.6	102.0	1.2	8.7	111.9
F2030	183.2	189.7	76.8	3.6	453.4	39.9	493.3	102.0	1.5	8.7	112.2
F2031	181.8	188.8	48.0	4.3	422.8	37.2	460.0	101.4	1.8	7.1	110.2
F2032	180.2	188.2	48.0	5.1	421.5	37.1	458.6	100.8	2.1	7.1	110.0
F2033	178.2	186.0	48.0	5.9	418.1	36.8	454.8	99.6	2.4	7.1	109.1
F2034	175.9	184.1	48.0	6.8	414.8	36.5	451.3	98.4	2.7	7.1	108.3
F2035	173.5	182.1	24.0	7.7	387.2	34.1	421.3	97.1	3.1	7.1	107.4
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.0%	1.8%	29.0%	88.4%	4.4%	2.3%	4.2%	0.2%	51.6%	60.6%	4.9%
10 years: F2015 to F2025	0.2%	1.6%	15.9%	63.8%	2.7%	1.7%	2.6%	2.7%	45.1%	21.8%	2.9%
20 years: F2015 to F2035	-0.2%	0.6%	1.9%	42.6%	0.2%	-0.3%	0.2%	1.2%	32.9%	10.0%	1.4%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-7: Medium Industrial Activity Scenario with Sensitivity on Size of Secondary Industries

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.4	82.2	0.0	6.5	88.7
F2017	176.6	165.7	42.0	0.1	384.3	33.8	418.1	83.8	0.0	6.5	90.4
F2018	178.0	169.4	42.0	0.1	389.6	34.3	423.8	85.9	0.0	6.5	92.5
F2019	180.2	174.0	54.0	0.1	408.3	35.9	444.3	88.4	0.1	8.3	96.7
F2020	182.0	179.3	109.9	0.2	471.4	41.5	512.9	78.2	0.1	26.3	104.6
F2021	183.4	183.6	156.8	0.3	524.1	46.1	570.2	93.2	0.1	15.2	108.6
F2022	185.4	189.0	135.8	0.4	510.5	44.9	555.4	95.8	0.2	15.2	111.2
F2023	187.3	193.9	114.8	0.6	496.6	43.7	540.3	98.2	0.3	8.7	107.1
F2024	189.2	199.2	114.8	0.8	503.9	44.3	548.3	100.7	0.4	8.7	109.7
F2025	190.4	202.0	114.8	1.1	508.3	44.7	553.0	102.2	0.5	8.7	111.4
F2026	191.3	204.4	114.8	1.5	512.0	45.1	557.0	103.5	0.6	8.7	112.8
F2027	192.1	206.6	114.8	1.9	515.4	45.4	560.8	104.7	0.8	8.7	114.2
F2028	192.9	209.2	114.8	2.4	519.2	45.7	564.9	106.1	1.0	8.7	115.8
F2029	193.2	209.7	114.8	3.0	520.6	45.8	566.4	106.6	1.2	8.7	116.5
F2030	192.7	210.0	76.8	3.6	483.3	42.5	525.8	106.8	1.5	8.7	117.0
F2031	191.8	209.6	48.0	4.3	453.7	39.9	493.6	106.5	1.8	7.1	115.3
F2032	190.8	209.6	48.0	5.1	453.4	39.9	493.3	106.2	2.1	7.1	115.4
F2033	189.3	207.9	48.0	5.9	451.0	39.7	490.7	105.2	2.4	7.1	114.7
F2034	187.7	206.7	48.0	6.8	449.2	39.5	488.7	104.4	2.7	7.1	114.2
F2035	186.1	205.4	24.0	7.7	423.2	37.2	460.5	103.5	3.1	7.1	113.8
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.1%	2.0%	29.0%	88.4%	4.5%	2.5%	4.3%	0.2%	51.6%	60.6%	5.0%
10 years: F2015 to F2025	0.5%	2.2%	15.9%	63.8%	3.1%	2.1%	3.0%	3.0%	45.1%	21.8%	3.2%
20 years: F2015 to F2035	0.1%	1.2%	1.9%	42.6%	0.7%	0.1%	0.6%	1.6%	32.9%	10.0%	1.7%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-8: Medium Industrial Activity Scenario with Sensitivity on Oil and Gas Project

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.8	163.1	42.0	0.0	380.9	33.5	414.5	82.2	0.0	6.5	88.8
F2017	176.7	165.5	42.0	0.1	384.2	33.8	418.0	83.8	0.0	6.5	90.4
F2018	178.1	169.0	42.0	0.1	389.1	34.2	423.4	85.9	0.0	6.5	92.5
F2019	180.3	173.0	54.0	0.1	407.4	35.9	443.3	88.2	0.1	8.3	96.6
F2020	181.9	177.5	109.9	0.2	469.6	41.3	510.9	78.0	0.1	26.3	104.4
F2021	182.9	181.0	156.8	0.3	521.0	45.8	566.8	92.8	0.1	15.2	108.1
F2022	184.6	185.3	135.8	0.4	506.0	44.5	550.6	95.2	0.2	15.2	110.5
F2023	186.3	189.5	114.8	0.6	491.1	43.2	534.4	97.5	0.3	8.7	106.4
F2024	188.8	194.6	114.8	0.8	499.0	43.9	542.9	100.1	0.4	8.7	109.1
F2025	191.0	197.9	114.8	1.1	504.8	44.4	549.2	102.0	0.5	8.7	111.1
F2026	194.4	201.5	114.8	1.5	512.2	45.1	557.2	104.1	0.6	8.7	113.4
F2027	196.6	205.0	114.8	1.9	518.3	45.6	563.9	105.9	0.8	8.7	115.4
F2028	198.7	208.9	114.8	2.4	524.7	46.2	570.9	107.9	1.0	8.7	117.6
F2029	200.1	210.7	114.8	3.0	528.5	46.5	575.0	108.9	1.2	8.7	118.8
F2030	200.4	211.9	76.8	3.6	492.7	43.4	536.1	109.4	1.5	8.7	119.6
F2031	199.6	211.6	48.0	4.3	463.5	40.8	504.3	109.1	1.8	7.1	118.0
F2032	198.3	211.3	48.0	5.1	462.6	40.7	503.4	108.7	2.1	7.1	117.9
F2033	196.1	208.7	48.0	5.9	458.6	40.4	499.0	107.3	2.4	7.1	116.8
F2034	193.5	206.5	48.0	6.8	454.7	40.0	494.8	106.0	2.7	7.1	115.8
F2035	190.8	204.3	24.0	7.7	426.8	37.6	464.3	104.6	3.1	7.1	114.9
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.1%	1.8%	29.0%	88.4%	4.4%	2.4%	4.2%	0.2%	51.6%	60.6%	5.0%
10 years: F2015 to F2025	0.5%	2.0%	15.9%	63.8%	3.0%	2.0%	2.9%	3.0%	45.1%	21.8%	3.1%
20 years: F2015 to F2035	0.3%	1.2%	1.9%	42.6%	0.7%	0.2%	0.6%	1.6%	32.9%	10.0%	1.7%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-9: Medium Industrial Activity Scenario with Sensitivity on Large Industrial Project

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.5	165.5	42.0	0.1	384.0	33.8	417.8	83.8	0.0	6.5	90.3
F2018	177.8	169.0	42.0	0.1	388.8	34.2	423.0	85.8	0.0	6.5	92.4
F2019	179.7	172.9	54.0	0.1	406.8	35.8	442.6	88.1	0.1	8.3	96.5
F2020	181.6	177.5	109.9	0.2	469.2	41.3	510.5	77.9	0.1	26.3	104.4
F2021	183.5	181.5	156.8	0.3	522.0	45.9	568.0	93.0	0.1	15.2	108.3
F2022	185.7	187.0	135.8	0.4	508.9	44.8	553.7	95.7	0.2	15.2	111.1
F2023	187.8	193.3	114.8	0.6	496.4	43.7	540.1	98.4	0.3	8.7	107.3
F2024	190.5	201.4	114.8	0.8	507.4	44.7	552.1	101.5	0.4	8.7	110.5
F2025	193.1	207.4	114.8	1.1	516.3	45.4	561.7	103.6	0.5	8.7	112.8
F2026	195.3	212.6	114.8	1.5	524.2	46.1	570.3	105.5	0.6	8.7	114.8
F2027	197.1	216.8	114.8	1.9	530.6	46.7	577.3	107.1	0.8	8.7	116.6
F2028	198.1	220.0	114.8	2.4	535.3	47.1	582.4	108.6	1.0	8.7	118.2
F2029	197.9	219.3	114.8	3.0	535.0	47.1	582.1	108.7	1.2	8.7	118.6
F2030	196.4	218.1	76.8	3.6	494.9	43.6	538.5	108.4	1.5	8.7	118.6
F2031	193.8	215.9	48.0	4.3	462.0	40.7	502.6	107.3	1.8	7.1	116.1
F2032	191.2	214.2	48.0	5.1	458.4	40.3	498.7	106.2	2.1	7.1	115.4
F2033	188.3	211.1	48.0	5.9	453.2	39.9	493.1	104.5	2.4	7.1	114.0
F2034	186.0	209.1	48.0	6.8	449.8	39.6	489.4	103.4	2.7	7.1	113.2
F2035	184.2	207.7	24.0	7.7	423.6	37.3	460.8	102.4	3.1	7.1	112.7
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.0%	1.8%	29.0%	88.4%	4.4%	2.4%	4.2%	0.2%	51.6%	60.6%	5.0%
10 years: F2015 to F2025	0.6%	2.5%	15.9%	63.8%	3.2%	2.2%	3.1%	3.1%	45.1%	21.8%	3.3%
20 years: F2015 to F2035	0.1%	1.3%	1.9%	42.6%	0.7%	0.2%	0.6%	1.5%	32.9%	10.0%	1.6%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-10: Medium Industrial Activity Scenario with Sensitivity on Boom and Bust Cycles in the Mining Industry

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.5	165.5	42.0	0.1	384.0	33.8	417.8	83.8	0.0	6.5	90.3
F2018	177.7	168.9	42.0	0.1	388.8	34.2	423.0	85.8	0.0	6.5	92.4
F2019	179.4	172.7	42.0	0.1	394.3	34.7	429.0	88.0	0.1	6.5	94.6
F2020	180.5	176.7	42.0	0.2	399.4	35.2	434.6	90.4	0.1	6.5	97.0
F2021	181.2	178.9	42.0	0.3	402.4	35.4	437.8	92.2	0.1	6.5	98.8
F2022	181.9	181.6	21.0	0.4	384.9	33.9	418.8	94.1	0.2	6.5	100.8
F2023	182.6	183.9	0.0	0.6	367.1	32.3	399.4	95.9	0.3	0.0	96.2
F2024	183.5	186.8	0.0	0.8	371.1	32.7	403.7	97.9	0.4	0.0	98.2
F2025	184.2	188.3	0.0	1.1	373.6	32.9	406.5	99.1	0.5	0.0	99.6
F2026	184.9	190.4	0.0	1.5	376.9	33.2	410.0	100.4	0.6	0.0	101.0
F2027	186.0	193.3	0.0	1.9	381.3	33.6	414.8	101.8	0.8	0.0	102.6
F2028	187.7	197.6	12.0	2.4	399.7	35.2	434.9	103.6	1.0	1.6	106.2
F2029	189.5	201.0	67.9	3.0	461.4	40.6	502.0	104.8	1.2	8.0	114.0
F2030	190.8	205.6	114.8	3.6	514.8	45.3	560.1	105.9	1.5	8.0	115.4
F2031	191.5	209.2	114.8	4.3	519.8	45.7	565.6	106.4	1.8	8.0	116.2
F2032	191.6	211.2	114.8	5.1	522.6	46.0	568.5	106.7	2.1	8.0	116.7
F2033	190.5	209.6	114.8	5.9	520.6	45.8	566.4	105.7	2.4	8.0	116.1
F2034	188.6	207.8	114.8	6.8	517.9	45.6	563.5	104.7	2.7	8.0	115.4
F2035	185.9	205.4	114.8	7.7	513.8	45.2	559.0	103.3	3.1	8.0	114.4
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	-0.1%	1.7%	2.6%	88.4%	1.0%	-1.1%	0.8%	3.0%	51.6%	11.7%	3.4%
10 years: F2015 to F2025	0.2%	1.5%	1.3%	63.8%	-0.2%	-1.2%	-0.3%	2.4%	45.1%	5.9%	2.0%
20 years: F2015 to F2035	0.1%	1.2%	27.4%	42.6%	1.6%	1.1%	1.6%	1.4%	32.9%	22.3%	1.7%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-11: Medium Industrial Activity Scenario with Sensitivity on Early Industrial Start

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.0	42.0	0.0	380.7	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.6	165.5	54.0	0.1	396.2	34.9	431.1	83.8	0.0	8.3	92.2
F2018	178.2	169.5	109.9	0.1	457.7	40.3	498.0	74.6	0.0	26.3	101.0
F2019	180.3	174.4	156.8	0.1	511.5	45.0	556.5	88.4	0.1	15.2	103.7
F2020	182.2	179.9	156.8	0.2	519.0	45.7	564.7	91.1	0.1	15.2	106.4
F2021	183.5	183.6	156.8	0.3	524.2	46.1	570.4	93.3	0.1	15.2	108.6
F2022	185.0	188.3	135.8	0.4	509.5	44.8	554.4	95.7	0.2	15.2	111.0
F2023	186.1	191.5	114.8	0.6	492.9	43.4	536.3	97.6	0.3	8.7	106.5
F2024	187.3	195.0	114.8	0.8	497.8	43.8	541.6	99.7	0.4	8.7	108.7
F2025	187.8	196.3	114.8	1.1	500.0	44.0	544.0	100.9	0.5	8.7	110.0
F2026	188.1	197.3	114.8	1.5	501.7	44.1	545.8	101.9	0.6	8.7	111.2
F2027	188.5	198.5	114.8	1.9	503.7	44.3	548.0	102.9	0.8	8.7	112.4
F2028	189.1	200.6	76.8	2.4	468.9	41.3	510.2	104.2	1.0	8.7	113.9
F2029	189.5	201.4	48.0	3.0	441.9	38.9	480.8	104.7	1.2	7.1	113.1
F2030	189.5	202.9	48.0	3.6	444.0	39.1	483.0	105.2	1.5	7.1	113.8
F2031	189.1	203.7	48.0	4.3	445.1	39.2	484.3	105.1	1.8	7.1	114.0
F2032	188.7	204.6	48.0	5.1	446.4	39.3	485.7	105.2	2.1	7.1	114.4
F2033	187.7	203.1	24.0	5.9	420.7	37.0	457.7	104.4	2.4	7.1	113.9
F2034	186.2	201.1	0.0	6.8	394.1	34.7	428.7	103.6	2.7	0.0	106.3
F2035	183.9	197.1	0.0	7.7	388.7	34.2	422.9	102.4	3.1	0.0	105.6
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.1%	2.1%	37.5%	88.4%	6.6%	4.5%	6.4%	3.6%	51.6%	52.1%	5.4%
10 years: F2015 to F2025	0.4%	1.9%	15.9%	63.8%	2.9%	1.9%	2.8%	2.8%	45.1%	21.8%	3.0%
20 years: F2015 to F2035	0.1%	1.0%	-3.1%	42.6%	0.2%	-0.3%	0.2%	1.5%	32.9%	5.0%	1.3%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-12: Low Industrial Activity with Eagle Gold and Minto Mines Ending in 2017

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.8	163.1	42.0	0.0	381.0	33.5	414.5	82.2	0.0	6.5	88.8
F2017	176.8	165.7	42.0	0.1	384.5	33.8	418.3	83.9	0.0	6.5	90.4
F2018	178.4	169.4	0.0	0.1	347.9	30.6	378.5	86.1	0.0	0.0	86.1
F2019	180.5	173.4	12.0	0.1	366.1	32.2	398.3	88.4	0.1	1.8	90.3
F2020	182.0	177.9	67.9	0.2	428.1	37.7	465.8	78.1	0.1	19.8	98.0
F2021	182.9	181.1	114.8	0.3	479.1	42.2	521.2	92.8	0.1	8.7	101.6
F2022	183.9	184.7	114.8	0.4	483.8	42.6	526.3	94.9	0.2	8.7	103.7
F2023	184.8	188.0	114.8	0.6	488.1	43.0	531.1	96.7	0.3	8.7	105.7
F2024	185.9	191.7	114.8	0.8	493.2	43.4	536.6	98.8	0.4	8.7	107.8
F2025	186.6	193.9	114.8	1.1	496.3	43.7	540.0	100.0	0.5	8.7	109.1
F2026	187.5	196.4	114.8	1.5	500.1	44.0	544.1	101.3	0.6	8.7	110.6
F2027	188.6	198.9	114.8	1.9	504.2	44.4	548.5	102.6	0.8	8.7	112.1
F2028	189.9	202.1	114.8	2.4	509.2	44.8	554.0	104.2	1.0	8.7	113.9
F2029	190.9	203.5	114.8	3.0	512.2	45.1	557.3	105.0	1.2	8.7	114.9
F2030	191.2	204.8	76.8	3.6	476.5	41.9	518.4	105.6	1.5	8.7	115.8
F2031	190.8	204.8	48.0	4.3	447.9	39.4	487.3	105.5	1.8	7.1	114.3
F2032	190.0	204.9	48.0	5.1	447.9	39.4	487.4	105.3	2.1	7.1	114.4
F2033	188.3	203.0	48.0	5.9	445.2	39.2	484.4	104.2	2.4	7.1	113.7
F2034	186.3	201.3	48.0	6.8	442.4	38.9	481.3	103.1	2.7	7.1	113.0
F2035	184.1	199.5	24.0	7.7	415.3	36.5	451.8	102.0	3.1	7.1	112.2
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.1%	1.9%	-17.4%	88.4%	2.7%	0.7%	2.5%	0.2%	51.6%	-8.3%	3.7%
10 years: F2015 to F2025	0.3%	1.8%	-8.7%	63.8%	2.9%	1.9%	2.8%	2.8%	45.1%	-4.1%	3.0%
20 years: F2015 to F2035	0.1%	1.0%	-4.4%	42.6%	0.6%	0.1%	0.6%	1.5%	32.9%	-2.1%	1.6%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-13: Low Industrial Activity Scenario with Eagle Gold, Minto Mines Ending in 2017 and Sensitivity on Government Spending

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.8	163.1	42.0	0.0	381.0	33.5	414.5	82.2	0.0	6.5	88.8
F2017	176.8	165.7	42.0	0.1	384.5	33.8	418.3	83.9	0.0	6.5	90.4
F2018	178.4	169.4	0.0	0.1	347.9	30.6	378.5	86.1	0.0	0.0	86.1
F2019	180.5	173.4	12.0	0.1	366.1	32.2	398.3	88.4	0.1	1.8	90.2
F2020	181.9	177.8	67.9	0.2	427.9	37.7	465.5	78.0	0.1	19.8	97.9
F2021	182.6	180.8	114.8	0.3	478.4	42.1	520.5	92.7	0.1	8.7	101.5
F2022	183.1	184.1	114.8	0.4	482.4	42.4	524.8	94.6	0.2	8.7	103.4
F2023	183.5	186.8	114.8	0.6	485.7	42.7	528.4	96.2	0.3	8.7	105.1
F2024	183.9	189.8	114.8	0.8	489.3	43.1	532.3	97.8	0.4	8.7	106.8
F2025	183.7	191.0	114.8	1.1	490.6	43.2	533.8	98.6	0.5	8.7	107.8
F2026	183.5	192.5	114.8	1.5	492.3	43.3	535.6	99.4	0.6	8.7	108.7
F2027	183.6	194.0	114.8	1.9	494.2	43.5	537.7	100.2	0.8	8.7	109.7
F2028	183.8	196.1	114.8	2.4	497.1	43.7	540.9	101.3	1.0	8.7	111.0
F2029	183.9	196.5	114.8	3.0	498.1	43.8	541.9	101.6	1.2	8.7	111.5
F2030	183.2	196.9	76.8	3.6	460.6	40.5	501.1	101.8	1.5	8.7	111.9
F2031	182.0	196.1	48.0	4.3	430.4	37.9	468.3	101.2	1.8	7.1	110.1
F2032	180.4	195.5	48.0	5.1	429.0	37.7	466.7	100.7	2.1	7.1	109.8
F2033	178.1	192.9	48.0	5.9	424.9	37.4	462.3	99.2	2.4	7.1	108.7
F2034	175.5	190.5	48.0	6.8	420.8	37.0	457.8	97.9	2.7	7.1	107.7
F2035	172.6	188.1	24.0	7.7	392.4	34.5	426.9	96.5	3.1	7.1	106.7
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.1%	1.9%	-17.4%	88.4%	2.7%	0.7%	2.5%	0.2%	51.6%	-8.3%	3.7%
10 years: F2015 to F2025	0.1%	1.7%	-8.7%	63.8%	2.8%	1.8%	2.7%	2.6%	45.1%	-4.1%	2.8%
20 years: F2015 to F2035	-0.2%	0.8%	-4.4%	42.6%	0.3%	-0.2%	0.3%	1.2%	32.9%	-2.1%	1.4%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-14: Medium Industrial Activity Scenario with Sensitivity on Tourism Sector

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.7	163.1	42.0	0.0	380.8	33.5	414.3	82.2	0.0	6.5	88.7
F2017	176.5	165.5	42.0	0.1	384.1	33.8	417.9	83.8	0.0	6.5	90.3
F2018	177.9	169.1	42.0	0.1	389.1	34.2	423.3	85.9	0.0	6.5	92.4
F2019	179.9	173.4	54.0	0.1	407.5	35.9	443.3	88.2	0.1	8.3	96.6
F2020	181.6	178.4	109.9	0.2	470.1	41.4	511.5	78.0	0.1	26.3	104.5
F2021	182.9	182.4	156.8	0.3	522.4	46.0	568.4	93.0	0.1	15.2	108.3
F2022	184.9	187.7	135.8	0.4	508.7	44.8	553.5	95.6	0.2	15.2	110.9
F2023	186.9	192.9	114.8	0.6	495.1	43.6	538.6	98.0	0.3	8.7	106.9
F2024	189.0	198.7	114.8	0.8	503.3	44.3	547.6	100.7	0.4	8.7	109.7
F2025	190.7	202.5	114.8	1.1	509.1	44.8	553.9	102.4	0.5	8.7	111.5
F2026	192.2	206.2	114.8	1.5	514.6	45.3	559.9	104.0	0.6	8.7	113.3
F2027	193.7	209.9	114.8	1.9	520.3	45.8	566.1	105.5	0.8	8.7	115.0
F2028	195.2	214.0	114.8	2.4	526.4	46.3	572.7	107.3	1.0	8.7	117.0
F2029	196.1	216.0	114.8	3.0	529.8	46.6	576.5	108.1	1.2	8.7	118.0
F2030	196.3	217.6	76.8	3.6	494.3	43.5	537.8	108.6	1.5	8.7	118.8
F2031	195.7	218.0	48.0	4.3	466.0	41.0	507.0	108.4	1.8	7.1	117.3
F2032	195.0	218.3	48.0	5.1	466.4	41.0	507.5	108.3	2.1	7.1	117.5
F2033	193.7	216.8	48.0	5.9	464.4	40.9	505.3	107.4	2.4	7.1	116.9
F2034	192.4	215.8	48.0	6.8	462.9	40.7	503.6	106.7	2.7	7.1	116.6
F2035	190.9	214.8	24.0	7.7	437.4	38.5	475.9	106.0	3.1	7.1	116.2
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.0%	1.9%	29.0%	88.4%	4.5%	2.4%	4.3%	0.2%	51.6%	60.6%	5.0%
10 years: F2015 to F2025	0.5%	2.2%	15.9%	63.8%	3.1%	2.1%	3.0%	3.0%	45.1%	21.8%	3.2%
20 years: F2015 to F2035	0.3%	1.4%	1.9%	42.6%	0.8%	0.3%	0.8%	1.7%	32.9%	10.0%	1.8%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Table A-15: Medium Industrial Activity Scenario with Sensitivity on Climate Change

Calendar Year	Energy Requirements							System Peak			
	Commercial Sales	Residential Sales	Industrial Sales	EV Sales	Total Sales	Losses	Total Generation Requirement	Non-Industrial Hourly Peak	EV Hourly Peak	Industrial Hourly Peak	System Hourly Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(MW)	(MW)	(MW)
Actuals											
F2010	176.1	144.8	30.3	---	351.2	30.8	381.9	67.0	---	5.6	72.6
F2011	169.2	156.2	43.3	---	368.7	32.1	400.8	70.8	---	5.6	76.3
F2012	181.9	166.2	44.0	---	392.1	34.6	426.7	77.2	---	5.1	82.2
F2013	182.6	165.3	40.5	---	388.5	35.0	423.5	78.1	---	4.6	82.7
F2014	177.2	160.4	36.3	---	373.9	28.4	402.3	72.3	---	4.2	76.5
F2015	181.4	162.2	37.2	---	380.7	37.3	418.0	77.9	---	4.1	82.1
Forecast											
F2016	175.8	163.1	42.0	0.0	380.9	33.5	414.5	82.2	0.0	6.5	88.8
F2017	176.7	165.5	42.0	0.1	384.3	33.8	418.1	83.8	0.0	6.5	90.4
F2018	178.0	168.8	42.0	0.1	388.9	34.2	423.2	85.8	0.0	6.5	92.4
F2019	180.2	172.6	54.0	0.1	406.9	35.8	442.7	88.0	0.1	8.3	96.3
F2020	181.6	176.6	109.9	0.2	468.4	41.2	509.6	77.5	0.1	26.3	104.0
F2021	182.7	180.0	156.8	0.3	519.8	45.7	565.5	92.1	0.1	15.2	107.5
F2022	184.2	184.1	135.8	0.4	504.5	44.4	548.9	94.3	0.2	15.2	109.7
F2023	185.8	187.9	114.8	0.6	489.0	43.0	532.1	96.3	0.3	8.7	105.3
F2024	187.3	191.8	114.8	0.8	494.7	43.5	538.2	98.2	0.4	8.7	107.3
F2025	188.5	194.2	114.8	1.1	498.6	43.9	542.5	99.7	0.5	8.7	108.8
F2026	189.4	196.2	114.8	1.5	501.8	44.2	546.0	100.7	0.6	8.7	110.0
F2027	190.3	198.3	114.8	1.9	505.3	44.5	549.8	101.8	0.8	8.7	111.3
F2028	191.1	200.5	114.8	2.4	508.9	44.8	553.6	102.8	1.0	8.7	112.5
F2029	191.7	201.5	114.8	3.0	511.0	45.0	555.9	103.4	1.2	8.7	113.3
F2030	191.5	201.9	76.8	3.6	473.9	41.7	515.6	103.5	1.5	8.7	113.6
F2031	190.6	201.4	48.0	4.3	444.3	39.1	483.4	103.0	1.8	7.1	111.9
F2032	189.5	200.8	48.0	5.1	443.4	39.0	482.4	102.3	2.1	7.1	111.5
F2033	188.1	199.2	48.0	5.9	441.1	38.8	479.9	101.4	2.4	7.1	110.9
F2034	186.3	197.6	48.0	6.8	438.6	38.6	477.2	100.3	2.7	7.1	110.2
F2035	184.4	195.9	24.0	7.7	412.0	36.3	448.3	99.2	3.1	7.1	109.5
Growth Rates:											
5 years: F2011 to F2015	0.7%	2.4%	5.8%	---	1.7%	5.2%	1.9%	3.2%	---	-5.7%	2.6%
5 years: F2015 to F2020	0.0%	1.7%	29.0%	88.4%	4.4%	2.3%	4.2%	0.1%	51.6%	60.6%	4.9%
10 years: F2015 to F2025	0.4%	1.8%	15.9%	63.8%	2.9%	1.9%	2.8%	2.7%	45.1%	21.8%	2.9%
20 years: F2015 to F2035	0.1%	1.0%	1.9%	42.6%	0.5%	0.0%	0.5%	1.3%	32.9%	10.0%	1.5%

Notes:

- Forecast assumes 8.8% losses
- Sales data at the point of delivery
- System peak data at generating station
- Historical and forecasted residential sales include street lights sales
- Historical commercial sales includes secondary sales

Appendix 4.2
Yukon Macroeconomic Model
2016-2035

14 July 2016
Revised: 16 March 2017

Executive Summary

The Yukon Macroeconomic Model (MEM) is a tool for generating future economic and demographic indicators for the Yukon. The Model outputs are then a key input into Yukon Energy's (YEC) electricity demand forecasting model, which provides a long-term outlook of YEC's electricity demand needs. This demand forecast ultimately informs the YEC 2016 Resource Plan (RP), which will present desirable supply options for meeting future customer electricity requirements.

The MEM is the first step of several towards the successful issuance of the RP. The economic and demographic indicators produced by the MEM are a critical step in forecasting future supply requirements.

This appendix provides an overview of the MEM, which is used to generate forecasts of key economic variables such as Gross Domestic Product and population. The time period for the MEM is 20 years (2016 to 2035); which is consistent with the demand forecast period, and the mandated planning period of the 2016 YEC RP.

A number of historical economic and demographic variables are used as inputs to the MEM, including: economic output by industry, labour productivity, employment, wages and other income, population, consumption of goods and services, exchange rates, commodity prices, and capital investment.

Model runs were undertaken for 14 economic scenarios; these scenarios were developed to represent a range of Yukon economic activity over the planning period. The scenarios primarily consider a range of industrial activity, mining in particular, and in addition, a range of government spending levels. Sensitivity analysis with respect to future activity in Yukon's smaller economic sectors (such as tourism) were also modeled. The 14 scenarios cover a wide but plausible range of potential outcomes.

Values of the key economic variables with relevance to electricity consumption and therefore, future electricity demand, are presented in the Table 1. These are for the base economic case (Scenario 3). The minimum, maximum and base key economic variables from all 14 scenarios are presented in the body of this report in Table 2.

Table 1: Yukon Macroeconomic Model Outputs – Base Case

	Current (2015)	Year 2025	Year 2035
Population (000's)	37.4	41.2	41.1
Households (000's)	17.7	17.7	17.8
Employment (000's)	19.7	21.0	20.6
Real Dollar Disposable Income ($M)	1,351	1,638	1,802
Real Dollar Gross Domestic Product ($M)	2,226	2,682	2,789

The appendix concludes with a discussion of the results generated by the Yukon MEM. It also includes an explanation of the improvements resulting from the forecasting approach adopted, relative to efforts in YEC's previous resource plans.

Contents

Executive Summary i
C4SE Firm Profile 1
Yukon Macroeconomic Model Specifications 1
Model Operation 2
Economic Scenarios 3
Yukon Microeconomic Model Results 8
Forecast Yukon Gross Domestic Product 9
Forecast Yukon Population 11
Forecast Number of Yukon Households 13
Forecast Yukon Employment 14
Forecast Yukon Per Capita Disposable Income 15

C4SE Firm Profile

The Centre for Spatial Economics (C4SE) was formed in 2000 as a partnership between two consulting firms, Stokes Economic Consulting and Strategic Projections Inc. The intent of the C4SE partnership is to improve the quality of quantitative economic research in small Canadian jurisdictions available to public and private organizations. Over its first fifteen years of operations, C4SE has developed an extensive client base. Public sector clients include provincial finance departments in Alberta, British Columbia, New Brunswick, Newfoundland and Labrador, Ontario and Saskatchewan. C4SE has also developed macroeconomic models for BC Hydro. A complete client list can be found here: (http://www.c4se.com/clients.html).

Robert Fairholm Economic Consulting joined the C4SE partnership in 2003 to increase C4SE's capacity and scope of services. In addition to the staff of these corporations, the C4SE draws from a list of academics and research consultants on an as-needed basis.

Robert Fairholm, Partner at C4SE and President at Robert Fairholm Economic Consulting Inc., was responsible for preparing the economic forecasts for the Yukon economy used in the YEC RP. Fairholm holds an MA in Economics from the University of Toronto and a BA in Economics from Queen's University. He has over 20 years of experience in economic analyses, modelling and forecasting. Prior to joining the C_4SE, Fairholm was the Managing Editor of the International Bank Credit Analyst from 2001 to 2003, and provided a monthly forecast of interest rates, equity markets, commodity prices, economic trends and currency movements in the world's principal economies. From 1993 to 2001, Fairholm directed the Canadian forecasting operations of Standard & Poor's Data Resources Incorporated. He was responsible for all the Canadian macro, industrial and provincial forecasts and related services. The C4SE model runs were facilitated on behalf of YEC by staff from the Business and Economic Research Branch, Yukon Economic Development.

Yukon Macroeconomic Model Specifications

The multi-sector MEM used to inform YEC's long-term demand forecast was initially developed by C4SE for the Yukon Government in 2010. The MEM has been regularly maintained and updated by C4SE since. The Yukon MEM is similar to those developed by the C4SE for its forecasting for other provincial governments and agencies. These models are categorized as "fixed-price" general equilibrium models. They are made up of a series of mathematical equations which together describe the linkages and dependencies between sectors in an economy. As the equations are executed in parallel during runs, this type of model is also known as a simultaneous equation model.

Quantity adjustments rather than price adjustments clear markets in the short to medium term. Examples of quantity adjustments used in the model include changes in a) the utilization of capital b) the utilization of labour and c) changes in the movement of labour. A fixed price structure is used because firms are price takers in the small open economies for which the models are designed. An example of this reality is the price of mine output such as copper and gold. The mining output of the Yukon does not significantly influence the global price for metals.

A distinction is made in the MEM between industries that primarily export and sectors that primarily serve the local economy. Rest-of-world forces largely influence investment decisions by sectors that focus on exports; whether national or international. Assumptions with respect to export-driven investment are set exogenously. The investment decisions made by non-export driven sectors are driven largely by economic activity and demographics within the local economy.

Investment in industries that are primarily export oriented (mining) are set based on views regarding growth in the rest of the world and economic policies that influence the cost of investment and profitability. Investment is determined by the expected amount of capital that will be needed to achieve a target level of output. The target is determined by growth in demand for the particular industry's product, which depends on the growth in the other industries in the local economy and domestic demand along with capital costs.

Model Operation

The MEM operates on a year-by-year basis. It attempts to achieve an internally-consistent and stable solution for the first year of the forecast; once this achieved, it then increments to the next year.

The list of MEM input and output variables is provided below:

Yukon Macroeconomic Model Inputs:	**Yukon Macroeconomic Model Outputs:**
• Global economic indicators (historical and forecast real GDP, inflation and interest rates); • Historical government economic policies; • Historical production capacity by sector and capacity utilization rates; • Historical real economic output by industry; • Historical labour productivity; • Historical population; • Historical employment, wages and other income; • Historical net population in---migration; • Historical consumption of goods and services by individuals, companies and government; • Historical investment;	• Production capacity by sector and capacity utilization rates; • Real GDP and inflation; • Consumption of goods and services by individuals, companies and government; • Labour productivity; • Employment, wages and other income; • Population; • Net population in---migration; and, • Real economic output by industry.

• Exchange rates; • Commodity prices; • Mineral production; and, • Capital spending and employment associated with export-oriented projects.	

Economic Scenarios

Notwithstanding the challenges of economic forecasting in a small jurisdiction where economic output can be significantly altered by the opening or closing of a single mine, the C4SE Yukon MEM represents a robust attempt to forecast a reasonably wide range of economic activity in the Yukon over the forecast period.

A total of 14 economic scenarios were conceived for Yukon economic activity over the forecast period. The development of the economic scenarios was seeded via a planning session with two engineers from YEC, two economists from Yukon Economic Development and an independent economist from Vector Research. The choice of scenarios is intended to cover a wide but plausible range of possible economic activity in the Yukon.

The draft scenarios were considered by a panel of business and institutional leaders at a one day economic retreat hosted by YEC in Whitehorse on September 2015. The session was facilitated by Dr. Mark Jaccard of Simon Fraser University. Feedback received at the session was used to refine the economic scenarios which were then presented to the Technical Advisory Committee for inclusion into the RP. The scenarios were further refined on the basis of RP Technical Advisory Committee feedback and advice from the Yukon Minerals Advisory Board.

Historically, and currently, mining is the largest non-government entity in the Territory. Due to the relatively large electricity demand of a single typical mining customer, this sector is a key uncertainty and risk in the YEC RP. The Yukon economy is small; in 2015, the Gross Domestic Product of Yukon accounted for 0.13% of total Canadian Gross Domestic Product. Any Yukon mine of economic scale would have a significant influence on overall Yukon economic output, therefore, mining is a key factor for consideration in all of the 14 scenarios developed by YEC. This is not to infer that future mines were included in every scenario, but mining was a key consideration in the development in all of the scenarios.

Uncertainty in the YEC demand forecast is not just from direct electricity demand from a mine, but also due to the secondary economic spin-off activity of mining. The potential influence of mining on the demand for electricity would occur even if a mine is not served by YEC from the electricity transmission grid. All mining activity has an impact on overall economic activity in the Yukon, including overall employment, the need for commercial services, and ultimately government services. These secondary linkages then drive future demand for electricity.

Mining project parameters were informed by publically available information including company presentations, technical reports and news releases. Key assumptions incorporated into the scenarios include estimates of development costs, timing and length of the mine development phases (construction, operation and reclamation).

While designing the industrial activity scenarios, assumptions were made in relation to the future of commodity prices. The Very Low Industrial Activity scenario assumes that commodity prices (particularly refined mine products such as gold and copper) would remain at currently low levels, or follow a decreasing trend over the next 20 years. In contrast, the Very High Industrial Scenario assumes commodity prices will rebound from current levels and increase over subsequent years, thus creating a favorable investment environment for the advancement of mining projects. The following four projects were selected to serve as proxies for mining activity of the forecast period: Eagle Gold, Coffee Gold, Wellgreen Platinum, and Casino (gold and molybdenum). Selection of the four projects was based on the current placing of each project with respect to mine permitting, feasibility assessment and the environmental assessment process.

Mining and the public sectors combined dominate the Yukon economy; the influence of Yukon's smaller economic sectors (tourism, agriculture, forestry and fishing) on total territorial economic output is relatively smaller. To explore the effects of changes in economic activity in Yukon's smaller economic sectors on potential electricity demand, sensitivity analyses were carried out by doubling input variable ranges to test the effects.

Federal transfer payments to the Yukon Government have significant influence on the Yukon economy. In the 2014/15 fiscal year, transfers from the Federal Government accounted for 83% of total Yukon Government revenues. As 39% of total Yukon Gross Domestic Product was attributable to the public sector in the 2015 calendar year, changes in growth rates and levels of federal transfers to the Yukon will have material effects on overall economic activity in the Yukon. For this reason, sensitivities were undertaken to determine the economic effects of changes in Federal transfer payments.

Federal transfer payments to the Yukon Government grew steadily and significantly during the 2000 to 2015 period, increasing by an average of 6.5% per annum. In all of the constructed scenarios, Federal transfers are expected to increase until at least 2019, at which the scenarios branch. In some scenarios, such as Low Industrial Activity with tapering government spending, Base Case with tapering government spending, and Low Mining Activity with Minto Mine ending production in 2017 and sensitivity analysis of government spending, transfers are expected to be flat from 2020 to the end of forecast period. It was assumed that government spending was capped on a real per person basis. In the remaining scenarios, the transfer payments, and government spending consequently, are assumed to grow on the average at a real rate of 0.5% per year per capita.

A total of 14 scenarios were modelled and they are described in the following paragraphs.

1. Very Low Industrial Activity

- Production at the Minto Mine ends after 2017.
- No new mines over the forecast period.
- Government spending is assumed to continue to grow beyond 2019.

2. Low Industrial Activity

- Production at the Minto Mine continues to the end of current productive life in 2022.
- One new medium-sized mine is brought into production. The Eagle Gold project is used as the proxy mine. Eagle Gold development begins in 2019 followed by full production from 2021 to 2035 with production tapering off and the mine closing in 2036.
- Government spending is assumed to continue to grow beyond 2019.

3. Base Case (Medium Industrial Activity)

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines:
    - Eagle Gold development begins in 2019 followed by production from 2021 to 2036.
    - Coffee development begins in 2022 followed by production from 2023 to 2036.
- Government spending is assumed to continue to grow beyond 2019.

4. High Industrial Activity including a new Large Mine

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Three new medium-sized mines are brought into production. The Eagle Gold, Coffee and Wellgreen projects are used as medium proxy sized mines:
    - Eagle Gold development begins in 2019 followed by production from 2021 to 2036.
    - Coffee development begins in 2022 followed by production from 2023 to 2036.
    - Wellgreen development begins in 2020 followed by production from 2022 to 2046.
- One new large mine is brought into production. The Casino project is used a large proxy mine. Casino mine development begins in 2018 and mine production begins in 2019, with operations continuing until 2043.
- Government spending is assumed to continue to grow beyond 2019.

5. Low Industrial Activity with tapering government spending

- Production at the Minto Mine continues to the end of current productive life in 2022.
- One new medium-sized mine is brought into production. The Eagle Gold project is used as a proxy mine. Eagle Gold development begins in 2019 followed by production from 2021 to 2036 with production beginning to taper off in 2035.

- Government spending is assumed to continue to grow only until 2019 after which time government spending growth is flat, i.e., government spending levels remain constant from 2020 to end of the forecast period.

6. Base Case with tapering government spending

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines.
    - Eagle Gold development begins in 2019 followed by production from 2021 to 2036 with production beginning to taper off in 2035.
    - Coffee development begins in 2022 followed by production from 2023 to 2036.
- Government spending is assumed to continue to grow only until 2019 after which time government spending growth is flat, i.e., government spending levels remain constant from 2020 to end of the forecast period.

7. Base Case with sensitivity analysis of smaller economic sectors (agriculture, forestry and fishing)

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines:
    - Eagle Gold development begins in 2019 followed by production from 2021 to 2036.
    - Coffee development begins in 2022 followed by production from 2023 to 2036.
- Government spending is assumed to continue to grow beyond 2019.
- Yukon's other economic sectors hold potential to influence economic output, though not at the same scale as the mining sector. Sensitivity analysis was undertaken to better understand the combined influence of the agriculture, forestry and fishing sectors on the MEM variables. This sensitivity analysis was executed by running the MEM with input variable ranges doubled compared to the base case to demonstrate the economic impacts.

8. Base Case with sensitivity analysis of natural gas projects

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines:
    - Eagle Gold development begins in 2019 followed by production from 2021 to 2036.
    - Coffee development begins in 2022 followed by production from 2023 to 2036.
- Government spending is assumed to continue to grow beyond 2019.
- Yukon's oil and gas sector holds potential to make a significant contribution to economic output. To understand the potential influence of this sector on the MEM variables, a sensitivity analysis was undertaken on one medium-sized natural gas project. Based on the limited data on gas projects available, a project with production estimated to last 15 years at a gas extraction

rate of 100 Mmcf/day was considered. The project related data were sourced from a feasibility study prepared by the Mines and Resources Oil & Gas Branch of the Yukon Government.

9. Base Case with later start of production for new Large Mine

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines:
    - Eagle Gold development begins in 2019 followed by production from 2021 to 2036.
    - Coffee development begins in 2022 followed by production from 2023 to 2036.
- One new large mine is brought into production, two years later than in Scenario 4. The Casino project is used a proxy large mine. Casino mine development begins in 2020 and mine production begins in 2021, continuing until 2045.
- Government spending is assumed to continue to grow beyond 2019.

10. Base Case with induced mining "bust and boom cycle"

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines. To illustrate to effects of a potential boom and bust cycle, the start of both projects is delayed to represent a bust period in the near term and both projects begin production at the same time to represent a boom period:
    - Eagle Gold development begins in 2028 followed by production from 2030 to 2041.
    - Coffee development begins in 2029 followed by production from 2030 to 2041.
- Government spending is assumed to continue to grow beyond 2019.

11. Base Case with advanced mine production timing

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines. The base case scenario is modified by bringing the two proxy mines into production two years earlier:
    - Eagle Gold development begins in 2017 followed by production from 2019 to 2034.
    - Coffee development begins in 2020 followed by production from 2021 to 2034.
- Government spending is assumed to continue to grow beyond 2019.

12. Low Mining Activity with Minto Mine ending production in 2017

- Production at the Minto Mine ends after 2017.
- One new medium-sized mine is brought into production. The Eagle Gold project is used as a proxy mine. Eagle Gold development begins in 2019 followed by production from 2021 to 2036.
- Government spending is assumed to continue to grow beyond 2019.

13. Low Mining Activity with Minto Mine ending production in 2017 and sensitivity analysis of government spending

- Production at the Minto Mine ends after 2017.
- One new medium-sized mine is brought into production. The Eagle Gold project is used as a proxy mine with development starting in 2019, followed by production from 2021 to 2036.
- Government spending is assumed to continue to grow to 2019 after which time growth in government spending is frozen.

14. Base Case with sensitivity analysis of tourism

- Production at the Minto Mine continues to the end of current productive life in 2022.
- Two new medium-sized mines are brought into production. The Eagle Gold and Coffee projects are used as proxy mines:
    - Eagle Gold development begins in 2019 followed by production from 2021 to 2036.
    - Coffee development begins in 2022 followed by production from 2023 to 2036.
- Government spending is assumed to continue to grow beyond 2019.
- Yukon's smaller economic sectors hold potential to influence economic output, although not at the same scale as the mining sector. To understand the influence of these sectors on the model output, a sensitivity analysis was undertaken across the industries which comprise the tourism sector including retail trade, accommodation, food services and transportation. The rate of tourism growth was doubled compared to the base case.

Yukon Microeconomic Model Results

The C4SE model generates outputs for an extensive list of economic variables. Output ranges and average values for the key economic variables with relevance to electricity consumption and therefore, future electricity demand, are presented in Table 2 below. To illustrate the range of key economic variables which inform the demand forecast, minimum, maximum and base values drawn from all 14 scenarios are presented for two future dates. Note that demographic parameters are much less variable than the economic parameters. The latter are heavily impacted by mining assumptions.

Table 2: Yukon Macroeconomic Model Outputs – Including Scenario Results

	Current (2015)	Year 2025	Year 2035
Population Base Case (000's)	37.4	41.2	41.1
Highest Scenario		43.1	42.6
Lowest Scenario		40.0	38.5
Households Base Case (000's)	17.7	17.7	17.8
Highest Scenario		18.4	18.4
Lowest Scenario		17.2	16.8
Employment Base Case (000's)	19.7	21.0	20.6
Highest Scenario		21.9	21.6
Lowest Scenario		20.4	19.0
Real Dollar Disposable Income Base Case ($M)	1,351	1,638	1,802
Highest Scenario		1,781	1,912
Lowest Scenario		1,548	1,611
Real Dollar Gross Domestic Product Base Case ($M)	2,226	2,682	2,789
Highest Scenario		4,238	4,459
Lowest Scenario		2,407	2,480

Descriptive charts for key economic variables which inform the electricity demand forecast are presented in the following sections. To avoid potential confusion that can be caused by 14 sometimes overlapping lines presenting 14 scenarios, the charts show 5 major scenarios (Very Low Industrial Activity, Low Industrial Activity, Low Industrial Activity with Early Minto Closure, Medium Industrial Activity, and Very High Industrial Activity) and the range of the remaining scenarios as a shaded area. The 5 major scenarios are selected due to their higher probability of realization compared to that of the rest of the scenarios.

Forecast Yukon Gross Domestic Product

Figure 1 illustrates forecast of Yukon Gross Domestic Product (Real dollars) over the forecast period for the economic scenarios. Growth in real GDP fall within a relatively narrow band except for the High Mining Activity including a new Large Mine scenario (scenario 4) and the Base Case with later start of production for new Large Mine scenario (scenario 9).

Figure 1: GDP including Mining Forecast

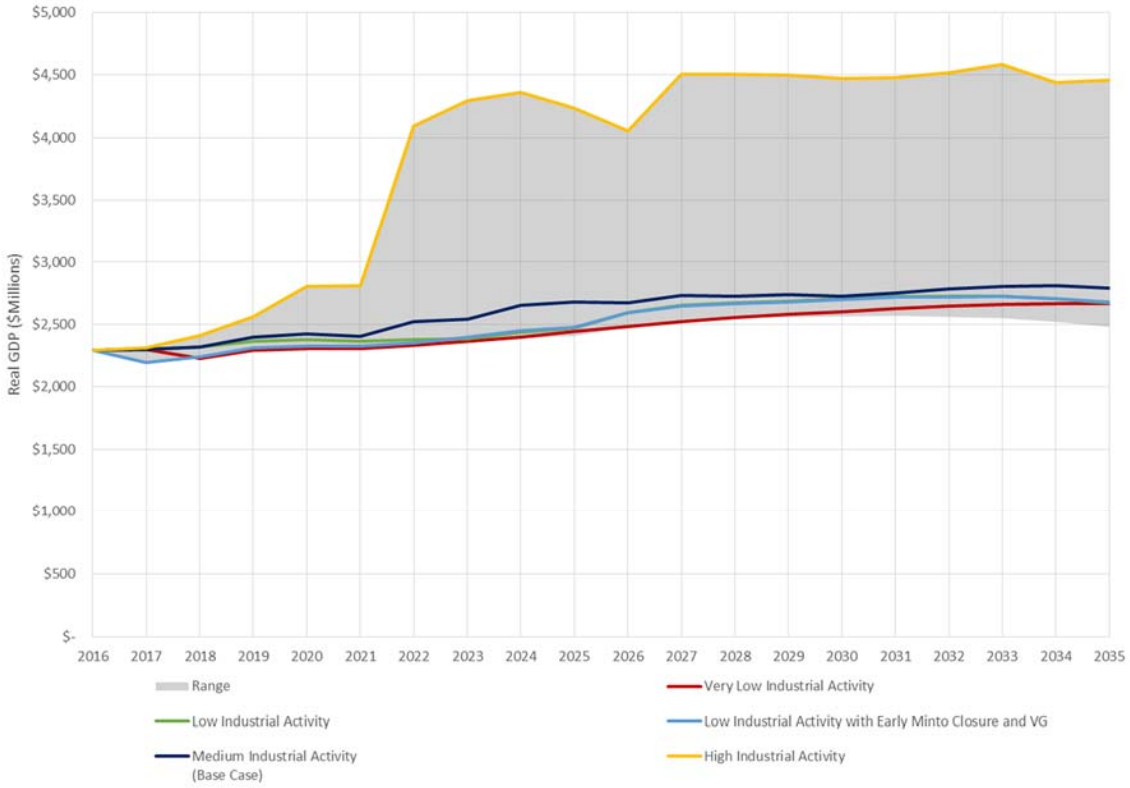
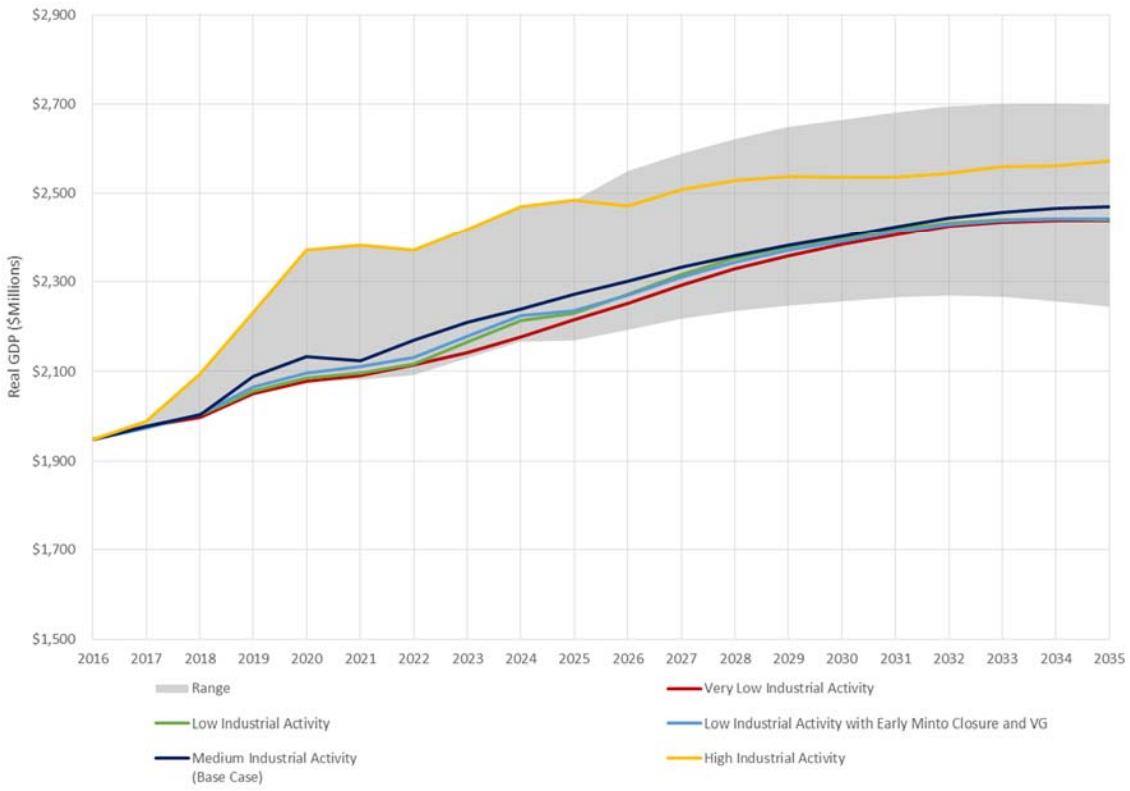


Figure 2 below illustrates a forecast of Yukon Gross Domestic Product (Real dollars) over the forecast period for the economic scenarios without the contribution of the mining industry. Growth in real GDP generally fall within a relatively narrow band except for the High Mining Activity including a new Large Mine scenario (scenario 4) and the Base Case with sensitivity on natural gas development (scenario 8).

Figure 2: GDP excluding Mining Forecast

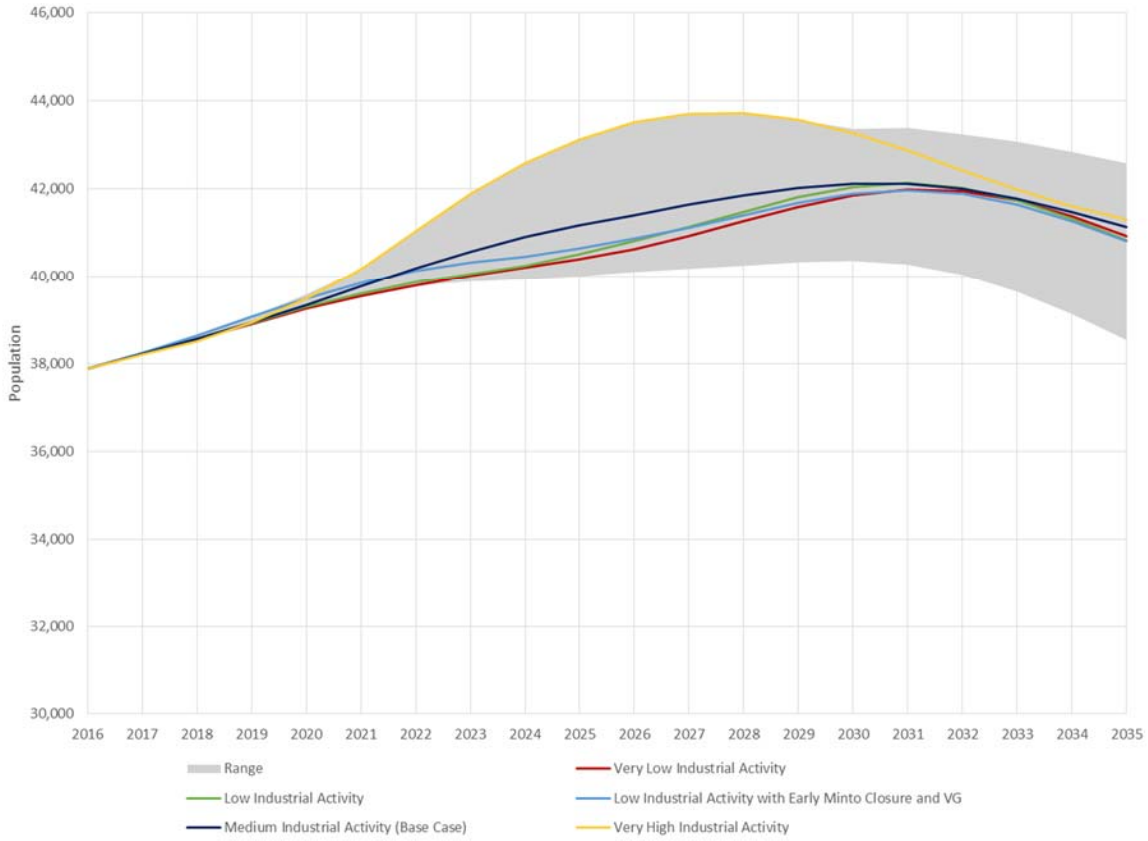


Forecast Yukon Population

Figure 3 below illustrates forecast of Yukon population over the forecast period for the economic scenarios. As Figure 3 shows, the population changes fall into a relatively narrow for all the scenarios. The direct connection between population growth and economic activity that is implicit in the YEC MEM by the slight decline in Yukon's population for the period after 2030. The MEM forecasts indicate an accelerating decline in the natural population growth rate, from 0.6% per annum currently to zero growth by 2030. After 2030, the difference between the number of deaths and births per year is expected to widen each year. The decline in the natural population growth rate will be compounded by an increasingly aging population. Whereas the 65+ age cohort represented only 11% of the total population in the Territory in 2015, by 2035 the 65+ age cohort is predicted to account for 23% of the population. This will translate into fewer people of working age. Further impacting Territory employment, the assumption is made that mineral production activities in the Yukon will become more automated, as a competitive measure. This will result in less operational employment opportunities in Yukon mines.

The small population of Yukon makes it a challenge to forecast long-term population. Nevertheless, changes in the Yukon population over the next 20 years will have a significant influence on YEC electricity demand, as residential and commercial sector electricity requirements tends to follow trends in population and housing starts.

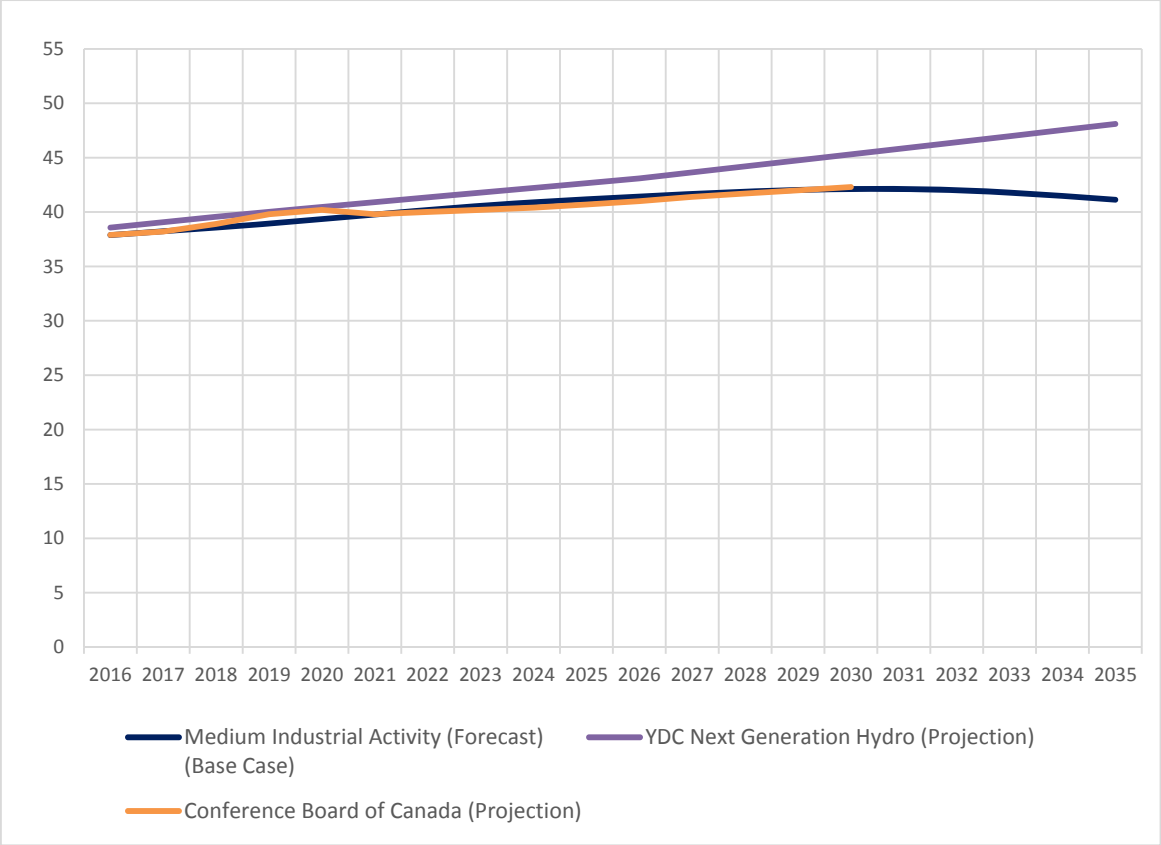
Figure 3. Population Forecast



The simplest approach to forecast the future is by extrapolation; this could include population projections. This approach implies that the past is the primary determinant of the future, and that recent trends will persist. Given inescapable demographic facts (i.e. the aging of the baby boomer generation), this approach will miss likely strategic outcomes, such as naturally declining employment levels or the need to import workers in the event of a domestic construction boom.

Forecasts of future population levels based on demographic trends (such as fertility and migration rates) are the basis of the C4SE and the Conference Board of Canada's population forecasts. As the fertility rate in Canada has been declining steadily for many years, and is expected to decline further, the forecast population growth in the Yukon is largely driven by assumptions regarding net in-migration. In contrast to the C4SE approach to long-term population forecasting, the Next Generation Hydro or previous forecasts done for YEC resource plans, were not directly informed by forecasts of economic activity. A comparison of recently developed population forecasts is illustrated in Figure 4.

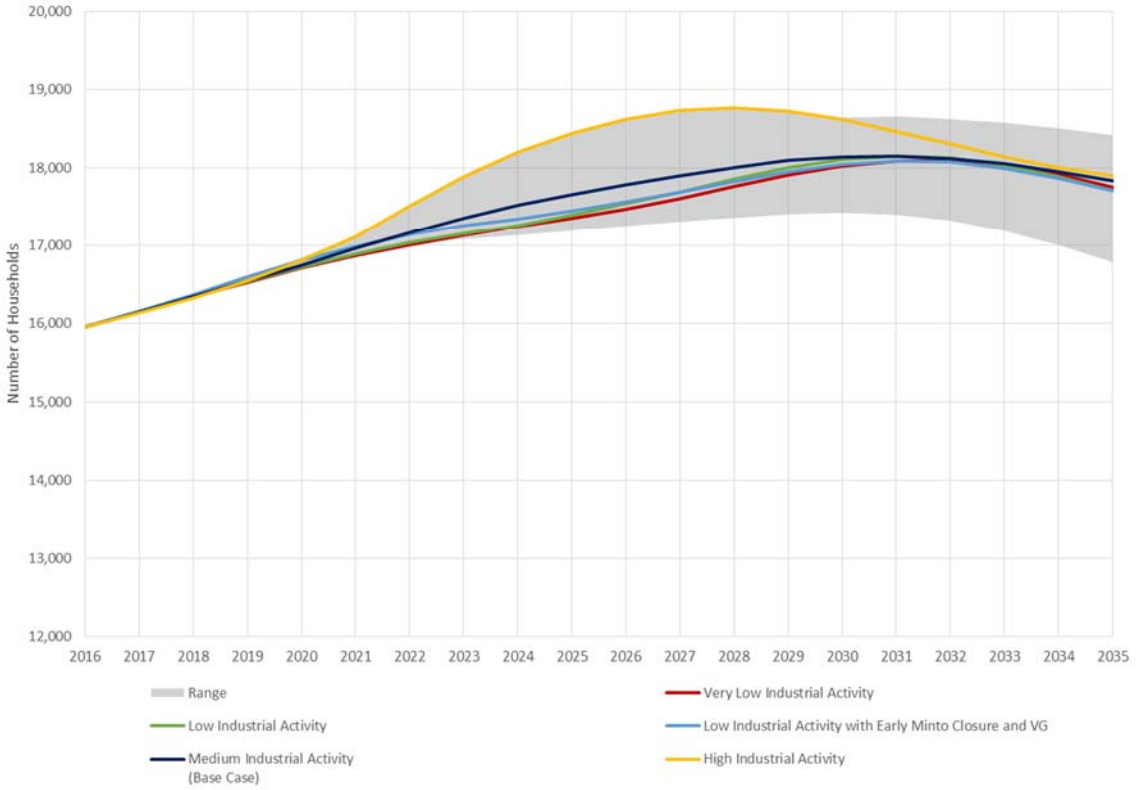
Figure 4. Projected and Forecast Yukon Population (in '000)



Forecast Number of Yukon Households

Figure 5 illustrates number of Yukon households forecast over the forecast period for the economic scenarios. As shown in Figure 5, growth in the number of households is forecast to be relatively steady over the forecast period. Consistent with the population forecast, the number of Yukon household peaks in the late 2020's before a gradual decline.

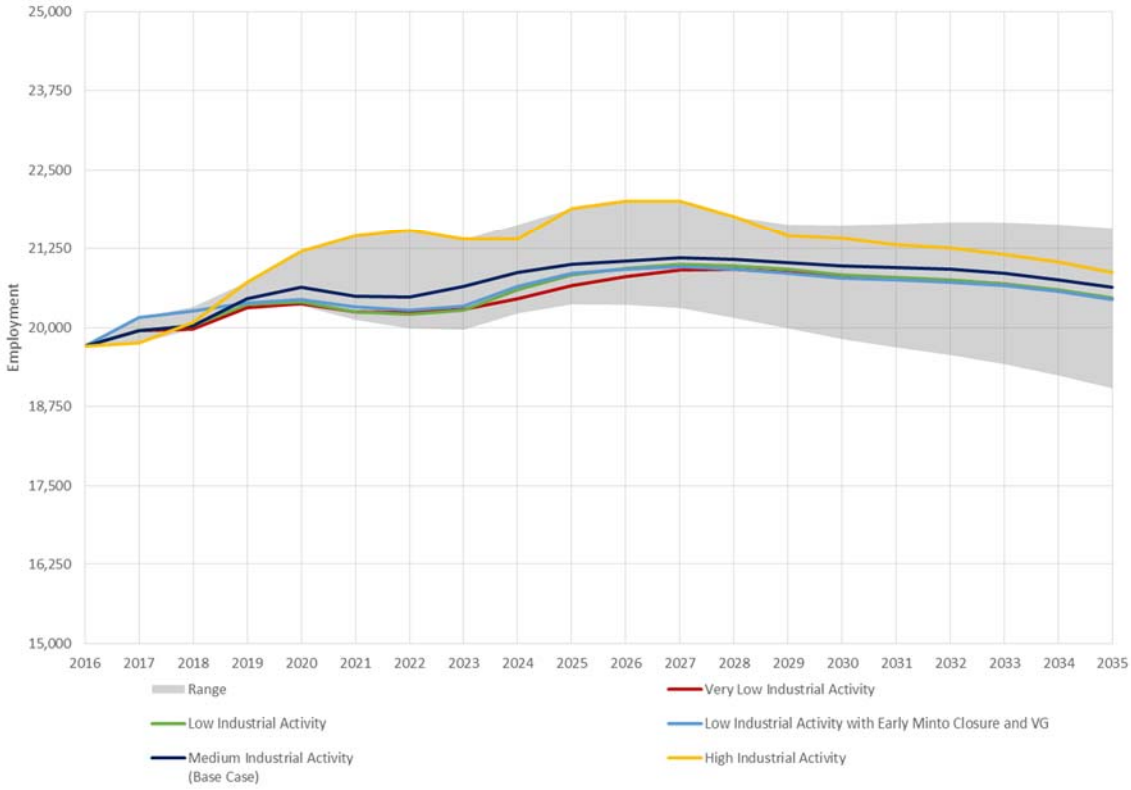
Figure 5. Number of Household Forecast



Forecast Yukon Employment

Figure 6 illustrates the forecast of total Yukon employment over the forecast period for the economic scenarios. The employment forecast is used to estimate commercial electricity demand over the forecast period, with the level of total employment directly related to electrical sales. As the level of total employment increases, electrical sales will also increase. Overall, total Yukon employment is forecast to grow until 2030 before beginning to decline slightly, a pattern consistent with the forecasts for population and the number of households as generated by the MEM.

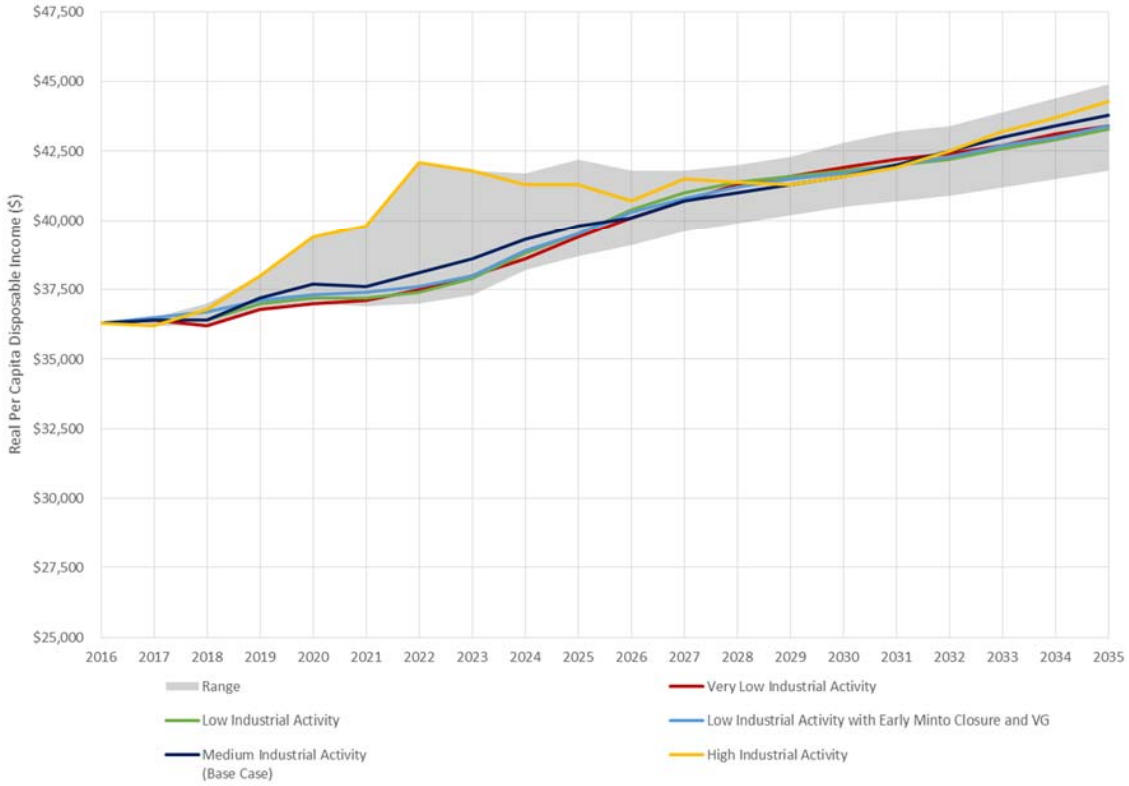
Figure 6. Employment Forecast



Forecast Yukon Per Capita Disposable Income

Figure 7 illustrates the forecast of total Yukon employment over the forecast period for the economic scenarios. Yukon per capita disposable income (Real dollars) is used to forecast electrical sales to residential customers and is directly related to sales. As disposable income increases, residential electrical demand will correspondingly increase. As shown in Figure 7, the MEM results indicate a relatively narrow range of variations in per capita disposable income over the forecast period. In contrast to the forecasts for population, number of households and employment, per capita disposable income is expected to steadily increase under all scenarios through to the end of the forecast period in 2035.

Figure 7. Real Per Capita Disposable Income Forecast



Appendix 4.3
Long Term Load and Demand Forecast 2016-2035

Itron
Knowledge to Shape Your Future

Electric | Gas | Water
information collection, analysis and application

Long Term Load and Demand Forecast

Yukon Energy Corporation (YEC)

Submitted to:

Yukon Energy Corporation
Whitehorse, YT, Canada

Submitted by:

Itron, Inc.
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Boston, Massachusetts 02116
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Itron

March 8, 2016

Contents

CONTENTS ..... **I**

1 OVERVIEW **1**

2 FORECAST DATA AND ASSUMPTIONS **5**

2.1 HISTORICAL CLASS SALES AND ENERGY DATA 5
2.2 WEATHER DATA 5
2.3 ECONOMIC DATA 8
2.4 PRICE DATA 11
2.5 APPLIANCE SATURATION AND EFFICIENCY TRENDS 12

3 FORECAST METHODOLOGY **15**

3.1 CLASS SALES FORECAST 15
3.1.1 Residential Model *15*
3.1.2 Commercial Model *20*
3.1.3 ST & SP Sales *23*
3.2 ENERGY AND PEAK FORECAST 24
3.2.1 Energy Forecast *24*
3.2.2 Peak Forecast *25*
3.3 SOLAR FORECAST 32

4 FORECAST SCENARIOS **34**

5 APPENDIX A: MODEL STATISTICS **39**

6 APPENDIX B: RESIDENTIAL SAE MODELING FRAMEWORK **45**

6.1 STATISTICALLY ADJUSTED END-USE MODELING FRAMEWORK 45
6.1.1 Constructing XHeat *46*
6.1.2 Constructing XCool *49*
6.1.3 Constructing XOther *52*

7 APPENDIX C: COMMERCIAL STATISTICALLY ADJUSTED END-USE MODEL **55**

7.1 COMMERCIAL STATISTICALLY ADJUSTED END-USE MODEL FRAMEWORK 55
7.1.1 Constructing XHeat *56*
7.1.2 Constructing XCool *58*
7.1.3 Constructing XOther *60*

8 APPENDIX D: INDUSTRIAL MODEL **62**

YUKON ENERGY

1 Overview

Itron, Inc. (Itron) was contracted by the Yukon Energy Corporation (YEC) to develop a process for forecasting system energy and peaks using a bottom up class level forecasting approach. Itron's modeling approach incorporates the 2015 SAE (Statistically Adjusted End-Use) indices, as well as current economic data. This document outlines underlying data, the structure of the models, and the modeling process.

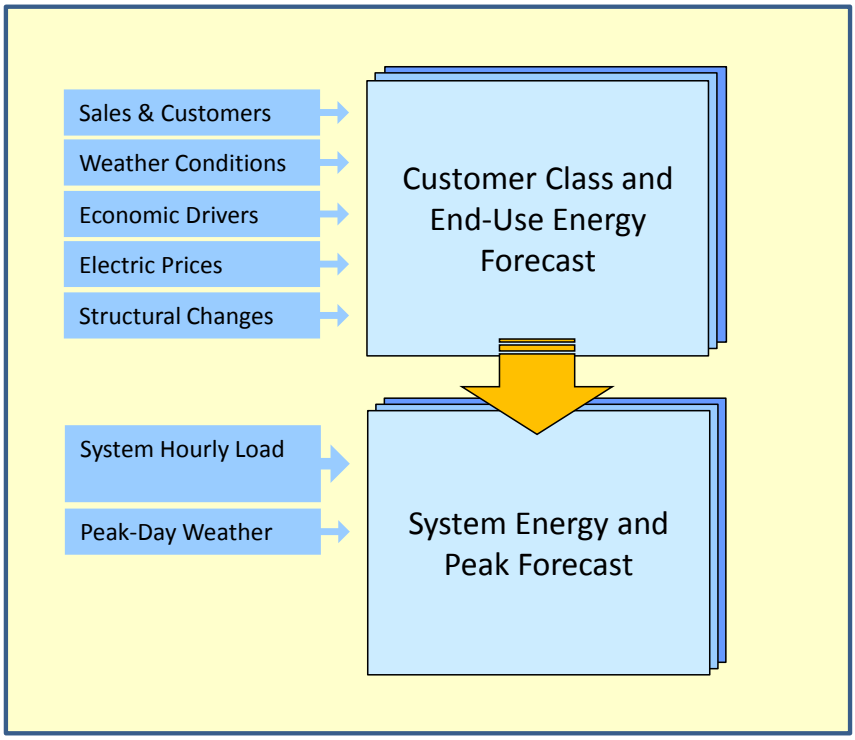
Itron constructed all forecasting and weather normalization models in MetrixND, Itron's statistical modeling application. MetrixND is ideally suited for this purpose as Itron designed and developed the software specifically to meet the needs of the utility industry. In this case, MetrixND generates monthly sales and peak demand. Further, MetrixND acts as the forecasting engine that supports hourly and sub-hourly processes for long-term planning, as well as real-time and day-ahead forecasting to support generation dispatch and load scheduling. Table 1-1 summarizes YEC energy and demand forecast (excluding industrial).

Table 1-1: Energy and Demand Forecast: Base Case

Year	Energy (MWh)		Peak (MW)	
2015	374,882		76.9	
2016	389,806	4.0%	82.2	6.9%
2017	393,583	1.0%	83.8	1.9%
2018	399,238	1.4%	85.9	2.5%
2019	406,423	1.8%	88.2	2.7%
2020	413,561	1.8%	90.8	2.9%
2021	418,684	1.2%	92.8	2.2%
2022	425,589	1.6%	95.2	2.6%
2023	432,219	1.6%	97.4	2.3%
2024	439,363	1.7%	99.8	2.4%
2025	443,536	0.9%	101.2	1.4%
2026	447,317	0.9%	102.5	1.3%
2027	451,336	0.9%	103.8	1.3%
2028	455,839	1.0%	105.2	1.4%
2029	457,568	0.4%	105.8	0.5%
2030	458,274	0.2%	106.1	0.3%
2031	457,059	-0.3%	105.8	-0.3%
2032	456,036	-0.2%	105.6	-0.2%
2033	452,276	-0.8%	104.6	-1.0%
2034	448,774	-0.8%	103.7	-0.8%
2035	444,998	-0.8%	102.8	-0.9%
2016-2025		1.4%		2.3%
2016-2035		0.7%		1.2%

The long-term energy and demand forecast is developed using a “build-up” approach. This approach entails first estimating class and end-use energy requirements and then using class and end-use sales projections to drive system peak demand. The forecast models capture not only economic activity and population projections, but also expected weather conditions, the impact of improving end-use efficiency and standards, and electricity prices. The forecast does include the impact of future conservation programs savings. Figure 1-1 shows the general approach.

Figure 1-1: Forecast Approach



In the long-term, both economic growth and structural changes drive sales and demand requirements. Structural changes are captured in the residential and commercial sales forecast models through SAE (Statistically Adjusted End-Use) specifications. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. End-use efficiency projections include the expected impact of new end-use standards and naturally occurring efficiency gains. The industrial sales forecast is derived using a generalized econometric model that relates industrial sales to regional industrial GDP growth. The Street Light (ST) sales forecast is also derived using a generalized econometric model that relates ST sales to the residential customer forecast. Table 1-2 summarizes customer class sales forecast excluding industrial saels.

YUKON ENERGY

Itron

Table 1-2: Customer Class Sales Forecast: Base Case (MWh)

Year	Residential		Commercial		ST		SP		Total	
2015	155,443		173,005		291		14		328,754	
2016	162,786	4.7%	175,799	1.6%	291	0.2%	14	0.2%	338,890	3.1%
2017	165,192	1.5%	176,657	0.5%	292	0.2%	14	0.0%	342,154	1.0%
2018	168,663	2.1%	178,079	0.8%	292	0.2%	14	0.0%	347,048	1.4%
2019	172,670	2.4%	180,300	1.2%	293	0.2%	14	0.0%	353,277	1.8%
2020	177,242	2.6%	181,919	0.9%	294	0.2%	14	0.0%	359,469	1.8%
2021	180,655	1.9%	182,937	0.6%	294	0.2%	14	0.0%	363,900	1.2%
2022	185,015	2.4%	184,559	0.9%	295	0.2%	14	0.0%	369,884	1.6%
2023	189,096	2.2%	186,226	0.9%	295	0.2%	14	0.0%	375,632	1.6%
2024	193,618	2.4%	187,904	0.9%	296	0.2%	14	0.0%	381,832	1.7%
2025	196,057	1.3%	189,080	0.6%	296	0.1%	14	0.0%	385,447	0.9%
2026	198,401	1.2%	190,013	0.5%	297	0.1%	14	0.0%	388,725	0.9%
2027	200,882	1.3%	191,017	0.5%	297	0.1%	14	0.0%	392,211	0.9%
2028	203,768	1.4%	192,043	0.5%	297	0.1%	14	0.0%	396,122	1.0%
2029	204,709	0.5%	192,601	0.3%	298	0.1%	14	0.0%	397,621	0.4%
2030	205,508	0.4%	192,416	-0.1%	298	0.0%	14	0.0%	398,235	0.2%
2031	205,253	-0.1%	191,620	-0.4%	298	0.0%	14	0.0%	397,186	-0.3%
2032	205,298	0.0%	190,696	-0.5%	298	0.0%	14	0.0%	396,306	-0.2%
2033	203,568	-0.8%	189,165	-0.8%	298	-0.1%	14	0.0%	393,044	-0.8%
2034	202,212	-0.7%	187,484	-0.9%	297	-0.1%	14	0.0%	390,008	-0.8%
2035	200,789	-0.7%	185,631	-1.0%	297	-0.1%	14	0.0%	386,731	-0.8%
2016-2025		2.1%		0.8%		0.2%		0.0%		1.4%
2016-2035		1.1%		0.3%		0.1%		0.0%		0.7%

The strong growth in Residential sales is the result of increasing saturation of electric heat. Residential electric heat saturation grows from approximately 12% in 2015 to 21% by 2025 before flattening out at 23% by 2031. This saturation is driven by the assumption that 95% of all new residential customers will have electric heat. Residential average use increases 1.0% annually through 2025. Commercial sales are also driven by increases in electric heat saturation. Growth rates in all classes begin to decline in the out years, driven by significant declines in the population and GDP forecasts.

2 Forecast Data and Assumptions

2.1 Historical Class Sales and Energy Data

The process begins by estimating long-term monthly sales models at the revenue class level. Forecast models are estimated for residential, commercial, industrial, and street lighting revenue classes. Regression models are estimated using historical monthly billing data that includes sales, customers, and revenue. The residential and commercial models are estimated using monthly billed sales, customer and price data for the period January 2006 to September 2015. The industrial model is estimated using monthly data for the period January 2006 to September 2015. Street light models are estimated using monthly billed sales data from January 2006 to September 2015.

System monthly energy and monthly demand data are derived from historical hourly load data for the period January 1, 2006 to September 30, 2015 with estimated hourly loads for the Elsa and Minto mines removed.

Hourly Elsa mine loads are approximated subtracting the Elsa SCADA data hourly load from the system loads to obtain a monthly system demand modifier. The modifier is further reduced by 0.28 MW which approximates the non-Elsa mine load from hourly SCADA data based on the average of the SCADA data demand after the Elsa mine closed in August 2013.

Hourly Minto mine loads are approximated by subtracting the Minto mine loads from the system loads to obtain a monthly system demand modifier from January 2013 through September 2015. The demand modifier for data prior to January 2013 is estimated by applying the average ratio of the demand modifier to the Minto non-coincident billing peaks and applying the ratio to the January 2006 through December 2012 time period.

2.2 Weather Data

YEC provided daily historical minimum and maximum dry bulb temperature data for Whitehorse, Canada for the period January1, 1970 to September 30, 2015. These data are obtained from Environment Canada and used as the proxy weather station for the entire YEC service territory.

Using these data, a daily average temperature concept is calculated, as well as daily Heating Degree Day (HDD) and Cooling Degree Day (CDD) concepts for numerous breakpoints. As class sales data is measured on a billing month basis, models are estimated using billing-

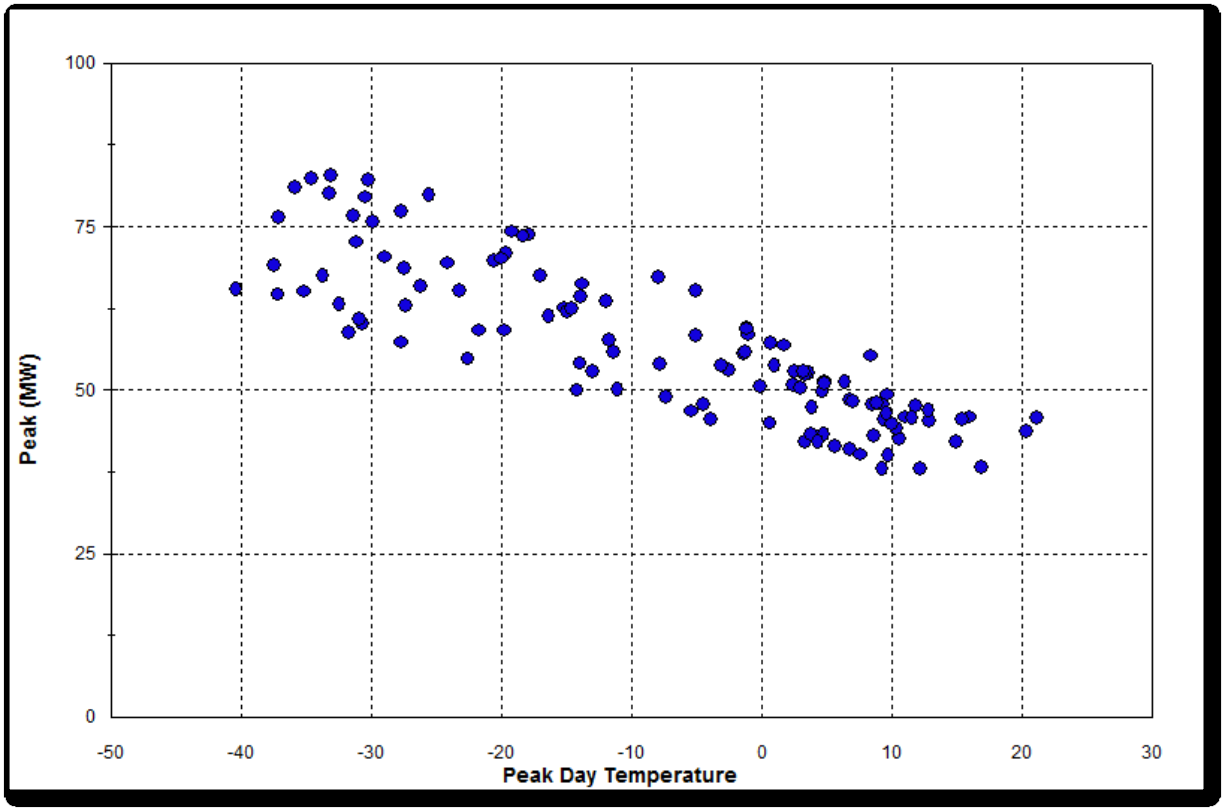
month or cycle-weighted HDD and CDD. These cycle-weighted HDD and CDD concepts are calculated using a meter read schedule, which sums the daily HDD and CDD concepts over the monthly billing cycles. Ultimately, our objective is to generate calendar-month sales and energy forecasts. To derive calendar month sales forecasts, simulation objects are used where billing month HDD and CDD in the estimated model are replaced with calendar month normal HDD and CDD and the number of billing days used in the estimated model is replaced with the number of calendar days.

Normal calendar and cycle-weighted degree days are calculated based on the 30-year period January 1, 1981 to December 31, 2010 using an average by date method.

Peak-Day Weather Variables

The peak forecast is generated from a monthly peak regression model. Peak-day HDD and CDD are derived from historical daily average weather data. Peak-day HDD and CDD are calculated by first finding the peak in each month (the maximum hourly demand), identifying the day, and finding the average temperature for that day. The average peak-day temperature is then used to construct peak-day HDD and CDD variables. The appropriate breakpoints for the HDD and CDD variables are determined by evaluating the relationship between monthly peak and the peak-day average temperature, shown in Figure 2-1.

Figure 2-1: Monthly Peak Demand vs. Temperature Relationship



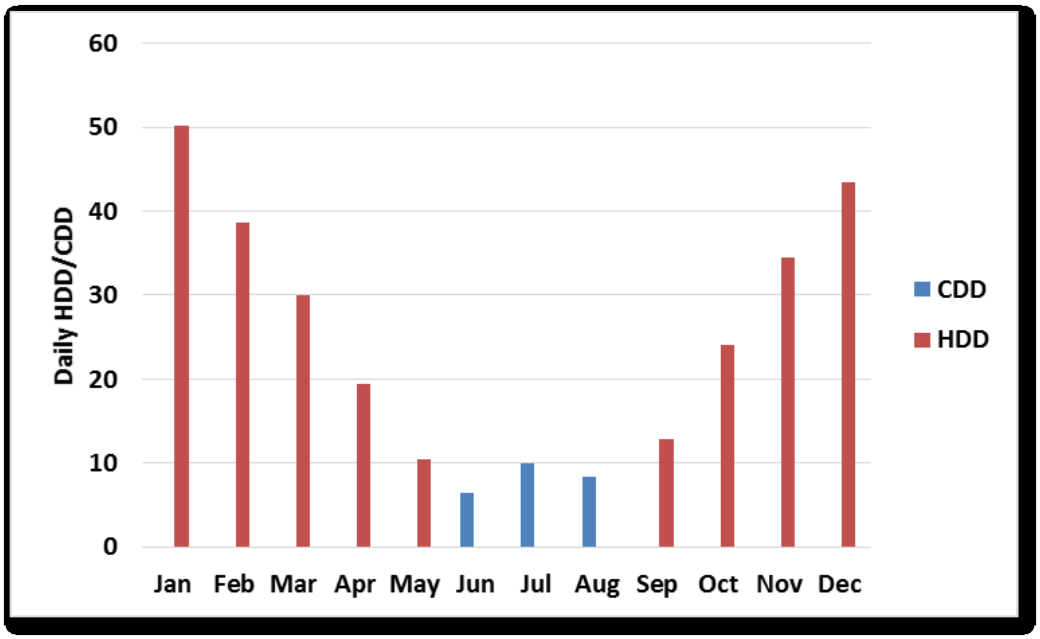
Monthly peak-day HDD and CDD are calculated for the estimation period – January 2006 to September 2015 based on these temperature relationships.

Normal peak-day CDD and HDD are calculated from monthly extreme temperature observations. This method is chosen because historic load data is not available prior to 2006; therefore peak day weather cannot be determined. For the months of June, July, and August the monthly maximum temperature is used, for all other months the monthly minimum is used. Normal peak-day HDD and CDD are calculated using 30 years of historical weather data (1981 to 2010). The calculation process entails using a *rank and average* approach as described below:

1. Find the lowest or highest temperature observation for a given month. This calculation occurs within the Loads.NDM.
2. *Rank* the monthly HDD and CDD in each year from the highest value to the lowest value.
3. *Average* across the annual rankings – average the highest HDD values in each year, average the second highest in each year, the third highest …., average the lowest HDD values in each year.

4. Assign the HDD and CDD values to specific months based on past weather patterns. The highest HDD is assigned to January and the highest CDD value is assigned to July. Figure 2-2 shows the calculated peak-day normal HDD and CDD

Figure 2-2: Peak-Day Normal HDD and CDD



2.3 Economic Data

Economic data was provided by YEC. These data are obtained from the Centre for Spatial Economics (C4SE) and include a base case and nine economic scenarios. The main differing factor among the scenarios is mining activity. The economic scenarios and their impact on the load and demand forecast will be covered in detail in the Forecast Scenarios section of this document.

The primary economic drivers in the residential model include income per capita, households, and population. Commercial sales are driven by commercial regional non-mining output, which represents territorial GDP without the contribution of the mining industry, and employment. The economic driver used in estimating the industrial sector model is mining output. Table 2-1 summarizes the primary economic drivers for the residential class.

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Table 2-1: Residential Drivers: Base Case

Year	Population		HouseHolds		Per Capita Income	
2015	37.4		15.7		36.1	
2016	37.9	1.2%	16.0	1.5%	36.3	0.6%
2017	38.2	0.9%	16.2	1.2%	36.4	0.3%
2018	38.6	0.9%	16.3	1.2%	36.4	0.0%
2019	38.9	1.0%	16.5	1.2%	37.2	2.2%
2020	39.3	1.0%	16.8	1.3%	37.7	1.3%
2021	39.8	1.1%	17.0	1.3%	37.6	-0.3%
2022	40.2	1.0%	17.2	1.2%	38.1	1.3%
2023	40.6	0.9%	17.4	1.0%	38.6	1.3%
2024	40.9	0.8%	17.5	1.0%	39.3	1.8%
2025	41.2	0.7%	17.7	0.8%	39.8	1.3%
2026	41.4	0.6%	17.8	0.7%	40.1	0.8%
2027	41.6	0.6%	17.9	0.7%	40.7	1.5%
2028	41.9	0.5%	18.0	0.6%	41.0	0.7%
2029	42.0	0.4%	18.1	0.4%	41.3	0.7%
2030	42.1	0.2%	18.1	0.3%	41.6	0.7%
2031	42.1	0.0%	18.2	0.1%	42.0	1.0%
2032	42.0	-0.3%	18.1	-0.2%	42.5	1.2%
2033	41.8	-0.5%	18.1	-0.4%	43.0	1.2%
2034	41.5	-0.7%	18.0	-0.6%	43.4	0.9%
2035	41.1	-0.8%	17.8	-0.7%	43.8	0.9%
2016-2025		0.9%		1.1%		1.0%
2016-2035		0.4%		0.6%		1.0%

Table 2-2 and Table 2-3 show output and employment drivers used in commercial and industrial forecasts.

Table 2-2: Commercial Drivers: Base Case

Year	Non-Mining GDP		Total Employment	
2015	1,938.2		19.7	
2016	1,947.6	0.5%	19.7	-0.1%
2017	1,977.0	1.5%	20.0	1.3%
2018	2,003.6	1.3%	20.0	0.4%
2019	2,089.3	4.3%	20.5	2.1%
2020	2,133.1	2.1%	20.6	0.9%
2021	2,123.0	-0.5%	20.5	-0.7%
2022	2,168.9	2.2%	20.5	-0.1%
2023	2,210.0	1.9%	20.7	0.8%
2024	2,238.7	1.3%	20.9	1.1%
2025	2,272.3	1.5%	21.0	0.6%
2026	2,300.6	1.2%	21.1	0.2%
2027	2,333.3	1.4%	21.1	0.3%
2028	2,359.1	1.1%	21.1	-0.1%
2029	2,382.0	1.0%	21.0	-0.3%
2030	2,402.2	0.8%	21.0	-0.2%
2031	2,423.5	0.9%	21.0	-0.1%
2032	2,443.6	0.8%	20.9	-0.1%
2033	2,457.6	0.6%	20.9	-0.3%
2034	2,466.5	0.4%	20.8	-0.5%
2035	2,470.7	0.2%	20.6	-0.6%
2016-2025		1.7%		0.7%
2016-2035		1.3%		0.2%

Table 2-3: Industrial Drivers: Base Case

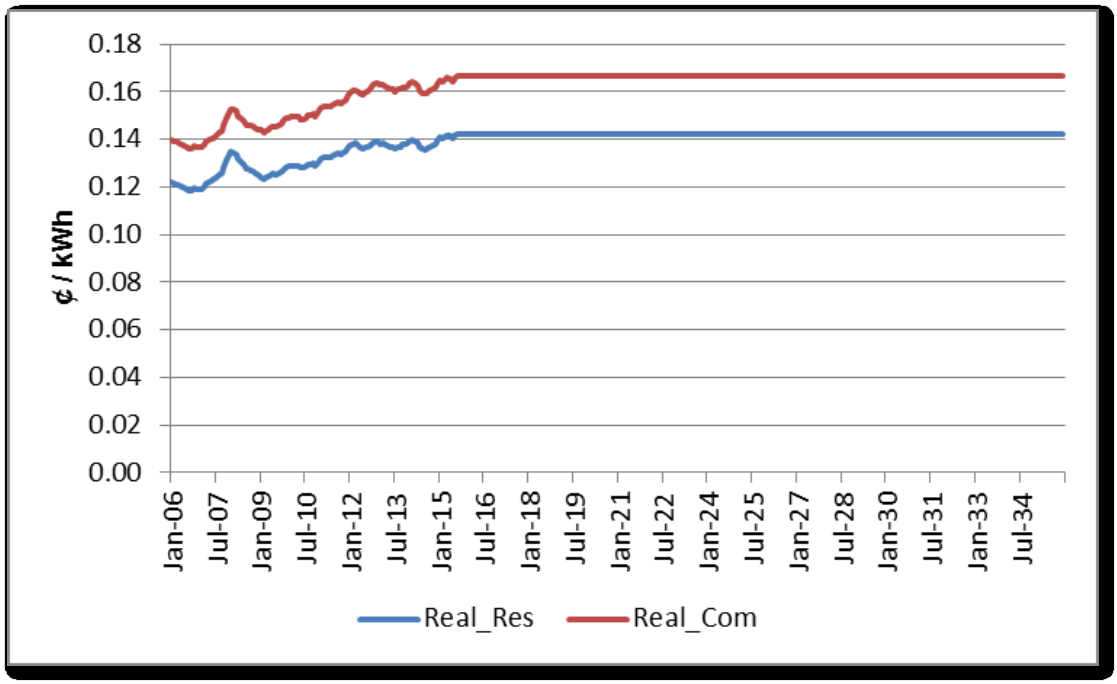
Year	Mining GDP	
2015	287.9	
2016	347.7	20.8%
2017	325.4	-6.4%
2018	316.4	-2.8%
2019	308.8	-2.4%
2020	291.9	-5.5%
2021	278.8	-4.5%
2022	353.9	26.9%
2023	334.0	-5.6%
2024	416.7	24.8%
2025	409.2	-1.8%
2026	375.0	-8.4%
2027	395.0	5.3%
2028	367.5	-7.0%
2029	354.2	-3.6%
2030	321.2	-9.3%
2031	327.4	1.9%
2032	343.4	4.9%
2033	344.8	0.4%
2034	346.0	0.3%
2035	318.4	-8.0%
2016-2025		2.5%
2016-2035		0.0%

2.4 Price Data

Historical average real prices are derived from historical billing and revenue data. Prices impact the class sales through imposed price elasticities. The residential and commercial price elasticity is -0.10. Itron's 2006 Price Effects survey identifies the range of price elasticities from 0.0 to 0.35 for residential customers and 0.0 to 0.5 for commercial customers. The selection of the price elasticity is based on adjusting the elasticity in the model and determining the impact on overall model fit.

Though the elasticities are small, relatively strong price increases through 2015 have a measurable impact on near-term usage. Over the long-term, constant real prices are assumed rendering the impact of elasticity in the forecast as unimportant while leaving the forecast unbiased regarding unadopted price increases and decreases. Figure 2-3 shows price forecasts by class.

Figure 2-3: Historical and projected real electricity prices (cents per kWh)

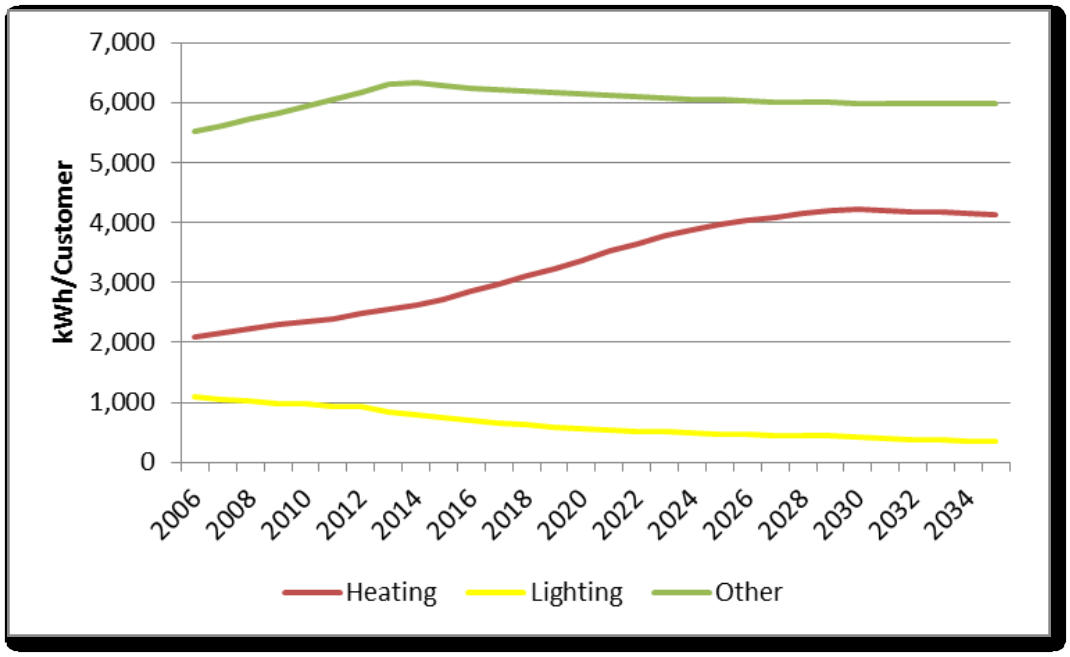


2.5 Appliance Saturation and Efficiency Trends

Over the long-term, changes in end-use efficiency and equipment stock impact energy and peak demand. These trends are explicitly captured in the forecast model variables. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types. Residential end-use efficiency and commercial end-use efficiency are derived from the U.S. Energy Information Administration's (EIA) 2015 West North Central Census Division forecast. Historic and projected residential end-use saturations are based on a combination of data from Natural Resources Canada (NRCan),a 2011 potential study, *Yukon Conservation and Demand Management Potential Review* (CPR), and a 2016 CPR study. The residential electric heat saturation projection is calculated using the assumption that 95% of all new customers use electric heat as their primary heating source.

Residential sales forecast are derived as the product of monthly customer forecast and average use forecast. For the residential average use model, end-use intensity projections (use per household) are aggregated into three generalized end-uses; heating, lighting, and other use, no residential cooling is present in YEC's service territory, per the 2011 potential study. Figure 2-4 shows the resulting aggregated end-use intensity projections.

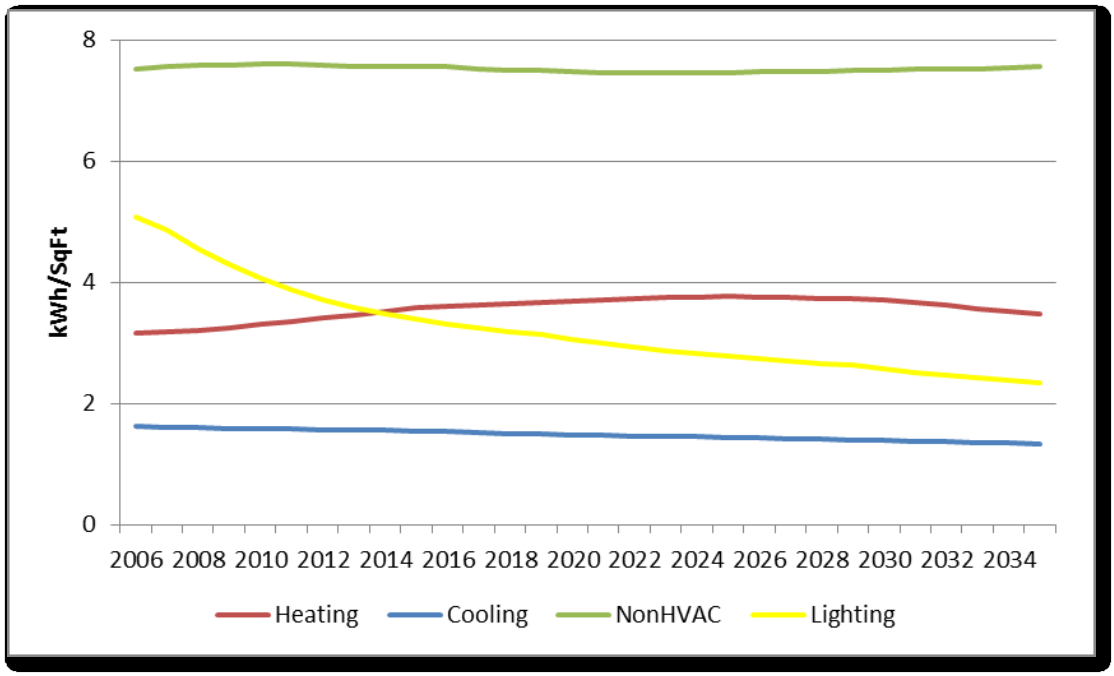
Figure 2-4: Residential End-Use Energy Indices [kWh per Customer]



The heating intensity increases 2.9% annually through the first 10 years of forecast period, driven by the assumption that 95% of all new customers will use electric heat. The 95% electric heat assumption is based on the Energy Solution Centre's work showing that 97% of new homes since 2013 use electric heat as their primary fuel source. After 2032, heating intensity begins to flatten out as the customer forecast declines driven by negative household growth projections. Non-weather sensitive use, "Other", which includes all appliances, plug loads, and water heating declines 0.4% through the first 10 years of the forecast, mainly driven by efficiency improvement in water heating and refrigeration, although this is partially offset by increases in plug loads. Lighting declines fairly steadily as the impact of the new lighting standards (that effectively eliminate traditional incandescent light bulbs) begin to take effect, intensity declines 2.4% through the first 10 years of forecast period.

For the commercial average use model, end-use intensity projections (use per square foot) are aggregated into four generalized end-uses; heating, cooling, lighting, and non-HVAC. It is important to point out that although a cooling intensity projection is developed there is no cooling variable in the commercial average use model; the variable was statistically insignificant. End-use consumption and commercial square footage data from the 2011 CPR was used to calibrate into base year end-use intensities. Projected end-use consumption figures from the 2016 CPR were then used as the basis for deriving intensity projections. Figure 2-5 shows commercial end-use energy intensity forecasts for the aggregated end-use categories.

Figure 2-5: Commercial End-Use Energy Intensity [kWh/SqFt]



Similar to the Residential intensity, Commercial heating intensity (use per square foot) is also increasing. The strong decline in historic and future lighting intensity is largely the result of improving lighting efficiency.

3 Forecast Methodology

3.1 Class Sales Forecast

Changes in economic conditions, prices, weather conditions, as well as appliance saturation and efficiency trends drive energy deliveries and demand through a set of monthly customer class sales forecast models. Monthly regression models are estimated for each of the following primary revenue classes:

- Residential
- Commercial
- Industrial
- Street Lights (ST)
- Space Lights (SP)

While Itron developed an Industrial model, YEC decided to remove the Industrial model (Appendix D) to manually manage the addition and subtraction of major industrial customers.

3.1.1 Residential Model

Residential average use and customers are modeled separately. The residential sales forecast is then generated as the product of the average use and customer forecasts.

The residential average use model is specified using an SAE model structure. The technique is fully described in Appendix B and has been adopted by 60 companies across North America.

While a traditional approach to forecasting sales is developing an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions, the approach cannot explicitly capture changes in the underlying energy efficiency of end-uses. In contrast, end-use models capture energy efficiency changes, but are cumbersome and require costly databases that track technology changes over time. The SAE approach blends econometric models with end-use information based on studies conducted by the U.S. Energy Information Administration. The SAE model exploits the strengths of econometric and end-use models by using national-level end-use data and local economic drivers calibrated to utility specific sales to capture growth based on changes in end-use technology.

The SAE approach begins by defining average use as a function of the four primary end-uses -- heating (XHeat), other use (XOther), and lighting (XLight)

$$ResAvgUse_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XOther_m) + +(B_3 \times XLight_m) + e_m$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$$XHeat = HeatUse \times HeatIndex$$

Where

$$HeatUse = f(HDD, Household\ Income, Household\ Size, Price)$$

$$HeatIndex = g(Heating\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

XOther captures non-weather sensitive end-uses, not including lighting:

$$XOther = OtherUse \times OtherIndex$$

Where

$$OtherUse = f(Seasonal\ Use\ Pattern, Household\ Income, Household\ Size, Price, Days)$$

$$OtherIndex = g(Other\ Appliance\ Saturation\ and\ Efficiency\ Trends)$$

XLight captures lighting end-use,

$$XLight = OtherUse \times LightIndex$$

Where

$$OtherUse = f(Seasonal\ Use\ Pattern, Household\ Income, Household\ Size, Price)$$

$$LightIndex = g(Lighting\ Saturation\ and\ Efficiency)$$

The specific calculations of the end-use variables are presented in Appendix B. Figure 3-1 to Figure 3-3 show the constructed monthly end-use variables.

Figure 3-1: Residential XHeat: Base Case (kWh per month)

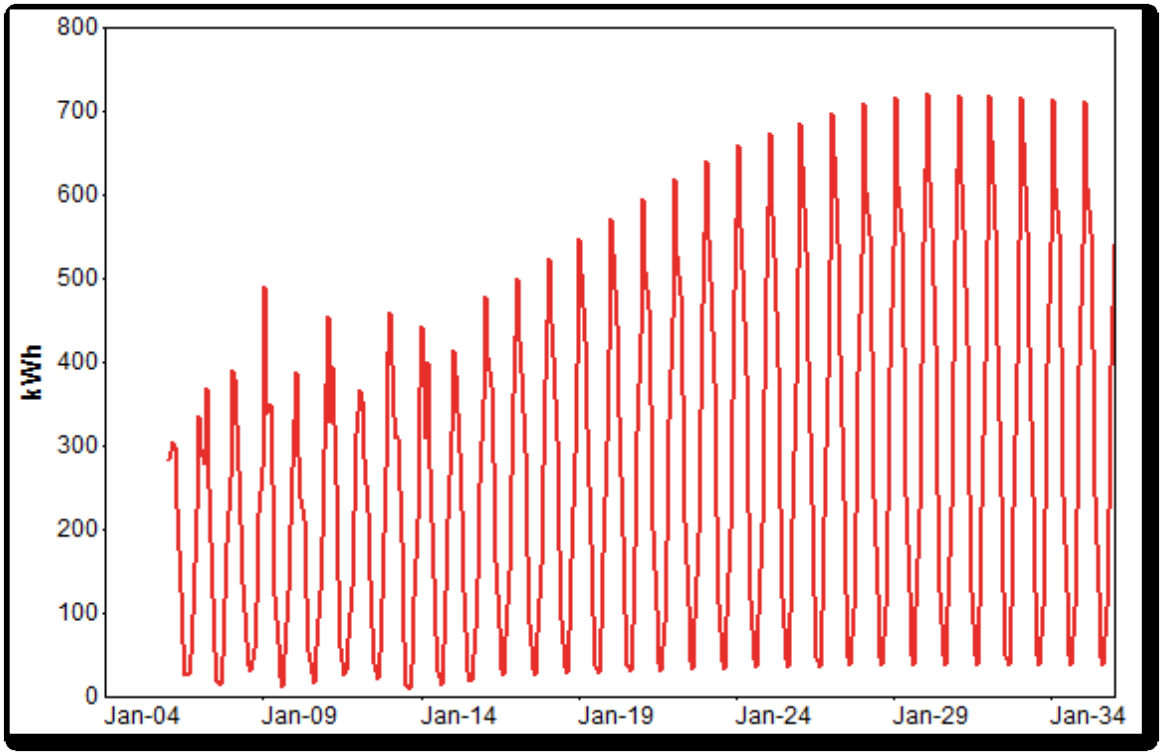


Figure 3-2: Residential XOther: Base Case (kWh per month)

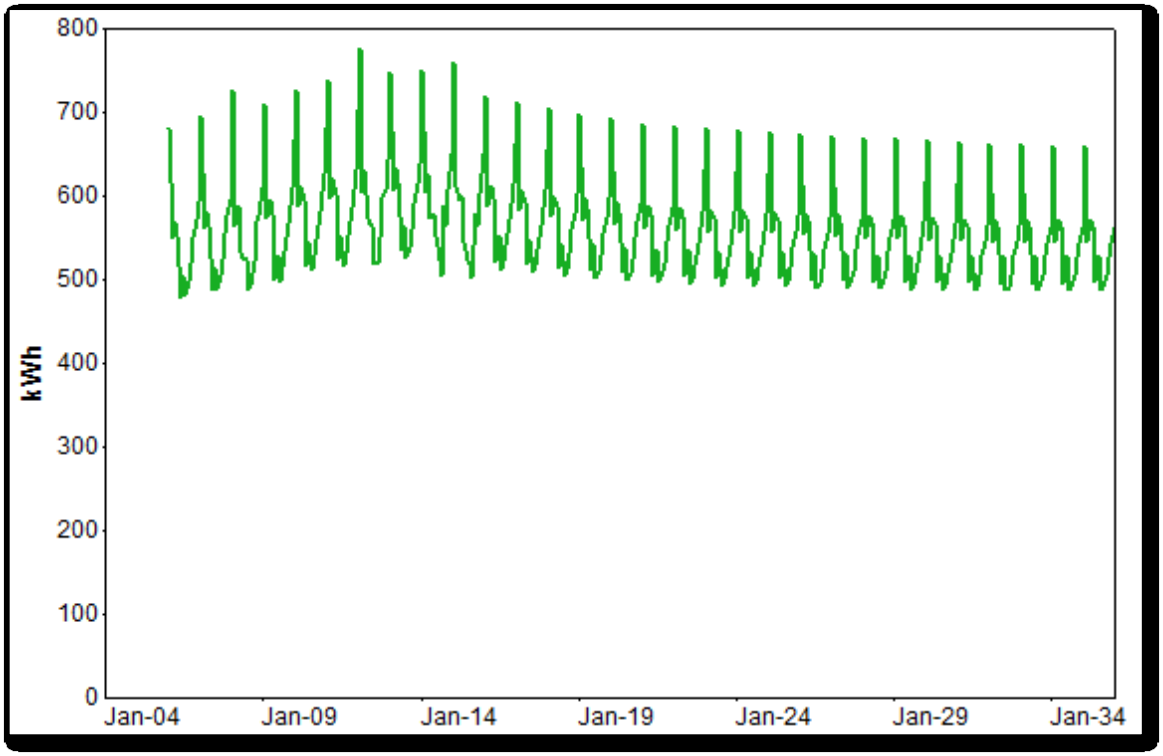
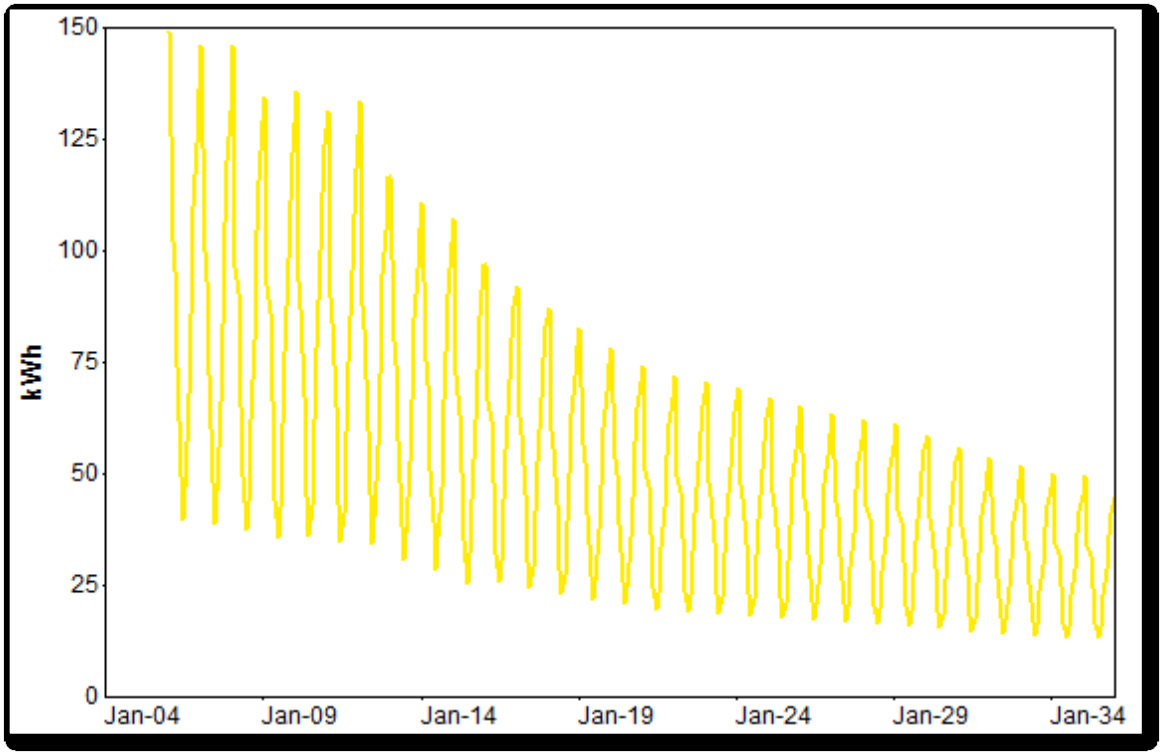
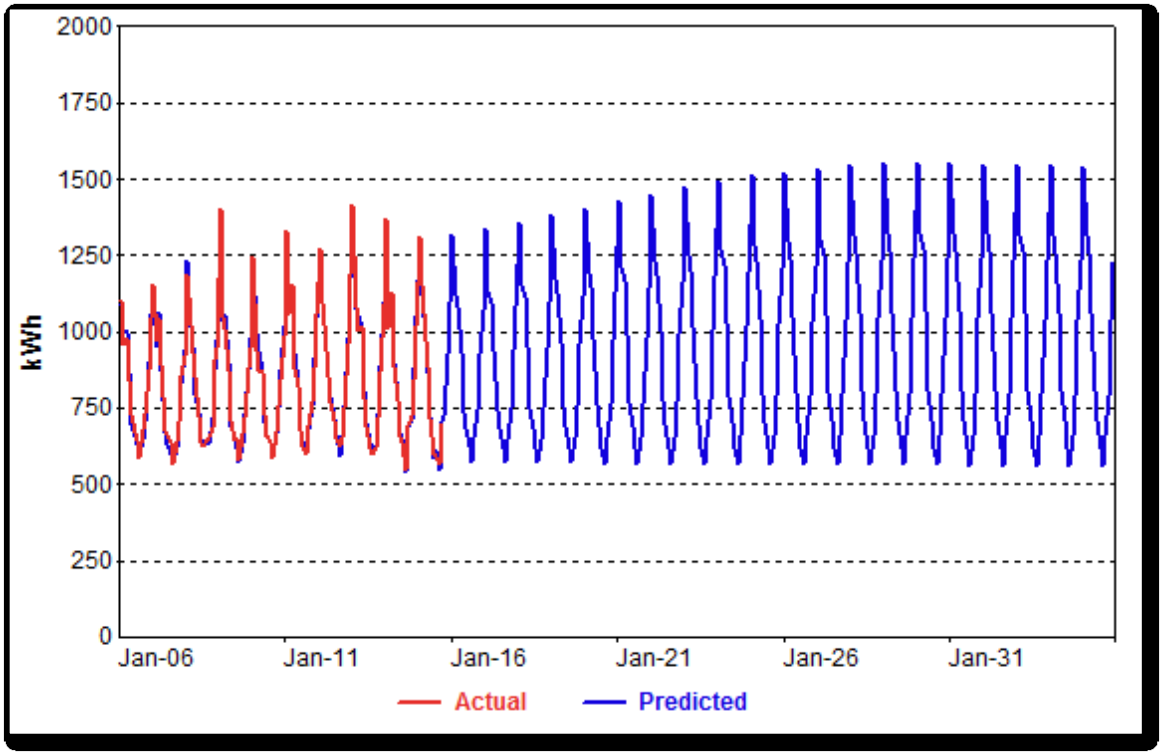


Figure 3-3: Residential XLight: Base Case (kWh per month)



The average use model is estimated over the period January 2006 through September 2015. The model explains historical average use well with an Adjusted R^2 of 0.98 and in-sample Mean Absolute Percent Error (MAPE) of 2.28%. The model accuracy was tested by estimating the model through September 2014 and calculating out of sample model statistics for the 12 withheld observations. The out of sample MAPE of 2.45% confirms that accuracy and robustness of the model. Figure 3-4 shows actual and predicted average use.

Figure 3-4: Actual and Predicted Residential Average Use: Base Case (kWh)



Model coefficients and statistics are provided in Appendix A: Model Statistics.

Use per customer is increasing by 1.0% annually through 2025. This is due to the increase in the electric heat saturation, the result of the assumption that 95% of new customers will use electric heat. Average use begins to flatten in the later years as customer growth declines and eventually becomes negative.

Residential Customer Forecast

The residential customer forecast is based on a monthly regression model that relates the number of customers to household projections. There is a strong correlation, 0.99, between the number of customers and households - customer growth tracks household projections with customers averaging 1.1% annual growth through 2025.

With 1.0% increase in average use and 1.1% customer growth, total residential sales average 2.1% growth between 2016 and 2025. Table 3-1 summarizes the residential forecast.

Table 3-1: Residential Forecast: Base Case

Year	Sales (MWh)		Customers		Avg Use (kWh)	
2015	155,443		15,179		10,241	
2016	162,786	4.7%	15,350	1.1%	10,605	3.6%
2017	165,192	1.5%	15,507	1.0%	10,653	0.4%
2018	168,663	2.1%	15,684	1.1%	10,754	0.9%
2019	172,670	2.4%	15,871	1.2%	10,880	1.2%
2020	177,242	2.6%	16,065	1.2%	11,033	1.4%
2021	180,655	1.9%	16,268	1.3%	11,105	0.7%
2022	185,015	2.4%	16,464	1.2%	11,238	1.2%
2023	189,096	2.2%	16,641	1.1%	11,363	1.1%
2024	193,618	2.4%	16,803	1.0%	11,523	1.4%
2025	196,057	1.3%	16,935	0.8%	11,577	0.5%
2026	198,401	1.2%	17,052	0.7%	11,635	0.5%
2027	200,882	1.3%	17,166	0.7%	11,702	0.6%
2028	203,768	1.4%	17,269	0.6%	11,800	0.8%
2029	204,709	0.5%	17,350	0.5%	11,799	0.0%
2030	205,508	0.4%	17,397	0.3%	11,813	0.1%
2031	205,253	-0.1%	17,405	0.0%	11,793	-0.2%
2032	205,298	0.0%	17,380	-0.1%	11,813	0.2%
2033	203,568	-0.8%	17,317	-0.4%	11,755	-0.5%
2034	202,212	-0.7%	17,226	-0.5%	11,739	-0.1%
2035	200,789	-0.7%	17,114	-0.7%	11,733	-0.1%
2016-2025		2.1%		1.1%		1.0%
2016-2035		1.1%		0.6%		0.5%

3.1.2 Commercial Model

Like the residential sector commercial average use and customers are modeled separately. The commercial sales forecast is then generated as the product of the average use and customer forecasts. The commercial SAE average use model is fully described in Appendix C and expresses monthly average use as a function of XHeat, XOther, and XLight. It is important to point out that an XCool variable was constructed and incorporated into the model at first but the variable was statistically insignificant and therefore removed. The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use efficiency improvements, with non-mining GDP and employment ($ComVar_m$), real price ($Price_m$), and monthly HDD: Non-mining GDP still includes the associated economic impact of mining activities in the non-mining sectors.

$$XHeat_m = EI_{heat} \times Price_m^{-0.10} \times ComVar_m \times HDD_m$$
$$XOther_m = EI_{other} \times Price_m^{-0.10} \times ComVar_m \times Days_m$$
$$XLight_m = EI_{light} \times Price_m^{-0.10} \times ComVar_m \times Days_m$$

The coefficients on price are imposed short-term price elasticities. A monthly forecast sales model is then estimated as:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XOther_m + B_3 XLight_m + e_m$$

Commercial Economic Driver

Output and employment are combined through a weighted economic variable where ComVar is defined as:

$$ComVar_m = (Employ_m^{0.25}) \times (Non - MiningOutput_m^{0.75})$$

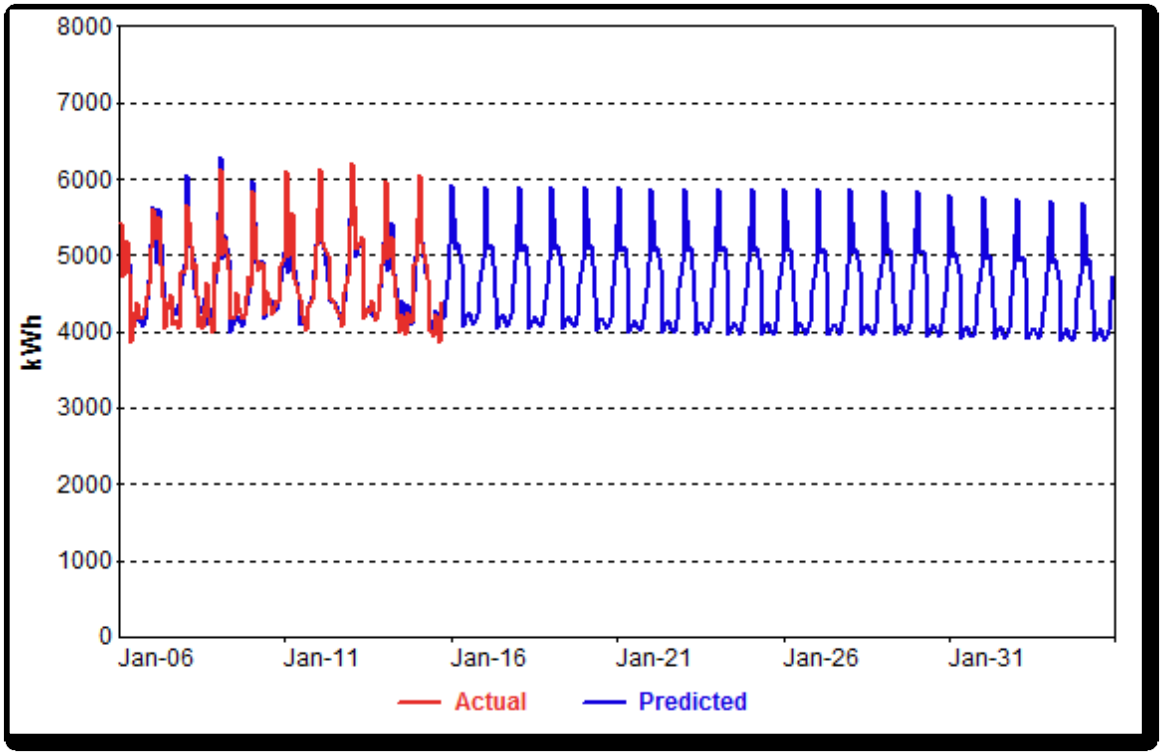
The ComVar uses a weight of 0.25 on employment and 0.75 on non-mining output. The weights were determined by evaluating the in-sample and out-of-sample model statistics for different sets of employment and output weights.

The resulting commercial average use model performs well with an Adjusted R^2 of 0.92 and an in-sample MAPE of 2.5%. The model accuracy was tested by estimating the model through September 2014 and calculating out of sample model statistics for the 12 withheld observations. The out of sample MAPE of 2.01% confirms that accuracy and robustness of the model Figure 3-5 shows actual and predicted monthly commercial average use.

Commercial Customer Forecast

The commercial customer forecast is based on a monthly regression model that relates the number of commercial customers to the residential customer forecast. There is a strong correlation, 0.96, between commercial and residential customers. With an implied elasticity of 0.92 on the residential customer variable commercial customer growth will be slightly less than residential. Commercial customer growth averages 1.0% through 2025.

Figure 3-5: Actual and Predicted Commercial Average Use: Base Case (kWh)



Model coefficients and statistics are provided in Appendix A: Model Statistics.

With 0.2% decrease in average use and 1.0% customer growth, total commercial sales growth average 0.8% between 2016 and 2025. The estimated model coefficients and model statistics are included in Appendix A: Model Statistics. Table 3-2 shows detailed commercial forecast.

Table 3-2: Commercial Forecast: Base Case

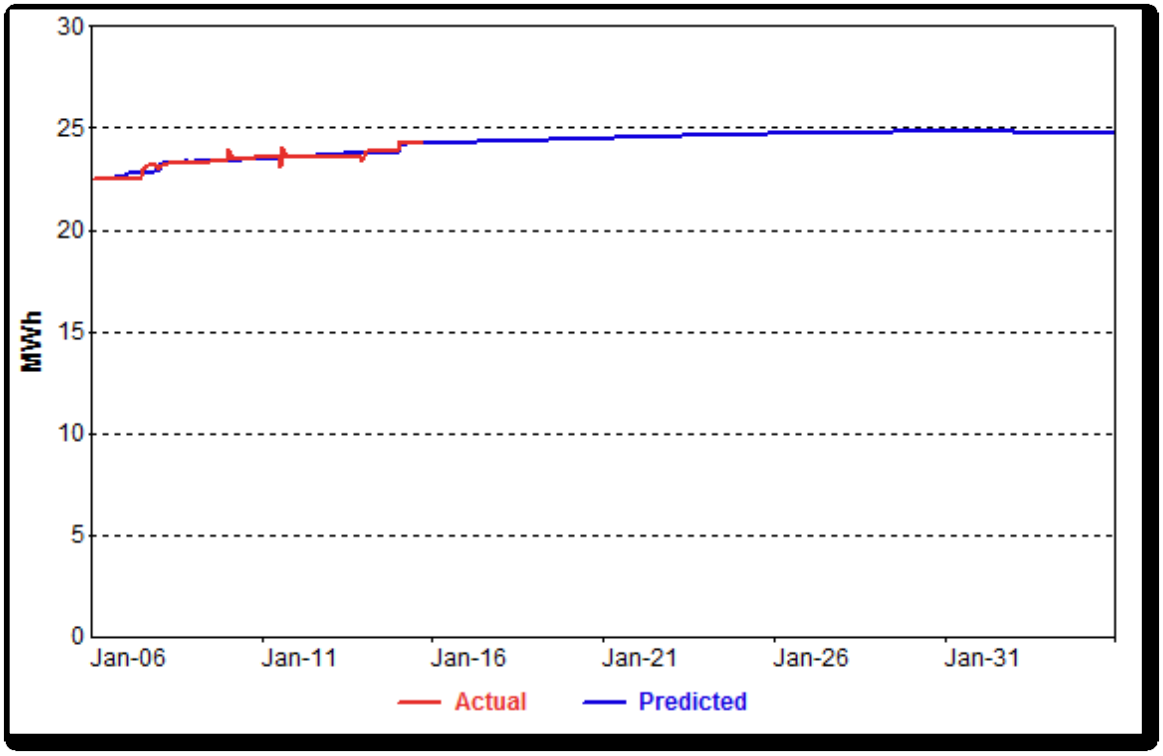
Year	Sales (MWh)		Customers		Avg Use (kWh)	
2015	173,005		3,105		55,719	
2016	175,799	1.6%	3,141	1.1%	55,977	0.5%
2017	176,657	0.5%	3,171	1.0%	55,717	-0.5%
2018	178,079	0.8%	3,204	1.1%	55,573	-0.3%
2019	180,300	1.2%	3,240	1.1%	55,646	0.1%
2020	181,919	0.9%	3,277	1.1%	55,507	-0.2%
2021	182,937	0.6%	3,316	1.2%	55,167	-0.6%
2022	184,559	0.9%	3,354	1.1%	55,034	-0.2%
2023	186,226	0.9%	3,387	1.0%	54,975	-0.1%
2024	187,904	0.9%	3,418	0.9%	54,969	0.0%
2025	189,080	0.6%	3,444	0.7%	54,907	-0.1%
2026	190,013	0.5%	3,466	0.6%	54,823	-0.2%
2027	191,017	0.5%	3,488	0.6%	54,768	-0.1%
2028	192,043	0.5%	3,508	0.6%	54,751	0.0%
2029	192,601	0.3%	3,523	0.4%	54,669	-0.1%
2030	192,416	-0.1%	3,532	0.3%	54,477	-0.4%
2031	191,620	-0.4%	3,534	0.0%	54,229	-0.5%
2032	190,696	-0.5%	3,529	-0.1%	54,042	-0.3%
2033	189,165	-0.8%	3,517	-0.3%	53,791	-0.5%
2034	187,484	-0.9%	3,499	-0.5%	53,578	-0.4%
2035	185,631	-1.0%	3,478	-0.6%	53,376	-0.4%
2016-2025		0.8%		1.0%		-0.2%
2016-2035		0.3%		0.5%		-0.3%

3.1.3 ST & SP Sales

The Street Light (ST) sales forecast is based on a generalized monthly regression model where ST sales are specified as a function of residential customers and year binaries. ST sales increase 0.2% annually through 2025, although the magnitude of sales in this class is insignificant in terms of its impact on total sales or system load. Figure 3-6 shows actual and predicted monthly ST sales.

Space Lights (SP) sales are fitted with a simple seasonal exponential smoothing model which holds the forecast constant.

Figure 3-6: Actual and Predicted ST Sales: Base Case (MWh)

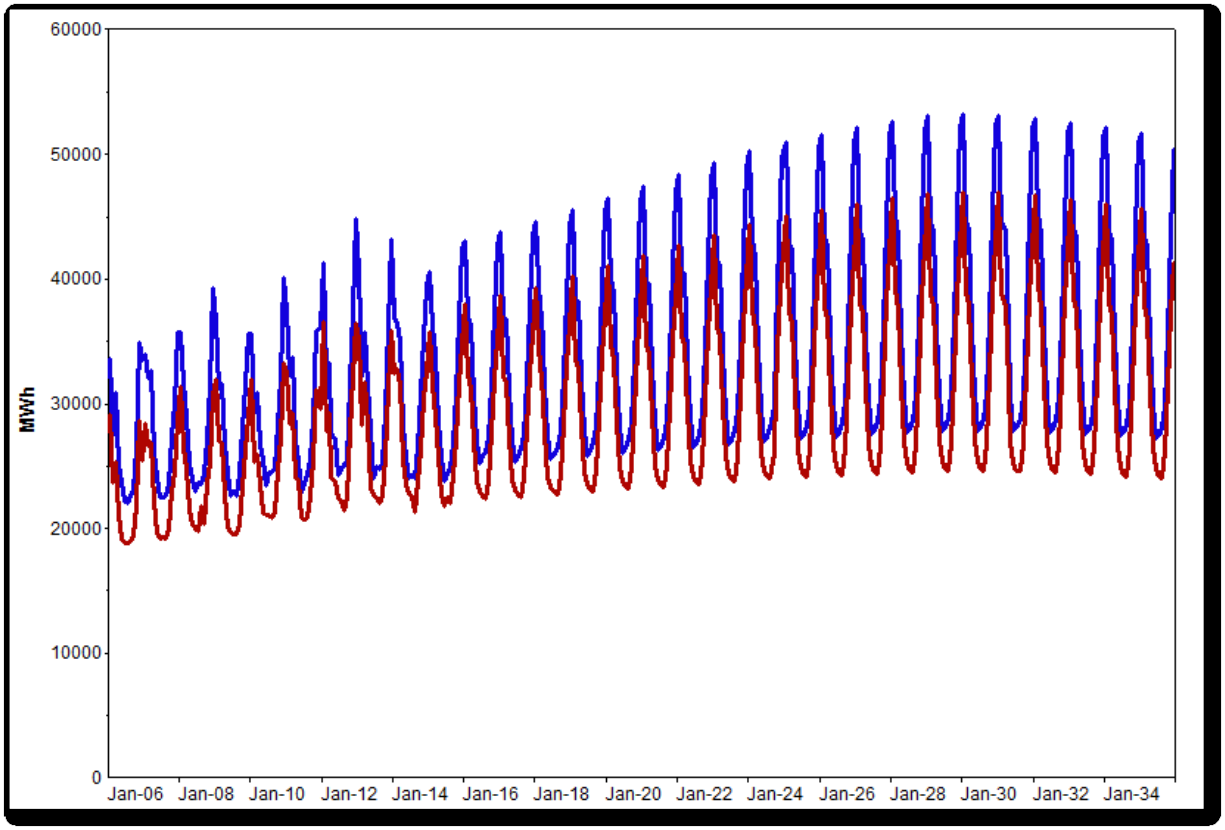


3.2 Energy and Peak Forecast

3.2.1 Energy Forecast

The YEC system energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the monthly *calendarized* total sales forecast (excluding industrial). The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (*unaccounted for energy*). Monthly adjustment factors are calculated as the average monthly ratio of energy to sales. Figure 3-7 shows the resulting monthly **sales** and **energy** forecast.

Figure 3-7: Energy and Sales Forecast: Base Case (MWh)



3.2.2 Peak Forecast

The long-term system peak forecast is derived through a monthly peak linear regression model that relates monthly peak demand (excluding industrial) to heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

The model variables ($HeatVar_m$, $CoolVar_m$, and $BaseVar_m$) incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models as well as peak-day weather conditions.

Heating and Cooling Model Variables

Heating requirements are driven by customer growth, economic activity, changes in end-use saturation, and improving end-use efficiency. These factors are captured in the class sales forecast models. The composition of the models allows us to estimate historical and forecasted heating and cooling load requirement.

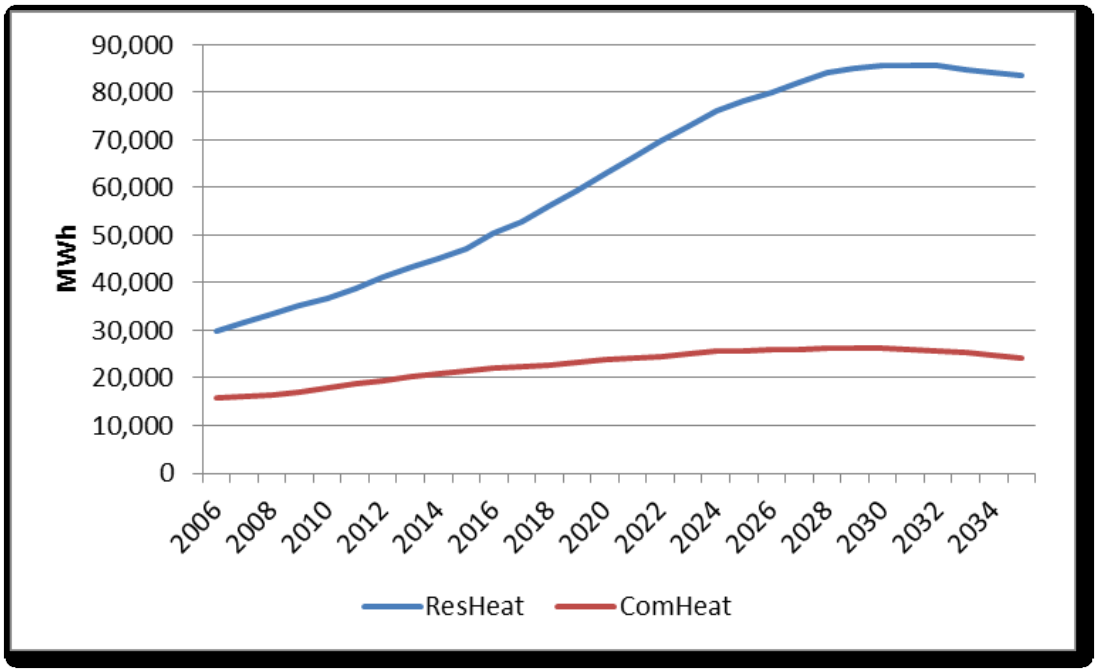
The estimated model coefficients for the heating (XHeat) combined with heating variable for normal weather conditions (*NrmXHeat*) gives us an estimate of the monthly heating load requirements. Heating requirements are calculated as:

$$HeatLoad_m = B_1 \times ResNrmXHeat_m + C_1 \times ComNrmXheat_m$$

B_1 and C_1 are the coefficients on *XHeat* in the residential and commercial models.

Figure 3-8 show resulting historical (weather normalized) and forecasted heating load requirements.

Figure 3-8: Annual Heating Load: Base Case (MWh)

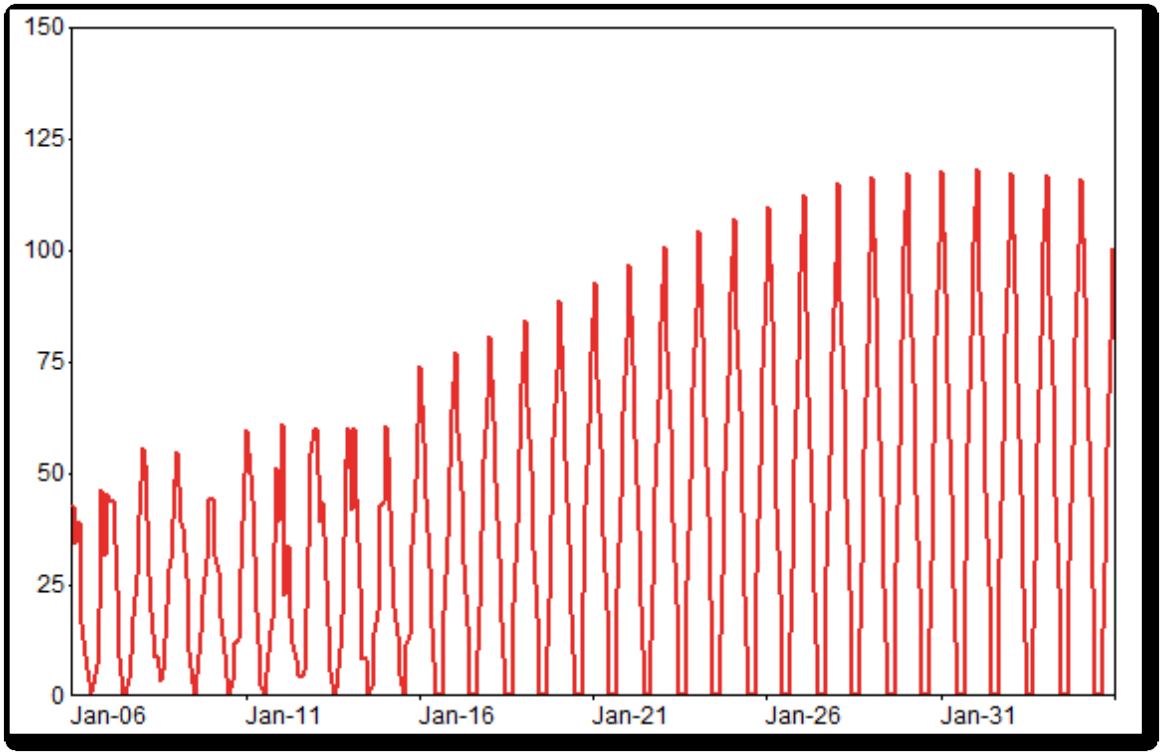


The impact of peak-day weather conditions is captured by interacting peak-day HDD with monthly heating load requirements indexed to a base year (2007). The peak model heating variable is calculated as:

$$HeatVar_m = HeatLoadIdx_m \times PkHDD_m$$

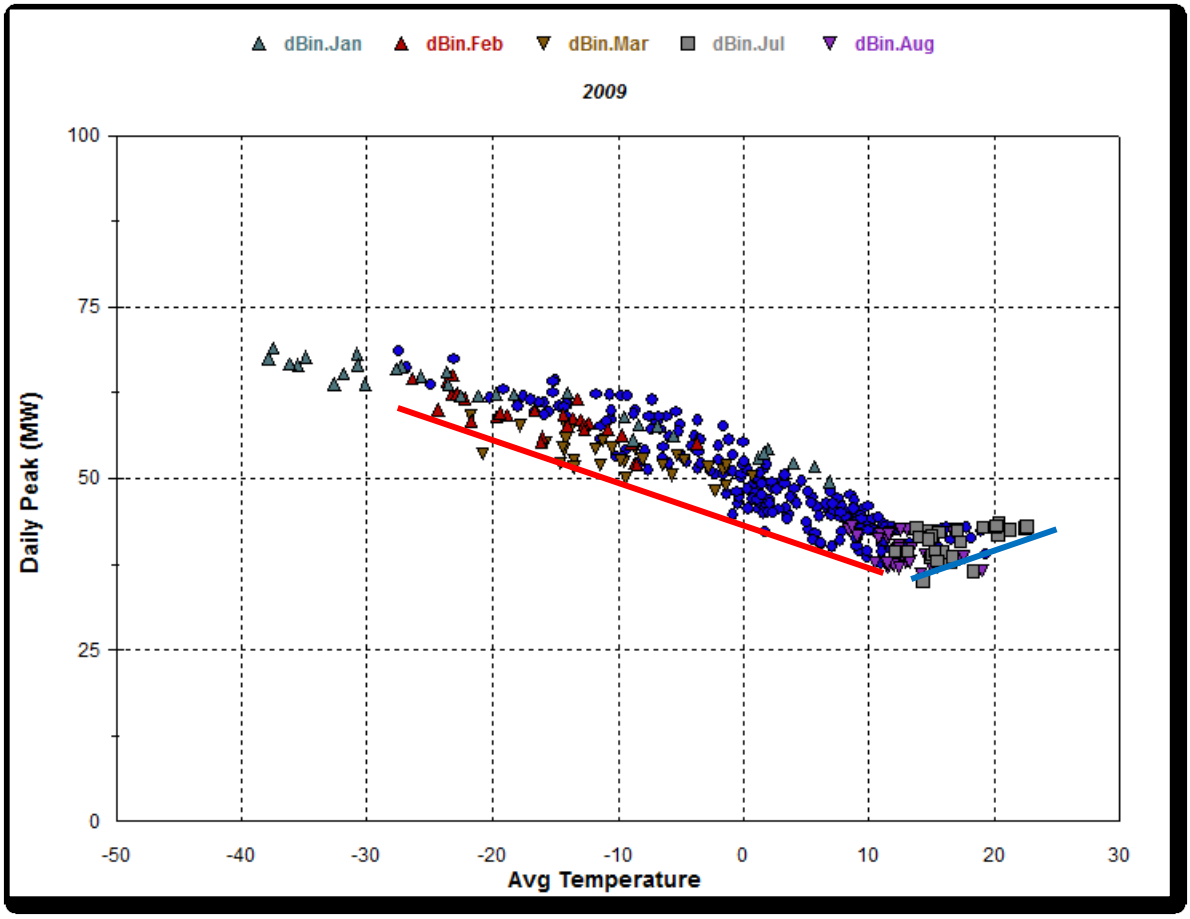
Figure 3-9 shows the resulting peak model heating variable.

Figure 3-9: Peak Model Heating Variable (Index): Base Case



The construction of the peak cooling variable takes on a different form as there is no cooling load associated with the class levels sales. Although there is no cooling variable in any of the class models, as they were statistically insignificant or the coefficients had the incorrect sign, it is likely that commercial cooling load does impact summer peaks. Figure 3-10 shows the relationship between daily peaks and average temperature in 2009. There is clearly a strong heating load that can be seen in the left-hand side of the scatter plot at temperatures below 10 degrees, but what is also evident is the cooling load on the right-hand side at temperatures above 13 degrees.

Figure 3-10: Daily Peaks Vs Temperature Relationship

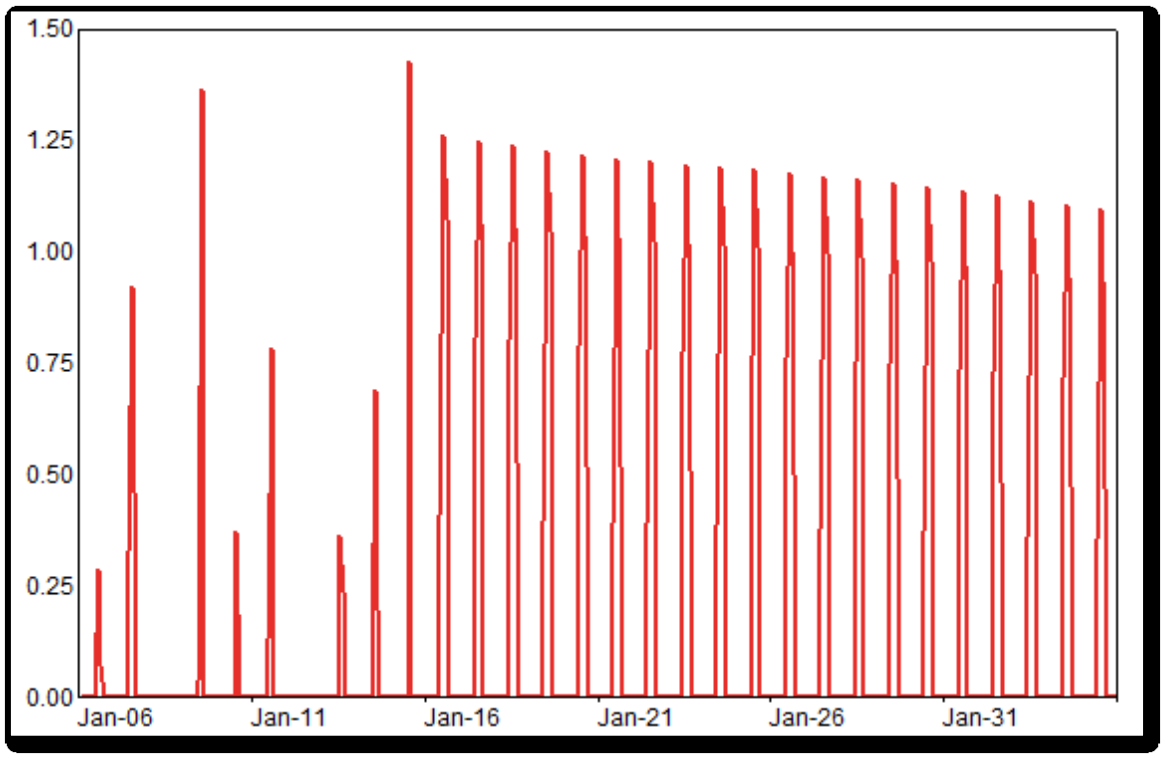


The peak cooling variable is constructed by interacting peak-day CDD with the commercial cooling intensity projections. When used in the peak model the cooling variable is marginally significant and does add additional load to the summer months. The peak model cooling variable is calculated as:

$$CoolVar_m = CommercialCoolingIntensity_y \times PkHDD_m$$

Figure 3-11 shows the resulting peak model cooling variable.

Figure 3-11: Peak Model Cooling Variable (Index): Base Case



Base Load Variable

The peak model base load variable ($BaseVar_m$) derived from the sales forecast models is an estimate of the non-weather sensitive load at the time of the monthly system peak demand. The base load variable is defined as:

$$BaseVar_m = ResOtherCP_m \times ComOtherCP_m + StLightingCP_m$$

Base load requirements are derived for each revenue class by subtracting out heating and cooling load requirements from total load requirements. Using the SAE modeling framework, class annual base load requirements are then allocated to end-uses at the time of monthly peak demand. For example, the residential water heating coincident peak load estimate is derived as:

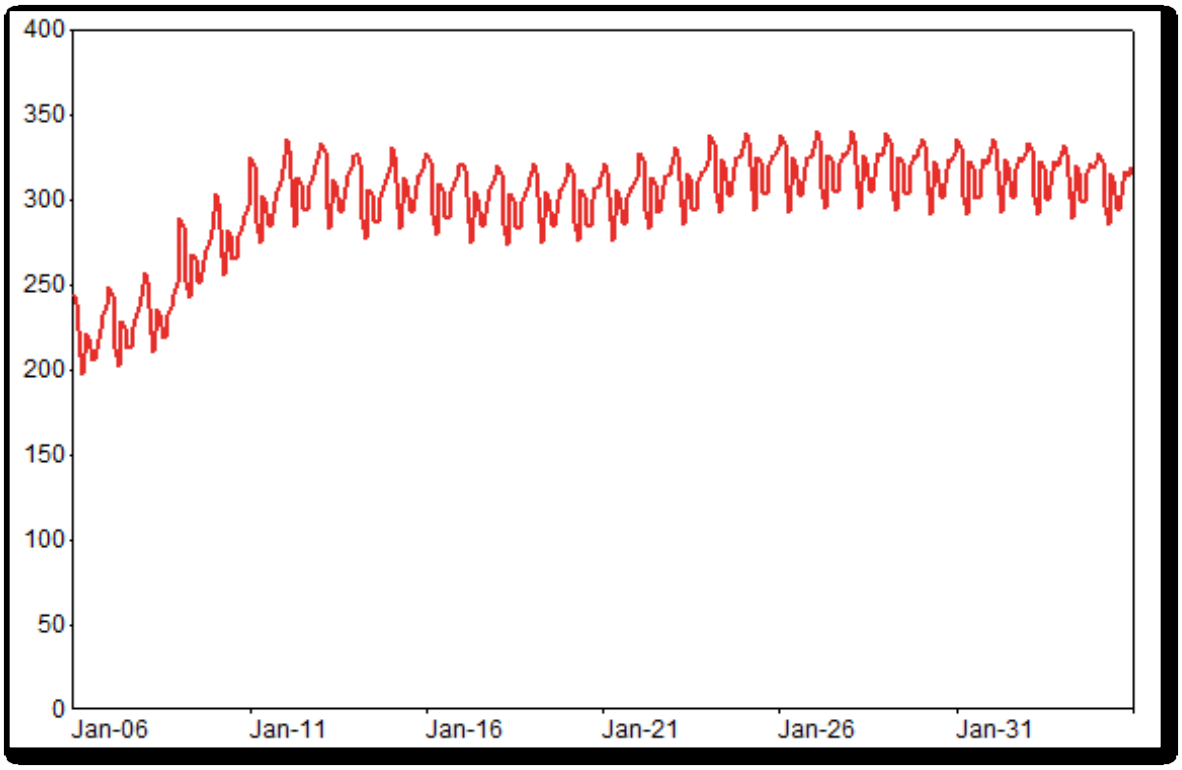
$$ResWaterCP_m = ResBaseLoad_m \times \left({ResWaterEI_a}/{ResBaseEI_a} \right) \times ResWaterFrac_m$$

Where

ResWaterEI = Annual water heating intensity (water use per household)
ResBaseEI = Annual base-use intensity (non-weather sensitive use per household)
ResWaterFrac = Monthly fraction of usage on at peak (estimates are based on Itron's hourly end-use load profile database)

End-use load estimates are aggregated by end-use and then revenue class resulting in the base load variable. Figure 3-12 shows the peak model base load variable.

Figure 3-12: Base Load Variable: Base Case



Model Results

The peak model is estimated over the period January 2006 to September 2015. The model explains monthly peak variation well with an adjusted R^2 of 0.97 and an in-sample MAPE of 2.36%. Figure 3-13 shows actual and predicted results. Model statistics and parameters are included in Appendix A: Model Statistics.

Figure 3-13: Peak Model: Base Case (MW)

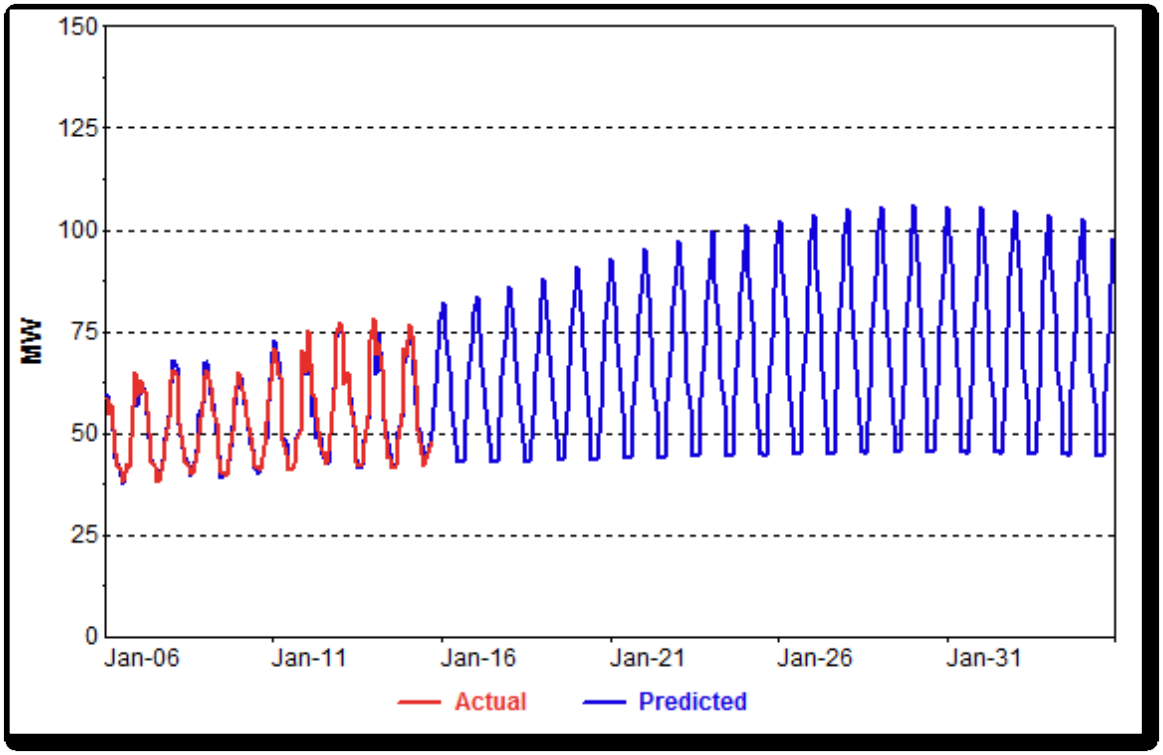


Table 3-3 shows the peak demand forecast (excluding industrial).

Table 3-3: Peak Demand Forecast: Base Case (MW)

Year	Peak (MW)	
2015	76.9	
2016	82.2	6.9%
2017	83.8	1.9%
2018	85.9	2.5%
2019	88.2	2.7%
2020	90.8	2.9%
2021	92.8	2.2%
2022	95.2	2.6%
2023	97.4	2.3%
2024	99.8	2.4%
2025	101.2	1.4%
2026	102.5	1.3%
2027	103.8	1.3%
2028	105.2	1.4%
2029	105.8	0.5%
2030	106.1	0.3%
2031	105.8	-0.3%
2032	105.6	-0.2%
2033	104.6	-1.0%
2034	103.7	-0.8%
2035	102.8	-0.9%
2016-2025		2.3%
2016-2035		1.2%

3.3 Solar Forecast

The forecast includes the impact of expected grid-connected solar generation. Currently there is very little grid-connected solar generation in the YEC service territory and it is not expected to grow to a point where it would significantly impact energy or peaks. Unlike many other parts of Canada and North America where solar is increasing in popularity due to decreases in system costs and utility incentives, which have made the systems economically viable, in Yukon the adaptation is not driven by economics or return on investment.

The solar generation forecast is derived by first forecasting the number of solar customers. Yukon provided 18 months of solar customer data, with a total of 16 grid-connected solar systems as of August 2015. A simple linear trend was imposed to predict the number of solar customers for the next 16 months, reaching 31 solar customers by December 2016. Starting in January 2017 the annual growth rate of solar capacity from the EIA's 2015 Annual Energy Outlook forecast is used to grow the solar customer forecast. Table 3-4 shows the resulting solar customer forecast.

An installed solar capacity forecast is then derived as the product of the solar customer forecast and the assumed average system size of 3.1 kW based on YEC's short-term expectations on size.

Using an 8760 hourly solar load shape for Whitehorse, provided by the National Renewable Energy Laboratory's PV Watt Calculator, monthly specific load factors are calculated. The month specific load factors are applied to the monthly capacity forecast to calculate the MWh solar generation forecast, shown in Table 3-4.

Table 3-4: Solar Forecast

Year	Solar Customers	Solar Capacity (kW)	Generation (MWh)
2015	15	48	45.3
2016	26	82	81.2
2017	32	98	99.2
2018	32	100	101.4
2019	33	103	104.3
2020	35	108	109.2
2021	37	114	115.4
2022	39	122	122.9
2023	42	130	131.4
2024	45	140	141.1
2025	48	150	151.4
2026	52	162	162.7
2027	56	173	174.5
2028	60	185	186.9
2029	64	197	198.7
2030	68	210	211.2
2031	72	222	224.1
2032	76	235	237.4
2033	80	248	250.0
2034	84	261	263.1
2035	88	274	276.6

4 Forecast Scenarios

In addition to the baseline economic forecast YEC provided 9 additional economic scenarios based on changing assumption regarding mining output and government transfer payments. These scenarios are used to generation alternative energy and load forecasts. Figure 4-1 defines the economic scenarios.

Figure 4-1: Economic Scenarios

Scenario Number	Definition
1	Very Low Mining Activity
2	Low Mining Activity
3	**Base Case (Medium Mining Activity)**
4	High Mining Activity + Large Mine
5	Low Mining Activity Scenario with sensitivity on government spending
6	"Base case" scenario with sensitivity on government spending
7a	"Base case" scenario with positive shock to Agriculture, Forestry and Logging industries
7b	"Base case" scenario with increased growth in Accommodations, Transportation and Warehousing, to account for tourism growth
9	"Base case" with sensitivity on large mine (later start of production)
10	Sensitivity on Boom and Bust Cycles in the Mining Industry

Figure 4-2 through Figure 4-6 compare the differences in the economic scenarios for the primary economic drivers of the sales models.

Figure 4-2: Real GRP

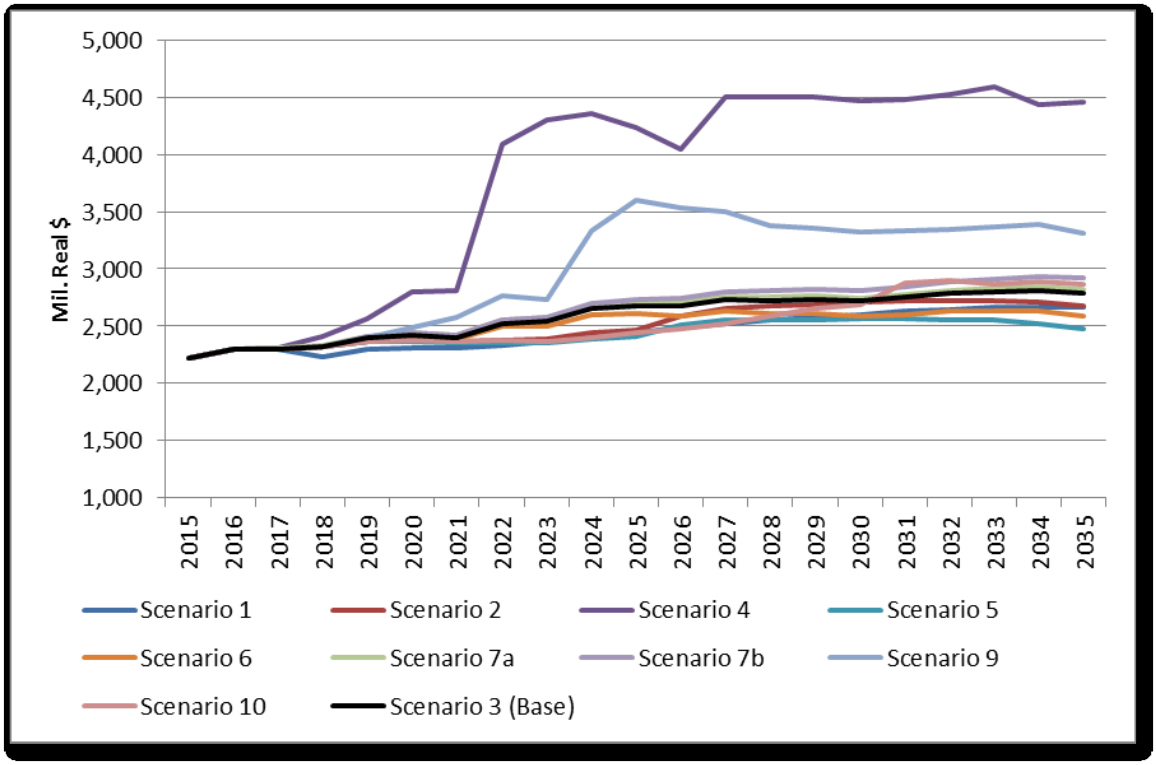


Figure 4-3: Real Mining GRP

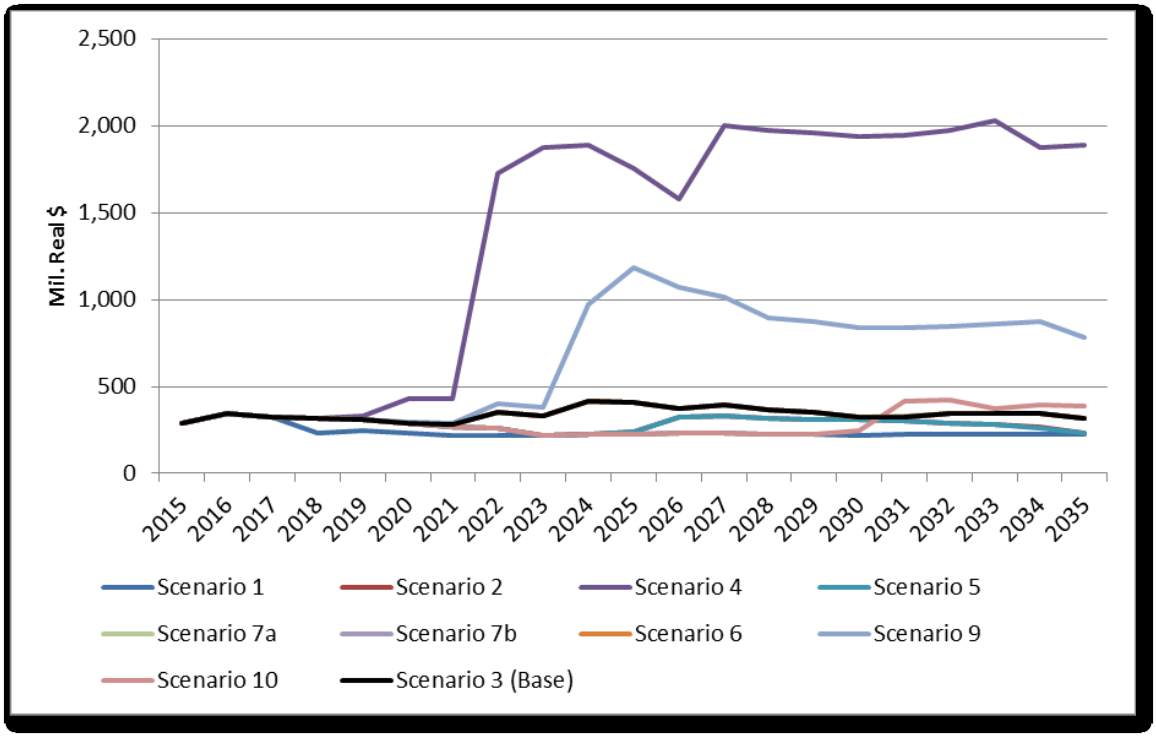


Figure 4-4: Real Income Per Capita

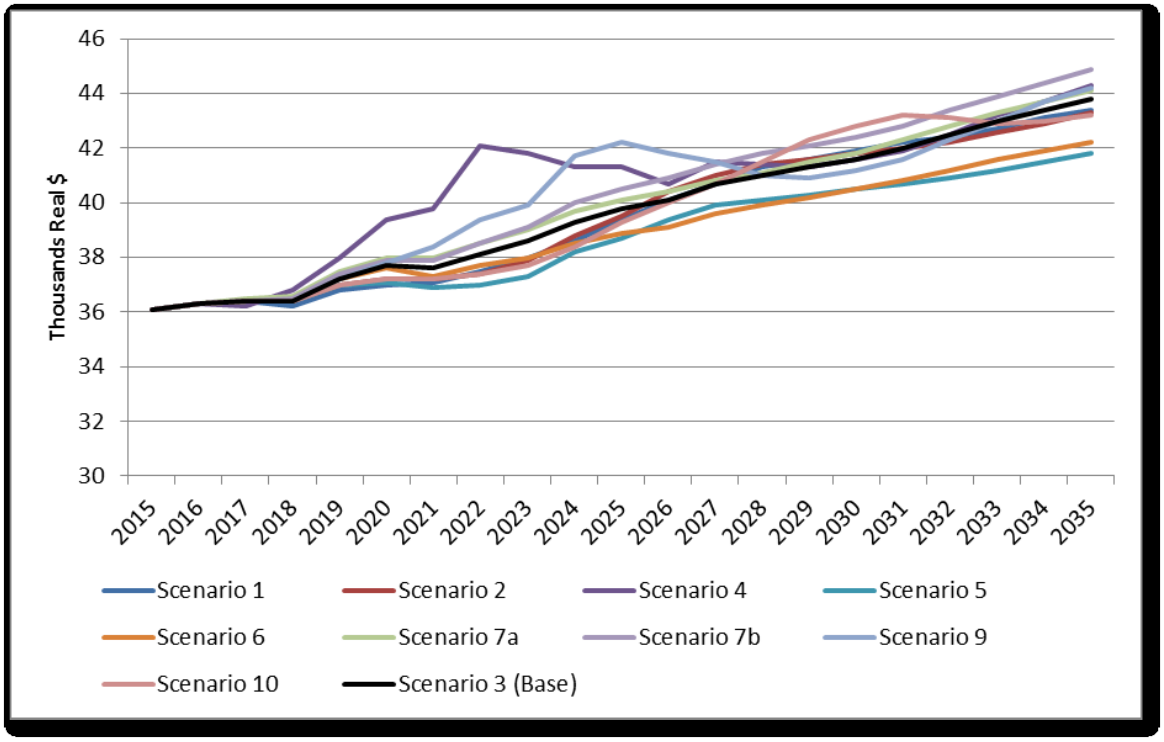


Figure 4-5: Households

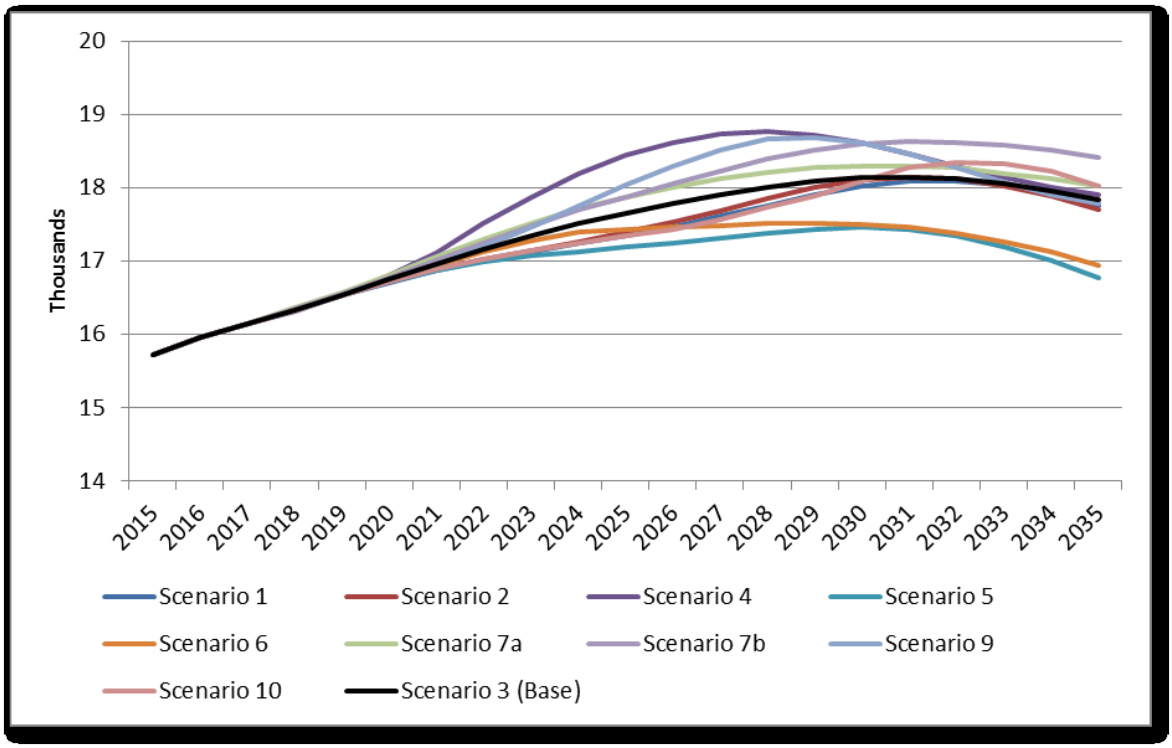
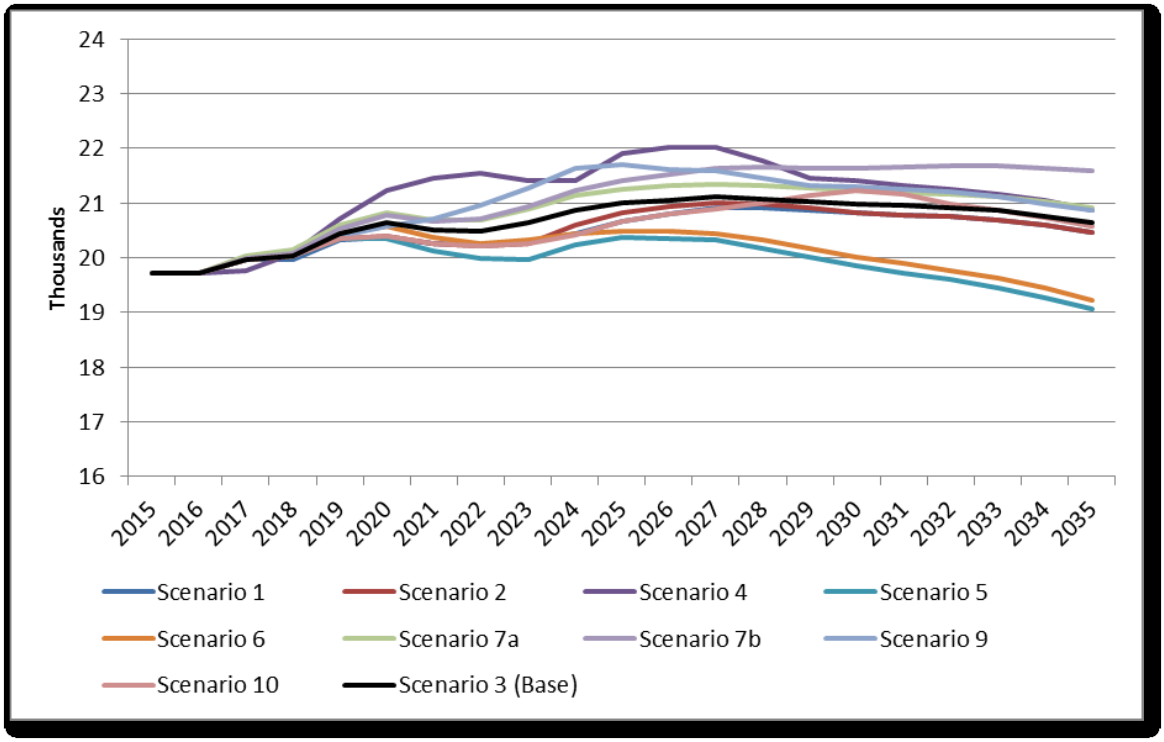


Figure 4-6: Employment



Using the same model specifications and estimation periods these alternative economic drivers are used to estimate class average use, customer, and total sales models, which are used to derive the total energy and peak forecast. Table 4-1 and Table 4-2 summarize the energy and peak forecasts (excluding industrial) under the different economic scenarios.

YUKON ENERGY

Table 4-1: Scenario Energy Forecasts (MWh)

Year	Scenario 1	Scenario 2	Scenario 3 (Base)	Scenario 4	Scenario 5	Scenario 6	Scenario 7a	Scenario 7b	Scenario 9	Scenario 10
2015	374,869	374,869	374,882	374,869	374,869	374,869	374,869	374,869	374,869	374,869
2016	389,838	389,838	389,806	389,787	389,838	389,838	389,871	389,845	389,838	389,838
2017	393,471	393,508	393,583	393,229	393,508	393,508	393,813	393,591	393,508	393,508
2018	398,655	398,959	399,238	399,487	398,959	399,033	399,877	399,351	399,022	398,959
2019	404,662	405,259	406,423	408,328	405,231	405,900	407,656	406,669	405,884	405,259
2020	410,315	411,147	413,561	419,071	410,864	412,617	415,850	414,354	413,338	411,147
2021	413,488	414,470	418,684	429,181	413,529	417,101	422,499	420,580	420,103	414,470
2022	417,526	418,476	425,589	443,664	416,432	422,717	430,885	428,846	429,069	418,422
2023	421,327	422,368	432,219	457,208	418,501	427,272	438,861	437,151	438,686	421,896
2024	426,018	427,366	439,363	469,431	421,096	431,495	447,093	446,365	451,128	426,194
2025	429,155	431,217	443,536	477,240	421,840	432,135	451,780	452,668	460,986	428,803
2026	432,997	436,247	447,317	482,259	423,236	431,956	455,580	458,631	469,635	432,080
2027	437,915	441,695	451,336	485,707	424,837	431,911	459,069	464,656	476,595	436,661
2028	444,362	448,292	455,839	486,885	427,419	432,587	462,852	471,134	481,364	443,542
2029	448,642	452,402	457,568	482,903	427,906	431,057	463,761	474,450	480,389	449,499
2030	452,004	455,219	458,274	478,673	427,375	429,285	463,713	476,473	477,130	456,369
2031	452,943	455,204	457,059	473,112	424,872	426,492	462,071	476,292	471,651	461,391
2032	452,646	454,048	456,036	468,669	422,067	424,090	460,920	475,902	466,634	463,667
2033	448,887	449,558	452,276	462,579	416,318	419,189	457,229	472,661	459,778	460,493
2034	444,835	444,855	448,774	458,069	410,492	414,419	454,039	469,885	454,795	456,311
2035	440,007	439,780	444,998	454,687	404,307	409,227	450,704	467,073	451,121	450,476
2016-2025	1.1%	1.1%	1.4%	2.3%	0.9%	1.2%	1.7%	1.7%	1.9%	1.1%
2016-2035	0.6%	0.6%	0.7%	0.8%	0.2%	0.3%	0.8%	1.0%	0.8%	0.8%

Table 4-2: Scenario Peak Forecast (MW)

Year	Scenario 1	Scenario 2	Scenario 3 (Base)	Scenario 4	Scenario 5	Scenario 6	Scenario 7a	Scenario 7b	Scenario 9	Scenario 10
2015	77.9	77.9	77.9	77.9	77.9	77.9	77.9	77.9	77.9	77.9
2016	82.2	82.2	82.2	82.2	82.2	82.2	82.2	82.2	82.2	82.2
2017	83.8	83.8	83.8	83.7	83.8	83.8	83.8	83.8	83.8	83.8
2018	85.8	85.8	85.9	86.0	85.8	85.8	86.0	85.9	85.8	85.8
2019	87.9	88.0	88.3	88.6	88.0	88.1	88.4	88.2	88.1	88.0
2020	90.3	90.4	90.8	91.6	90.3	90.6	91.0	90.9	90.7	90.4
2021	92.0	92.2	92.8	94.3	92.0	92.5	93.2	93.0	93.0	92.2
2022	94.0	94.1	95.2	97.8	93.8	94.7	95.8	95.6	95.7	94.1
2023	95.9	96.0	97.4	100.9	95.4	96.6	98.2	98.0	98.4	95.9
2024	97.9	98.1	99.8	103.8	97.2	98.6	100.7	100.7	101.5	97.9
2025	99.2	99.5	101.2	105.7	98.2	99.5	102.2	102.4	103.6	99.1
2026	100.5	101.0	102.5	107.1	99.1	100.2	103.5	104.0	105.5	100.4
2027	101.9	102.5	103.8	108.3	100.1	101.0	104.7	105.5	107.1	101.8
2028	103.7	104.2	105.2	109.4	101.3	101.9	106.1	107.3	108.6	103.6
2029	104.6	105.1	105.8	109.1	101.6	102.0	106.6	108.1	108.7	104.8
2030	105.3	105.7	106.2	108.6	101.8	102.0	106.8	108.6	108.4	105.9
2031	105.2	105.5	105.8	107.4	101.2	101.4	106.5	108.4	107.3	106.5
2032	105.1	105.2	105.6	106.5	100.6	100.9	106.2	108.3	106.2	106.7
2033	104.1	104.0	104.6	105.0	99.1	99.6	105.2	107.4	104.5	105.7
2034	103.1	102.9	103.7	103.9	97.7	98.4	104.4	106.7	103.4	104.7
2035	101.9	101.7	102.8	103.1	96.3	97.1	103.5	106.0	102.5	103.3
2016-25	2.1%	2.1%	2.3%	2.8%	2.0%	2.1%	2.5%	2.5%	2.6%	2.1%
2016-35	1.1%	1.1%	1.2%	1.2%	0.8%	0.9%	1.2%	1.4%	1.2%	1.2%

YUKON ENERGY

5 Appendix A: Model Statistics

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructResCyc.XHeat	1.177	0.032	37.187	0.00%
mStructResCyc.XOther_MinusLght	1.119	0.018	62.183	0.00%
mStructResCyc.XLight	0.875	0.129	6.785	0.00%
mBin.Feb	22.047	9.737	2.264	2.56%
mBin.Apr	-30.172	9.785	-3.083	0.26%
mBin.Jul	44.623	9.819	4.544	0.00%
mBin.Oct	-26.794	10.308	-2.599	1.07%
mBin.Yr06	29.029	8.516	3.409	0.09%
mBin.Aug08	77.193	27.27	2.831	0.56%
mBin.May11	80.668	27.336	2.951	0.39%
mBin.Sep13Plus	-24.492	6.672	-3.671	0.04%

Model Statistics	
Iterations	1
Adjusted Observations	117
Deg. of Freedom for Error	106
R-Squared	0.985
Adjusted R-Squared	0.984
AIC	6.669
BIC	6.928
Log-Likelihood	-545.13
Model Sum of Squares	5,111,380.58
Sum of Squared Errors	76330.61
Mean Squared Error	720.1
Std. Error of Regression	26.83
Mean Abs. Dev. (MAD)	19.44
Mean Abs. % Err. (MAPE)	2.28%
Durbin-Watson Statistic	2.113

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.HHs	954.365	2.83	337.209	0.00%
mBin.Jul12Plus	91.567	37.903	2.416	1.73%
AR(1)	0.901	0.042	21.407	0.00%

Model Statistics	
Iterations	11
Adjusted Observations	116
Deg. of Freedom for Error	113
R-Squared	0.998
Adjusted R-Squared	0.998
AIC	7.449
BIC	7.52
Log-Likelihood	-593.62
Model Sum of Squares	81,670,717.77
Sum of Squared Errors	189,190.68
Mean Squared Error	1,674.25
Std. Error of Regression	40.92
Mean Abs. Dev. (MAD)	25.19
Mean Abs. % Err. (MAPE)	0.18%
Durbin-Watson Statistic	2.59

YUKON ENERGY

Commercial Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructComCyc.ComXHeat	2070.155	80.337	25.769	0.00%
mStructComCyc.ComXOther_MinusLght	334.946	4.359	76.834	0.00%
mStructComCyc.ComXLight	522.353	148.641	3.514	0.07%
mBin.Jul	156.426	55.407	2.823	0.57%
mBin.Yr06	-225.44	51.274	-4.397	0.00%
mBin.Yr10	261.034	50.148	5.205	0.00%
mBin.Aug08	582.936	156.758	3.719	0.03%
mBin.May11	561.317	156.764	3.581	0.05%
mBin.Sep11Plus	353.772	31.715	11.155	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	117
Deg. of Freedom for Error	108
R-Squared	0.929
Adjusted R-Squared	0.924
AIC	10.146
BIC	10.358
Log-Likelihood	-750.55
Model Sum of Squares	33,411,686.23
Sum of Squared Errors	2,556,679.15
Mean Squared Error	23,672.96
Std. Error of Regression	153.86
Mean Abs. Dev. (MAD)	116.05
Mean Abs. % Err. (MAPE)	2.50%
Durbin-Watson Statistic	2.201

YUKON ENERGY

Commercial Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	161.017	38.738	4.157	0.01%
ResCusts.Filled	0.191	0.003	69.332	0.00%
mBin.Apr	21.973	5.457	4.027	0.01%
mBin.May	81.281	6.123	13.274	0.00%
mBin.Jun	86.779	6.125	14.168	0.00%
mBin.Jul	89.14	6.129	14.544	0.00%
mBin.Aug	91.462	6.133	14.914	0.00%
mBin.Sep	97.459	6.329	15.398	0.00%
mBin.Oct	59.685	6.361	9.383	0.00%
mBin.Nov	1098.10%	5.692	1.929	5.65%
mBin.Sep10	-110.892	15.352	-7.223	0.00%
mBin.Yr06	11.582	7.404	1.564	12.08%
mBin.Yr09	-31.211	6.499	-4.802	0.00%
MA(1)	0.362	0.096	3.772	0.03%

Model Statistics	
Iterations	14
Adjusted Observations	117
Deg. of Freedom for Error	103
R-Squared	0.993
Adjusted R-Squared	0.992
AIC	5.601
BIC	5.931
F-Statistic	1075.78
Model Sum of Squares	3,384,250.50
Sum of Squared Errors	24,924.87
Mean Squared Error	241.99
Std. Error of Regression	15.56
Mean Abs. Dev. (MAD)	10.98
Mean Abs. % Err. (MAPE)	0.39%
Durbin-Watson Statistic	1.882

ST Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	19.923	0.34	58.643	0.00%
mFcstCyc.ResCusts	0	0	10.69	0.00%
mBin.Yr06	-0.642	0.056	-11.437	0.00%
mBin.Yr07	-0.428	0.053	-8.154	0.00%
mBin.YrPlus15	0.387	0.057	6.751	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	117
Deg. of Freedom for Error	112
R-Squared	0.91
Adjusted R-Squared	0.907
AIC	-3.839
BIC	-3.721
Log-Likelihood	63.58
Model Sum of Squares	23.33
Sum of Squared Errors	2.31
Mean Squared Error	0.02
Std. Error of Regression	0.14
Mean Abs. Dev. (MAD)	0.1
Mean Abs. % Err. (MAPE)	0.41%
Durbin-Watson Statistic	1.186

YUKON ENERGY

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	10.702	2.474	4.326	0.00%
mCPkEndUses.BaseVar	0.125	0.011	11.628	0.00%
mWthr.HeatVar13	0.526	0.013	39.029	0.00%
mWthr.CoolVar10	1.754	0.827	2.121	3.62%
mBin.Jan	-3.895	0.738	-5.278	0.00%
mBin.Feb	-2.912	0.684	-4.259	0.00%
mBin.Jun	-1.779	0.698	-2.548	1.22%
mBin.Aug06	4.566	1.886	2.421	1.72%
mBin.Jun07	3.684	2.015	1.828	7.04%
mBin.Sep12	4.451	1.885	2.361	2.00%

Model Statistics	
Iterations	1
Adjusted Observations	117
Deg. of Freedom for Error	107
R-Squared	0.974
Adjusted R-Squared	0.972
AIC	1.306
BIC	1.542
Log-Likelihood	-232.43
Model Sum of Squares	13,597.11
Sum of Squared Errors	364.1
Mean Squared Error	3.4
Std. Error of Regression	1.84
Mean Abs. Dev. (MAD)	1.27
Mean Abs. % Err. (MAPE)	2.36%
Durbin-Watson Statistic	1.888

6 Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are drive energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal shell integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes the SAE approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The source for the the SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

6.1 Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

6.1.1 Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \quad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \quad (4)$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2005 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \quad (5)$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \quad (6)$$

In Equation 4, 2005 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \quad (7)$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2005 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 6-1.

Table 6-1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	505
Electric Space Heating Heat Pump	190

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a ten year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \times$$

$$\left(TenYearMovingAverageElectric\ \mathrm{Price}_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\ \mathrm{Price}_{y,m}\right)^{\gamma} \quad (8)$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05,7}}\right)^{\kappa} \quad (9)$$

Where:

- *BDays* is the number of billing days in year (*y*) and month (*m*), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2005
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

6.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_{y}$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_{y} = StructuralIndex_{y} \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_{y}^{Type} \Big/ Eff_{y}^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \tag{11}$$

Data values in 2005 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times CoolShare_{05}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2005 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 6-2.

Table 6-2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,661
Space Cooling Heat Pump	369
Room Air Conditioning	315

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectric\ \mathrm{Price}_{y,m} \right)^{\phi} \times \left(TenYearMovingAverageGas\ \mathrm{Price}_{y,m} \right)^{\gamma} \quad (13)$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\ Price_{y,m}}{Elec\ Price_{05}}\right)^{\lambda} \times \left(\frac{Gas\ Price_{y,m}}{Gas\ Price_{05}}\right)^{\kappa} \quad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2005.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

6.1.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \quad (15)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers.

The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_{y}^{Type} \Big/ \frac{1}{UEC_{y}^{Type}} \right)}{\left(Sat_{05}^{Type} \Big/ \frac{1}{UEC_{05}^{Type}} \right)} \times MoMult_{m}^{Type} \times \left(TenYearMovingAverageElectric\ \mathrm{Price}\right)^{\lambda} \times \left(TenYearMovingAverageGas\,\mathrm{Price}\right)^{\kappa} \quad (16)$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{HHSize_{y}}{HHSize_{05}} \right)^{0.46} \times \left(\frac{Income_{y}}{Income_{05}} \right)^{0.10} \times \left(\frac{Elec\,\mathrm{Price}_{y,m}}{Elec\,\mathrm{Price}_{05}} \right)^{\phi} \times \left(\frac{Gas\,\mathrm{Price}_{y,m}}{Gas\,\mathrm{Price}_{05}} \right)^{\lambda} \quad (17)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (18)$$

7 Appendix C: Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2010 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

7.1 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

7.1.1 Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

where, $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),
$HeatIndex_y$ is the annual index of heating equipment, and
$HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y / Eff_y \right)}{\left(HeatShare_{04} / Eff_{04} \right)} \quad (4)$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft} \right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \quad (5)$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{04}} \right) \times \left(\frac{Output_y}{Output_{04}} \right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}} \right)^{-0.18} \quad (6)$$

where, *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days
WgtHDD is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
HDD is the annual heating degree days for 2004,
Output is a real commercial output driver in year (y),

Price is the average real price of electricity in month (m) and year (y),

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

7.1.2 Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \qquad (7)$$

where, $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
$CoolIndex_y$ is an index of cooling equipment, and
$CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_{y} = CoolSales_{04} \times \frac{\left(CoolShare_{y} / Eff_{y} \right)}{\left(CoolShare_{04} / Eff_{04} \right)} \qquad (8)$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh/Sqft_{e}}\right) \quad (9)$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \quad (10)$$

where, *WgtCDD* is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
CDD is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

7.1.3 Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y,m} \times \mathrm{OtherUse}_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_{y}^{Type} \Big/ Eff_{y}^{Type}}{Share_{04}^{Type} \Big/ Eff_{04}^{Type}} \right) \tag{12}$$

where, *Weight* is the weight for each equipment type,
Share represents the fraction of floor stock with an equipment type, and
Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh \Big/ Sqft_{e}} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y.m}}{Price_{04}}\right)^{-0.18} \quad (14)$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

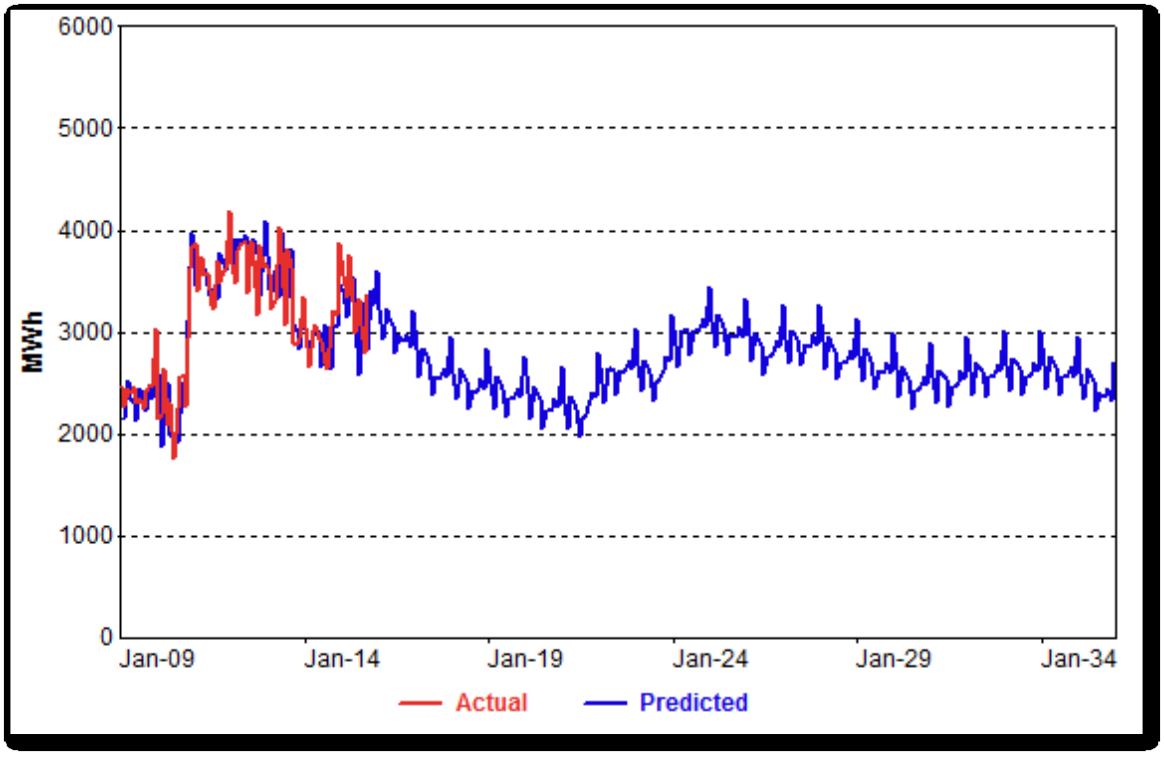
8 Appendix D: Industrial Model

While Itron developed the Industrial model, this model is not used in the final forecast. YEC chose to remove the model results in favor of manually adjusting the forecast based on large industrial customer changes. This Appendix documents the model developed by Itron.

The industrial sales forecast is based on a generalized monthly regression model where industrial sales are specified as a function of mining output and monthly binaries to capture seasonal load variation and shifts in the data.

The final model's Adjusted R^2 is 0.73 with in-sample MAPE of 7.09%. The relatively low Adjusted R^2 and high MAPE are due to the "noisy" nature of industrial monthly billing data. Actual and predicted monthly industrial sales are depicted in Figure 8-1. Model specification and statistics are shown in Table 8-2 and Table 8-3.

Figure 8-1: Actual and Predicted Industrial Sales: Base Case (MWh)



Given the volatility of mining output, industrial sales growth will vary; sales are projected to decrease through 2021 before increasing through the 2022-25 period. Table 8-1 shows the industrial forecast

Table 8-1: Industrial Sales Forecast

Year	Sales (MWh)	
2015	39,782	
2016	36,236	-8.9%
2017	31,919	-11.9%
2018	30,031	-5.9%
2019	29,055	-3.3%
2020	27,827	-4.2%
2021	27,466	-1.3%
2022	31,369	14.2%
2023	31,713	1.1%
2024	36,073	13.7%
2025	36,287	0.6%
2026	34,444	-5.1%
2027	34,978	1.6%
2028	33,551	-4.1%
2029	32,249	-3.9%
2030	30,303	-6.0%
2031	30,415	0.4%
2032	31,391	3.2%
2033	31,653	0.8%
2034	31,520	-0.4%
2035	29,507	-6.4%
2016-2025		0.3%
2016-2035		-0.9%

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Table 8-2: Industrial Model Specification

Variable	Coefficient	StdErr	T-Stat	P-Value
Economics.MiningGRP	6.228	1.168	5.332	0.00%
mBin.Nov10Plus	1492.275	319.361	4.673	0.00%
mBin.Sep13Plus	-620.462	301.337	-2.059	4.35%
mBin.Jan	-335.293	121.363	-2.763	0.74%
mBin.Feb	-582.235	157.396	-3.699	0.05%
mBin.Mar	-274.006	181.018	-1.514	13.50%
mBin.Apr	-316.668	196.71	-1.61	11.23%
mBin.May	-369.204	206.264	-1.79	7.81%
mBin.Jun	-641.672	210.491	-3.048	0.33%
mBin.Jul	-455.372	209.665	-2.172	3.35%
mBin.Aug	-455.413	203.57	-2.237	2.87%
mBin.Sep	-422.67	191.929	-2.202	3.12%
mBin.Oct	-322.226	168.599	-1.911	6.04%
mBin.Nov	-396.904	121.54	-3.266	0.17%
AR(1)	0.904	0.055	16.514	0.00%

Table 8-3: Industrial Model Statistics

Model Statistics	
Iterations	13
Adjusted Observations	80
Deg. of Freedom for Error	65
R-Squared	0.778
Adjusted R-Squared	0.73
AIC	11.575
BIC	12.022
Log-Likelihood	-561.52
Model Sum of Squares	20,472,920.14
Sum of Squared Errors	5851872.22
Mean Squared Error	90028.8
Std. Error of Regression	300.05
Mean Abs. Dev. (MAD)	215.38
Mean Abs. % Err. (MAPE)	7.09%
Durbin-Watson Statistic	2.538

Appendix 4.4
Industrial Energy and Peak Demand Forecast 2016-2035

14 November 2016

Contents

1.1 Introduction 2
1.2 Background 2
1.3 Source of Information 2
1.4 Industrial Projects Requirements 3
1.4.1 Potential Industrial Developments 4
1.4.2 Carmacks Copper Project 5
1.4.3 Brewery Creek Project 6
1.4.4 Existing Industrial Developments 7
1.5 Industrial Activity Scenarios 9
1.5.1 Very Low Industrial Activity 9
1.5.2 Low Industrial Activity 9
1.5.3 Medium Industrial Activity 9
1.5.4 High Industrial Activity 9
1.5.5 Sensitivity Scenarios 10
1.6 Industrial Energy and Peak Demand Forecast 10
1.6.1 Industrial Energy Forecast 10
1.6.2 Industrial Peak Demand Forecast 13

1.1 Introduction

The industrial load forecast includes all customers in the industrial rate class. At this time, the only large industrial customers in the territory are mines. All other industries of the territorial economy (e.g., agriculture, construction and forestry) are captured in the commercial forecast.

The industrial load and peak demand forecast considers the electricity requirements for mines connected to the grid. Historically, the alternative for industrial customers was to operate and meet power requirements with on-site thermal generation from imported fossil fuels (e.g., diesel). Recently, mining companies have relied on other resource options such as liquefied natural gas (e.g., Stornoway's Renard diamond mine), wind (e.g., Glencore's Raglan mine and Rio Tinto's Diavik mine) or solar photovoltaic (e.g., Sandfire Resources' DeGrussa Copper-Gold Mine) to meet industrial projects energy requirements.

1.2 Background

The Yukon Territory economy is sensitive to fluctuation in commodity prices which impacts the global mineral resource industry. From 2012 to 2014, the contribution of the Mining and Oil and Gas Extraction industry to the territorial GDP has averaged just over 21%.

Prior to the Faro Mine closure in 1988, industrial power requirement amounted to 43% of the energy and 30% of the total demand on the system (Whitehorse-Aishihik-Faro and Mayo-Dawson grids; 1996/97 Cost of Service Study).

The years following the closure at Faro saw substantial capacity and energy surplus hydro generation when compared to the load. The connection of new industrial customers (i.e., Minto mine and the Bellekeno silver mine) to the grid in 2008 and 2010 eroded the surplus. During the same period, commercial and residential electricity requirements have increased significantly. Recent residential and commercial developments increased pressure on existing generating assets due to the high penetration of electrical heating (over 90% for both commercial and residential classes).

In 2013, the Bellekeno silver mine ceased operations, decreasing industrial demand by about 32%. In 2016, Capstone Mining announced it would cease operations at Minto mine in the near future unless commodity prices would increase.

Since 2011, several projects such as Wellgreen (Wellgreen Platinum Corp.), Eagle Gold (Victoria Gold Corp.), and the Coffee Gold Project (Goldcorp, formerly Kaminak Gold Corp.), have continued exploration activities, feasibility work or sought permitting.

1.3 Source of Information

The industrial load and peak demand forecast uses data from proxy mines to estimate electricity needs from mines connected to the grid. Information used to generate the industrial peak and load forecast includes:

- information provided on specific projects in operation or planning phase via direct communication with mining companies

- historical demand and sales data
- information included in past YEC regulatory applications
- information from YEC 2011 Resource Plan

In many instances, the information is preliminary and will be subject to changes as the mining companies advance the engineering and definition of their respective project. To that effect, Yukon Energy will adjust the energy and peak demand forecast should material change occur in the future.

1.4 Industrial Projects Requirements

Due to the significant cost of the transmission lines required to connect some industrial projects to the Yukon Power System (YPS), only a subset projects closer to the grid were considered to be connected to the grid for the industrial load and peak demand forecast. The projects retained were as follow:

- Potential Industrial Developments
    - Victoria Gold Eagle Gold Project
    - Copper North's Carmacks Copper Project
    - Golder Predator's Brewery Creek Project
- Existing Industrial Developments
    - Capstone Mining's Minto mine
    - Alexco Resources' Bellekeno mine

It should be noted that the availability of details relating to the various phases of an industrial project is not consistent amongst projects. A project like Victoria Gold's Eagle Gold project has more information on energy and peak demand requirements through all phases of its project life than a project such Golder Predator's Brewery Creek Project.

Unless specified, Yukon Energy assumed the entirety of the energy and peak demand requirements would have to be met using the utility's assets and thus, did not include any contribution by generating assets located at the project site.

It is generally recognized that load profile of industrial projects across the calendar year is constant; therefore, not as sensitive to fluctuations in weather conditions as non-industrial loads are. Unless otherwise stated within the information available, monthly industrial energy and peak demand requirements were assumed constant throughout the year.

The following subsections present the energy and peak demand requirements at the point of delivery (i.e., exempt of losses) assumed for each of the industrial projects. The forecast of the total energy and peak demand requirements, including the losses, is presented in the last section of this report. The losses include transmission and distribution line losses, transformer losses and station service loads. A review of actual sales and generation data indicates overall losses on the Yukon Power System for the

2012-2015 period is 8.8%. This represents an increase of 0.1% from the 8.7% reported in the 2012 GRA[1] and LNG Part III application[2].

1.4.1 Potential Industrial Developments

This section describes power requirements for potential industrial developments that have gone through permitting or are going through the environmental and socio-economic review.

1.4.1.1 Eagle Gold Project

The property is located 45 km from the grid and 45 km north of the Town of Mayo. The project has all the necessary permits to move the project forward to construction and later, production. The project can be divided between the following four stages with associated duration:

- Construction: 1.5 years
- Production: 10 years
- Post-Production
    - Rinsing: 2 years after end of production
- Closure: 3 years after end of rinsing

Power requirement during the construction phase is estimated at less than 1 GWh/month. For the purposes of the industrial load forecast, 1 GWh/month or 12 GWh/year is assumed (Table B-1). Assuming an 85% load factor, the anticipated peak demand at the site is 1.6 MW (Table B-1).

During the production phase, Victoria Gold is also looking at implementing a summer and winter schedule whereby peak demand would decreased between the months of December until the mid-March (Table B-1). The load would then ramp up for the reminder of the year.

Energy requirement during the rinsing and closer phases are similar and estimated at 4 GWh/month or 48 GWh/year (Table B-1). Assuming a load factor of 85%, peak demand, net of losses, is estimated at 6.5 MW (Table B-1).

[1] Yukon Energy Corporation, 2012. 2012/2013 General Rate Application, application submitted to the Yukon Utilities Board, April 2012.
[2] Yukon Energy Corporation, 2013. *Application for an Energy Project Certificate and an Energy Operation Certificate Regarding the Proposed Whitehorse Diesel-Natural Gas Conversion Project*, application submitted to the Yukon Utilities Board, December 2013.

Table B-1: Eagle Gold Project Power Requirements over Project Life

Phase	Duration	Peak Demand	Load Factor	Annual Energy Requirement
	(Years)	(MW)	(%)	(GWh)
Construction	1.5	1.6	85%	12.0
Production	10	18.2 (Summer)	85%	114.8
		8.0 (Winter)	85%	
Post-Production	2	6.5	85%	48.0
Closure	3	6.5	85%	48.0

Notes:

- *Numbers rounded to nearest digit after the decimal point*
- *Excludes losses*
- *Does not assume any on-site generation*
- *Summer season extends from the start of December to mid-March*
- *Winter season is defined as Mid-March to end of November*
- *Victoria Gold Corporation is updating its feasibility study in 2016*
- *Numbers presented in the table are subject to changes in the future*
- *Includes 10% contingency*

1.4.2 Carmacks Copper Project

The property is located 12 km from grid and 38 km northwest of Carmacks. The forecast peak demand during the production phase is estimated at 14 MW (Table B-2). Connection of the project to the Yukon Power System is expected to occur during the construction phase. Before the interconnection to the YPS is completed, Copper North would rely on on-site thermal power to meet immediate needs. Once connected, the energy need is expected to last for about 8 months at 0.2 GWh/month or 1.6 GWh for the entire period (Table B-2). Peak demand during construction is expected to be 0.5 MW (Table B-2).

Total anticipated energy requirement during production phase is estimated at 6 GWh/month or 72 GWh/year (Table B-2). Mine life included in the YESAB project proposal is 7 years but current resources indicate mine life could be extended to 10+ years. For the 20-year energy and peak demand forecast, the mine life was assumed to be 10 years (Table B-2).

Energy and peak demand requirements during reclamation and closure are estimated at 200 MWh/month or 2.4 GWh/year and 0.5 MW, respectively, for a duration of 2 years after end of production. The project needs to complete the YESAB review process before moving forward.

Table B-2: Carmacks Copper Project Power Requirements over Project Life

Phase	Duration	Peak Demand	Load Factor	Annual Energy Requirement
	(Years)	(MW)	(%)	(GWh)
Construction	0.75	0.5	60%	1.6
Production	10	14	60%	72.0
Post-Production	N/A	N/A	N/A	N/A
Closure	2	0.5	60%	2.4

Notes:

- *Numbers rounded to nearest digit after the decimal point*
- *Excludes losses*
- *Initial construction loads met with onsite thermal generation*
- *Does not assume any more contribution from on-site generation*
- *Load assumed constant throughout the year*
- *Preliminary data for reclamation and closure period, may be subject to change in the future*

1.4.3 Brewery Creek Project

The property is located 55 km southeast of Dawson City and 27 km from the 69 kV Mayo-Dawson transmission line. At this time, there is limited information available that would suggest this is a firm load for resource planning purposes (i.e., no recent regulatory filings or publically available information defining potential load requirements).

Energy and peak demand information from the 2014 Preliminary Economic Assessment[3] were considered for the industrial load forecast. Power requirement during construction are expected to be met with the existing on-site thermal assets.

During the production phases, winter peak demand is expected to reach 1.8 MW for a 9-year production period (Table B-3). Energy requirements are estimated at 23.5 GWh/year (Table B-3)broken down as follow:

- 5 GWh/year or 1.1 GWh/month during the winder period
- 18.6 GWh/year or 2.4 GWh/month during the operating period

The information on closure and reclamation suggest Golden Predator will implement a passive solution that will not result in material power requirement over a 15-year period. As such, neither energy nor peak demand requirements were considered in the industrial forecast for this project.

[3] EBA, A Tetra Tech Company, 2014. 2012 Preliminary Economic Assessment for the Brewery Creek Property Yukon Territory, Canada National Instrument 43-101 Technical Report, report submitted to Golden Predator Exploration Ltd. November 2014.

Table B-3: Brewery Creek Project Power Requirements over Project Life

Phase	Duration	Peak Demand	Load Factor	Annual Energy Requirement
	(Years)	(MW)	(%)	(GWh)
Construction	1	N/A	N/A	N/A
Production	9	1.8 (Winter)	32%	23.5
		3.9 (Operating)	54%	
Post-Production	N/A	N/A	N/A	N/A
Closure	N/A	N/A	N/A	N/A

Notes:

- *Numbers rounded to nearest digit after the decimal point*
- *Excludes losses*
- *Power requirements during construction assumed to be provided by on-site thermal generation*
- *Operating season defined as start of March until late October*
- *Winter season is defined as late October to end of February*
- *Does not assume any more contribution from on-site generation*
- *Load assumed constant throughout the year*
- *No major loads expected during closure period*
- *Includes 19% contingency*

1.4.4 Existing Industrial Developments

This section describes power requirements for existing industrial developments. Of the two properties, only the Minto mine is still operating. Alexco's Bellekeno mine was considered as a potential project should commodity prices increase in the near-future.

1.4.4.1 Minto Mine

The Minto Mine is located 27 km west of Minto Landing. The Copper-Gold mine started production in 2007. In 2008, the mine was connected to the newly built spur line between the mine site and Minto Landing as part of the Phase 1 of the Carmacks-Stewart Transmission Line project.

Historical data indicate the mine has an operating winter peak load of 6 MW (assuming a power factor of 0.95). Actual annual energy requirements have averaged 36.7 GWh for the 2014-2015 period. Pursuant to the power purchase agreement (PPA) between Yukon energy and Capstone Mining Corporation (formerly Minto Exploration Ltd.), the company could elect to increase its annual energy requirements to 42 GWh/year at a peak load of 6 MW (assuming power factor of 0.95). The maximum energy and peak demand requirements outlined in the PPA were used for the purposes of estimating the industrial electrical requirements (Table B-4). The mine is assumed to operate until mid-2022[4].

[4] Minto Explorations Ltd., 2012. *Minto Phase VI Preliminary Feasibility Study Technical Report Minto Mine Yukon, Canada*, report prepared by Minto Explorations Ltd., December 2012.

Table B-4: Minto Project Power Requirements over Project Life

Phase	Duration	Peak Demand	Load Factor	Annual Energy Requirement
	(Years)	(MW)	(%)	(GWh)
Construction	N/A	N/A	N/A	N/A
Production	6.5	6.0	80%	42.0
Post-Production	N/A	N/A	N/A	N/A
Closure	N/A	N/A	N/A	N/A

Notes:

- *Numbers rounded to nearest digit after the decimal point*
- *Excludes losses*
- *Does not assume any more contribution from on-site generation*
- *Load assumed constant throughout the year*
- *Last year of production period is expected to last 6 months*

1.4.4.2 Bellekeno mine

Alexco's Bellekeno mine is located in the Keno region. Alexco is also operating a mill in the Keno region and plans to develop other silver deposits in the vicinity to use this mill in the near-term. The project started production in 2010 and operated until its temporary closure in 2013. The mine life was initially estimated to be 10 years. Based on the duration of historical mining activities, it is estimated that the projects has a remaining life of 7 years (Table B-5).

Table B-5: Bellekeno Project Power Requirements over Project Life

Phase	Duration	Peak Demand	Load Factor	Annual Energy Requirement
	(Years)	(MW)	(%)	(GWh)
Construction	N/A	N/A	N/A	N/A
Production	3	3.5	65%	20.0
	4	2.6	66%	15.0
Post-Production	N/A	N/A	N/A	N/A
Closure	N/A	N/A	N/A	N/A

Notes:

- *Numbers rounded to nearest digit after the decimal point*
- *Excludes losses*
- *Load assumed constant throughout the year*

Actual energy sales averaged 12 GWh/year for the 2011-2012 period. Peak load is estimated at about 3.5 MW based on actual demand data. At the time of the closure, information provided by Alexco suggested the project had three additional years of production with an energy requirement of 20 GWh/year and peak load of 3.5 MW. This period would be followed by four years of production with a lower energy requirement estimated at 15 GWh/year and peak load of 2.6 MW. The remaining life of the Bellekeno mine was assumed for the purposes of estimating the industrial electrical requirements (Table B-5).

1.5 Industrial Activity Scenarios

Four major scenarios and a set of sensitivity scenarios were defined on the basis of the intensity of industrial activity. The following subsections describe the assumptions relating to the timing and life of the existing and planned industrial projects. Industrial projects assumed to connect to the Yukon Power System are also presented below.

1.5.1 Very Low Industrial Activity

The Very Low Industrial Activity scenario assumes the following:

- Minto Mine remains the only mine connected to the grid with mine closure at the end of 2017.

For the purposes of estimating energy and peak demand requirements over the planning period (2016-2035), no new mines are assumed to connect to the grid.

1.5.2 Low Industrial Activity

The Low Industrial Activity scenario assumes the following:

- Minto Mine remains the only mine connected to the grid with mine closure in mid-2022.

For the purposes of estimating energy and peak demand requirements over the planning period (2016-2035), no new mines are assumed to connect to the grid.

1.5.3 Medium Industrial Activity

The Medium Industrial Activity (Base Case) scenario assumes the following:

- Minto Mine remains in operation and connected until mine closure at the end of 2022.
- Eagle Gold (Victoria Gold) connects to the grid with construction starting in 2019, production starting in mid-2020 and mine closure activities starting in 2030.

1.5.4 High Industrial Activity

For the High Industrial Activity scenario, the following was assumed:

- Minto Mine remains in operation and connected until closure in 2022
- Alexco Mine coming back online in 2020 until 2026
- Three medium mine connecting to the Yukon Power System as follow:
    - Victoria Gold's Eagle Gold from 2017 to 2034
    - Copper North's Carmacks Copper from 2020 until the end of 2031

- Golden Predator's Brewery Creek from 2020 until the end of 2030

1.5.5 Sensitivity Scenarios

A total of 11 sensitivity scenarios were defined to quantify the impact of climate change, other industries and sectors of the Yukon economy. These scenarios focus on variations on mining starts and impacts on the territorial economy. The sensitivity scenarios considered the following:

- Impact of mining boom and bust cycle
- Early and late mining starts
- Potential oil and gas development
- Changes in government spending as a proxy to variations in federal transfer payments
- Increase in activity of Yukon's smaller economic sectors including tourism, forestry, agriculture, and fishery.

For each of the sensitivity scenario, timing of the project start was consistent with the econometric scenario description presented in the appendix on Yukon Macroeconomic Model 2016-2035 (Appendix B). For instance, under the impact of Boom and Bust cycle scenario (Scenario 10), construction of the Eagle Gold project is assumed to start in 2028 as opposed to 2019 for the Base Case (Scenario 3)

Because the sensitivity scenarios are variations on the four major industrial activity scenarios, only energy and peak demand data for those four scenarios are discussed and presented in this document. Detailed numerical data on industrial energy and peak demand requirements for the sensitivity scenarios can be found in the Energy and Peak Demand Forecast Data 2016-2035 appendix (Appendix A).

1.6 Industrial Energy and Peak Demand Forecast

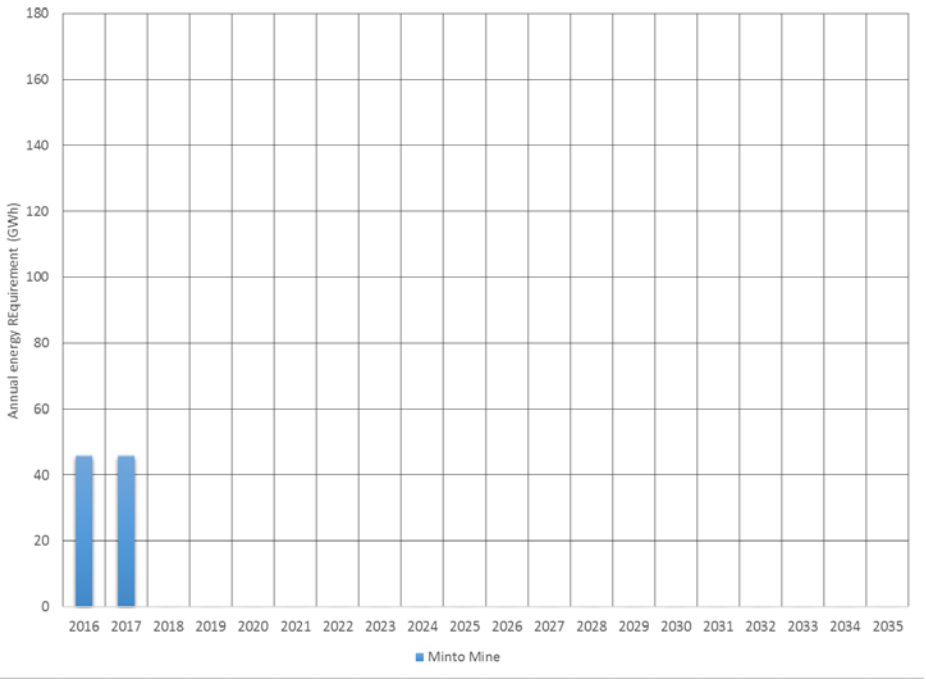
The industrial energy and peak demand forecast considered the same mines and timing described in the appendix on Yukon Macroeconomic Model 2016 – 2035 (Appendix B). Only the forecast for the four major scenarios are presented below. Results for the sensitivity scenarios are effectively variations of the four major scenarios. Industrial forecasts for all scenarios are included in Appendix A. All the forecast values presented in this section are inclusive of losses end represent the energy and peak demand YEC needs to meet at the generating stations.

1.6.1 Industrial Energy Forecast

The Very Low Industrial Activity shows a constant energy requirement for 2016 and 2017 at 45.7 GWh/yr (Figure 1). After 2017, Minto mine is assumed closed for the remaining of the forecast period (Figure 1). No other industrial projects are assumed for this scenario

The Low Industrial Activity shows a constant energy requirement between 2016 and 2021 at 45.7 GWh/yr (Figure 2). In 2022, Minto mine is expected to operate for 6 months and therefore, decrease its energy requirement by half (Figure 2). After 2022, this scenario assumes one industrial project would start operation but would not connect to the Yukon Power System.

Figure 1: Very Low Industrial Activity Energy Forecast



Similar the Low Industrial Activity scenario, the Medium Industrial Activity (Base Case) scenario assumes the Minto mine is in operation through mid-2022 (Figure 3). A peak energy requirement of 170.6 GWh/year is estimated to occur in 2021 and is due to the first full year of production at Eagle Gold and the last full production year at Minto mine (Figure 3). Energy requirements decrease over the following two years as a result of the Minto mine closure and level off at 124.9 GWh/year for the 2023-2029 period (Figure 3). Starting in 2030, energy requirements materially decrease due to the end of the production period at Eagle Gold and the start of the post-production and closure activities until 2035 (Figure 3).

Figure 2: Low Industrial Activity Energy Forecast

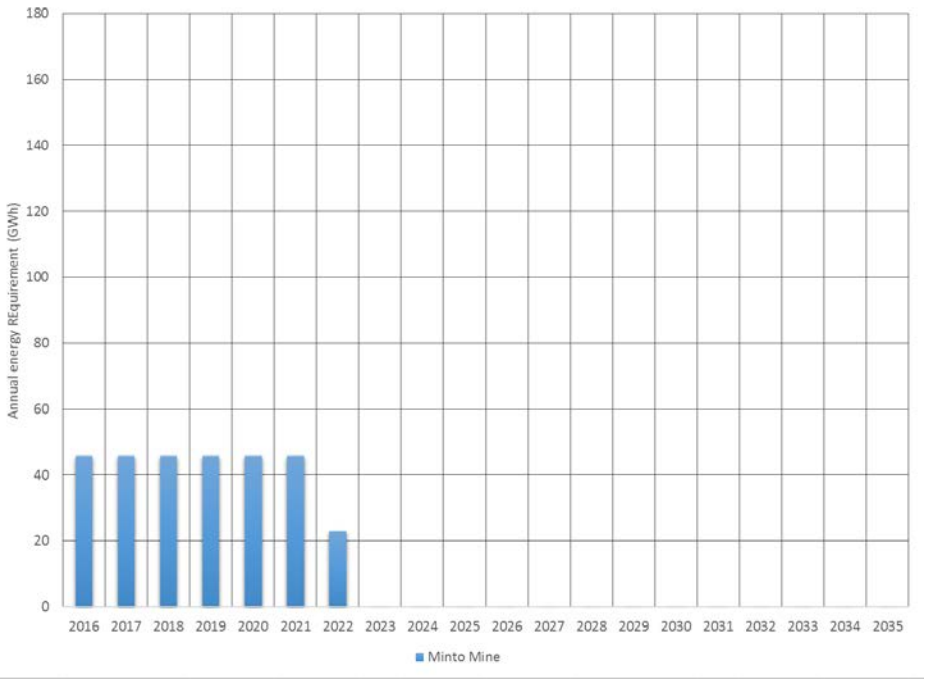
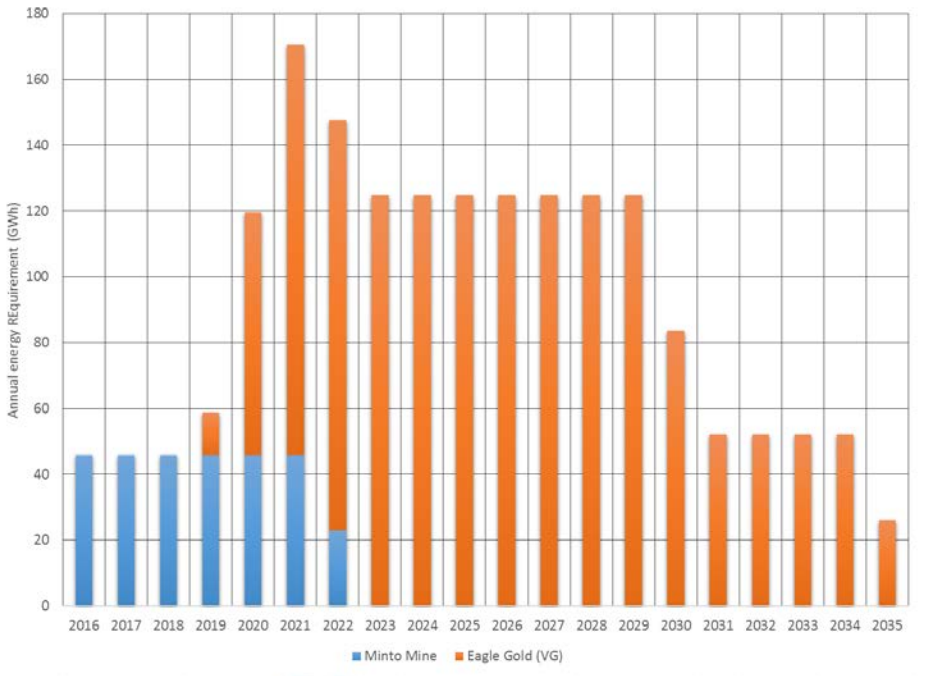


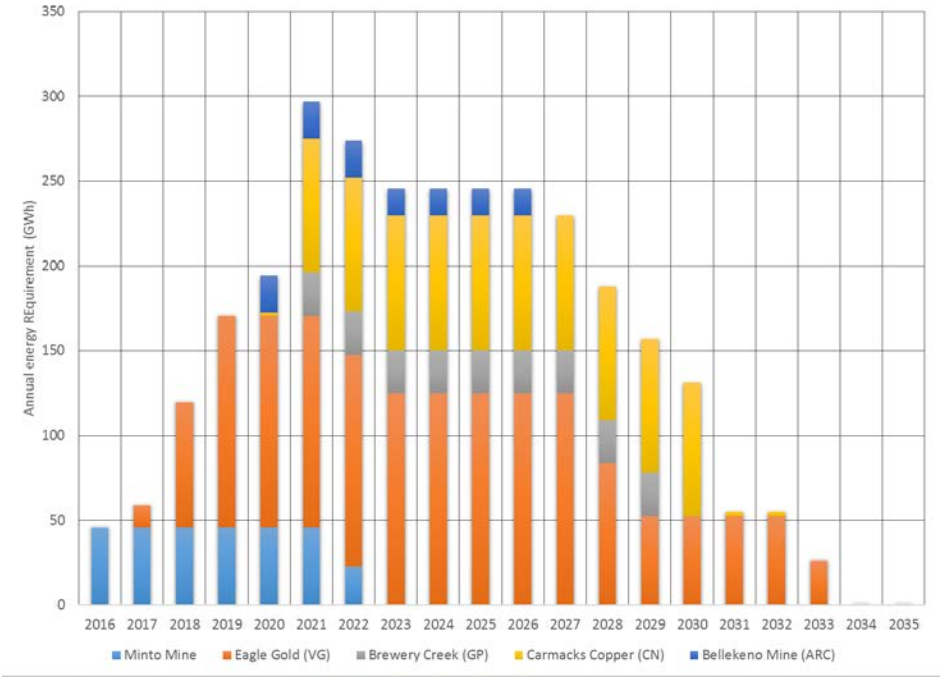
Figure 3: Medium Industrial Activity (Base Case) Energy Forecast



For the High Industrial Activity, Minto mine is still assumed to operate at 45.7 GWh/year until 2022 where its energy requirement decreases to 22.8 GWh (Figure 4). Industrial energy requirements start ramping up in 2019 to culminate at 296.9 GWh/year in 2022 (Figure 4). The material increase is in part

due to the start of construction and later, production at the Eagle Gold property (Figure 4). Compounding the effect of the Eagle Gold project is the start of construction and production activities at the Carmacks Copper, Brewery Creek and Bellekeno mine in 2020. Subsequent to 2021, energy requirements decrease by 22.9 GWh and 28.3 GWh for 2022 and 2023, respectively. This reduction is due to the closures of the Minto mine. Beyond 2023, industrial energy needs remains constant at 245.7 GWh/year until 2026. After 2026, the Bellekeno mine is assumed to shut down. Forecast energy requirement begins to ramp down in 2027 until 2030. Several factors explain this decrease, notably the transition from production to post-production and closure at Eagle Gold project and the expected closure of the Brewery Creek project. From 2031 to 2033, energy requirements are intended to support closure activities at Carmacks Copper and Eagle Gold projects. The industrial energy forecast decrease to 0 GWh/year for the last two years of the forecast period.

Figure 4: High Industrial Activity Energy Forecast



1.6.2 Industrial Peak Demand Forecast

The contribution of the industrial projects to the overall system peak for the Very Low Industrial Activity and Low Industrial Activity scenarios are closely related to the production activities at the Minto mine. A contribution to the peak of 6.5 MW is expected until 2017 and 2022 for Very Low Industrial Activity (Figure 5) and Low Industrial Activity (Figure 6) scenarios, respectively. Subsequent to the Minto mine closure, the industrial demand contributing to the overall system peak is expected to drop off to 0 MW.

Figure 5: Very Low Industrial Activity Peak Demand Forecast

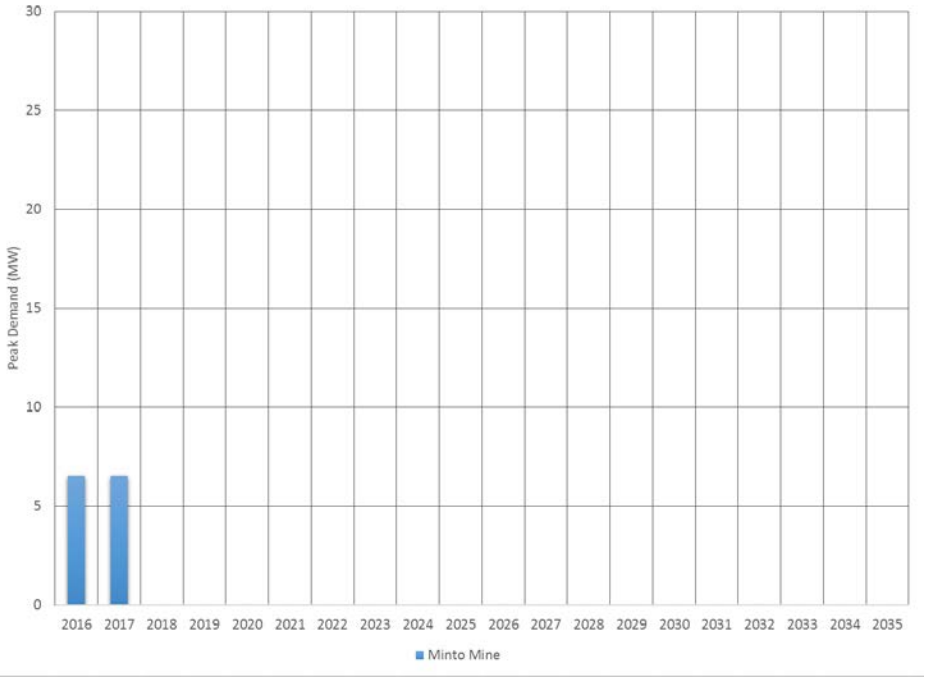
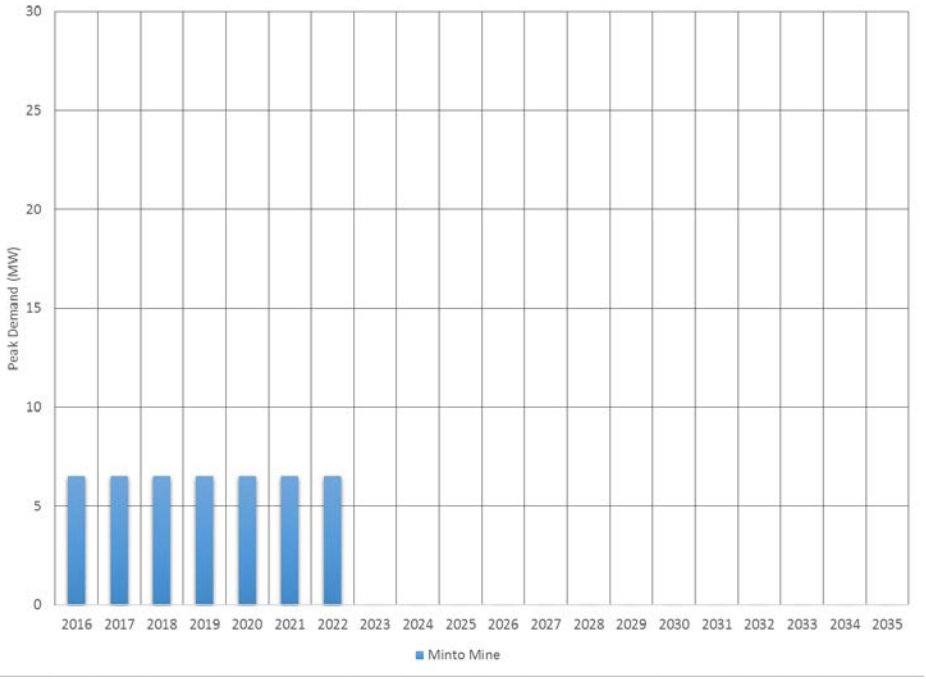


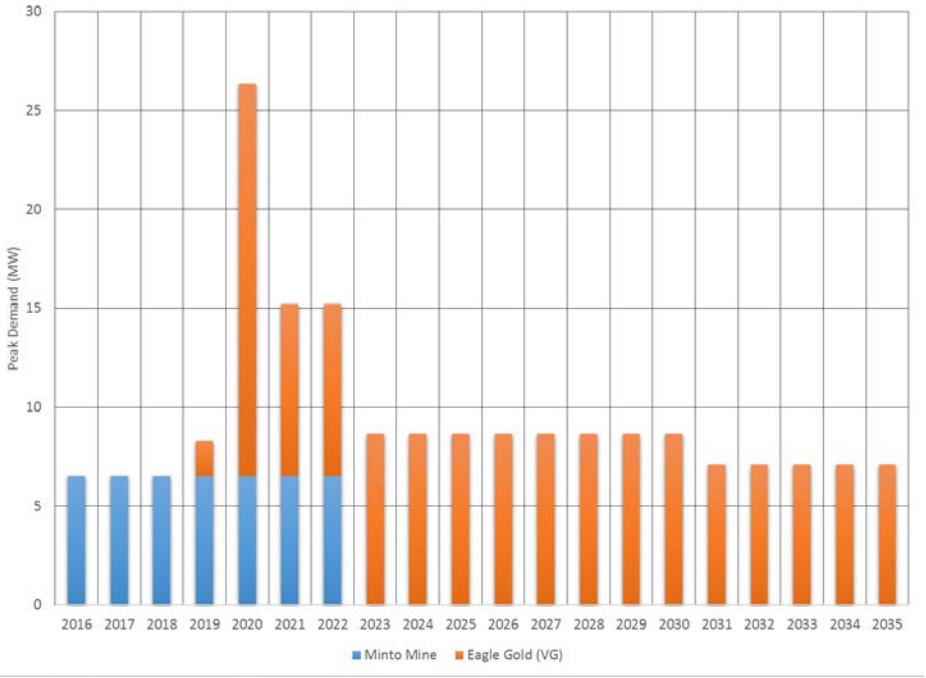
Figure 6: Low Industrial Activity Peak Demand Forecast



The forecast peak demand for the Medium Industrial Activity scenario shows an increase of 26.4 MW as the connected mine, Victoria Gold's Eagle Gold project, starts its production phase in 2020 (Figure 7). For the remainder of its operation phase, the contribution of the Eagle Gold project to the peak demand is estimated at approximately 8.7 MW (Figure 7); this corresponds to the peak demand during the

winter period (November to January). Summer peak demand (February to October) for the project at the point of delivery is just over 19.8 MW. Although greater than the winter peak demand, the summer peak demand is non-coincident to the non-industrial peak demand forecasted to occur in January of each forecasted year. Only one year (2020) shows a contribution of the project of 19.8 MW to the system peak demand attributable to the transition from construction to production.

Figure 7: Medium Industrial Activity (Base Case) Peak Demand Forecast

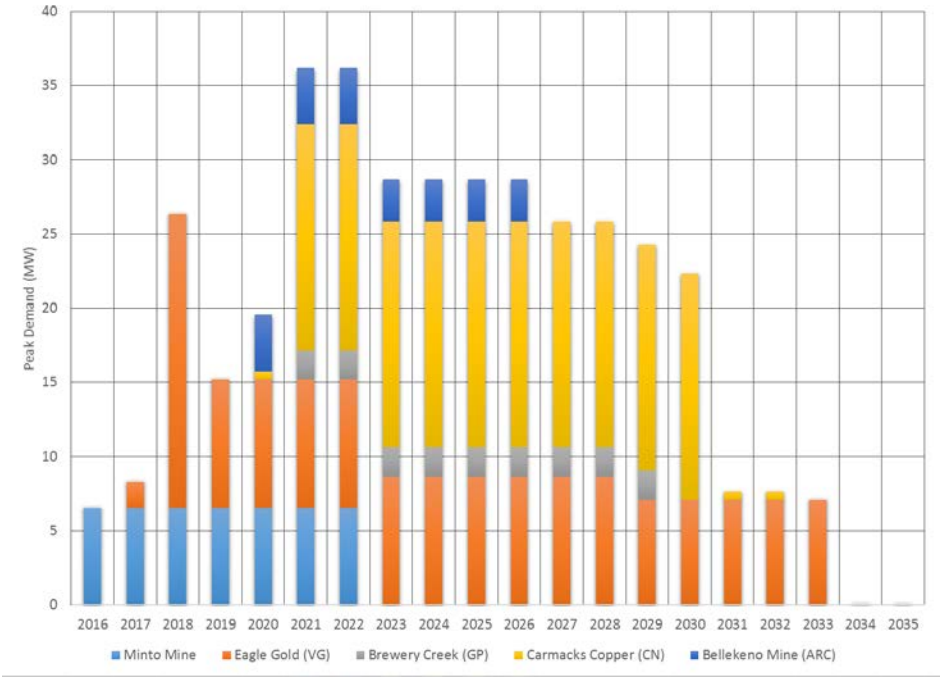


For the High Industrial Activity scenario, the contribution to the overall system peak of the industrial peak demand is estimated to reach 36.2 MW in 2021 (Figure 8).

Prior to 2021, industrial peak demand is expected to contribute 26.3 MW to the system peak in 2018 (Figure 8). This elevated demand is associated with the transition between construction phase and the production phase at the Eagle Gold project. This is similar to what is expected in 2020 under the Base Case scenario (Figure 7).

After 2021, peak demand is expected to gradually decrease until 2030 where it is expected to reach 22.3 MW. After 2030, the peak industrial demand decreases to 7.7 MW and stay relatively constant until 2034 where it drops to zero (Figure 8). The drop occurring in 2031 is associated with the end of the production period and start of the closure activities at the Eagle Gold Project and end of production at Golden Predator's Brewery Creek project (Figure 8).

Figure 8: High Industrial Activity Peak Demand Forecast



Appendix 4.5
Electric Vehicle Investigation

Final Report

Electric Vehicle Investigation

February 2016

Submitted to:
Yukon Energy Corporation
Whitehorse YT Y1A6S7
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Table of Contents

Executive Summary **1**

1 Introduction **4**
Objective 4
Background on Plug-in Electric Vehicles and Charging Infrastructure 4
Structure of Report 7

2 Electric Vehicle and Charging Impacts in Cold Weather **7**
Cold Weather Impacts on Vehicle Range 8
Cold Weather Impacts on Vehicle Charging Time 12
Summary of Findings 14

3 Plug-in Electric Vehicle Market Assessment **16**
Plug-in Electric Vehicle Forecasting in Yukon Territory 16
Greenhouse Gas Impacts of Plug-in Electric Vehicles 26

4 Grid Impacts of PEVs **30**
Energy Consumption and Loadshapes of PEVs 30
Feeder Impacts for Yukon Energy 34
Impact on ATCO Assets 41

5 Conclusions and Recommendations **42**

List of Figures

Figure 1. Electric Vehicle Range vs Temperature 9
Figure 2. Annual Income Estimates for Census Families and Individuals, By Province, 2009-2014 18
Figure 3. Yukon - Population by five-year age groups and sex 19
Figure 4. Commuting Modes in Canada, Yukon, Whitehorse, and Outside Whitehorse 21
Figure 5. Vehicles registered in the Yukon, 2000–2014 23
Figure 6. Whitehorse Transportation Fuel Costs, 1999 - 2012 24
Figure 7. PEV Forecasts for Yukon Territory in Low, Medium, and High Scenarios, 2015-2035 26
Figure 8. GHG Emission Reductions from PEV Forecasts 28
Figure 9. Forecasted Energy Demand (MWh) for EV Deployment Scenarios 33
Figure 10. Daily Loadshapes for Electric Vehicles in Various Charging Scenarios 34
Figure 11. Forecasted Pea k Demand (MW) for EV Deployment in Different Charging Scenarios 37
Figure 12. Winter and Summer Loadings on the Haines Junction Feeder 38
Figure 13. Winter and Summer Loadings on the Dawson Feeder 39
Figure 14. Peak Load Impact of EV Deployment on ATCO's Assets (S150 and S170) 42

List of Tables

Table 1. Estimated charging times using various EVSE (hours:minutes) 7
Table 2. Electric Vehicle Supply Equipment Categories 13
Table 3. Parameters Influencing PEV Adoption 17
Table 4. Yukon mode of transportation to work 20
Table 5. Home to Work Commuting in Whitehorse, 2002 21
Table 6. PEV Deployment in Yukon Territory (Percent of Total On-Road Vehicles) 26
Table 7. GHG Emissions for Electricity and Gasoline 27
Table 8. GHG Emissions Rates (gCO2e/km) for various vehicle types and different operation conditions 29
Table 9. Energy Consumption of Plug-in Electric Vehicles 31
Table 10. Estimated Daily PEV Energy Consumption (in units of kWh) in the Yukon for Summer and Winter 32
Table 11. Peak Demand (in MW) during Summer (Apr 1–Sept 30), by Year for PEV Deployment Scenarios 35
Table 12. Peak Demand (in MW) during Winter (Oct 1–Mar 31), by Year for PEV Deployment Scenarios 36
Table 13. Electric Vehicle Deployment and Stressed Assets 40

Executive Summary

The deployment of plug-in electric vehicles has the potential to reduce petroleum consumption and greenhouse gas emissions dramatically, and increase energy independence through the utilization of locally produced energy. However, the success of long-term transportation electrification will depend in part on the near-term deployment of vehicles and charging infrastructure. Yukon Energy stands to play a significant role in the transition towards higher rates of plug-in electric vehicle adoption and the deployment of charging infrastructure. The objective of this report is to provide Yukon Energy Corporation and partners an assessment of the technical feasibility of plug-in electric vehicles (PEVs) in the Yukon Territory and their potential opportunities and impact to the current grid. The goal of this project is to determine to what extent an active engagement in PEV and charging station deployment is a wise investment in the Yukon. Additionally this project determines the potential long-term associated impacts or opportunities for electrical sales and peak and base loads.

ICF's investigation of the potential for electric vehicles in the Yukon Territory is focused on 1) a review of cold weather impacts on plug-in electric vehicles and charging infrastructure, 2) a market assessment for the Yukon Territory, including vehicle forecasts, and associated greenhouse gas impacts of electric vehicle deployment, and 3) a grid impact assessment regarding the amount of energy that Yukon will need in the future, and the potential stress on some distribution assets. ICF's key findings are summarized here:

- ICF's literature review indicates that residents in the Yukon Territory will have difficulty maintaining normal functionality of electric vehicles during the coldest months of the year; however, electric vehicles, particularly plug-in hybrid electric vehicles (PHEVs), are still a viable transportation option. The main hurdle for electric vehicle adoption in the Yukon Territory will be vehicle performance in below freezing temperatures. The range of an electric vehicles can be more than halved in below freezing temperatures, requiring double the electricity to charge these vehicles for daily use (or relying more significantly on plug-in hybridization). Notably, even a halving of the range of many PHEVs on the market today will keep the electric range of the vehicle within the scope of the average Yukon commute. One factor bolstering the potential for electric vehicles in the Yukon Territory is the ubiquitous availability of vehicle charging at homes and business, which is tied to the availability of plug-in engine block heaters.
- ICF developed three electric vehicle penetration scenarios–low, medium, and high–with varying assumptions regarding the growth in total vehicle sales, electric vehicles sales, vehicle offerings (e.g., light trucks), vehicle pricing, and fuel pricing. Generally, ICF finds that there is low to modest potential for electric vehicle adoption in the Yukon Territory, with percent of new sales ranging from 2.6–11.7% by 2035. Limited electric vehicle offerings, notably limited availability of plug-in electric light-duty trucks, is a major hindrance to electric vehicle adoption in the Yukon Territory. About 60% of new vehicle registrations in the Yukon Territory are light-duty trucks; if this pattern of vehicle ownership persists over time, then it will be challenging for the Yukon Territory to increase electric vehicle adoption moving forward.

- On-road gasoline and on-road diesel use accounts for about 50 percent of total Yukon greenhouse gas emissions. Even at low adoption levels, electric vehicles can have a substantive impact on greenhouse gas emissions. ICF estimates that PEVs could reduce greenhouse emissions by about 120–410 MT by 2025 and 650–2,800 MT by 2035. For the sake of comparison, the Government of Yukon reports a total of 638,000 MT of GHG emissions in the territory.
- The forecasted levels of electric vehicles will have only minor grid impacts in the Yukon. ICF's grid impact assessment is based on assumptions regarding vehicle charging levels, vehicle energy consumption, and the rate schedules that consumers might use. ICF assessed the impacts of electric vehicle adoption on peak load assuming that vehicles (PHEVs and battery electric vehicles) charge on a time-of-use (TOU) rate at Level 1 (110 V) or Level 2 (220 V), or on a standard household rate (i.e., non TOU[1]). We find that the maximum peak demand occurs at Level 2 charging on a TOU rate, with a range of 0.1–1.4 MW and 0.6–9.4 MW in 2025 and 2035, respectively, across the three electric vehicle adoption scenarios (low, medium, and high). ICF notes that the peak demand has the same values as peak energy values, simply with units of MWh–our current understanding of how electric vehicles charge does not allow us to make estimates at less than one hour intervals. As a result, we simply assume that the demand (MW) is constant over a one-hour period (yielding energy demand in units of MWh).
- ICF also assessed the potential for impacts on Yukon Energy's distribution assets, by reviewing the potential increased load on Yukon Energy feeders. We looked at the Haines Junction and Dawson 2 feeders, which distribute about 1.8% and 1.3% of the electricity that Yukon generates. Using a fair share assumption (i.e., that electric vehicles are adopted proportionally to electricity consumption), and considering the load associated with the high electric vehicle deployment scenario in 2035 (when there are nearly 1,900 PEVs assumed to be on the road in the Yukon), ICF finds that the additional load from PEVs may have an impact on Yukon's distribution assets assuming that no upgrades occur over the study time period. This is particularly true in the winter months when charging demands are likely to increase.
- ICF also considered the potential for electric vehicle clustering. This is important because more than 75% of the Yukon Territory population is located in Whitehorse. However, most of the distribution assets in Whitehorse are owned and operated by ATCO. In other words, the only way that clustering would have an impact on Yukon Energy's assets is if electric vehicle deployment were concentrated outside of Whitehorse and consistently charged at higher-than-expected levels, which ICF believes is unlikely. ICF and Yukon Energy did reach out to ATCO regarding this study, and were informed that breakers are not the weak points in their distribution system; rather they highlighted that there are a variety of issues associated with managing load and assets in the downtown core (of Whitehorse), with a focus on a planned 25 kv conversion project. ATCO noted that ICF's forecasts for increased load from electric vehicle adoption would change ATCO's annual load increase from about 2.2% per year to 2.24% per year and 2.39% per year in the low and high cases, respectively. ATCO has agreed that the

[1] ICF does not assume an explicit blend of Level 1 and Level 2 charging for the non TOU rate; rather the rate is reflective of the time that vehicles would charge. The power draw associated with this rate implies that it is about a 50-50 blend of Level 1 and Level 2 charging.

magnitude of this potential load increase should be included in their incremental load growth forecasts moving forward.

- Finally, despite the modest potential for electric vehicles in the Yukon, Yukon Energy has the opportunity to establish a leadership position in the market with only minor investment. More specifically, targeted outreach and education to consumers in the near-term future, as interest for electric vehicles increases over the next several years, will be critical. Furthermore, strategic partnerships and engagement with other stakeholders, including ATCO, automobile manufacturers, and local automobile dealerships, can help establish a leadership position in the market. ICF is not seeking to over-state the potential in the Yukon for electric vehicles, but low-investment engagement such as keeping updated on market developments and consumer interest over the next several years could have significant implications in the mid- to long-term future for resource planning.

1 Introduction

The deployment of plug-in electric vehicles (PEVs) has the potential to reduce petroleum consumption and greenhouse gas (GHG) emissions dramatically, and increase energy independence through the utilization of locally produced energy. However, the success of long-term transportation electrification will depend in part on the near-term deployment of vehicles and charging infrastructure. The transition towards higher rates of PEV adoption and the corresponding charging infrastructure requires a broad range of stakeholders to prepare and plan for deployment. Yukon Energy is understandably keen on engaging in this space given the opportunity; however, there are challenges and obstacles, namely the impacts of cold weather on electric vehicle operation that must be considered.

Objective

The objective of this report is to provide Yukon Energy Corporation and partners an assessment of the technical feasibility of PEVs in the Yukon and their potential opportunities and impact to the current grid. The goal of this project is to determine to what extent an active engagement in PEV deployment is a wise investment in the Yukon, and to determine what the associated impacts or opportunities might be in the long term for electrical sales and peak and base loads.

Background on Plug-in Electric Vehicles and Charging Infrastructure

Vehicles

Electricity is used as transportation fuel in three types of vehicles: hybrid electric vehicles (HEV), which are powered by both an internal combustion engine (ICE) and an electric motor; plug-in hybrid electric vehicles (PHEV), which have an ICE and larger battery packs than HEVs and are designed to plug into the electrical grid to charge the vehicle; and battery electric vehicles (BEV), which plug into the electrical grid and are then powered solely by energy from the battery. In the context of this report, vehicles that use electricity from the grid are referred to as plug-in electric vehicles (PEV), a term that includes both PHEVs and BEVs.

The battery technology used in PEVs has been in development for over a decade; however, limitations on stability, energy capacity, energy storage capacity, and the cost of producing the battery have been barriers to widespread deployment in vehicles. Despite the latest advances in rechargeable battery technology, most recently using lithium-ion technology, the energy densities of batteries are still about two orders of magnitude less when compared to common liquid fuels used in ICEs. Prior to 2012, PEVs were limited to niche markets, introduced in demonstration programs, converted by aftermarket companies, or legacy PEVs from the deployment in the 1990s. More recently, the number of vehicle offerings is steadily increasing. For instance, both the Nissan LEAF (a BEV) and the Chevrolet Volt (a PHEV) have been available since early 2011; today, there are more than twenty (20) PEV offerings in the marketplace. However, these vehicles are not available everywhere.

Most PHEVs are designed to provide an all-electric driving range of 16 to 65 km. However, when the battery state of charge falls to a predetermined limit, the system automatically switches to the ICE.

Battery-related costs tend to be lower for PHEVs as compared to BEVs because of the smaller battery size, but this is partially offset by the additional expense of outfitting a vehicle with two powertrains (electric and ICE). PHEVs can have two types of drivetrain architectures, characterized as series or parallel configurations. The series PHEV is designed for electric motor propulsion only, with the ICE acting as a backup generator. Currently, the only series PHEV on the market is the Chevrolet Volt. The parallel PHEV is based on a conventional HEV architecture and has two powertrains, one with the electric motor and one with the ICE. The parallel PHEV is equipped with additional battery capacity and a higher power electric system to extend the electric motor propulsion system range. Parallel PHEV models based on aftermarket conversions of the Prius have been available in the past, but in the near future most original equipment manufacturers (OEM) models are expected to produce parallel PHEVs as well.

BEVs operate solely on an electric powertrain and therefore are equipped with more batteries to extend the operating range. This is a very simple architecture where the battery drives the electric motor to propel the vehicle. This simplified architecture may make BEVs less expensive than the comparable PHEVs in some cases, but given the greater need for electricity, BEVs also typically have a heavier reliance on infrastructure with faster charging times.

PEV Charging

Electric vehicle charging infrastructure (often referred to as electric vehicle supply equipment, EVSE) is typically differentiated by the maximum amount of power provided to a PEV battery. Two primary types of EVSE provide either alternating current (AC) or direct current (DC) electricity to PEVs. Current SAE standards are as follows:

- **Level 1 AC** – These chargers use standard 120 volt (V), single phase service with a three prong electrical outlet at 15-20 amperage (A). Local codes may apply to limit cord and plug connection length. Level 1 charging outlets should have ground fault interrupters installed and a 15 A minimum branch circuit protection. Level 1 charging requires no new electrical service for a building operating on an existing circuit. The main drawback of Level 1 charging is the time required to recharge the PEV. At 15 A and 85% electrical transfer efficiency, the power delivered is 1.4 kW.[2] This leads to longer charging times (ranging from about 4–20 hours, depending on the size of the battery).
- **Level 2 AC** – These chargers are used specifically for PEV charging and are rated at less than or equal to 240 V AC, and less than or equal to 80 A. Level 2 EVSE requires additional grounding, personal protection system features, a no-load make/break interlock connection, and a safety breakaway for the cable and connector. If 240 V service is not already installed at the charging site, a new service drop will be required from the utility. With a 40 A, 240 V service power can be delivered at 7.5 kW which shortens charging time considerably for PEV. These chargers use a standard SAE approved J1772 connector
- **Level 1 & 2 DC** – Level 1 & 2 DC chargers, also known as DC fast chargers, provide power much faster than the AC counterparts. However, DC fast chargers are more expensive to build and operate

[2] For the sake of comparison, most engine block heaters use between 0.4-1.5 kW of power.

due to the equipment and electrical upgrades necessary to operate them. Thus, they are less common than Level 2 AC chargers, and will not likely be used for residential applications. Few PEVs are currently equipped with compatible hardware for DC charging, but certain models such as the Nissan LEAF, Mitsubishi iMiEV, Kia Soul, BMW i3, Volkswagen eGolf, and Tesla do come with "fast charging" as an option. SAE approved (in 2013) the DC charging standard for the Level 1 and 2 DC coupler and connector as part of the J1772 standard.[3] The central component of the standard is the Combo Connector, which maintains the functionality of the previous J1772 connector and introduces two new pins that provide the option of charging via DC. DC charging typically requires a dedicated circuit of 20–100 A, with a 480 V service connection. Power is typically delivered in the range of 50–150 kW.

Charging Times

One of the common questions asked about PEVs is: How long do they take to charge? The simple answer is: It depends. One of the key aspects to understand about PEVs is the battery pack: The battery capacity is the amount of electrical charge a battery can store. Maximum capacity can only be reached; however, under optimal discharge conditions that account for the magnitude of the current, the allowable terminal voltage of the battery, and other external conditions such as temperature. PEV manufacturers have optimized battery packs to provide maximum capacity through devices such as battery thermal management systems. Thermal management systems maintain a constant temperature around the battery pack to prevent potential impacts from extreme hot or cold temperatures.

In addition to temperature, vehicle charging time is heavily dependent on the current type (AC or DC), electric potential difference (V), current (A), maximum power (kW), and the on-board charging capabilities of the vehicle. The most important determination of charging time is generally the charging capabilities of the vehicle. For example, the Chevy Volt and original Nissan LEAF both included a 3.3 kW on-board charger; Nissan has since upgraded to 6.6 kW on-board chargers. The Tesla charging system has a capacity of 10 to 20 kW. Battery capacities vary amongst vehicles, therefore electric vehicle range also varies.

The times needed to replenish a battery halfway and fully for the Toyota Prius Plug-in, Chevy Volt, and Nissan LEAF are shown in Table 1 below. Charging times on Level 1 infrastructure are primarily suitable for small battery vehicles, such as the Volt, which require over 7 hours to fully charge. Estimated charge times using DC fast charging for the Prius Plug-in, Volt and LEAF are included.[4] For DC fast charging, calculations assume the battery is charged to only 80% and the remaining 20% is completed by charging at a slower rate. If left connected at high power, the time to fully charge the battery will increase above an hour due to the nature of direct DC fast charging. Furthermore, some industry observers have voiced

[3] EVs get boost from new SAE standard for dc fast charging, SAE Vehicle Engineering Online. Available online at: http://www.sae.org/mags/sve/11484/

[4] ICF notes that neither the Prius Plug-in nor Chevrolet Volt is equipped with the appropriate charging couplers to charge using a DC fast charger; these values are shown for illustrative purposes only.

concerns about the effects of fast charging on battery life due to potential over-heating and over-voltage; however, Nissan reports that proper cooling and voltage can allay these effects.[5]

Table 1. Estimated charging times using various EVSE (hours:minutes)

Charger Type	Charge	Vehicle		
		Prius	Volt	LEAF
		4.4 kWh (3.5 kWh usable)	16 kWh (12.8 kWh) useable)	24 kWh (21.6 kWh useable)
Level 1 1.4 kW	Half	1:34	3:42	7:42
	Full	3:08	7:25	15:25
Level 2 7.5 kW	Half	0:40	1:34	3:16
	Full	1:20	3:09	6:32
DC Fast 50 kW	Half	0:02	0:06	0:12
	Full	0:05	0:47	1:39
DC Fast 150 kW	Half	0:01	0:02	0:04
	Full	0:02	0:41	1:25

Structure of Report

The remainder of this report includes the following:

- Section 2 provides an overview of how cold weather impacts PEV performance and charging.
- Section 3 includes ICF's market assessment, with a focus on the potential for PEV adoption in the Yukon Territory, as well as our low, medium, and high forecasts for the region out to 2035.
- Section 4 reviews the potential grid impacts of the PEV deployment scenarios, with a focus on Yukon Energy distribution assets.
- Section 5 concludes with recommendations.

2 Electric Vehicle and Charging Impacts in Cold Weather

Plug-in electric vehicles currently make up less than 1% of vehicle sales in Canada, with only seven models currently available.[6] As a reminder, this report uses the term PEV to include BEVs and plug-in PHEVs. A recent survey in Canada however has shown that there is a demand for PHEVs, with more than

[5] Mark Perry, Nissan, EVS26, May 6-9, 2012. Los Angeles, CA.

[6] Axsen, J., S. Goldberg, J. Bailey, G. Kamiya, B. Langman, J. Cairns, M. Wolinetz, and A. Miele (2015). Electrifying Vehicles: Insights from the Canadian Plug-in Electric Vehicle Study. Simon Fraser University, Vancouver, Canada. http://rem-main.rem.sfu.ca/papers/jaxsen/Electrifying_Vehicles_(FINAL)_V2.8_(July10).pdf, (last accessed July 23, 2015)

a third of participants wanting to buy a PEV, mostly PHEVs.[7] In the Yukon Territory however, cold weather performance will be a critical issue to the viability of PEVs.

Limited studies are available for PEVs in the coldest regions of the world, but it is clear that cold temperatures primarily impact the time it takes to use all of the battery energy or recharge a PEV battery. This report outlines specific issues related to impacts on vehicle range, including the impact of auxiliary power consumption and reduced efficiency from cold weather conditions on battery life. Additionally, this report outlines the impact on charging infrastructure (namely, EVSE) to transfer electricity to the vehicle in cold weather conditions.[8]

Cold Weather Impacts on Vehicle Range

Two things happen when a vehicle system is cold: 1) it will lead to an increase in auxiliary power consumption as drivers increase energy demand to heat the passenger cabin and to operate the defogger, and 2) vehicle components will become less efficient from increases in internal friction as an engine or battery gets colder. The greatest impact on range in cold weather usually comes from auxiliary loads, such as cabin heaters and fans and component heaters (i.e., battery heaters). Conventional vehicles use waste heat to help warm the cabin, but because all-electric vehicles do not generate sufficient waste heat, an electric heater must be used. Cabin heating therefore reduces the battery charge and potential range of a PEV. For some PEVs, a pre-heating setting is available to allow the battery and cabin heaters to run while still plugged in, preventing any initial loss in range to heat the vehicle. PHEVs are able to heat the cabin from engine rather than battery thereby minimizing battery efficiency loses at the expense of gasoline. However, like other gasoline engines, these PHEVs will need engine block heater to operate properly in extremely cold climates.

A cold battery also reduces regenerative braking which is used by most PEVs to increase driving range. Vehicles are typically outfitted with an electric heater to warm up the battery, which can draw as much as 6 kW of electricity. Some vehicle manufacturers are beginning to offer more efficient heaters and researchers are looking at methods to improve the insulation and special window coatings to reduce heating demand, but it is unlikely these solutions will be available in the near-term future.

Based on findings of the AAA Automotive Research Center, PEV battery range on a limited number of sample vehicles was reduced by nearly 60% at -7°C (20°F), largely due to the vehicles auxiliary loads.[9] Another report by researchers at Carnegie Mellon University found similar results, which increased the emissions associated with PEVs because of the additional electricity requirements.[10] This may be less of an issue for Yukon Energy customers where 99.6% of power generation in 2014 was from clean

[7] Ibid.

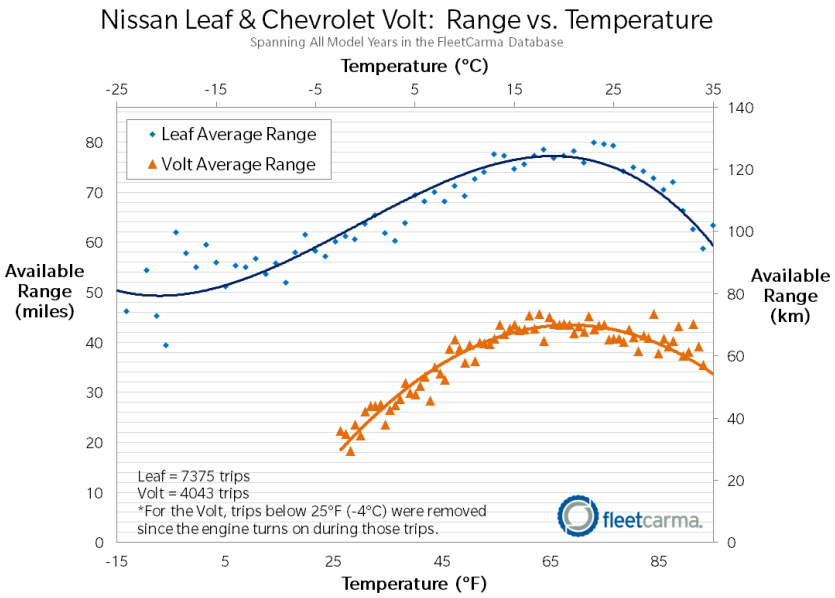
[8] ICF notes that we did not consider the power requirements associated with pre-heating the interior of the vehicle, as we assume that this load is comparable to the load of an engine block heater for conventional vehicles using an internal combustion engine.

9 AAA Automotive Research Center, 2014, http://newsroom.aaa.com/2014/03/extreme-temperatures-affect-electric-vehicle-driving-range-aaa-says/.

[10] Yuksel, T. and Michalek, J., 2015, Effects of Regional Temperature on Electric Vehicle Efficiency, Range, and Emissions in the United States, http://pubs.acs.org/doi/pdf/10.1021/es505621s.

hydropower, unless backup power is required from Yukon's fleet of diesel or natural gas generators (which is discussed in more detail in Section 3). FleetCarma, a vehicle monitoring service for major auto manufacturers, aggregated data from Chevrolet Volt and Nissan Leaf drivers to assess the range impact at temperatures between -25°C (-15°F) and 35°C (100°F).[11]

Figure 1. Electric Vehicle Range vs Temperature



Source: *FleetCarma*

Based on over 11,000 logged trips, driving range was reduced by about half in colder temperatures. At extreme cold temperatures, PHEVs automatically switch back to operating on the internal combustion engine, as noted in the graph that Volts switched to the engine at -4°C. Vehicle range was reduced by driver habits, such as using seat heaters to reduce the need for cabin heat.

PEVs require good battery thermal management to operate in the coldest months. Allowing the battery to be plugged in continuously to Level 1 chargers may help keep the battery warm and will be critical to normal function.[12] PEVs can be adapted to winter road conditions as the battery cells create a lower center of gravity to help vehicles gain traction.

Fleet Case Studies

Calstart: Calstart studied electric trucks in Chicago, with testimony from three fleets and input from custom electric vehicle suppliers: AMP Electric Vehicles, Motiv Power Systems, and Smith Electric

[11] FleetCarma, 2013, 'Electric Vehicle Range for the Nissan Leaf and Chevrolet Volt in Cold Weather,' http://www.fleetcarma.com/nissan-leaf-chevrolet-volt-cold-weather-range-loss-electric-vehicle/. The Chevrolet Volt turns on the gasoline engine intermittently at temperatures below 25°F (-4°C), so trips with ambient temperatures below that threshold were excluded.

[12] Arctic Energy Alliance, 2013, 2013 Electric Vehicle Update http://www.aea.nt.ca/files/download/5500e4297ef91bf,

Vehicles.[13] The average minimum temperature for the study was -21°C, going as low as -27°C, with -12°C the observed threshold that fleets began to notice a difference in vehicle operations. Lithium ion battery vehicles were observed to have a loss of 10-20% charge at temperatures between -10 to 0°C, and a loss of up to 40% charge at temperatures below -20°C. Cabin heating was found to be an additional drain on battery life, lowering the charge another 20-40%. Overall it was found that these specific electric trucks with a 130 km range were reduced to a range of 32 km on days with temperatures below -10°C.

Hydro Québec: Hydro Québec collected data on 30 Mitsubishi i-MiEV BEVs in both Europe and near Montreal for 3 years from 2010–2013.[14] Twenty-seven companies and organizations took part in the initiative, which involved 31 users for a total of 650 vehicle-months and 740,000 km driven. A compact four-seater, the i-MiEV has a range of 120 km, with a 16 kWh lithium-ion battery. It takes about six hours to charge at Level 2 (240 V) or 12 to 21 hours at Level 1 (120 V). Every car in the project was equipped with on-board instruments to register energy consumption (charging pattern) and the effect of temperature on charging and users' charging habits. An observed loss of range of 13 km when temperatures were between 0°C and 10°C due to heating the interior of the vehicle. The range of the BEV used depends heavily on the ambient temperature and loss of range increased to 40% in below freezing conditions. Car heating has more of an effect (13 km less when the temperature is between 10°C and 20°C) than air-conditioning (5 km less when the temperature is above 20°C).

Manitoba Hydro: Manitoba Hydro added Hymotion lithium ion battery packs to 10 existing Toyota Prius Hybrids in 2008, allowing the vehicles to plug-in to charge, converting the traditional hybrid vehicles to PHEVs[15] Manitoba Hydro then monitored the vehicle for 3 years in the Winnipeg area. Driving 233,000 km over the course of the study, noting on average an additional 10% savings to fuel economy over the traditional Prius. Electricity use in the winter was not closely monitored, however vehicles were noted to have a significant range drop and required some modifications to the vehicles to enhance performance. The original 12V Prius batteries had to be replaced with newer and more efficient 12V battery and then were trickle charged whenever the vehicles were plugged in. Tests were run with engine blankets and electric in-car warmers, which both proved effective at reducing range issues associated with heating the interior.

Manitoba Hydro, in collaboration with the Province of Manitoba, Mitsubishi Heavy Industries, New Flyer Industries, Winnipeg Transit and Red River College, operate an all-electric bus on a daily, 20 km route[16]. The route runs a loop from the Winnipeg Richardson International Airport where it charges whiles waiting at the stop. Chargers are roof mounted and replace two operational hours of charge in approximately 10 minutes. The electric bus was originally a demonstration project used as a shuttle for

[13] CALSTART, E-Truck Performance in Cold Weather, June 2014 - http://www.calstart.org/Libraries/Publications/E-Truck_Performance_in_Cold_Weather.sflb.ashx

[14] Hydro-Quebec, November 2013, Mitsubishi Electric Vehicle Pilot Project, http://www.hydroquebec.com/transportation-electrification/pdf/mitsubishi-pilot-project-report.pdf (last accessed July 10, 2015).

[15] Center for Emerging Renewable Energy Inc., October 2011, Manitoba PHEV Demonstration Final Summary Report, http://www.gov.mb.ca/ia/energy/transportation/images/phev_summary_report.pdf (last accessed July 10, 2015).

[16] New Flyer, November 2014, New Flyer Battery-Electric Buses Enter Into Service With Winnipeg Transit, http://www.newflyer.com/index/112714-battery-electric-bus-winnipeg-transit (last accessed August 12, 2015).

Manitoba Hydro beginning in March 2014[17], and was so successful that the airport route was added in November 2014. Manitoba Transit has installed additional chargers in their fleet yard in anticipation of future electric vehicle additions.

Province of Manitoba: The Province of Manitoba signed an MOU with Mitsubishi in 2011 to test two Mitsubishi i-MiEV BEVs for two years[18]. Winter testing included driving in temperatures as low as -29°C, the lowest (public) recorded driving temperature of an electric vehicle within Manitoba. Tests included driving vehicles to battery depletion in temperatures ranging from -15°C to -29°C, where it was discovered that all interior heating had to be redirected to the defogger to maintain an unfrozen windshield. When operating in these negative temperatures, the average ranges of the iMiEVs was discovered to drop to 40-50 km, less than half of the average range of 110-120 km.

Lessons Learned from Vehicle Testing

Electric vehicle manufacturers have been unable to share externally many of their cold weather testing results. This is due in a large part to the current research and development happening to improve cold weather vehicle operations and increase vehicle efficiencies. Current research for many manufacturers revolves around thermal management systems, specifically whether air-cooled or liquid-cooled batteries can produce the best performance in weather extremes. Improvements for alternative heating packages are being explored as well, such as Tesla's "cold weather package" which provides additional seat warmers, windshield fluid heaters, and modified intake grills.

Kia added new heating technologies to the 2015 all-electric Kia Soul, including a new heat pump, air intake controller, driver-side only heating options, and technology to pre-heat the vehicle while charging[19]. Kia tested these PEVs in the Arctic Circle, successfully operating the Soul in -40°C temperatures, including letting the PEVs become cold soaked by sitting in sub-zero temperatures for over 8 hours.

Battery testing is a major component to ongoing research and development of electric vehicles, as this is a constantly evolving technology. New battery materials and configurations are being tested, in efforts to find a longer-lasting battery that can handle cold weather and still be affordable.

Arctic Energy Alliance: The Arctic Energy Alliance began testing a Chevrolet Volt in January 2015.[20] Housed primarily in Yellowknife, the PHEV is being used throughout the Northwest Territories. To date, the electric range has been more than sufficient to accommodate the Yellowknife daily commute of 6.3 km, however while the average summer range has been approximately 67 km, the winter range was

[17] Manitoba Hydro, Electric Vehicles, https://www.hydro.mb.ca/environment/electric_vehicles.shtml (last accessed August 12, 2015)
[18] Electric Vehicle Technology & Education Centre, December 2013, All-Electric Mitsubishi i-MiEV in Manitoba, http://www.meetar.com/mitsubishi-imiev-in-manitoba-blogs-red-river-college/
[19] Kia, February 2014, The world's toughest boot camp – Kia weathers the extremes, http://kia-buzz.com/ps_ev_winter_test/
[20] Arctic Energy Alliance, 2015, Electric Vehicle, http://aea.nt.ca/research/electric-vehicle

only 35 km.[21] This information is not entirely accurate for temperatures at or below -10°C, for at this temperature the internal combustion engine automatically turns on.

Arctic Energy Alliance has also noted a handful of traditional hybrid vehicles (non-plugins) in the Northwest Territories. A Hay River resident will soon have what they believe is the first Tesla in the Territory.

Home conversions: The first PEVs deployed in the Yukon Territory were conversions, as opposed to vehicles that come directly from the manufacturer[22]. The Government of Yukon has sponsored a course at Yukon College and at a local high school to convert vehicles to run off electricity. Currently there are at least three home-conversions in the Dawson area, and at least two in Whitehorse. Home conversions however do not have many of the auxiliary heating options that factory ready PEVs have, so typically are not able to be driven during the winter months.

Quantum Machine Works: In March 2014, Quantum Machine Works of Whitehorse purchased a Ford Focus PEV for the company use[23]. Purchased from a dealership in Vancouver, the PEV has worked great for the company in temperatures as low as -28°C. While the average warm weather vehicle range has been 100 km, in the winter the range drops to approximately 60 km. The PEV typically used for short trips by several employees, and is constantly connected to a charger when not in use. Quantum has had several other companies ask about the vehicle and has offered to loan it out for test drives.

Cold Weather Impacts on Vehicle Charging Time

Most electric vehicle chargers manufactured for residential and commercial use are suitable for outdoor use, although some perform better in extreme cold weather conditions. The operation of all equipment can be impacted when covered in snow or ice, particularly the charging cable, which could be encased if lying on the ground or coiled. If equipment must be outside, retractable charging cables or protecting the equipment with some form of shelter is preferable. Further, when siting charging equipment outside, considerations should be made for snow plow operations. Installing bollards, curbs, or wheel stops could help minimize equipment damage. Sub-surface heating of the charging space is another option, including hydronic (small tubes under the pavement circulating heated water and anti-freeze) and electric radiant (low-voltage mats under the pavement heated by electricity) heating.[24]

Chargers, also known as electric vehicle supply equipment, are available in a variety of charging levels. As noted previously, chargers are currently divided into Level 1, Level 2 and DC Fast Charging categories.[25]

[21] Email interview with Nick Walker, Arctic Energy Alliance, August 18, 2015.
[22] Interview with Shane Andre, Government of Yukon, August 6, 2015.
[23] Interview with Lee Johnson, Quantum Machine Works, August 5, 2015.
[24] Chittenden County RPC, June 2014, Electric Vehicle Charging Station Guidebook, http://www.driveelectricvt.com/docs/default-source/default-document-library/electric-vehicle-charging-station-guidebook-.pdf?sfvrsn=0
[25] U.S. Department of Energy Alternative Fuels Data Center, April 2015, Developing Infrastructure to Charge Plug-In Electric Vehicles, http://www.afdc.energy.gov/fuels/electricity_infrastructure.html

Table 2. Electric Vehicle Supply Equipment Categories

	Level 1 Charging	Level 2 Charging	DC Fast Charging
Electrical Circuit	120V AC	208V or 240V AC	480V AC
Equipment Needed	None- Standard Outlet used for Block Heaters	Home or public charging equipment	Designated DC Fast chargers and charge receptacles on vehicles.
Charging Rate (Kilometres Per Charging Hour) [26]	3-8 km	16-32 km	80-113 km in 20 minutes

In addition to the physical impacts of extreme cold weather, some types of electric vehicle chargers have difficulty transferring electricity to the vehicle. As discussed below, case studies and lessons learned from charging equipment manufacturers may mitigate potential impacts.

Charging Case Studies

Hydro-Quebec: Between 2010 and 2013, Hydro-Quebec operated an electric vehicle pilot project to understand a number of issues, including how the ambient temperature impacted PEV charging.[27] The initiative included nine Level 1 workplace chargers, 47 Level 2 chargers (27 residential and 20 workplace), and one DC fast charger. The researchers found that the Level 2 charging time was not affected by the ambient temperature and was the same year-round. However, researchers noted the DC fast charger took considerably longer than the standard 30 minutes to charge a vehicle to 80% capacity in colder conditions. The extended charge length is related to the battery pack's internal resistance (in addition to temperature, calculated based on battery size, chemical properties, age, and discharge current), which will be higher during extreme cold conditions.[28] Numerous batteries are being tested and developed to determine which batteries are best for PEVs and PHEVs for the life of the vehicle.

Airport Cooperative Research Program (ACRP): According to researchers contracted by ACRP, PEV charging stations are not typically affected by extreme cold. Researchers advised that cold weather airports consider installing Level 1 charging stations in long-term facilities so that batteries could charge slowly and be kept warm, replacing any parasitic loss that would occur while the batteries are not in use.[29]

North Sea Region Electric Mobility Network: Researchers in Gothenburg, Sweden evaluated a pilot project with CHAdeMO fast chargers located around the city.[30] In an environment that frequently reaches extreme low temperatures, users reported a variety of charging impacts. If the battery

[26] Average charging capabilities under optimal temperatures, not Yukon winter temperatures.
[27] Hydro-Quebec, November 2013, Mitsubishi Electric Vehicle Pilot Project, http://www.hydroquebec.com/transportation-electrification/pdf/mitsubishi-pilot-project-report.pdf
[28] Transport Evolved, November 2014, Electric Car Rapid Charging, https://transportevolved.com/2014/11/06/electric-car-rapid-charging-need-know/
[29] Airport Cooperative Research Program, ACRP Synthesis 54, Electric Vehicle Charging Stations at Airport Parking Facilities, http://onlinepubs.trb.org/onlinepubs/acrp/acrp_syn_054.pdf
[30] North Sea Region Electric Mobility Network, November 2012, Experiences from the Gothenburg fast charging project for electric vehicles, http://archive.northsearegion.eu/files/repository/20130716113751_FastCharge_Pilot_GOTHENBURG.pdf

temperature was less than 10°C (50°F), it was difficult to charge beyond 20% capacity with the fast charger. Further, the charging cables felt 'like a pipe' in cold temperatures and there was often a problem returning the plug to the base after charging. Finally, the display was difficult to read in cold weather. These charging issues apply only to the fast chargers used in this study.

Engine Block Heater Outlets as Electric Vehicle Chargers

Helping to offset the loss of charge from cold weather is the widespread availability of Level 1 charging in the Yukon. Engine block heaters require similar electricity load and connections as Level 1 PEV charging (including a weatherized 120V outlet); ICF reviewed several block heater specifications available from retailers online and found a power draw in the range of 0.4-1.5 kW. As these connections are pre-existing across businesses and home in the Yukon, Level 1 charging is possible for almost all drivers.

Awareness of using these outlets as PEV chargers however is not widespread. Current PEV drivers in the Yukon indicated that they utilize these outlets daily, however never would have considered them for PEV use before they researched PEV charging.[31,32] Business owners currently offer these outlets as a necessity in winter, not expecting to have the same electricity demand the remainder of the year, so year round usage may require corporate policy changes.

Lessons learned from EVSE Manufacturer Testing

Certain types of DC fast charging equipment are unable to function properly in extreme cold. For example, Eaton DC fast charger screens were switched out to prevent fade-out in cold weather and some ChargePoint networking capabilities have reportedly gone down in extreme cold weather and need to be rebooted.[33] Some DC fast charger manufacturers, such as AeroVironment, have created a cold weather package option that testing has shown can accommodate temperatures as low as -30°C (-22°F).[34]

Summary of Findings

ICF's literature review indicates that residents in the Yukon Territory will have difficulty maintaining normal functionality of electric vehicles during the coldest months of the year; however, electric vehicles, particularly PHEVs, are still a viable transportation option. The hurdle for market penetration will be that the PEV range in below freezing temperatures will be less than half of the average vehicle range. This may require more electricity to charge these vehicles, consumers making sure that there vehicle has sufficient range (including the battery and a combustion engine, as with the PHEV), or behavioral change. For daily use in cold winter months, however, the reduced electric vehicle range may still be within the scope of the average Yukon commute, an average of 15 minutes for the

[31] Interview with Lee Johnson, Quantum Machine Works, August 5, 2015.
[32] Interview with Shane Andre, Government of Yukon, August 6, 2015.
[33] Interview with Michelle McCutcheon-Schour, Vermont Clean Cities, November 21, 2014
[34] AeroVironment, http://www.chargepoint.com/files/Nissan_DC_Quick_Charger_datasheet.pdf

Whitehorse area and 15.7 minutes for the entire Yukon Territory (based on 2011 Census data)[35] or 4.1 km for Whitehorse and 3.9 km for the entire Yukon Territory (based on the 2006 Census data).[36] Dealerships in Yukon are not currently selling PEVs, requiring vehicles to be ordered online or from southern provinces. Training is needed for Yukon dealerships and mechanics on how to service these vehicles.

Unique to the Yukon market however is the vast abundance of Level 1 charging at homes and businesses, due to the readily available charging for engine block heaters. Awareness campaigns to educate the public and businesses that these can be used as chargers may increase the demand for electric vehicles. The Government of Yukon has indicated that they could easily promote electric vehicle charging, particularly as this additional electricity demand in warmer months would help even out the demand cycle.

Like conventional vehicles, precautions will need to be taken to allow the vehicles to start and function normally, including keeping the vehicles in garages and using good battery thermal management systems. Allowing the battery to remain plugged in to even a Level 1 charger will keep the battery warm and will be critical to normal function.[37] Further, drivers may want to consider alternative options to increase the cabin temperature, such as the use of seat heaters. By pre-starting these vehicles while attached to a charger, drivers can allow the vehicle cabin to warm and the windshield to defog before operating the vehicle on a reduced range; ICF estimates that this pre-heating will have the same or similar energy consumption as engine block heaters currently in use.

Additional precautions will also need to be exercised when installing and maintaining charging infrastructure, including public and workplace chargers that may be exposed to the elements.

[35] Statistics Canada, 2011 National Household Survey, Statistics Canada Catalogue no. 99-012-X2011031.

[36] Statistics Canada, 2006 Census of Population, Statistics Canada Catalogue no. 97-561-XCB2006010.

3 Plug-in Electric Vehicle Market Assessment

Plug-in Electric Vehicle Forecasting in Yukon Territory

Consumers' willingness to pay for new technology, as well as the extent to which they value their convenience will play a large role in PEV deployment. Consumer surveys in the US indicate the manufacturer's suggested retail price (MSRP) of a PEV is a critical factor, with nearly 70% of survey respondents claiming it is the most important factor in deciding their purchase.[38] Furthermore, consumers expect PEVs to be cost-competitive with similar internal combustion engine (ICE) vehicle models, with a majority desiring a sticker price under $30,000.[39] While consumers do acknowledge the higher cost of PEVs and are willing to pay more, the price differential between a PEV and a conventional vehicle or even an HEV remains too high to induce larger volumes of vehicle sales.

Consumers' expectations regarding price, range, and charging time are in many cases not met by PEVs available today.[40] These barriers make converting potential consumers into actual purchasers a significant challenge. As discussed previously, vehicle price is the primary barrier to widespread PEV adoption in the near-term. Even with incentives, the initial costs of PEVs generally remain higher than HEVs and ICE vehicles.

To develop forecasts for Yukon Territory, ICF considered the parameters identified in the table below. The subsequent subsections discuss these parameters in more detail. ICF notes that we typically rely on hybrid electric vehicle (HEV) ownership data as a good indicator of the potential for PEV adoption. The premise of the relationship between HEV ownership and PEV adoption is that households that value non-economic benefits are more likely to purchase PEVs, and HEV owners show a willingness to pay to reduce gasoline use that goes beyond the economic benefits of using an HEV. While we were able to obtain vehicle registration counts from the Government of Yukon, they did not include HEV registration data. Despite this limitation in our forecasts, the parameters in the table below do provide good indicators for PEV adoption.

[38] Deloitte Touche Tohmatsu Ltd, "Gaining Traction: A Customer View of Electric Vehicle Mass Adoption in the U.S. Automotive Market," 2010, http://www.deloitte.com.br/publicacoes/2007/MFG.Gaining_Traction_customer_view_of_electric_vehicle_mass_adoption.pdf.

[39] Ibid.

[40] Deloitte, "Gaining Traction: Will Consumers ride the electric vehicle wave?" Deloitte Global Services Ltd., 2011.

Table 3. Parameters Influencing PEV Adoption

Parameter	Description
Income	Studies have found that consumers of electric vehicles typically earn more than the average household
Commuting Patterns	Drivers consider many factors when purchasing vehicles; their daily work commuting is a significant factor. Interestingly, Yukon residents on average have a significantly shorter commuting distance than other parts of Canada
Access to Charging	Households that own their property are more likely to adopt a PEV than those who rent, according to market research by various analysts. Further, access to charging at workplaces can be a significant driver for growth.
Vehicles & Fuel Pricing	Vehicle population, population and economic growth, and vehicle turnover provide boundary conditions for the volume of and the rate at which PEVs can be deployed. Whereas fuel prices (gasoline and diesel) can impact consumer decision-making,

Income and Demographics

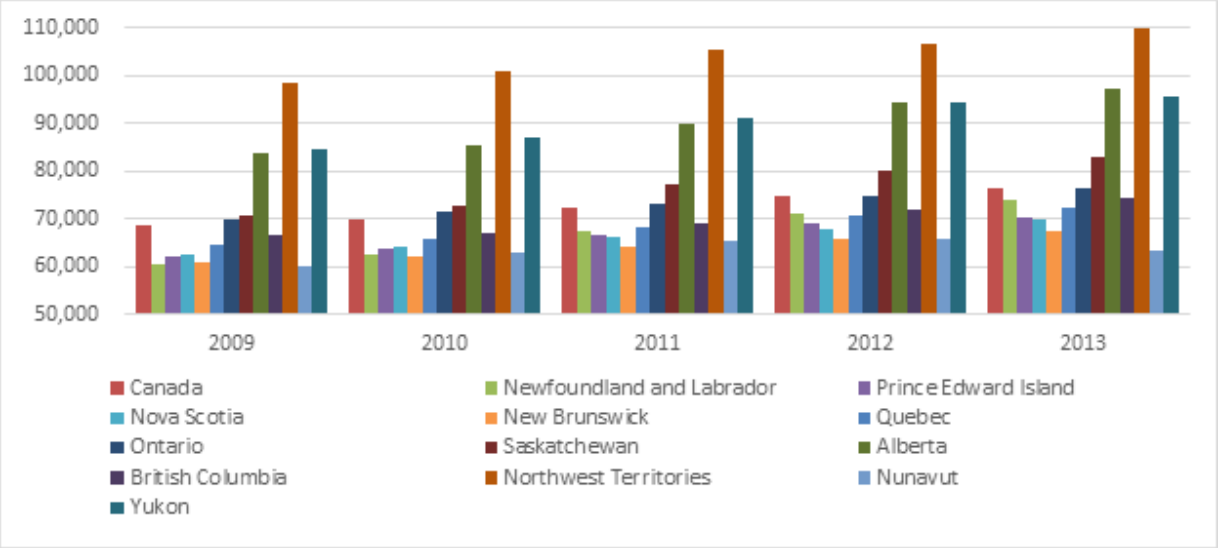
Key takeaways for Yukon Territory:

- The annual median income is relatively high compared to other provinces
- A large proportion of Yukon residents are within the age range of typical PEV consumers

Studies have found that consumers of electric vehicles typically earn more than the average household, with current PEV owners in Canada earning an annual income greater than $90,000.[41,42,43,44] Yukon residents may demonstrate greater rates of PEV adoption compared to other regions due to their higher than average median income. For the past five years, for instance, the annual median family income for a Yukon family is relatively high compared to other provinces and territories in Canada, with a median income of $95,360 per family in 2013, the third highest in the country (see Figure 2).

[41] Axsen, J., J. Bailey, and M.A. Castro (2015). Preference and lifestyle heterogeneity among potential plug-in electric vehicle buyers. Energy Economics 50, 190-201.
[42] Axsen, J., S. Goldberg, J. Bailey, G. Kamiya, B. Langman, J. Cairns, M. Wolinetz, and A. Miele (2015). Electrifying Vehicles: Insights from the Canadian Plug-in Electric Vehicle Study. Simon Fraser University, Vancouver, Canada. Available online at http://rem-main.rem.sfu.ca/papers/jaxsen/Electrifying_Vehicles_(FINAL)_V2.8_(July10).pdf
[43] The International Council on Clean Transportation (2012). Consumer Acceptance of Electric Vehicles in the US. Available at: http://www2.epa.gov/sites/production/files/2014-09/documents/kodjak121312.pdf .
[44] Oceanus – Electric Vehicle Information Exchange (2012). Electric Vehicle Survey Panel. Available online at: www.evix.com.

Figure 2. Annual Income Estimates for Census Families and Individuals, By Province, 2009-2014.

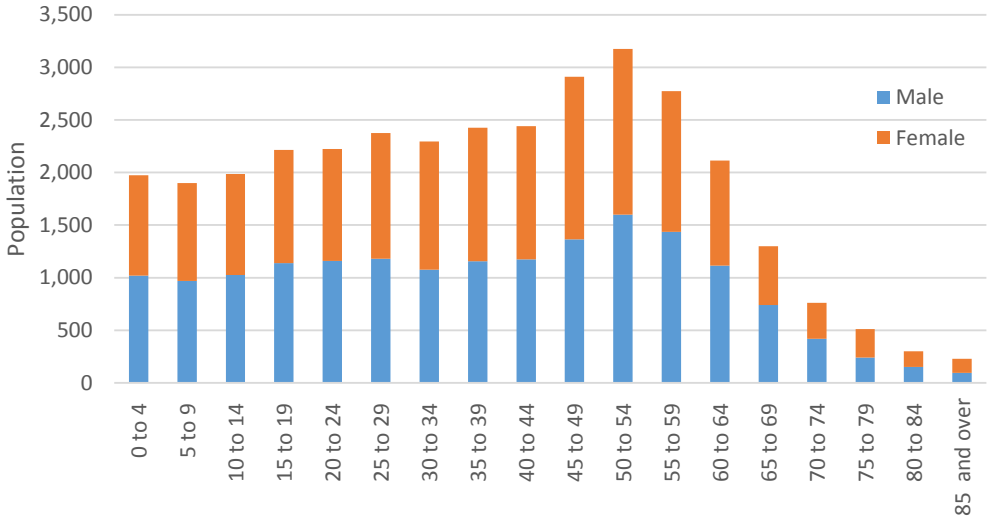


Source: StatsCanada

The previously referenced studies also found the majority of PEV consumers to be between the ages of between 35 and 54, with an average age of 46 years old. The demographics of Yukon residents support increased PEV adoption potential due to the high number of residents within the age category of PEV consumers[45], as shown in Figure 3.

[45] Statistics Canada, (2011). Focus on Geography Series, 2011 Census. Available at: http://www12.statcan.gc.ca/census-recensement/2011/as-sa/fogs-spg/Facts-pr-eng.cfm?Lang=Eng&GC=60.

Figure 3. Yukon - Population by five-year age groups and sex.



Source: 2011 Census Data, StatsCanada

Population and Commuting Patterns

Key takeaways for Yukon Territory:

- The majority of residents live in urban areas
- There are a significant number of daily commuters
- Commuter trip length is less than the range of PEVs in cold climates

Several factors related to commuting patterns of residents result in the potential for increased adoption rates of PEVs in the Yukon. While the population density overall is very low, at 0.1 persons per square kilometre, the majority of residents in the Yukon live in metropolitan or agglomeration areas (CMA/CA) (77%; 26,028 persons), with 69% of the population within the capital city of Whitehorse itself.[46] Of these residents, there are a significant number of daily commuters, with 75% of Whitehorse residents driving a vehicle to work (see Table 4).

[46] Statistics Canada (2011). Focus on Geography Series, 2011 Census. Available at: http://www12.statcan.gc.ca/census-recensement/2011/as-sa/fogs-spg/Facts-pr-eng.cfm?Lang=Eng&GC=60.

Table 4. Yukon mode of transportation to work

Commute Mode	Percent
Car, truck, van as driver	75%
Car, truck, van as passenger	8%
Public transit	5%
Walk to work	7%
Bicycle	3%
Other (motorcycles, taxi, etc.)	2%
Source: Government of Yukon (2011 Canadian Census)	

As discussed previously in Section 2, the Yukon's cold climate impacts charging abilities and driving range of PEVs, reducing the range of PEVs up to approximately 60%. Considering this reduced driving range, the average commuter trip length is still comparable to the expected PEV range. For instance, a survey conducted by the City of Whitehorse in 2000 indicated that most commuters drive less than 10 km one-way to work (Table 5).[47] The City of Whitehorse's Transportation Demand Management Plan Employee Survey,[48] which surveyed 207 employees from Yukon Government, Yukon Energy and City of Whitehorse, validates the 2000 report numbers referenced above. Compared to Canadians, Yukon residents on average have a significantly shorter commuting distance, with a median distance of 3.9 km for Yukon residents versus 7.6 km for Canadians (Figure 4).

[47] Public Service Commission, City of Whitehorse (2000). "How Do You Get to Work" A Transportation Survey of Whitehorse Area Employees: Technical Report. Available at: http://www.whitehorse.ca/home/showdocument?id=1602.

[48] Whitehorse Transportation Demand Management Plan, City of Whitehorse, YT, March 2015. Available online at http://www.whitehorse.ca/home/showdocument?id=4250

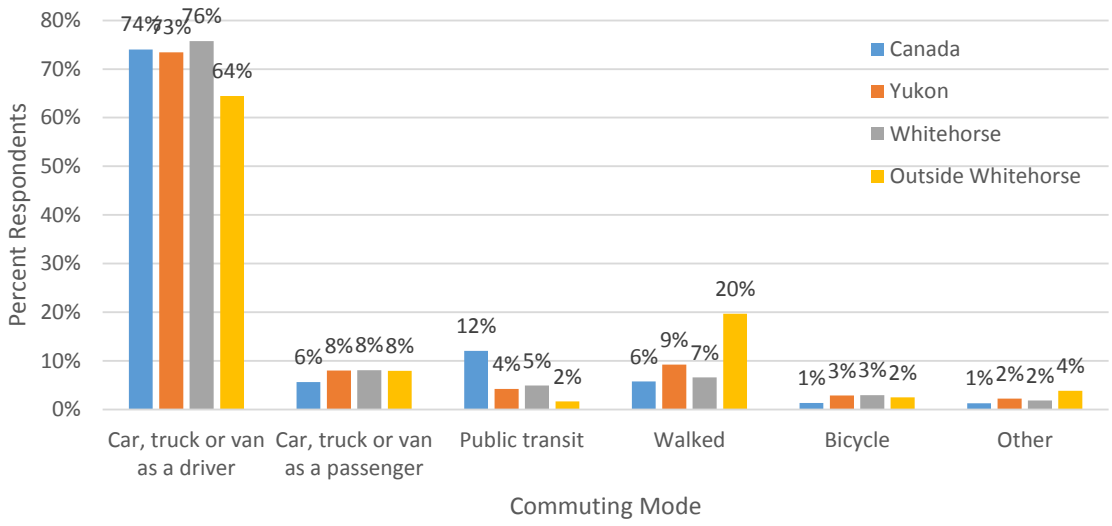
Taking into consideration the fact that many people (43%) use their vehicle at lunch time, increasing the daily range requirements, the daily commute of most residents remains below the typical range of PEVs in cold climates.

Table 5. Home to Work Commuting in Whitehorse, 2002

Responses to transport survey question: "Approximately how many kilometres is it from your home directly to work (one-way)?"		
Distance	No. of Responses	Percent of Responses
< 5 km	639	29.5%
5–10 km	618	28.5%
10–25 km	672	31.0%
> 25 km	239	11.1%
Total	**2,168**	**100%**

Source: Public Service Commission, 2000

Figure 4. Commuting Modes in Canada, Yukon, Whitehorse, and Outside Whitehorse



Source: 2011 Canadian Census

Access to Charging Stations

Key takeaway for Yukon Territory:

- Access to suitable areas for home charging
- Access to suitable charging infrastructure at work

As colder temperatures increase the time needed to charge PEV batteries, access to charging infrastructure is an important factor to consider. The majority of Yukon residents live in houses[49] (75.9%) versus apartments (23.9%) (compared to 65.8% and 34.3% of Canadians, respectively).[50] These dwelling types are more likely to have access to a garage, providing an area protected from the elements, thereby reducing the charging time required.

Access to suitable charging infrastructure is also available to residents at work. According to the City of Whitehorse survey[51], 72.3% of commuters have plug-ins available at work parking areas and for those that do not have access to plug-ins, 20.1% already start their car periodically throughout the day. The remaining portion either do not bring their vehicles to work on very cold days, have a command start or have access to parking in a heated garage.

Vehicles and Fuel Prices

Key takeaways for Yukon Territory:

- Vehicle registration in the Yukon is steadily increasing annually; however, vehicle purchasing patterns indicate a preference for light-duty trucks, for which there are few PEV offerings today.
- Gas and diesel prices are on average higher in Yukon Territory (although prices in Whitehorse are sometimes comparable to lower mainland prices), resulting in higher fuel cost savings with the purchase of a PEV.

Increased forecast adoption of electric vehicles can also be supported by evidence of increasing vehicle registration in the Yukon, as electric vehicles are a portion of these increasing registrations. Vehicle registration in the territory has steadily increased annually at an average rate of 3% since 2001 (see Figure 5).[52] Most vehicles registered are classified as *vehicles up to 4.5 tonnes* (passenger vehicles and light-duty trucks).

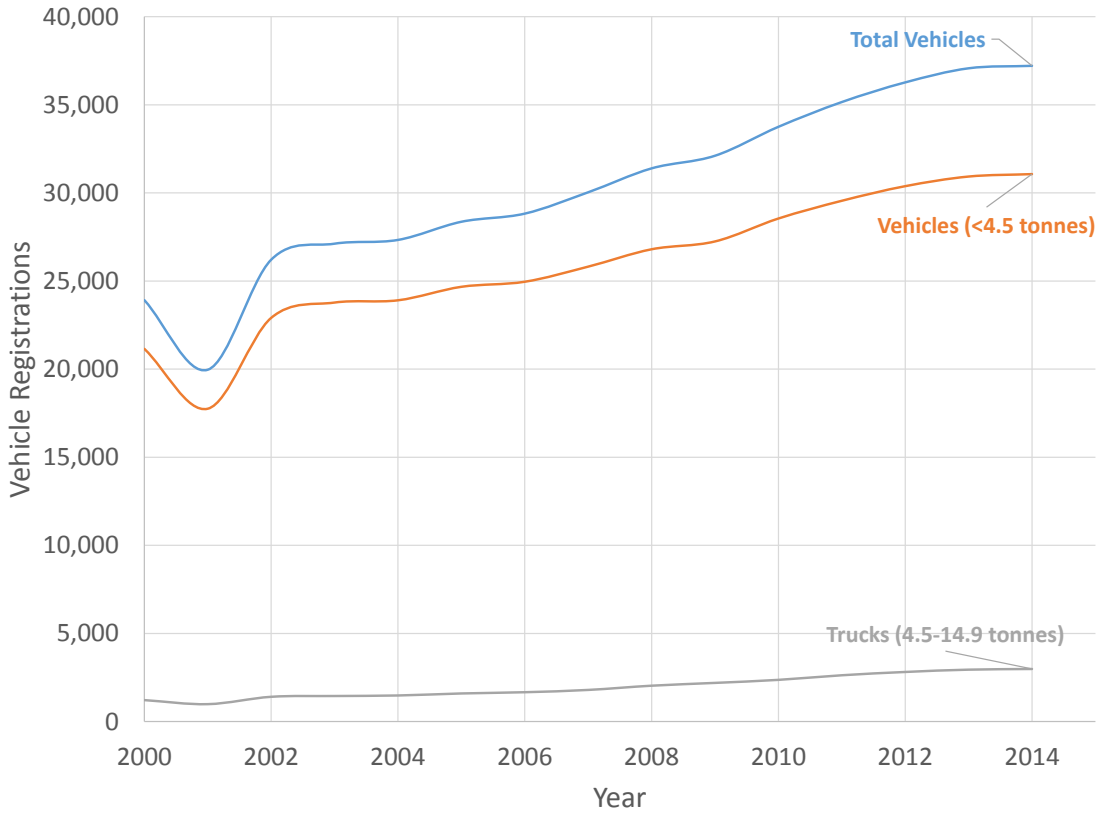
[49] Houses include single-detached houses, semi-detached houses and row houses. Apartments include apartment buildings, duplexes and other movable dwellings.

[50] Statistics Canada (2011). Focus on Geography Series, 2011 Census. Available at: http://www12.statcan.gc.ca/census-recensement/2011/as-sa/fogs-spg/Facts-pr-eng.cfm?Lang=Eng&GC=60.

[51] Public Service Commission, City of Whitehorse (2000). "How Do You Get to Work" A Transportation Survey of Whitehorse Area Employees: Technical Report. Available at: http://www.whitehorse.ca/home/showdocument?id=1602.

[52] Government of Yukon, Energy, Mines and Resources (2012), An Energy Strategy for Yukon Priority Action: Yukon Transportation Sector Information Paper. Available at: http://www.energy.gov.yk.ca/pdf/yt_sector_info_paper.pdf

Figure 5. Vehicles registered in the Yukon, 2000–2014[53]



Source: Statistics Canada (2015)

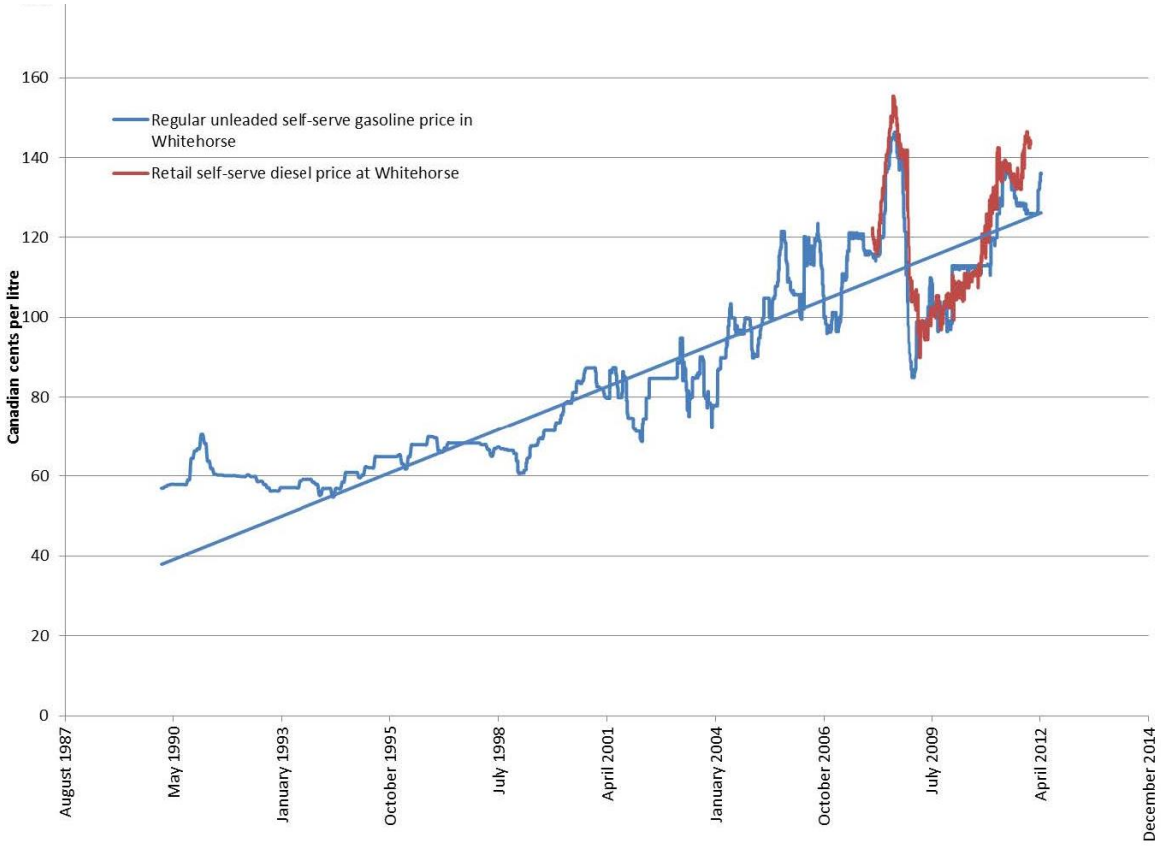
Gasoline and diesel prices also play a significant role in adoption rates of electric vehicles.[54] Conventional fuel prices are high in the Yukon, with the price of diesel and gasoline steadily increasing from 1999–2012 (Figure 6).[55] The higher fuel cost savings for PEV consumers in the Yukon results in increased adoption potential within the territory.

[53] Statistics Canada, CANSIM, table 405-0004

[54] Axsen, J., S. Goldberg, J. Bailey, G. Kamiya, B. Langman, J. Cairns, M. Wolinetz, and A. Miele (2015). Electrifying Vehicles: Insights from the Canadian Plug-in Electric Vehicle Study. Simon Fraser University, Vancouver, Canada. http://rem-main.rem.sfu.ca/papers/jaxsen/Electrifying_Vehicles_(FINAL)_V2.8_(July10).pdf, (last accessed August 18, 2015)

[55] Government of Yukon, Energy, Mines and Resources (2012), An Energy Strategy for Yukon Priority Action: Yukon Transportation Sector Information Paper. Available at: http://www.energy.gov.yk.ca/pdf/yt_sector_info_paper.pdf

Figure 6. Whitehorse Transportation Fuel Costs, 1999 - 2012



Source: Yukon Bureau of Statistics

PEV Forecasts for Yukon Territory

ICF estimates about 3,000 vehicles sold in Yukon Territory in 2014; showing average increase of about 5-6% (year-over-year) for the last 7 years.[56] Data from the Motor Vehicles Section of the Government of Yukon indicate that about 39% of registered light-duty vehicles since 2009 are passenger cars.[57] Statistics Canada only reports data for "British Columbia and the Territories", and does not report new vehicle sales for the Yukon Territory; however, the aggregated data for British Columbia and the Territories indicate that over the same time period for which we have total vehicle registration data (2009-2014), 41% of new light-duty vehicle sales were passenger cars. Further, for comparative purposes, we note that the country-wide average is about 43% of new light-duty vehicle purchases are passenger cars and 57% are light trucks. This vehicle split limits the potential of PEVs in the near-term future because there are limited offerings available today in the cross-over segments and light trucks.

[56] Based on ICF analysis of vehicle sales, registered vehicle data, and population (via Statistics Canada).

[57] Vehicle registration data also includes heavy-duty trucks, buses, and other vehicles; however, for the purposes of this analysis, we only considered vehicles less than 4,500 kg.

To estimate sales growth moving forward, ICF used a combination of forecasted demand for vehicle kilometres traveled, population growth, and economic growth. ICF assumes a year-over-year increase in new vehicle sales of 1.0% for 2015-2035. [58] For vehicle-kilometres traveled (VKT), ICF reviewed the most recently available data from the Canadian Vehicle Survey, which reports average VKT growth for all of Canada at 2.5% for the period from 2000-2009.[59] However, in Canada's Energy Future 2013, the National Energy Board reports an assumed growth of 1.0% in VKT. ICF notes that VKT is a good proxy for forecasting, and more reliable than fuel consumption, for instance, because it is largely unaffected by vehicle efficiency/fuel economy.

Growth rates for electric vehicles are derived from hybrid electric vehicle adoption in multiple jurisdictions, modified for local factors such as income and demographics, and commuting patterns. Generally we forecast exponential growth in the first 5-9 years of electric vehicle adoption, with that growth tailing off into a linear function by year 10. That linear growth is not a constant over time; rather, it increases with vehicle price reductions in the years 10-15, and decreases thereafter.

ICF developed three penetration scenarios out to 2035:

- **Low**: Assumed low levels of PHEVs deployed in light-duty passenger vehicles; no penetration in light-duty trucks. PEVs represent about 3% of new passenger car sales in 2025 in this scenario, increasing to 6.7% of new passenger car sales in 2035. ICF opted not to include light-duty trucks because there is significant uncertainty around automobile manufacturers' willingness to transition their electrification plans to their light trucks. Generally, ICF assumes that OEMs will meet fuel economy and GHG standards by focusing on a combination of fuel efficiency improvements and electrification for conventional light-duty passenger cars; whereas, OEMs will focus almost exclusively on fuel efficiency improvements (e.g., via light weighting and powertrain improvements) for light-duty trucks.[60]
- **Medium**: Assumed modest levels of PHEVs deployed in passenger vehicles with low levels of adoption in light-duty trucks. PEVs represent about 7% of new passenger car sales in 2025 and 18% in 2035. PEVs represent about 2.7% of new light truck sales in 2025 and 6.7% in 2035.
- **High**: Assumed more aggressive levels of PHEVs deployed in passenger vehicles; some penetration in light-duty trucks. In this scenario, ICF assumes that OEMs take a more aggressive approach towards meeting existing regulations via the deployment of plug-in hybrid and battery electric trucks. PEVs represent about 7.8% of new passenger car sales and 5.5% of new light-truck sales in 2025, increasing to 23.2% and 13.4% in 2035.

[58] ICF notes that the variations in our forecasts are all linked to the same VKT and sales growth forecasts, which are linked to other forecasts of population and economic growth. This growth is held constant across each EV deployment scenario developed; the variation arises from parameters such as vehicle availability and vehicle pricing.

[59] Natural Resources Canada, Canadian Vehicle Survey, 2009. Available online at http://oee.nrcan.gc.ca/publications/statistics/cvs09/pdf/cvs09.pdf

[60] The U.S. Energy Information Administration's Reference Case in the Annual Energy Outlook 2015, for instance, forecasts an average ratio of nearly 60-to-1 for electrified powertrains (including PHEVs and BEVs) in cars versus trucks through 2040. Over the same time period, the fuel efficiency of light trucks is forecasted to improve at a comparable rate to passenger vehicles.

ICF assumed a 50-50 split of PHEVs between the PHEV32 and PHEV64 vehicle categories in each deployment scenario. Figure 7 below show the cumulative PEVs in each scenario and Table 6 below includes the total number of EV passenger cars and light-trucks deployed in each scenario, as well as the share of electric vehicles of the total on-road vehicle fleet in the Yukon from 2015–2035.

Figure 7. PEV Forecasts for Yukon Territory in Low, Medium, and High Scenarios, 2015-2035

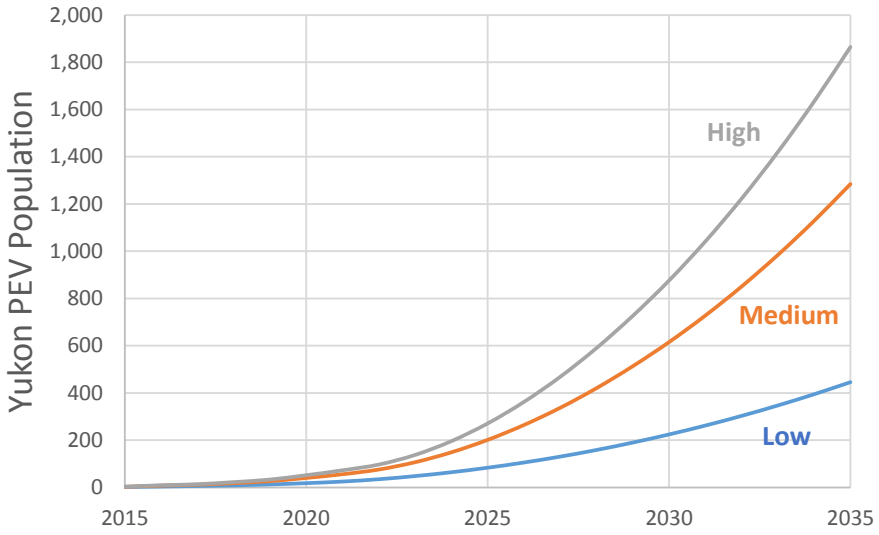


Table 6. PEV Deployment in Yukon Territory (Percent of Total On-Road Vehicles)

Deployment Scenario	Vehicle Type	2015	2020	2025	2030	2035
Low	Passenger Cars	2	18	83	224	445
	%Total Vehicles	0.0%	0.0%	0.2%	0.5%	1.1%
Medium	Passenger Cars	2	34	175	544	1,144
	Light Trucks	1	6	26	71	140
	%Total Vehicles	0.0%	0.1%	0.5%	1.5%	3.0%
High	Passenger Cars	1	33	183	640	1,397
	Light Trucks	2	19	87	235	467
	%Total Vehicles	0.0%	0.1%	0.7%	2.1%	4.4%
	Total Vehicles	37,736	38,556	39,602	40,833	42,214

Greenhouse Gas Impacts of Plug-in Electric Vehicles

PEV have zero tailpipe GHG emissions; however, there are upstream emissions attributable to electricity generation that must be accounted for to conduct a proper GHG reduction analysis. In the case of the Yukon Territory, even the upstream emission factors are small because such a large share of the generation profile comes from renewable resources, predominately hydropower. The emission factors

for transportation fuels are reported on a lifecycle or well-to-wheels basis and are reported as grams of carbon dioxide equivalents per unit of energy (g CO_2eq/MJ) – also referred to as carbon intensity. ICF used emission factors from GHGenius, as shown in Table 7 below.

Table 7. GHG Emissions for Electricity and Gasoline

Fuel	Carbon intensity (gCO_2eq/MJ)
Electricity*	8.24 g/MJ
Gasoline	87.29 g/MJ
*Assumes 3% of power generated is from diesel generators	

The GHG emission reductions are reported as the difference between a light-duty internal combustion engine vehicle using gasoline and a PEV using electricity (and gasoline for PHEVs). The carbon intensity of electricity reported in the table above does not account for the fact that electricity used to power a motor is more energy efficient than gasoline. As a result, one must apply a factor referred to as the energy economy ratio (EER). For electricity, the value is 3.4; in other words, after accounting for the EER of electric vehicles, the effective carbon intensity of electricity is 2.42 gCO_2eq/MJ.

GHG Emission Reductions

The equations below shows how the various parameters outlined previously are combined into calculations to yield the GHG emission reductions attributable to vehicles using gasoline and electricity, or a combination thereof.

$$GHG_{gasoline} = PEVs * \left(\frac{VMT}{mpg}\right) * \delta_{gasoline} * CI_{gasoline},$$

where $\delta_{gasoline}$ is the energy density of gasoline, 34.69 MJ/L, and $CI_{gasoline}$ is the carbon intensity of gasoline.

$$GHG_{PHEV} = PHEVs * \left[\left(\frac{(1-eVMT)}{mpg}\right) * \delta_{gasoline} * \frac{CI_{gasoline}}{EER_{Fuel}} + \frac{eVMT}{mpg} * \delta_{gasoline} * CI_{electricity}/ EER_{electricity}\right]$$

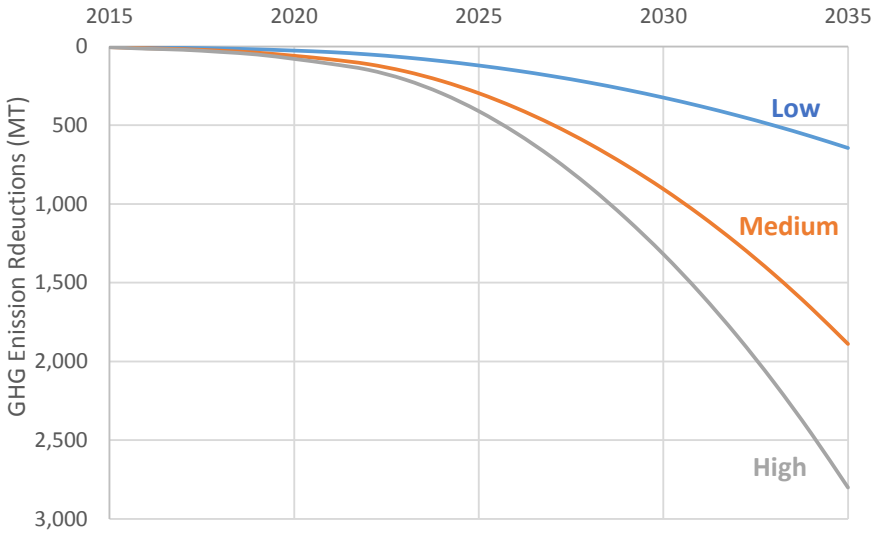
$$GHG_{BEV} = BEVs * \left(\frac{VMT}{mpg}\right) * \delta_{gasoline} * CI_{electricity}/EER_{electricity}$$

$$GHG\ Emission\ Reductions = \Delta\left(GHG_{gasoline}, GHG_{PHEV} + GHG_{BEV}\right), \text{ where}$$

$$PEVs = PHEVs + BEVs.$$

Figure 8 below shows annual reductions as metric tons for each of the PEV deployment scenarios developed previously.

Figure 8. GHG Emission Reductions from PEV Forecasts



ICF estimates that PEVs could reduce GHG emissions by about 120–410 MT by 2025 and 650–2,800 MT by 2035. For the sake of reference, the Yukon Transportation Sector GHG emissions report[61] on-road diesel and on-road gasoline accounted for 274,000 MT CO2e in 2012, representing about 50% of total GHG emissions for the Yukon Territory (638,000 MT CO2e). These GHG reduction estimates account for the cold weather performance of plug-in electric vehicles and assume that the range of PHEVs is halved in the winter months (e.g., from 64 km to 32 km) and that there is twice as much electricity consumed in battery electric vehicles–in other words, we do not assume that drivers travel fewer kilometres, rather that they need to charge their vehicles more. Table 8 below shows the estimated emissions performance of conventional vehicles running on gasoline compared to PHEVs and BEVs in standard operating (or summer) conditions and in cold weather (or winter). The values are shown for new vehicles purchased in the year indicated, and do not represent the fleet average vehicle performance.

[61] Yukon Greenhouse Gas Emissions: The transportation sector, Updated Report 2015. Available online at http://www.env.gov.yk.ca/publications-maps/documents/Yukon_Transportation_Sector_GHG_Emissions_Final_Updated_Report_March_2015.pdf

Table 8. GHG Emissions Rates (gCO2e/km) for various vehicle types and different operating conditions

Conditions	Year	Conventional ICE		PHEV32		PHEV64		BEV	
		Car	Light Truck	Car	Light Truck	Car	Light Truck	Car	Light Truck
Standard Operation / Summer	2015	218	277	118	161	19	35	6	9
	2020	166	239	91	139	16	28	6	9
	2025	127	182	70	107	13	22	6	9
	2030	127	182	70	107	13	22	6	9
	2035	127	182	70	107	13	22	6	9
Cold Weather Operation / Winter	2015	240-273	305-346	186-211	243-275	130-147	139-157	13	18
	2020	183-208	263-299	143-162	210-238	100-113	106-121	13	18
	2025	140-159	200-227	110-125	161-182	77-87	82-93	13	18
	2030	140-159	200-227	110-125	161-182	77-87	82-93	13	18
	2035	140-159	200-228	110-125	161-182	77-87	82-93	13	18

The emissions rates for cold weather are reported as a range to account for impacts to both conventional vehicles and electric vehicles. For instance, the Natural Resources Canada reports a 12–28% increase in fuel consumption (per US EPA estimates) in urban commutes, increased highway fuel consumption as a result of increased aerodynamic resistance, increased resistance from poor road conditions, and the energy density of winter gasoline formulations.[62] For illustrative purposes, we use an estimated increase in emissions linked to increased fuel consumption of 10–25% for conventional vehicles. The GHG emission rates for PHEVs are linked to the share of kilometres traveled using electricity or gasoline, and the range of estimates for cold weather operation reflects the range of estimates for when the vehicle is operating using its combustion engine. ICF also notes that the emission rates plateau in improvement in 2025 and are constant thereafter, reflecting Environment Canada's regulations related to vehicular GHG emissions, proposed in 2012 and adopted in 2014.[63]

4 Grid Impacts of PEVs

One of the key concerns about PEVs is the potential impact to the electric grid. If vehicle charging occurs coincident with peak demands, increased loads will drive a need for new investment in generation, transmission and distribution capacity. If charging can be managed to occur primarily in off-peak periods, much of the load will potentially be served with existing infrastructure such that impacts on the electric grid will be significantly reduced and there will be a potential for significant grid benefits, such as deferred or avoided investments in generation, transmission, and distribution capacity. Furthermore, PEVs have the potential to help level load and support higher penetration of renewable generation on the grid by using the vehicles' batteries for storage.

In the following subsections, ICF outlines our approach to analyzing the potential grid impacts of PEVs in the Yukon Territory, namely by reviewing the potential energy consumption of PEVs and the corresponding load profiles of those vehicles.

Energy Consumption and Loadshapes of PEVs

Given that there is not a profile of PEV energy consumption in the Yukon Territory, ICF relied on energy consumption profiles developed elsewhere. In a recent report for the California Electric Transportation Coalition, ICF developed energy consumption profiles shown in the table below.

[62] Natural Resources Canada, Learn the facts: Cold weather effects on fuel efficiency, Available online at http://www.nrcan.gc.ca/energy/efficiency/transportation/cars-light-trucks/buying/16748.

[63] Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations (SOR/2014-207)

Table 9. Energy Consumption of Plug-in Electric Vehicles

Vehicle Type (battery size)	Vehicle Kilometres Traveled		eVKT		Energy Consumption (kWh)	
	Daily	Annual	Daily	Annual	Daily	Annual
PHEV16 (4 kWh)	66	24,090	16	5,840	3.5	1,278
PHEV32 (8 kWh)			32	11,680	7.0	2,555
PHEV64 (16 kWh)			49	17,885	10.7	3,909
BEV (24-80 kWh)	48	17,370	48	17,374	10.3	3,770

These data are developed largely based on information from the EV Project.[64] The plug-in hybrid electric vehicles (PHEVs) are distinguished by their so-called all electric range or the estimated distance that each vehicle can travel using only battery power. These are listed as PHEV16, PHEV32, and PHEV64, capable of traveling an estimated 16, 32, and 64 km using only battery power before engaging the internal combustion engine.

ICF developed the values in the table above for PHEVs assuming that they would drive similar distances as the Chevrolet Volt (a PHEV64) and that they will exceed their all-electric range. For the purposes of this analysis, we excluded the consideration of PHEV16s, with the underlying assumption that the negative impacts on vehicle range would preclude them from deployment in the Yukon Territory. ICF held these values constant over time, considering the following: On one hand, battery technology will likely improve by 2035 to enable PEVs to travel longer distances. On the other hand, the lifetime of batteries for use in automotive applications is not well understood today. ICF recognizes that the constant VKT for PEVs is a simplifying assumption; however, given the uncertainty regarding battery technology today and into the future, we recommend a conservative simplifying assumption whereby VKT is held constant over the course of the analysis.

The all-electric range of these vehicles is likely to be reduced significantly in the winter months in the Yukon. Based on the research outlined previously in Section 2, ICF assumed a 50% reduction in the range of plug-in electric vehicles. We did not however, include any additional load during winter months for pre-heating the vehicle. Based on our research, pre-heating for plug-in electric vehicles would be the same or similar to the demand generated by engine block pre-heaters. ICF developed the daily energy consumption profiles shown in the table below for the Yukon Territory in summer (April to September) and winter (October to March) months.

[64] See for instance, The EV Project, Q2 2013 Quarterly Report

Table 10. Estimated Daily PEV Energy Consumption (in units of kWh) in the Yukon for Summer and Winter[65]

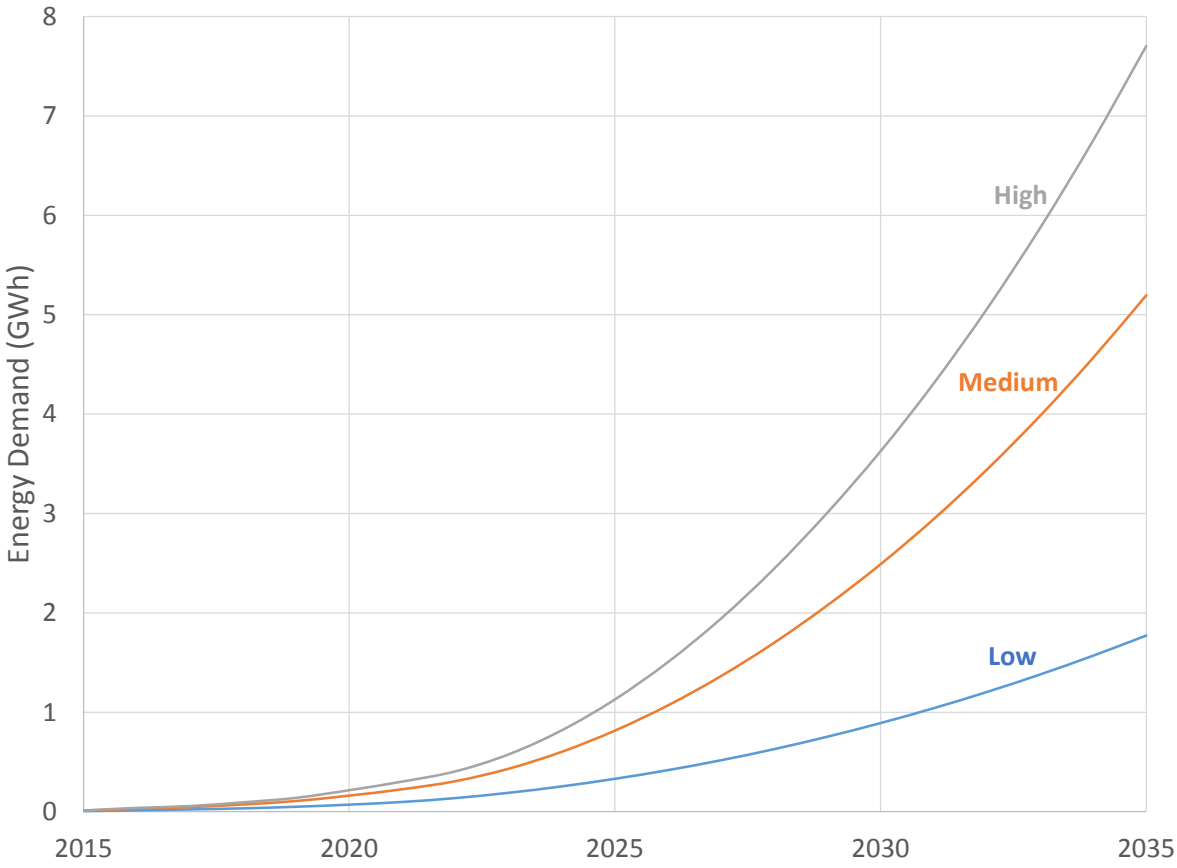
PEV Type	Passenger Car		Light Truck	
	Summer (Apr–Sept)	Winter (Oct–Mar)	Summer (Apr–Sept)	Winter (Oct–Mar)
PHEV32	7.0	7.0	10.0	10.0
PHEV64	10.7	14.0	15.3	15.3
BEV	10.3	20.6	14.8	29.5

We assume that passenger car and light truck PHEV32s deplete the full range of their battery in both summer and winter months; and in the winter months, they simply consume more gasoline to account for the additional reduced range using the battery. We assume that passenger car PHEV64s will consume the additional 24% of energy that the battery is capable of delivering in winter months. In the case of light truck PHEV64s, we assume that they consume the entirety of their battery power in both winter and summer months. For BEVs, we assumed that the vehicle would use its full range based on estimated battery sizing.

The figure below shows the forecasted energy demand (in MWh) of EVs in the low, medium, and high deployment scenarios.

[65] These values do not include line losses.

Figure 9. Forecasted Energy Demand (GWh) for EV Deployment Scenarios



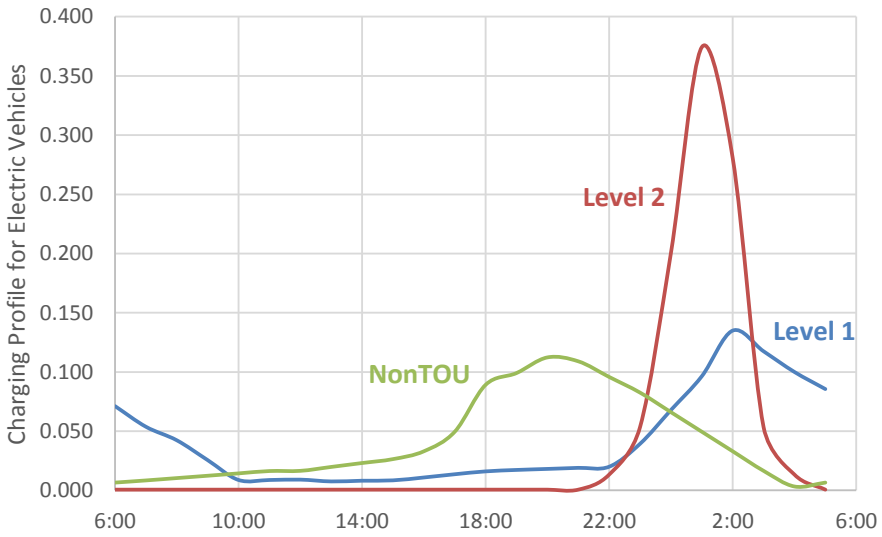
ICF also developed loadshapes for various charging scenarios, considering various charging levels and rate profiles. ICF considered both Level 1 and Level 2 charging; as noted previously, Level 1 charging is at 110 V and peaks around 1.4 kW. Level 2 charging is at 240 V and peaks around 7.5 kW. Note that many electric vehicles available today, particularly PHEVs, are power-limited by the on-board charger. For instance, the charging hardware on the Toyota Prius Plug-in and Ford Energi series of vehicles limit the charging rate to 3.3 kW. Nissan, on the other hand, quickly changed over to providing consumers with a 6.6 kW on-board charging rate within two generations of the LEAF. Given the long-term outlook of the illustrative analysis shown here, we assume a peak power demand of 7.5 kW at Level 2 charging.

For both Level 1 and Level 2 charging, we assume that there are time-of-use rates in place that incentivize charging at certain times of day. Ultimately, the structure of the TOU rate is up to the utility or load-serving entity. For the purposes of this analysis, we simply assumed that charging would be pushed off-peak.

The following bullets describe briefly the various charging scenarios considered, including charging level and rate assumptions:

- **L1 residential charging, TOU rate**: Level 1 charging at home is a proxy for charging of PHEVs with smaller batteries, like the PHEV16 or PHEV32. The normalized profile is based on a similar start time as L2 charging; however, it is stretched out over a longer period.
- **L2 residential charging, TOU rate**: Level 2 charging at home is a proxy for BEV or PHEV64 charging.
- **Residential charging, Non-TOU rate**: Residential charging in the non-TOU case is a modified version of what is reported in the EV Project for Nashville, Tennessee in the US–a region without a TOU rate.[66]

Figure 10. Daily Loadshapes for Electric Vehicles in Various Charging Scenarios



Note that the area under the curve of the daily load profiles shown in the figure above is normalized to 1.0. The daily charging profile has been normalized to 1.0 for illustrative purposes. In other words, the integrated area under the curve is equal to 1.0; and that value is adjusted in the analysis depending on the vehicle type and battery size. We did not modify the daily loadshapes over the analysis period; the loadshapes shown in the figure above were held constant over time.

ICF combined the energy consumption, load profiles, and PEV deployment scenarios to develop multiple load scenarios for analysis.

Feeder Impacts for Yukon Energy

The tables below include the peak demand (in units of MW) for summer (Table 11; April 1 to September 30) and winter months (October 1 to March 31), for each of the PEV deployment scenarios, and each charging scenario. The numbers shown are for weekday charging, with the note that weekend charging has lower demand.

[66] ICF does not assume an explicit blend of Level 1 and Level 2 charging for the non TOU rate; rather the rate is reflective of the time that vehicles would charge. The power draw associated with this rate implies that it is about a 50-50 blend of Level 1 and Level 2 charging.

ICF notes that peak energy values (in MWh) are not shown, but that they are equivalent to peak demand, simply in different units (MW). The reason these values are equivalent is that our current understanding of how vehicles charge does not allow us to make estimates at less than one hour intervals. As a result, we simply assume that the demand (MW) is constant over a one-hour period (yielding energy demand in units of MWh). In other words, the peak demand values listed in the tables below also represent our best estimate of peak load (in MWh). We effectively assume that charging events are staggered to some extent over each hour interval. In order for these values to not be representative of peak demand, one would have to assume that a large percentage of electric vehicles initiated charging events simultaneously (on the minute scale, not hourly scale).

Table 11. Peak Demand (in MW) during Summer (Apr 1–Sept 30), by Year for PEV Deployment Scenarios

Charging Scenario	Summer Peak Demand, Weekday, by Year (MW)				
	2015	2020	2025	2030	2035
Low PEV Deployment Scenario					
Level 1 TOU	0.0	0.0	0.1	0.3	0.6
Level 2 TOU	0.0	0.1	0.3	0.8	1.7
NonTOU	0.0	0.0	0.1	0.3	0.5
Medium PEV Deployment Scenario					
Level 1 TOU	0.0	0.1	0.3	0.8	1.7
Level 2 TOU	0.0	0.1	0.8	2.3	4.8
NonTOU	0.0	0.0	0.2	0.7	1.5
High PEV Deployment Scenario					
Level 1 TOU	0.0	0.1	0.3	1.1	2.4
Level 2 TOU	0.0	0.2	1.0	3.3	7.0
NonTOU	0.0	0.1	0.3	1.0	2.1

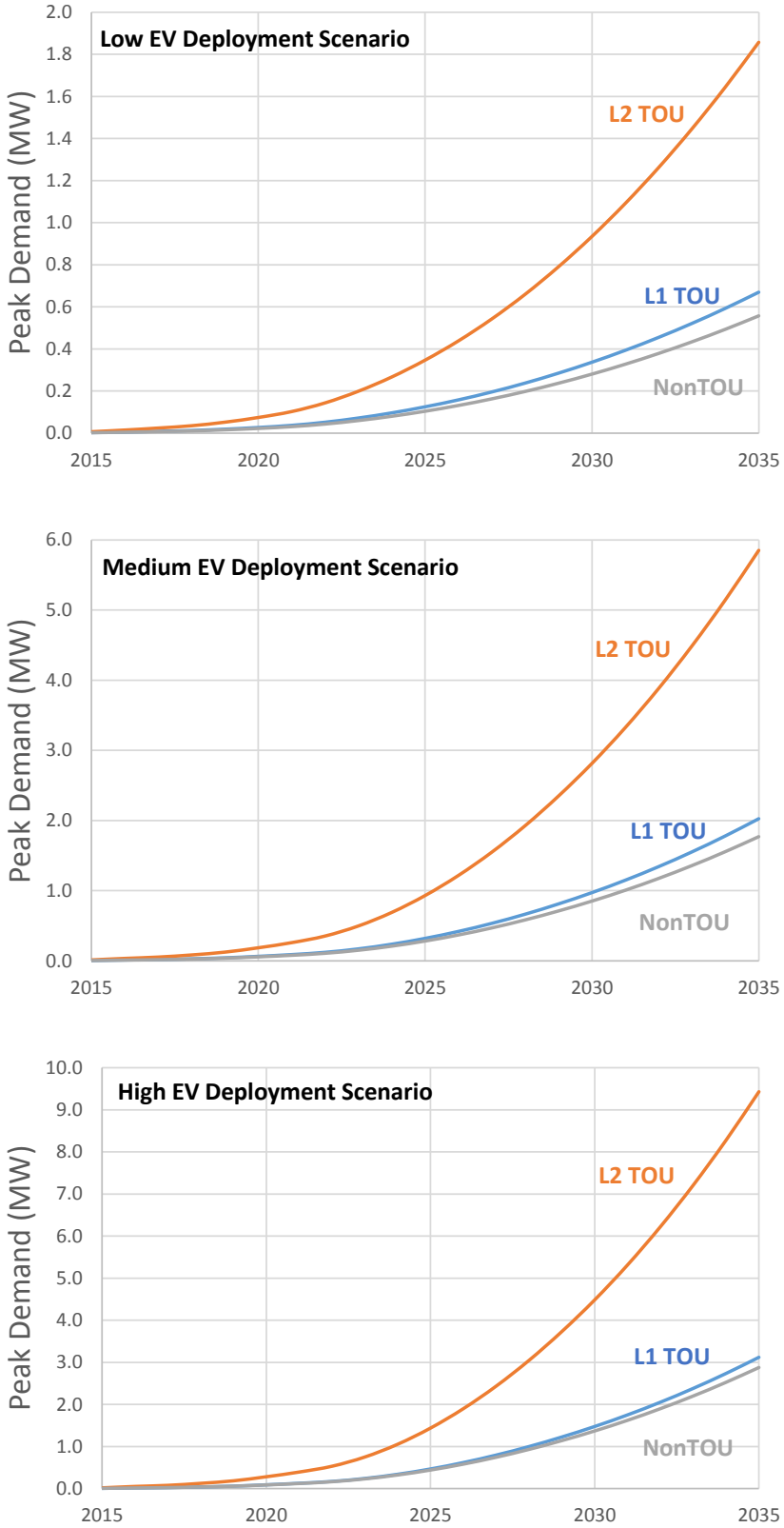
Table 12. Peak Demand (in MW) during Winter (Oct 1–Mar 31), by Year for PEV Deployment Scenarios

Charging Scenario	Winter Peak Demand, Weekday, by Year (MW)				
	2015	2020	2025	2030	2035
Low PEV Deployment Scenario					
Level 1 TOU	0.0	0.0	0.1	0.3	0.7
Level 2 TOU	0.0	0.1	0.3	0.9	1.9
NonTOU	0.0	0.0	0.1	0.3	0.6
Medium PEV Deployment Scenario					
Level 1 TOU	0.0	0.1	0.3	1.0	2.0
Level 2 TOU	0.0	0.2	0.9	2.8	5.9
NonTOU	0.0	0.1	0.3	0.9	1.8
High PEV Deployment Scenario					
Level 1 TOU	0.0	0.1	0.5	1.5	3.1
Level 2 TOU	0.0	0.3	1.4	4.5	9.4
NonTOU	0.0	0.1	0.4	1.4	2.9

The L2 TOU scenario has the highest peak (in MW) for each deployment scenario because of the way the load profile is developed (see Figure 10). The L2 TOU load profile assumes that drivers are provided with a price signal or incentive to encourage shifting at "off-peak" periods (i.e., at night). Similarly, the rate at which power is drawn during a charging event is higher. As a result the peak demand is predictably higher than the other charging scenarios. Also note that the values shown are for weekday peak demand, and that weekend peak demand is not shown simply because the values are consistently lower than for weekday charging events. ICF notes that the actual peak demand for the Yukon Territory is likely to be a mix of the various charging scenarios, with any near-term deployment likely to resemble the non-TOU charging scenario, simply because there is not an electric vehicle specific TOU rate.

The graphs in Figure 11 below show the peak demand (in MW) for the low, medium, and high EV deployment scenarios under different charging assumptions (L1, L2, and non-TOU).

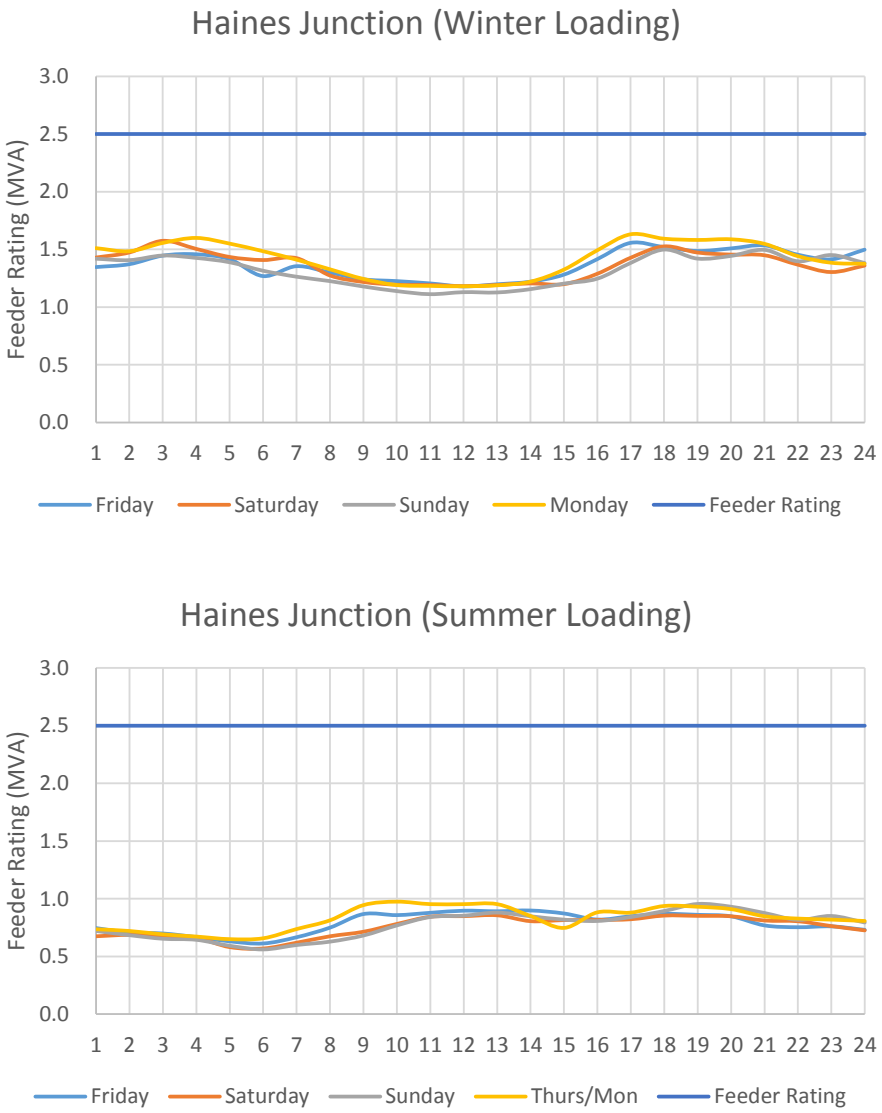
Figure 11. Forecasted Pea k Demand (MW) for EV Deployment in Different Charging Scenarios



Yukon Energy provided maximum ratings for several assets owned by Yukon Energy. For illustrative purposes, ICF selected two feeders to conduct our feeder impact analysis, focusing on feeders that are most likely to be overloaded based on data provided:

- The Haines Junction feeder (see figure below) is considered relatively high loading and is rated at 2.5 MW with a peak load of 1.6 MW (in the winter months).

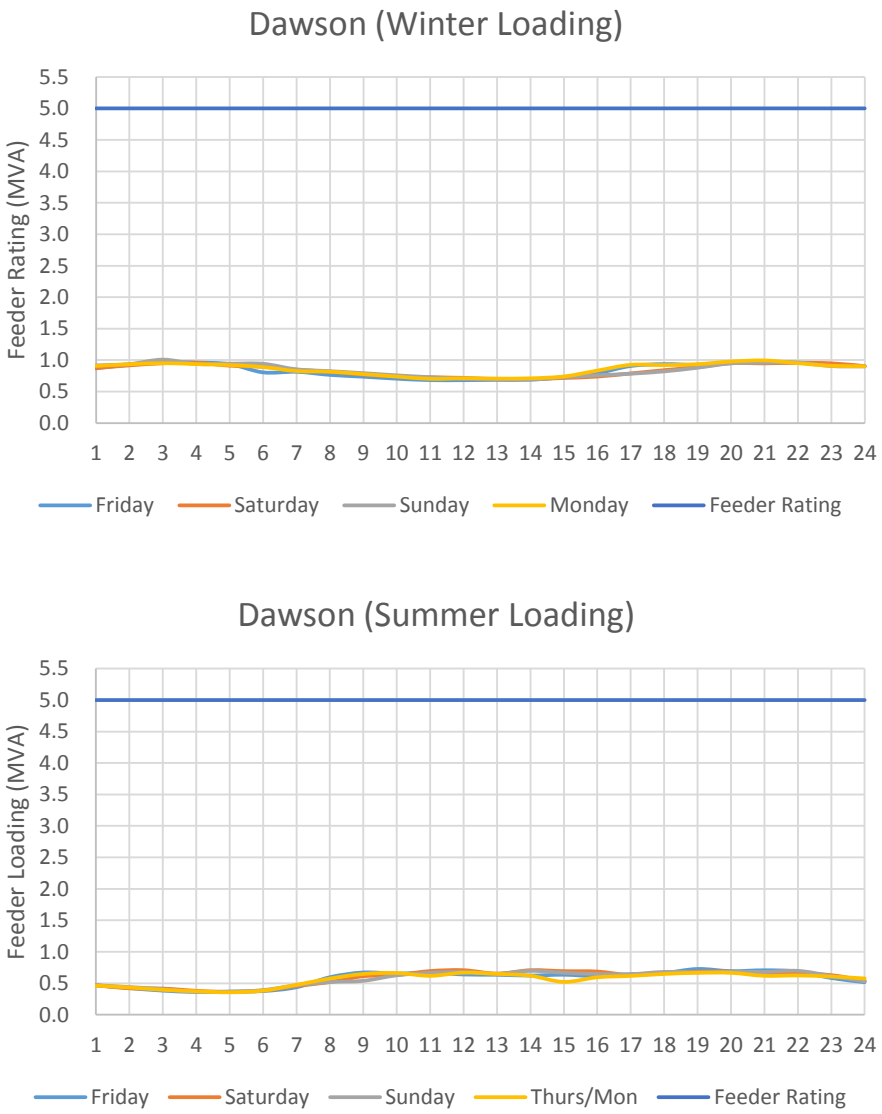
Figure 12. Winter and Summer Loadings on the Haines Junction Feeder



*Note: The summer "Monday" profile is a combination of half of Thursday and half of Monday

- The Dawson 2 feeder (see figure below) is low loading and is rated at 5.0 MW with a peak load of about 1.0 MW (also in the winter months).

Figure 13. Winter and Summer Loadings on the Dawson Feeder



*Note: The summer "Monday" profile is a combination of half of Thursday and half of Monday

One of the factors that our forecasts lacks is geographic distribution of PEVs. In other work, we have simply assumed that PEVs will be deployed in regions similar to the way that HEVs have been purchased. These data usually comes via vehicle registrations; however, as noted previously, we did not have this information available.

We present two ways to consider PEV adoption in Yukon Energy's territory:

- We assume that PEVs will be charged in a similar pattern in which electricity is currently distributed in Yukon Energy's service territory. This is a "fair-share" assumption i.e., that PEVs will be distributed across feeders according to their share of the distribution load.

- We assume that PEVs are clustered on certain feeders to determine the potential impacts.

ICF was provided distributed load on all Yukon Energy feeders and four ATCO feeders from 2013-2015 (year to date). Based on these data sets, the Haines Junction and Dawson 2 feeders distribute about 1.8% and 1.3% of the electricity. If we do a fair share distribution of the load associated with the high PEV deployment scenario in 2035 (when vehicle penetration is at its highest and there are nearly 1,900 PEVs assumed to be on the road), then this yields the equivalent of 34 and 24 PEVs on the Haines Junction and Dawson 2 circuits, representing a peak daily demand of about 0.23–0.99 MW and 0.17–0.71 MW, respectively, in the winter months.[67] Given the rating on both of these circuits and the current load, the additional load from PEVs may have an impact on Yukon's distribution assets in the winter months, depending on a) vehicle clustering, b) the timing of vehicle charging, and c) the types of electric vehicles) charging at the same time.

In the second part of the analysis, ICF considered the potential for PEV clustering. With more than 75% of the Yukon Territory population located in Whitehorse, it is unlikely that Yukon Energy's distribution assets will experience any severe clustering of PEVs. However, for the purposes of this analysis, we calculated the maximum number of PEVs that could charge on both the Haines Junction and Dawson 2 feeders before the assets would become stressed and trigger an upgrade. We performed this calculation using the three different charging profiles (L1-TOU, L2-TOU, and NonTOU) and for PHEVs and BEVs. Table 13 below highlights the maximum number of vehicles that can charge on each of the distribution assets before triggering an upgrade.

Table 13. Electric Vehicle Deployment and Stressed Assets

Feeder	Charging Profile	Maximum No. of Vehicles	
		PHEV	BEV
Haines Junction	L1-TOU	672	235
	L2-TOU	221	118
	NonTOU	822	398
Dawson 2	L1-TOU	2,827	1,035
	L2-TOU	974	522
	NonTOU	3,437	1,662
*ICF notes that we did not have a rating for ATCO feeders, and could not conduct the same analysis for Whitehorse			

The population of PEVs in the year 2035 for the three scenarios ranges from about 500–1,900. As the table above shows, you would need significant PEV clustering, representing 12–50% of the PEVs forecasted to be on the road charging at the same time on the Haines Junction feeder at Level 2 to trigger an upgrade.

[67] The daily load is presented as a range, with the minimum representing a passenger car PHEV32 (7 kWh/day) and the maximum representing a light-truck BEV (29.5 kWh/day).

Based on our analysis, it is unlikely that PEV charging will trigger upgrades to Yukon Energy's distribution assets, and will have minimal grid impacts absent more rapid adoption of PEVs than expected. That said, there are several variables that can change which would modify our conclusion:

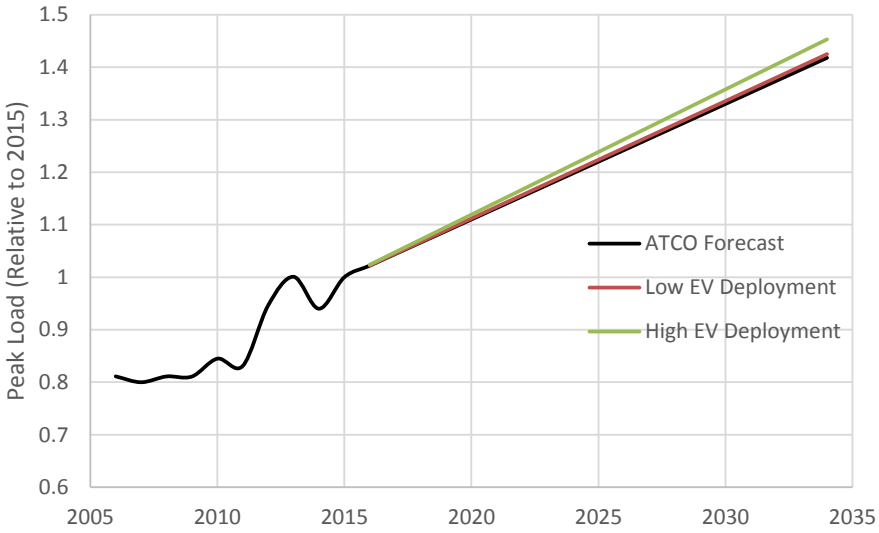
- Technological improvements to PEVs will likely yield larger batteries in the future, thereby increasing the daily load from PEV charging.
- Charging behavior can change depending on factors such as price signals (e.g., via utility intervention) and charging availability.
- Consumer purchasing preference could change over time, yielding a shift from light truck purchasing to passenger cars. One of the limiting factors for PEV deployment in our analysis is the assumed new truck sales as a percentage of new vehicle sales. If this changes over time, and the percentage of light duty passenger cars increases accordingly, then the electrification potential will increase accordingly.
- Policy changes could shift consumer purchasing as well. Incentives could induce a more significant deployment of PEVs in the near- to mid-term future. Furthermore, regulations that require reduced GHG emissions, perhaps with a focus on the transportation sector, can act as a strong incentive for electrification.

Impact on ATCO Assets

The feeders considered in the impact analysis in the previous subsection are a long distance from the City of Whitehorse, where 75% of the Yukon Territory's population resides and where ICF anticipates most electric vehicles will be deployed. Haines Junction, for instance, is a 90-minute drive from the City of Whitehorse and has a population under 1,000, whereas Dawson City is 6 hours north, does not have paved roads in the city, and has a population of 2,000. The distribution assets for the City of Whitehorse are primarily controlled by ATCO Electric, thereby limiting our ability to assess analytically the impact to their assets. ICF and Yukon Energy reached out to ATCO to help characterize the potential impacts on their system. The following information is a summary provided by ATCO and edited by ICF.

When contacted regarding the study, ATCO engineers noted that breakers are not the weak points in their distribution system; rather they highlighted that there are a variety of issues associated with managing load and assets in the downtown core, with a focus on a 25kv conversion project. ATCO expressed some reservations about modeling the increased load from the deployment of EVs and attributing the additional upgrades to EVs. For the sake of reference, ATCO noted that the low and high deployment scenarios would increase their load from about 2.2% per year to 2.24% per year and 2.39% per year, respectively. The figure below shows the forecasted peak load on ATCO's S150 and S170 feeders in Whitehorse (black line), with the impact of the electric vehicles in the low (red line) and high (green line) EV deployment scenarios. ATCO has agreed that the magnitude of this potential load and peak demand increases should be included in their incremental load growth forecasts. However, they also concluded that while it does not alleviate any existing loading issues, it further supports foreseeable upgrades that have already been identified as high priorities.

Figure 14. Peak Load Impact of EV Deployment on ATCO's Assets (S150 and S170)



5 Conclusions and Recommendations

ICF's finds modest potential for electric vehicles in the Yukon, with comparably modest GHG reduction potential. In a high forecasted electric vehicle deployment scenario at high charging, ICF's analysis indicates that it is conceivable that Yukon's distribution assets are stressed in the long-term future (e.g., around 2030–2035) absent any upgrades. However, this stress is dependent on a higher level of charging (Level 2 vs Level 1) and can be mitigated by shifting charging throughout the day (e.g., via workplace charging). Given the ubiquitous presence of engine block-heaters, it seems more likely to ICF that Level 1 charging will be more common than Level 2 charging at residences and workplaces.

The market potential for electric vehicles is constrained to some extent because of the cold weather in the Yukon, especially in the coldest months of the year. Most notably, vehicles may lose more than 50% of their advertised electric-powered range in cold weather. There are also near-term limitations on the electric vehicle market in the Yukon, namely the lack of dealerships selling electric vehicles and the limited vehicle offerings available more broadly to consumers. For instance, more than 60 percent of new vehicles sales are light trucks in the Yukon, likely because of weather and driving conditions, and other factors (e.g., consumer preference). As of 2015, electric vehicle manufacturers do not offer many models that can compete in this class.

Despite the limitations, electric vehicles, particularly PHEVs, are still a viable transportation option in the Yukon. Despite the potential loss of electric range, PHEVs also have the ability to run on petrol. Even after losing a portion of electric range due to cold weather, many electric vehicles will still provide sufficient range within the scope of the average Yukon commute. Furthermore, ICF may be under-estimating the potential for technological change and improvements in battery technology, thereby mitigating some of the concerns about diminished range.

The prevalence of engine block heaters also gives the potential electric vehicle market a boost in Yukon. These block heaters are effectively an ubiquitous electric vehicle charging network, currently available at homes and businesses. Public education and outreach could help new vehicle buyers understand the potential for vehicle electrification, and how the existing infrastructure can support that potential.

ICF generally recommends utility engagement in the electric vehicle market that keeps the utility slightly ahead of consumer preference and interest. There are a handful of electric vehicles in the Yukon, and interest is likely to improve moving forward. In that regard, Yukon Energy has an opportunity to support the deployment of electric vehicles through education and outreach to interested consumers, particularly in the role of trusted advisor that is common for a utility. ICF also recommends a more substantive engagement with ATCO, given their role as utility provider to the majority of residents in Whitehorse, where ICF anticipates the most significant electric vehicle deployment. To date, ATCO is justifiably focused on more pressing issues impacting their assets; however, moving forward, Yukon can work with ATCO to incorporate electric vehicle deployment into mid- and long-term resource planning. Outside of working with ATCO, Yukon Energy has an opportunity to maintain engagement with consumers and other stakeholders (e.g., automobile manufacturers and dealership) in the electric vehicle market space in the Yukon, thereby establishing a leadership position.

Appendix 4.6
Home Heating Retrofit Business Case Study

Home Heating Retrofit Business Case Study

Prepared by:

Yukon Energy Corporation

With support from Yukon Government Energy Branch

May 3, 2016

Executive Summary

Home heating represents a significant potential growth market for Yukon Energy and the electrification of heating also offers a means to significantly reduce greenhouse gas emissions in the Yukon. The number of homes in Yukon using electric heat is also a significant factor in how much electricity Yukon Energy needs to generate, particularly during peak periods.

To help understand the home heating market, Yukon Energy, with support from the Yukon Government Energy Branch, completed this study to analyze the business case for home owners to switch heating systems from fossil fuels to electric heat. This report also looks at the non-economic drivers that may affect the choice of home heating system and importance of economics as compared to other drivers. Finally, the report quantifies the reduction in GHG emissions from the switch to electric heat.

To complete the analysis for this report, the energy use of an archetype Yukon home was modelled at four thermal enclosure (insulation) levels which correspond to significant changes in insulation and air sealing practices. The energy model results were used to calculate the total fuel load for each level of insulation and heating system, which in turn were used to calculate annual fuel costs and GHG emissions. The upfront costs of completing the retrofit, maintaining and insuring each system, as well as the annual fuel costs were analyzed to understand the business case for a Yukon homeowner to retrofit their home with electric heat. Other non-economic drivers such as GHG emissions, safety and ease of maintenance are also discussed.

The economic analysis indicates that, at current prices, a retrofit from a functional oil or propane furnace to electric heating would increase homeowners' annual fuel costs with the exception of heat pumps. These increased fuel costs are partially offset by a small reduction in maintenance costs. Comprehensive home insurance costs were found to be relatively uniform across home heating types. The retrofit to a cold climate heat pump offers fuel savings and the payback period may be acceptable for some home owners.

The results of this cost analysis indicate that at current fuel pricing, there is no business case for home owners to switch from fossil fuel heat to electric heat for economic reasons. Consequently, it is not expected that many existing oil or propane heated homes will switch to electric heat in the near future as a cost saving measure.

Table of Contents

Executive Summary i

Table of Figures 3

1 Introduction 1

2 Methodology 1

2.1 Home Energy Use 1

2.2 Heating System Retrofit Costs 2

2.3 Heating System Operating Costs 2

2.3.1 Fuel Costs 2

2.3.2 Maintenance Costs 3

2.3.3 Insurance Costs 3

2.4 Business Case 3

2.5 Non-Financial Considerations 3

3 Results 4

3.1 Retrofit Costs 4

3.2 Operating Costs 5

3.2.1 Cost of Fuels 5

3.2.2 Maintenance and Insurance Cost 6

3.3 Economic Modeling Results 7

3.3.1 Annual Operating Costs 7

3.3.2 Break-Even Fuel Pricing 7

3.3.3 Impact of Carbon Pricing 8

3.4 Non-Financial Considerations 11

3.4.1 Greenhouse Gas (GHG) Emissions 11

3.4.2 Other 11

4 Conclusions and Next Steps 11

Appendices 13

Appendix A Description of Archetype Home 14

Appendix B Oil Prices and Carbon Tax Required for a Five Year Payback 15

Table of Figures

Table 1: Annual Heating System Maintenance and Insurance Cost 6
Table 2: Total Annual Operating Costs by Heating System 6
Table 3: Change in Total Annual Costs 7
Table 4: Simple Payback of Cold Climate Air Source Heat Pump Retrofit 7
Table 5: Oil Pricing for a 5 Year Retrofit Payback 8
Table 6: Propane Pricing for a 5 Year Retrofit Payback 8
Table 7: Annual CO2e Emissions 8
Table 8: Annual Carbon Tax 8
Table 9: Simple Payback for a Cold Climate Air Source Heat Pump with $30/tonne Carbon Tax 10
Table 10: Simple Payback for a Cold Climate Air Source Heat Pump with $100/tonne Carbon Tax 10
Table 11: Oil prices required for a 5 year retrofit payback - $30/tonne carbon tax 15
Table 12: Propane prices required for a 5 year retrofit payback - $30/tonne carbon tax 15
Table 13: Oil prices required for a 5 year retrofit payback - $100/tonne carbon tax 15
Table 14: Propane prices required for a 5 year retrofit payback - $100/tonne carbon tax 15

Figure 1: Retrofit Costs (Labour, Equipment and Material) 4
Figure 2: Annual Fuel Cost 5
Figure 3: Annual Fuel Costs with $30/tonne Carbon Tax 9
Figure 4: Annual Fuel Costs with $100/tonne Carbon Tax 10

1 Introduction

Home heating represents a significant potential growth market for Yukon Energy and the electrification of heating also offers a means to significantly reduce greenhouse gas emissions in the Yukon. The number of homes in Yukon using electric heat is also a significant factor in how much electricity Yukon Energy needs to generate, particularly during peak periods.

To help understand the home heating market, Yukon Energy, with support from the Yukon Government Energy Branch, completed this study in analyze the business case for home owners switching heating fuels from fossil fuels to electric heat. Most existing homes in the Yukon are heated primarily with oil or propane. However, analysis of the energy labelling requirements in the City of Whitehorse and energy assessment data show that the majority of newly constructed homes are heated electrically. This report also looks at the non-economic drivers that may affect the choice of home heating system and importance of economics as compared to other drivers. Finally, the report quantifies the reduction in GHG emissions from the switch to electric heat.

2 Methodology

2.1 Home Energy Use

The energy use of an archetype Yukon home was modelled at four thermal enclosure (insulation) levels. The enclosure levels selected corresponded to significant changes in insulation and air sealing practices, and included:

- Older Home (pre-1980s) – 2x4 walls (R11), uninsulated slab, ceiling (R40), 7 air changes per hour (ACH) (@50Pa)
- Newer Home (1980s and newer) – 2x6 walls (R21), 2ft perimeter slab insulation (R5), ceiling (R40), 5 ACH (@50Pa)
- Energy Efficient Home (Whitehorse Green Building Standard) – 2x6 walls (R28), whole slab (R10), ceiling (R60), 1.5 ACH (@50Pa)
- Super-Insulated Home – Double stud wall (R60), whole slab (R10), ceiling (R80), 1.5 ACH (@50Pa)

It is not expected that there are a large number of super-insulated homes currently heated with fossil fuels. However, this insulation level was modelled to evaluate the effects of increased insulation values as well as to allow the model to be used for a follow-up economic analysis on increasing thermal envelope performance. The layout for the archetype home can be found in Appendix A. Energy use modelling of the archetype home was completed using BEOpt, a free modelling software package developed by the National Renewable Energy Laboratory of the US Department of Energy's Office of Energy Efficiency. This software was chosen for its ease of use and availability to anyone wanting to recreate the model and adapt it to their requirements. The BEOpt model estimated the total energy needs of the home, reported by end-use including heating. These results were used to calculate total

fuel loads for each insulation level and heating system, which in turn was used to calculate annual fuel cost and GHG emissions.

2.2 Heating System Retrofit Costs

Cost estimates for both the labor and materials to remove an existing oil or propane furnace and replace it with an electrical heating system in the archetype house were obtained from local contractors and previous reports[1]. The study examined switching from both oil and propane forced air furnaces to the following range of electric heating systems:

- electric baseboard
- electric forced air furnace
- cold climate heat pump with electric back-up
- electro-thermal storage with forced air circulation

In each case an assumption was made that the home was upgraded from a 100 amp to 200 amp service to meet the additional load from the electrical heating system, but would not require an upgrade to the neighborhood transformer. For the electric forced air systems, it was assumed that no upgrades were needed to the ducting and for the electric baseboard installation it was assumed that the ducting was left in the home.

2.3 Heating System Operating Costs

2.3.1 Fuel Costs

The amount of energy required to maintain the archetype home at 19 °C was estimated using the BEOpt model. This was used to calculate the quantities of oil, propane or electricity to heat the archetype home, which was then used to calculate the associated fuel costs. The price of electricity was based on the 2015 electrical rates including rate riders[2], and an assumption was made that the cost of heating is incremental to the existing base electrical use of the home. The costs of heating with oil and propane were calculated using Yukon Government posted prices for furnace oil and propane (500 gallon tank) delivered to a residence of Whitehorse on December 9, 2015. The efficiency of the oil furnace was assumed to be a 90% and the efficiency of the propane furnace was assumed to be 95%. These efficiencies are a conservative assumption and more fuel would be used for less efficient furnaces.

In order to understand how future potential carbon pricing might impact the costs of fossil fuels and thereby impact the business case for conversion to electrical heating, a carbon tax of $30 and $100/tonne of CO_2 equivalent (CO_2e) was included in the operating costs of the fossil fuel heating systems as a scenario.

[1] *Draft Shifting Demand: Yukon Home Heating Trends,* Yukon Government Energy Branch, November 17, 2015, Yukon Housing Website, Energy Efficient Heating http://www.housing.yk.ca/eeh.html accessed December 2015
[2] Riders R and J at a net increase of 18.21% and Riders E and F for a net decrease of $0.0124/kWh

2.3.2 Maintenance Costs

The costs of maintaining a home heating system can change depending on the type heating system. Both oil and propane furnaces as well as heat pumps require annual maintenance, while electrical heating systems do not. All forced air systems require the home owner to check and change filters periodically. Estimated annual maintenance costs of each heating system were obtained from local contractors and previous reports.

2.3.3 Insurance Costs

Home insurance costs may depend on the type of heating system in the home and annual insurance costs for each system were obtained from local insurance agents. Some insurance companies require oil tanks to be replaced periodically. The cost for tank replacement was not considered in this study.

2.4 Business Case

The costs of completing the retrofit, annual fuel costs as well as maintenance and insurance costs of each system were analyzed to understand whether Yukon homeowners have an economic business case to retrofit their fossil fuel based heating system with electric heating. In cases where the annual operating costs of electric heating systems are lower than the corresponding operating costs of fossil-fuel based heating systems, the simple payback period on the upfront costs of the electric heating system was estimated.

In cases where the annual operating costs of electric heating systems are higher than the corresponding operating costs of fossil-fuel based heating systems at current fuel prices, the break-even fossil fuel prices required to provide homeowners with a 5 year simple payback on the retrofit investment were also calculated for each electrical heating option.

2.5 Non-Financial Considerations

Currently 24% of the GHG emissions in the Yukon are a result of space heating with oil or propane[3]. Electricity produced on the Yukon Integrated Grid is generated by over 99% renewable (hydro and wind) with only a small amount generated from burning diesel or natural gas. Home owners may choose to switch to electric heat in order to reduce the GHG emissions from their homes. A home in the Yukon that is serviced by an isolated diesel grid (e.g. Watson Lake) may only be heated electrically if written permission is obtained from their service provider as per the Yukon Utilities Board Terms of Reference. The GHG emissions for electricity supplied from an isolated diesel grid would be higher that calculated in this report due to the fact that all electricity is generated by diesel instead of majority hydro. This report assumes that the archetype home is in Whitehorse.

Other non-economic drivers such as safety and ease of maintenance are also documented, based on comments from homeowners shared by contractors.

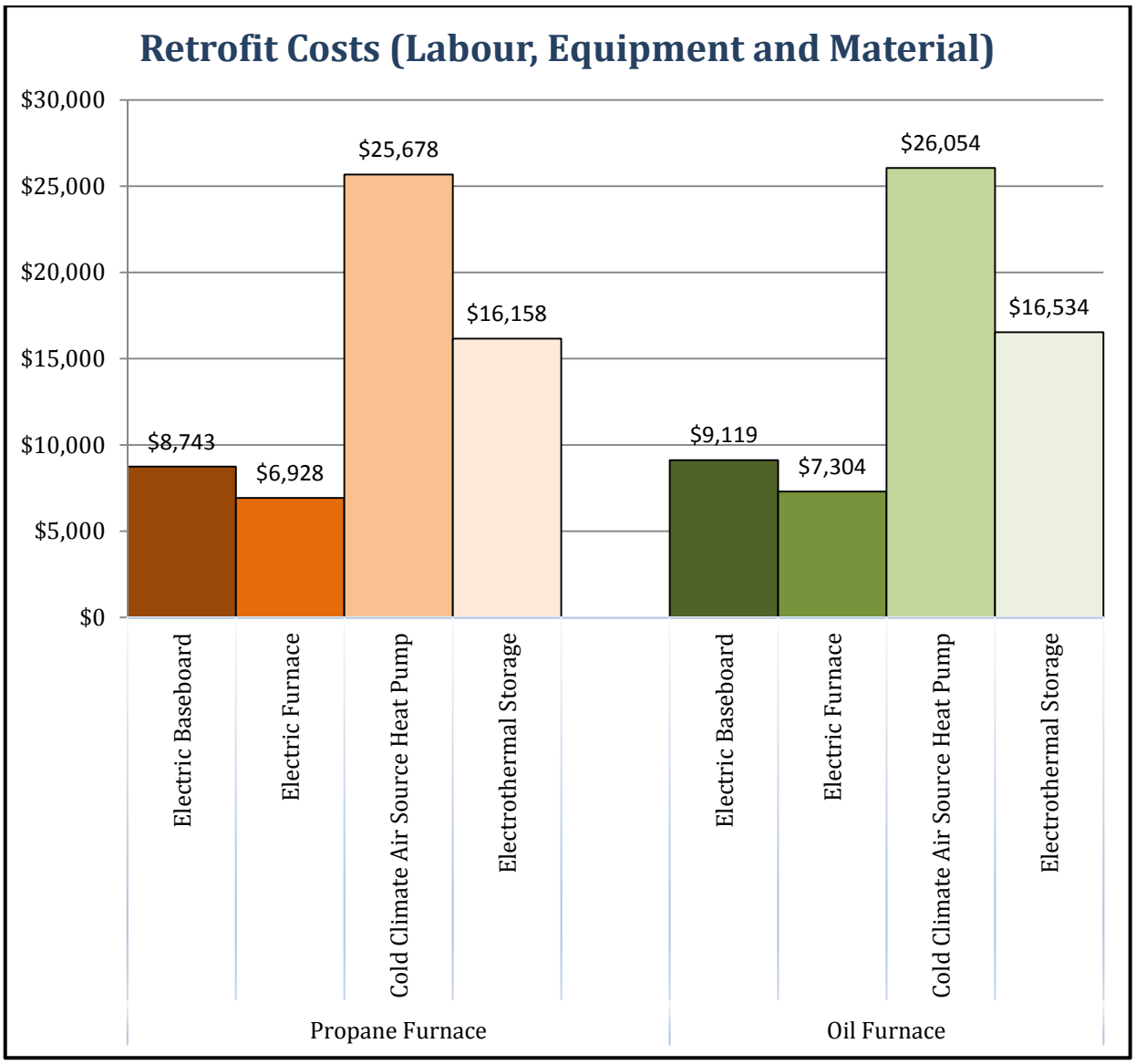
[3] *Yukon Greenhouse Gas Emissions: The Transportation Sector, Updated Report 2015*, prepared by Malcolm Taggart in association with Forest Pearson for the Yukon Government Climate Change Secretariat, March 23, 2015. Calculations assuming year is 2012.

3 Results

3.1 Retrofit Costs

A summary of the total labor, equipment and material costs involved in retrofitting existing fuel oil and propane based heating systems to electrical heating is presented in Figure 1 below.

Figure 1: Retrofit Costs (Labour, Equipment and Material)



In general, the retrofit costs in the case of an oil furnace are slightly higher than in the case of a propane furnace due to the additional time required to remove the oil tank. The retrofit costs of the air source heat pumps and electrothermal storage are both higher due to the higher costs of the heating units

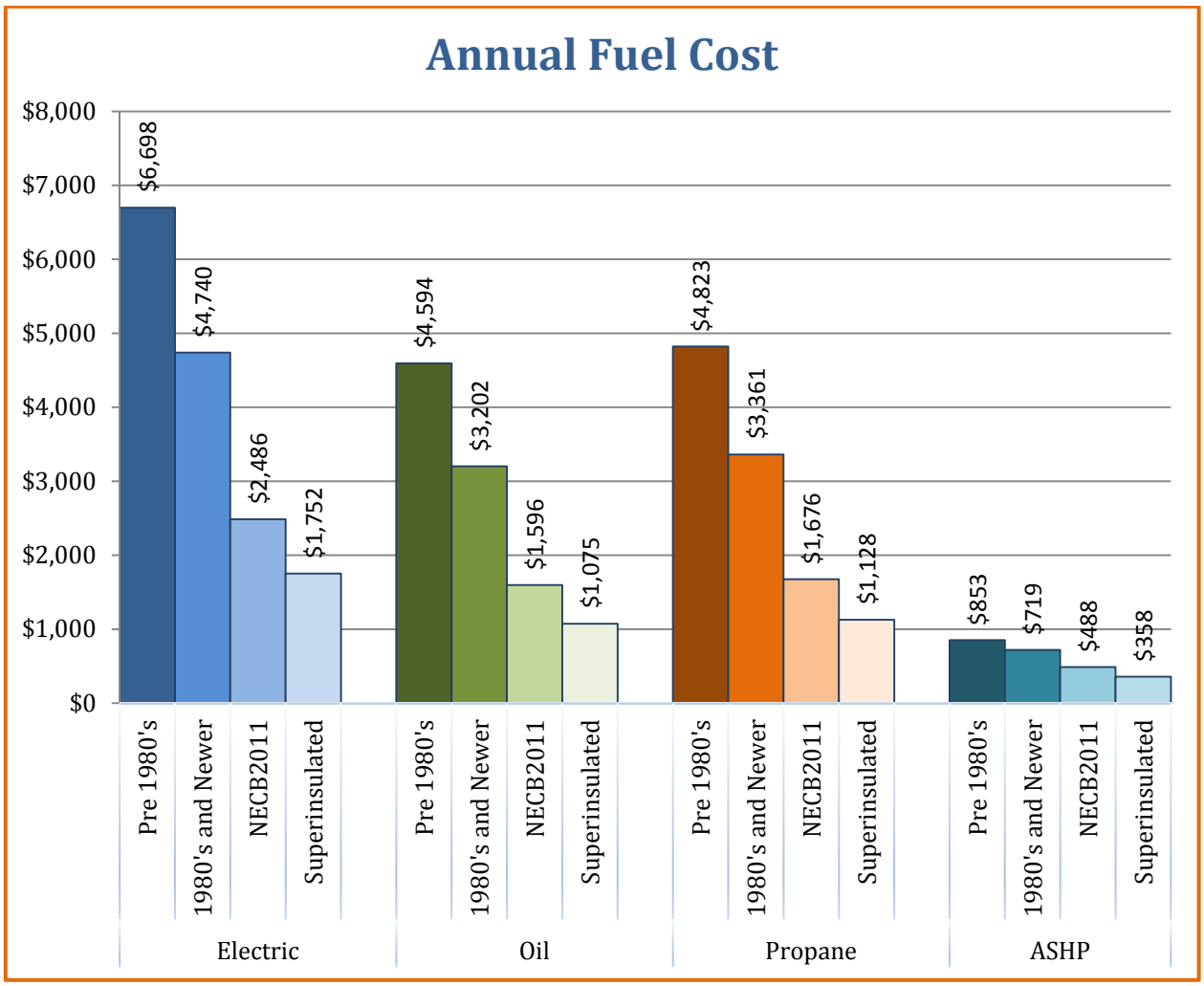
(equipment) when compared to baseboard heaters or an electric furnace. The costs of an electrical service upgrade is included for all of the retrofit options.

3.2 Operating Costs

3.2.1 Cost of Fuels

The annual fuel costs for each heating system and building enclosure level are summarized in Figure 2 below.

Figure 2: Annual Fuel Cost



The data in illustrates the significantly higher heating requirements and heating costs of an older home when compared to a modern home. The older homes require nearly three times as much heat as homes built to meet the current code, and the four times more than a super-insulated home. The data also shows that the annual fuel costs for the electric baseboards, electric furnaces and electrothermal heating systems are higher than the corresponding fuel costs for the propane and oil heating systems.

This result is consistent for all building envelope types. The exception is the cold climate air source heat pump (ASHP), which offers lowest annual fuel costs of all heating types. These heat pumps use a refrigerant system involving a compressor and a condenser to bring heat from the outdoors into the home. Cold climate heat pumps can function down to an outdoor air temperature of around -25°C before it is more efficient to switch to an electric resistance heat back-up. Heat pumps use much less electricity than conventional resistance electric heaters.

3.2.2 Maintenance and Insurance Cost

Estimated annual maintenance and insurance costs for each heating system are provided in Table 1 below.

Table 1: Annual Heating System Maintenance and Insurance Cost

	Annual Maintenance	Annual Insurance
Oil Furnace	$220	$1,424
Propane Furnace	$158	$1,424
Electric Baseboard	$0	$1,395
Electric Furnace	$0	$1,424
Electrothermal Storage	$0	$1,424
Cold Climate Heat Pump	$250	$1,424

Oil and propane furnaces have burners that require annual inspection and maintenance, while electric systems do not require the same level of annual maintenance. All forced air systems require a small amount of work by the owner to check and replace air filters as required. The cost of filters, and the time to check the filters, were not considered. Heat pumps required an annual maintenance by a specially trained professional.

The estimates received for insurance on the archetype home did not show a significant cost difference between a home with an oil or propane heating system and a home with an electric heating system. One insurance provider did offer a discount for electric baseboard heat.

The total annual operating cost for each system, including fuel, maintenance and insurance is shown in Table 2 below. The data show that the total operating costs of the electric baseboards, electric furnaces and electrothermal heating systems are higher than the fossil fuel heating systems for all enclosure levels. Cold climate air source heat pumps offer the lowers annual operating costs of all heating systems.

Table 2: Total Annual Operating Costs by Heating System

	Annual Operating Cost			
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Oil Furnace	$5,983	$4,669	$3,153	$2,660
Propane Furnace	$5,864	$4,566	$3,070	$2,583
Electric Baseboard	$8,082	$6,032	$3,666	$2,903
Electric Furnace	$8,111	$6,061	$3,695	$2,932
Electrothermal Storage	$8,111	$6,061	$3,695	$2,932
Cold Climate Air Source Heat Pump	$2,887	$2,469	$2,072	$1,939

3.3 Economic Modeling Results

3.3.1 Annual Operating Costs

The change in annual operating costs, including cost of fuel, maintenance and insurance, of each retrofit scenario, are presented in Table 3 below.

Table 3: Change in Total Annual Costs

	Change in Annual Fuel, Maintenance & Insurance Cost from Oil Furnace			
Heating System	**Pre 1980s**	**1980s and Newer**	**NECB 2011**	**Super-Insulated**
Electric Baseboard	$2,099	$1,363	$514	$243
Electric Furnace	$2,128	$1,392	$543	$272
Electrothermal Storage	$2,128	$1,392	$543	$272
Cold Climate Heat Pump	-$3,097	-$2,199	-$1,081	-$720
Heating System	**Change in Annual Fuel, Maintenance & Insurance Cost from Propane Furnace**			
Electric Baseboard	$2,219	$1,465	$597	$319
Electric Furnace	$2,248	$1,494	$626	$348
Electrothermal Storage	$2,248	$1,494	$626	$348
Cold Climate Heat Pump	-$2,977	-$2,097	-$998	-$644

The results shown in indicate that a retrofit from a functional oil or propane furnace to an electric baseboard, electric furnace or electro-thermal storage system would result in an increase in annual operating costs at current fuel prices.

A retrofit to a cold climate air source heat pump would deliver savings to the homeowner from reduced annual operating costs. The simple payback period for the investment in a retrofit to a cold climate air source heat pump is presented in Table 4 below.

Table 4: Simple Payback of Cold Climate Air Source Heat Pump Retrofit

	Simple Payback of Cold Climate Air Source Heat Pump Retrofit - Years			
Heating System	**Pre 1980s**	**1980s and Newer**	**NECB 2011**	**Super-Insulated**
Furnace Oil	8.4	11.8	24.1	36.2
Propane	8.6	12.2	25.7	39.9

The data in Table 4 show that the operating costs savings from heat pumps may offer an acceptable payback period for some homeowners of just over 8 years for older building envelopes. However, the payback period becomes progressively longer and less acceptable for newer building envelopes with lower overall heating requirements. It should also be noted that heat pumps are a relatively rare in the Yukon and thus far the market uptake has been modest.

3.3.2 Break-Even Fuel Pricing

Five years is generally considered a reasonable payback period for homeowners to invest in home upgrades which deliver savings in operating costs. The break-even fuel prices that would deliver a 5 year payback on retrofits from an oil or propane furnace to electric systems are presented in Tables 5 and 6. These fuel prices were calculated to help understand the price points at which home owners may start

to switch heating systems for as a cost saving measures. It should be noted that current oil and propane prices are $1.005/L and $0.713/L respectively, and the pricing of these fuels peaked at $1.36 and $1.18 in November 2011 and February 2014 respectively.

The data in Tables 5 and 6 illustrate that fossil fuel prices need to reach levels significantly higher than recent peak pricing in order for electric baseboard, electric furnace or electro-thermal storage system to deliver an economic payback in a reasonable timeframe (5 years).

Table 5: Oil Pricing for a 5 Year Retrofit Payback

	Oil prices required for 5 year retrofit payback			
	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Electric Baseboard	$1.81	$1.96	$2.44	$2.91
Electric Furnace	$1.73	$1.84	$2.21	$2.57
Electrothermal Storage	$2.14	$2.42	$3.37	$4.30

Table 6: Propane Pricing for a 5 Year Retrofit Payback

	Propane prices required for 5 year retrofit payback			
	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Electric Baseboard	$1.25	$1.34	$1.66	$1.97
Electric Furnace	$1.20	$1.28	$1.53	$1.77
Electrothermal Storage	$1.48	$1.68	$2.33	$2.97

3.3.3 Impact of Carbon Pricing

Home heating is a large emitter of greenhouse gases in the Yukon. Table 7 below shows the annual CO2e emissions for the study home at each insulation level.

Table 7: Annual CO2e Emissions

	Annual GHG Emissions (CO2e) by Home Insulation Level			
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Furnace Oil	11.88	8.29	4.13	2.78
Propane	9.67	6.74	3.36	2.26

The addition of a carbon tax on oil or propane would increase the cost of these fuels, thus improving the business case for a retrofit to electric heating. To understand the impacts a future carbon tax could have on the business case of retrofits, a carbon tax of $30 and $100/tonne of CO^2e was applied to the annual operating costs of oil and propane heating systems. The incremental annual carbon tax costs at both prices are shown in Table 8 below.

Table 8: Annual Carbon Tax

	Annual Carbon Tax at $30/ Tonne			
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Furnace Oil	$356	$249	$124	$83
Propane	$290	$202	$101	$68
	Annual Carbon Tax at $100/ Tonne			
Furnace Oil	$1,188	$829	$413	$278
Propane	$967	$674	$336	$226

Figures 3 and 4 below show the annual fuel costs for each heating system and insulation level, with carbon taxes applied at $30 and $100/tonne of CO_2e. This data show that even with a carbon tax as high as $100, electricity is still a more expensive heating fuel choice than oil or propane.

Figure 3: Annual Fuel Costs with $30/tonne Carbon Tax

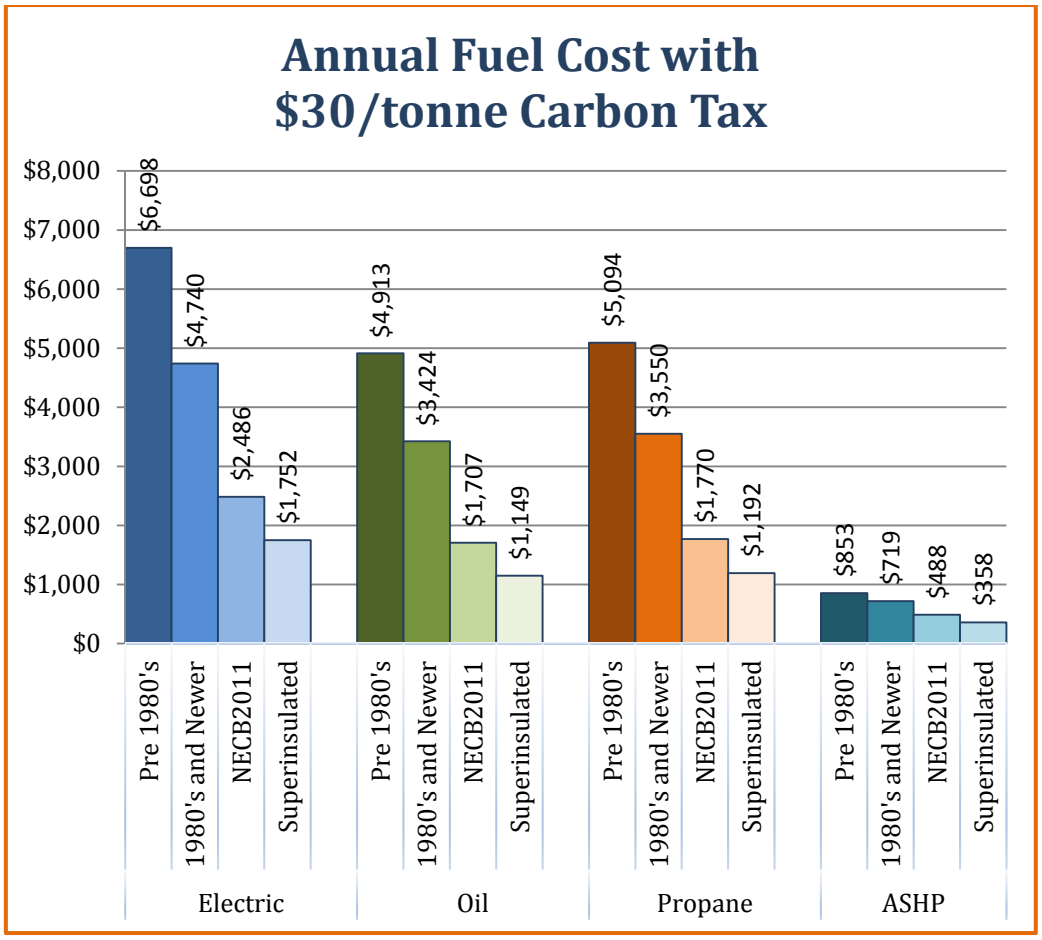
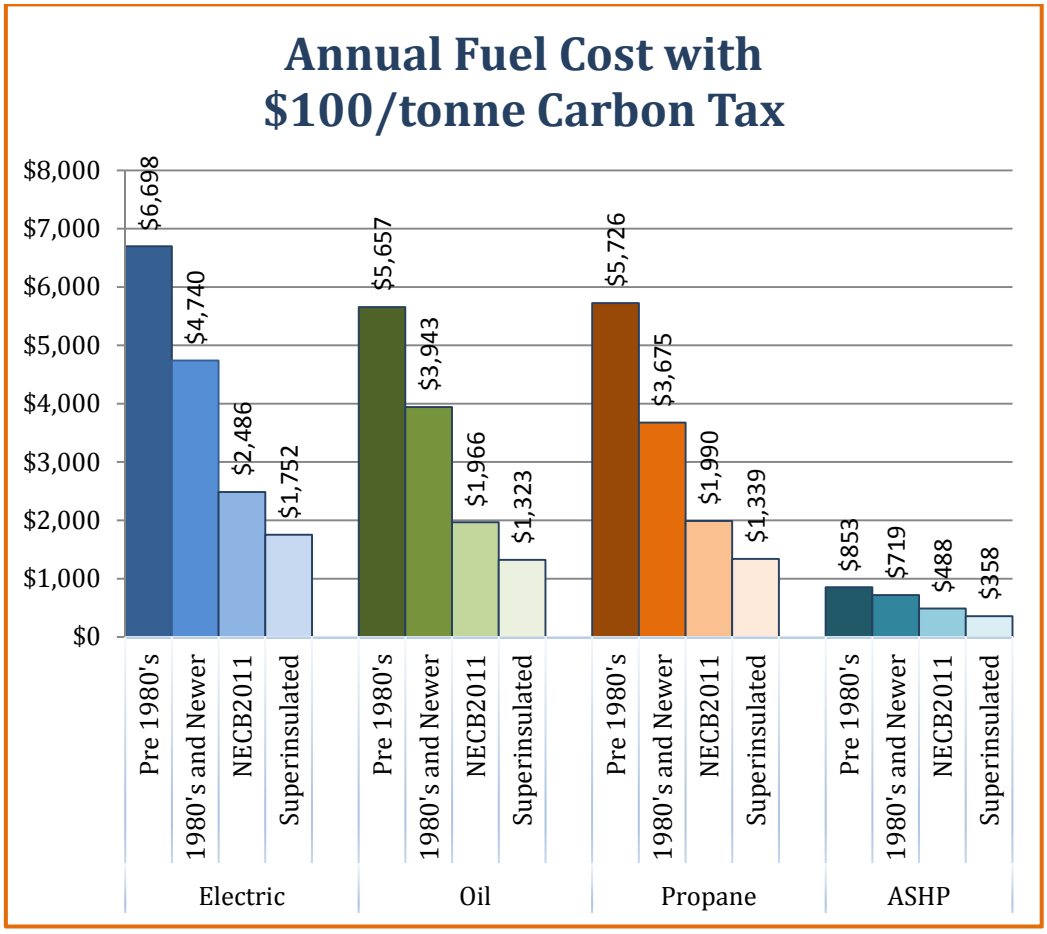


Figure 4: Annual Fuel Costs with $100/tonne Carbon Tax



The payback period for the Cold Climate Air Source Heat Pump with the $30 and $100/tonne of CO_2e carbon tax applied can be seen in Tables 10 and 11 below. The data in Tables 9 and 10 show that the inclusion of a carbon tax reduces the payback period of cold climate air source heat pumps to 6-8 years for older building envelopes. However, the payback period remains long for newer building envelopes with lower overall heating requirements.

Table 9: Simple Payback for a Cold Climate Air Source Heat Pump with $30/tonne Carbon Tax

Simple Payback of Cold Climate Air Source Heat Pump Retrofit - $30/tonne carbon tax				
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Furnace Oil	7.5	10.6	21.6	32.4
Propane	8.0	11.3	23.7	36.6

Table 10: Simple Payback for a Cold Climate Air Source Heat Pump with $100/tonne Carbon Tax

Simple Payback of Cold Climate Air Source Heat Pump Retrofit - $100/tonne carbon tax				
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Furnace Oil	6.1	8.6	17.4	26.1
Propane	6.6	9.4	19.5	29.9

A carbon tax would also affect the break-even fossil fuel prices which would deliver a 5 year payback on a retrofit to electrically heated systems. Appendix B show the prices that oil and propane would have to reach to give a five year retrofit payback with a $30 and $100/tonne of CO_2e carbon tax applied.

It was found that for a $30/tonne tax, oil prices would need to be between $1.74/L and $4.22/L while propane would need to cost between $1.21/L and $2.92/L to achieve a five year payback on a heating system retrofit. At a $100/tonne tax, oil prices would need to be between $1.55/L to $4.04/L and propane prices between $1.11/L and $2.83/L for a five year payback on a heating system retrofit.

3.4 Non-Financial Considerations

3.4.1 Greenhouse Gas (GHG) Emissions

As shown in Table 7, the electrification of a home heating system from oil or propane could reduce the GHG emissions. Given the growing concern about climate change, some homeowners may choose to change their heating system in order to reduce their personal GHG emissions footprints.

3.4.2 Other

When choosing a heating system for a home, homeowners may take other considerations into account in addition to cost and GHG emissions. These non-economic considerations were noted from discussions with contractors and homeowners. These considerations include:

- Safety: Burning fossil fuels could result in carbon monoxide being released into the home, which is dangerous and potentially fatal.
- Environmental Liability: The cost of remediating a hydrocarbon spill from an oil tank can be very high and a liability that homeowners and insurance companies are becoming less comfortable assuming.
- Commercial Convenience: The convenience offered by a monthly electrical bill instead of large fuel bills after a fill-up is attractive to many homeowners.
- Maintenance: Not having to remember to arrange an annual furnace service is also a convenience offered by electric heating systems.

4 Conclusions and Next Steps

The results of this study indicate that with current fuel and electricity pricing, home owners are unlikely to switch from fossil fuel heat to electric heat for economic reasons. The payback for a retrofit to a cold climate heat pump in an older home may be acceptable to some homeowners. The introduction of a carbon tax, even as high as $100/tonne CO_2e would not change the business case for home heating retrofits, also with the exception of bringing the payback period for Air Source Heat Pumps retrofits in older home to six years. Research from the Oak Ridge National Laboratory[4] shows that consumers

[4] D Greene. How Consumers Value Fuel Economy: A Literature Review, EPA-420-R-10-008, March 2010. Available online: http://www3epa.gov/otaq/climate/regulations/420r10008.pdf

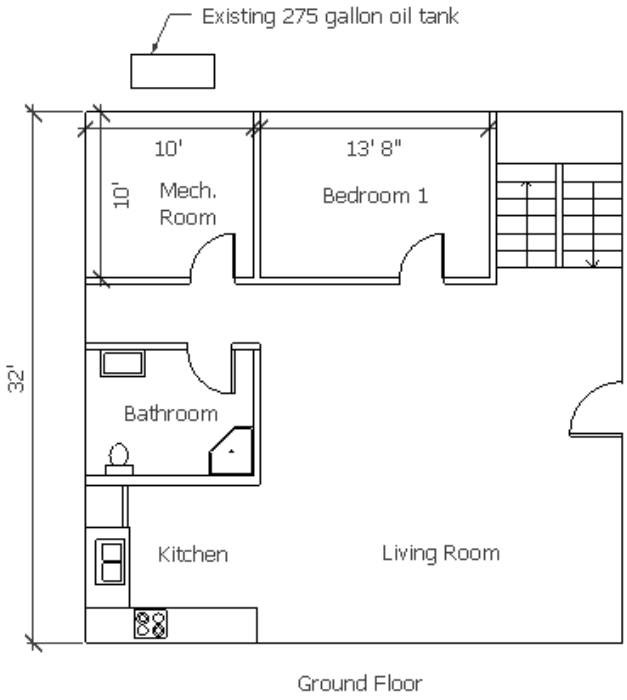
heavily discount future fuel savings in comparison to upfront cost due to the high uncertainty of fuel prices.

Additional areas of study to build on the findings of this report could be:

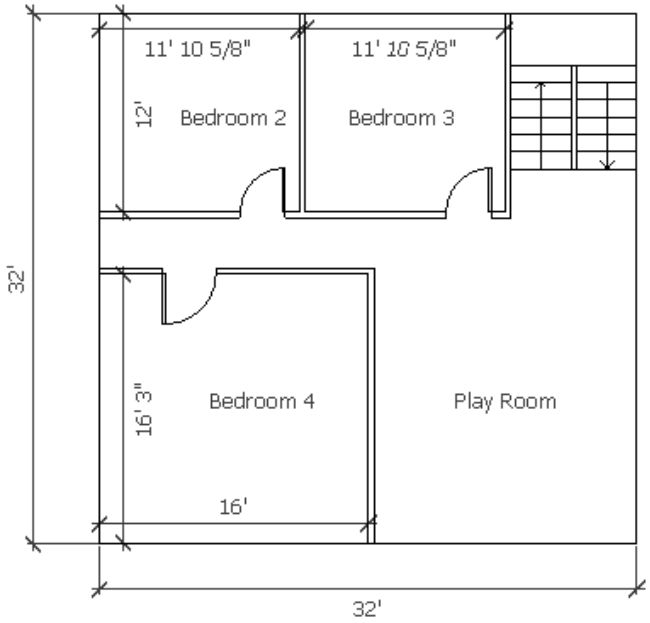
- A survey to confirm the primary drivers of homeowners' choice of home heating system.
- Further analysis to assess the impact of secondary biomass heating on the net heating needs of a home, and resulting changes to the economics of electric retrofits.
- Economics of the retrofit for a homeowner interested in installing solar panels and participating in the governments microgeneration program
- Further investigation into the insurance costs for home heated by different heating options. For example, requirements to replace oil tanks periodically were not addressed in the insurance estimates received.
- Confirmation of the retrofit costs by sourcing quotations for additional contractors, as well as homeowners themselves increasing the number of pricing quotations, either directly or from homeowners that have actually completed a heating system retrofit, would be helpful to refine the cost estimates used in the study.

Appendices

Appendix A: Description of Archetype Home[5]



Ground Floor



Second Floor

[5] Plans based off Cold Climate Housing Research Center's "Southwest Prototype Home," http://www.cchrc.org/sites/default/files/docs/spruce_plans_final.pdf.

Appendix B: Oil Prices and Carbon Tax Required for a Five Year Payback

Table 11: Oil prices required for a 5 year retrofit payback - $30/tonne carbon tax

	Oil prices required for a 5 year retrofit payback - $30/tonne carbon tax			
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Electric Baseboard	$1.74	$1.88	$2.36	$2.83
Electric Furnace	$1.66	$1.77	$2.13	$2.49
Electrothermal Storage	$2.06	$2.35	$3.29	$4.22

Table 12: Propane prices required for a 5 year retrofit payback - $30/tonne carbon tax

	Propane prices required for a 5 year retrofit payback - $30/tonne carbon tax			
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Electric Baseboard	$1.21	$1.31	$1.64	$1.96
Electric Furnace	$1.16	$1.23	$1.48	$1.73
Electrothermal Storage	$1.44	$1.63	$2.29	$2.92

Table 13: Oil prices required for a 5 year retrofit payback - $100/tonne carbon tax

	Oil prices required for a 5 year retrofit payback - $100/tonne carbon tax			
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Electric Baseboard	$1.55	$1.70	$2.18	$2.65
Electric Furnace	$1.47	$1.58	$1.95	$2.31
Electrothermal Storage	$1.88	$2.16	$3.11	$4.04

Table 14: Propane prices required for a 5 year retrofit payback - $100/tonne carbon tax

	Propane prices required for a 5 year retrofit payback - $100/tonne carbon tax			
Heating System	Pre 1980s	1980s and Newer	NECB 2011	Super-Insulated
Electric Baseboard	$1.11	$1.21	$1.54	$1.87
Electric Furnace	$1.06	$1.13	$1.38	$1.63
Electrothermal Storage	$1.33	$1.53	$2.19	$2.83

Appendix 4.7
Mirrlees Assessment Report

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Yukon Energy KV-16 August 2016 Inspection

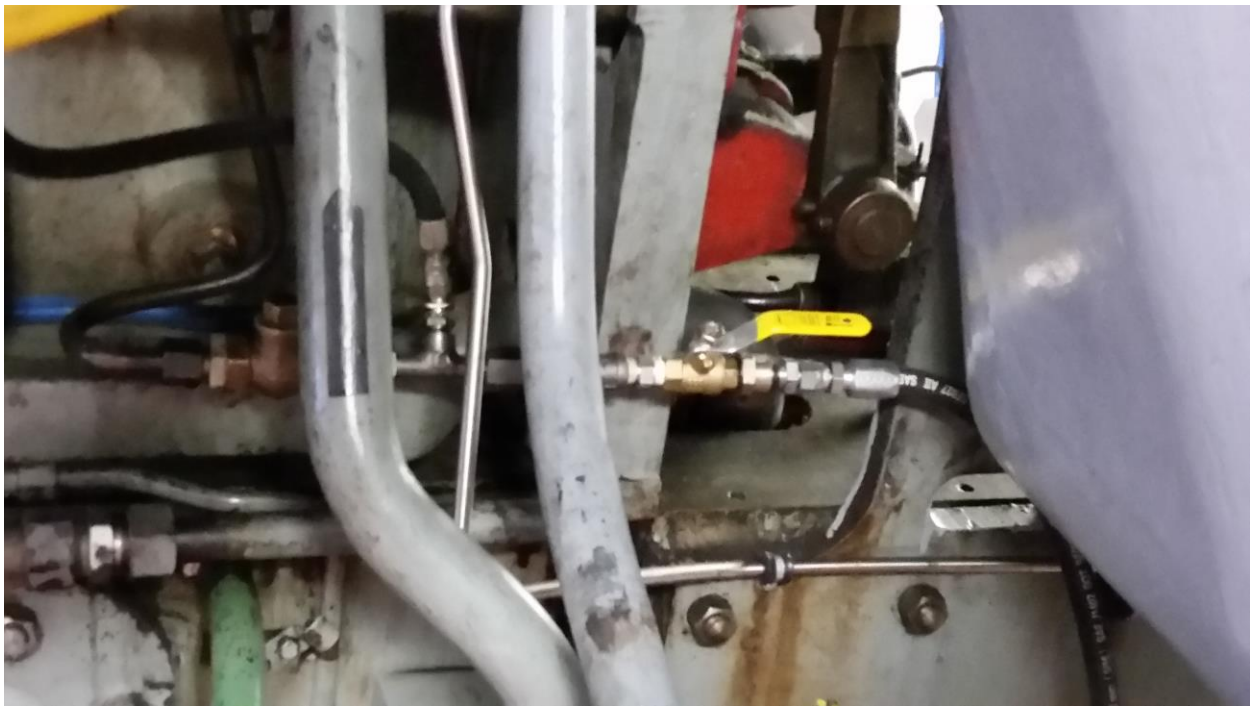
Overview

Inspections were completed on WD3 and FD1.
Since the BC Hydro report of 2004, the two engines have been overhauled. Although in better condition, the engines still do not meet Yukon Energy's criteria for emergency standby and peaking. These engines are intended to run for longer periods of time at base load operation; not the present mode of operation. Testing the engines for one hour a month causes more wear and tear, thus requiring more maintenance than a continuous running engine.

These engines are over 45 years old and do not meet today's environmental emission standards. In the future, this may cost Yukon Energy a major capital investment to upgrade the exhaust system to meet today's standards.

WD3 KV-16
S/N 6444-1
Engine Hours
Last Major Overhaul Completed: Sept 2008
Last Overhaul Hours 39040

Engine Test
The lubricating rocker pressure regulator was removed from WD2 to replace the manual valve that was installed at the last overhaul. This valve was found to be defective and the manual valve was reinstalled. (This regulator valve could not be sourced by MAN at the last overhaul.)



The engine did not start at first attempt; some fuel pumps were sticking.
All fuel pumps and linkage were oiled and racks freed.
All three engine air tank valves were opened to make one system (Operations say this is a common problem on starting).
Engine was started and ran on line up to 3.7 MW for one hour.

Engine started to overheat, jacket water cooling system was up to 200° F.
No alarm came on; **needs to checked**.
Aftercooler outlet temperature should be between 110° and 120° F with a maximum temperature of 125° F.
'A' bank was up to 150° F and the alarm came on.
'B' bank was running at 138° F with no alarm.

Concerns
The secondary cooling system uses untreated river water and the engine pipe work and valves look original and could be over 45 years old.

The overheating problem could also be restrictions in the pipe work due to 45 years of scale build up. The scale could also be blocking the plate type heat exchangers. Cleaning and inspections of the plate heat exchangers is a one to two-week job with parts.

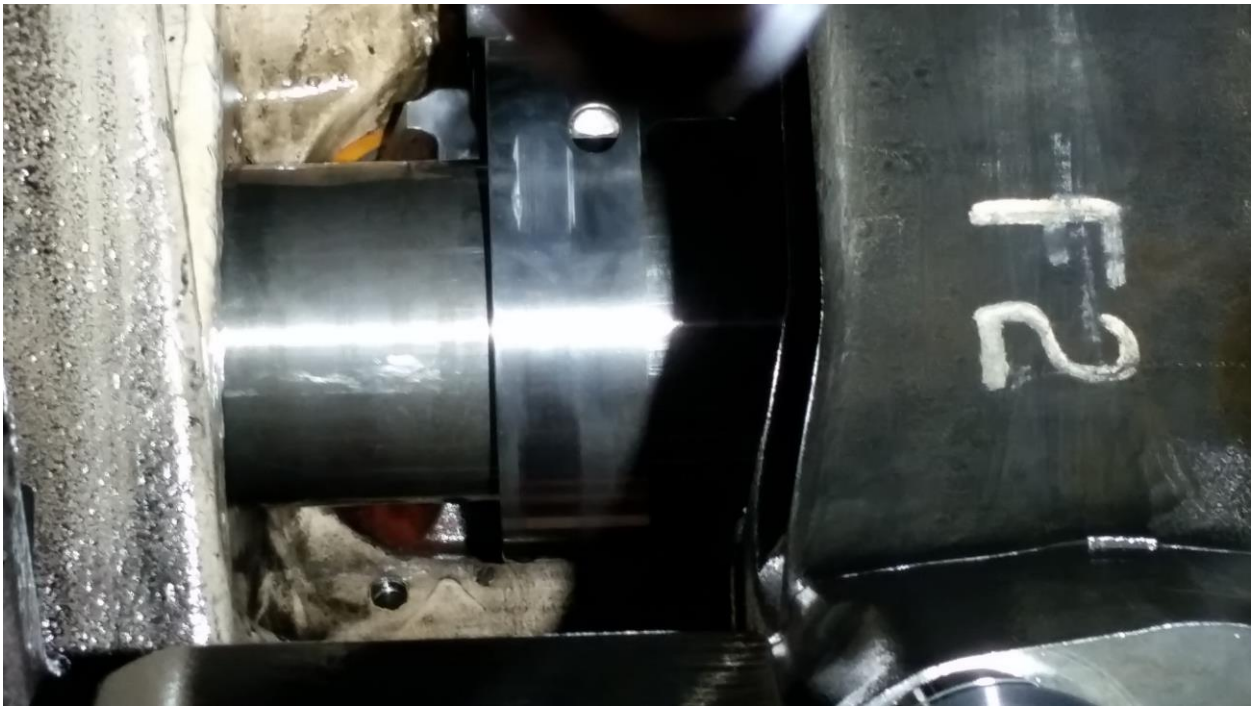
The raw water pump may not be operating properly. There is also a possibility of a closed valve in the system due to WD1 and WD2 taken out of service.

There are only two pumps installed for cooling of engines, which are fed from the hydro plant. After the unit was taken off line, the operator switched over to the other pump.
The pump taken out of service should be checked to make sure it is operational.

The engine jacket water and valve cage cooling system ran on river water from installation until the last overhaul in 2006 when the engine cooling system was changed to anti-freeze.
Some erosion of both the block and liner lands was observed at the last overhaul due to the river water. The liner lands were filled with plastic steel.

Engine Internal Inspection
A visual inspection completed on the outside of the engine.
Doors 2, 4, 6 and 8 removed from 'A' bank side
Doors 1, 3, 5 and 7 removed from 'B' bank side.

Visual signs of B6 exhaust cam (K22448) picking up. B6 crankcase door was removed.
Unable to inspect further due to type of clearance on the unit.
Recommend removal of cam door for more detailed inspection. If the cam needs to be replaced, this job could take up to a month after the parts are sourced.



Bottom of cylinder liners that could be seen are showing signs of polishing.
The piston oil return still has the spay type return plugs installed.
The extent of the polishing is not known and can be caused by the short runs or the liners not properly honed at the time of the last overhaul.

If a piston needs to be removed, it could take anywhere from a week to a month after the parts are sourced depending on what is found.

Operations noted that the gear train is extremely noisy in the winter months, which could be caused by engine foundation movement. The original grout that is installed is prone to crumbling due to the type used at the time of installation.

Replacing the grout requires the complete strip down of the engine and removal of the generator to jack up the bed plate; this would run into millions of dollars and the engine out of service for a year or more and that's if all the parts can be sourced.

Recommend that crankshaft deflections be taken in beginning of spring, the middle of summer, fall, and the middle of winter to see if there is crankshaft and bedplate movement. Inter-gear clearances should be checked at the same time.
This job is about one week.

If a failure occurs of any the gears or inter-gear brackets, the engine will be out of commission for an extremely long time until the parts are made.

There was no overhaul report submitted to Yukon Energy from DEAS, so there is no record of tolerances (liners, piston grove clearances, gear backlash). This could have a major impact on future parts requirements, down time, and costs.

This engine has been down rated due to the generator having one coil isolated.
Max load is 4.5 MW. Estimated cost to repair the generator is $1 to 1.5 million with a down time of over six months.

Faro

Plant is kept in a clean and orderly manner.

FD1 KV-16
S/N 6451-1
Engine Hours: 247.5 on the hour meter
Last Major Overhaul Completed: Oct 2009
Hours at last Overhaul: 22277

Engine Internal Inspection

A visual inspection completed on the outside of the engine.
Doors 2 and 8 removed from 'A' bank side.
Doors 3 and 7 removed from 'B' bank side.

Engine inside was clean.
Liners that could be seen still had the cross hatch.

Engine Test

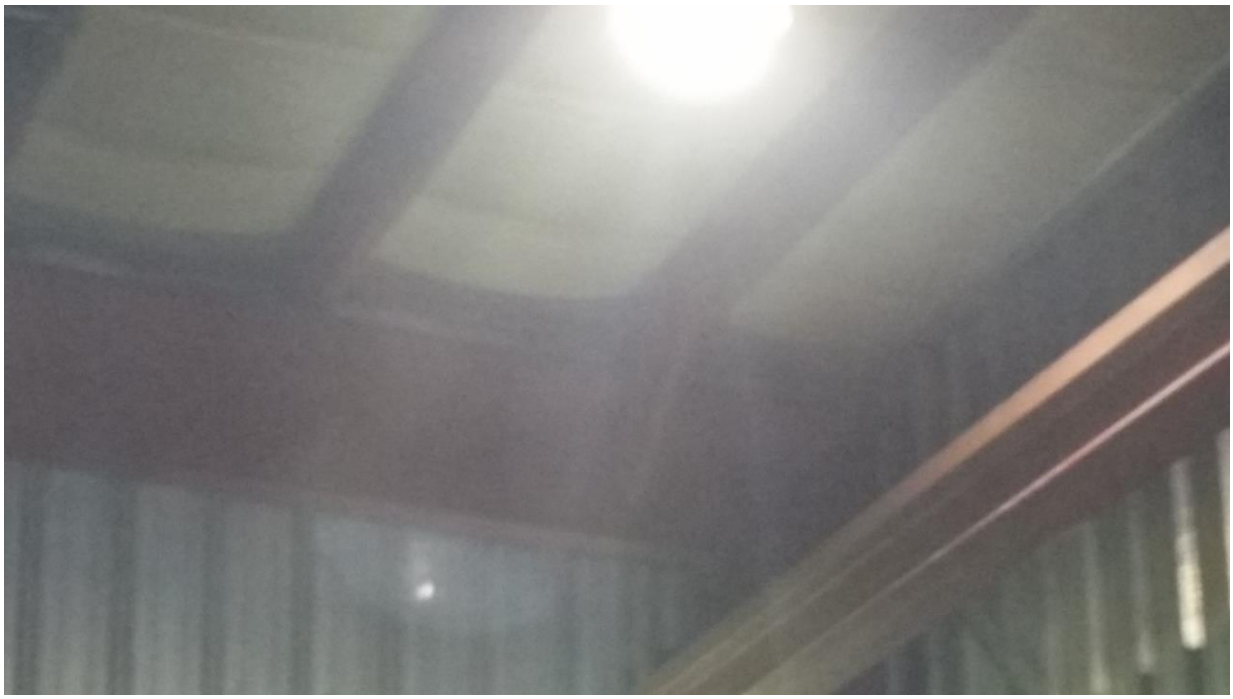
Engine remote started from Whitehorse and started first time.
Engine was loaded to 2 MW

Large amount of oil is getting into the exhaust system due to the wrong Fairchild Valves install. MAN supplied these valves, and were installed at the last overhaul.
The lubricating rocker pressure regulator was replaced with a manual valve at the last overhaul (this regulator valve could not be sourced at the last overhaul). With the engine being in auto start, the valve is left open causing oil to enter the cylinder liners through the valves.

Engine Concerns
Mechanical emergency over-speed and low lube oil pressure trip shutdown blocked with a wedge. It was found that the unit trips off when running.
This could have a catastrophic failure if there is a governor failure.

Misalignment of the tripping lever mechanism is caused by movement of the cylinder block.
The mechanical overspeed trip and low lube pressure is now not operational and is relying on the electrical shut downs
Realignment of the tripping mechanism is needed; this could take up to a month to correct.

Heavy exhaust smoke fills the plant from oil in the exhaust pipes when starting the engine requiring operator evacuation.
Large amounts of smoke from the stacks drifts over the town on start up.



Recommendation
The cylinder head rocker lubrication valve should be closed when the engine is not running, requiring someone to be at site when starting the engine.
Fairchild valves for valve guide lubrication need changing to the correct ones. (WD2 valves checked for use on FD1, but they are also the wrong ones.)

Next Maintenance PM
Valves need resetting, exhaust has some blown gaskets need replacing, water manifold pipe needs the supports fixing,

Engine Common Failures
Jacket water leaks from the liner "O" rings. This is a minimum two-week job with the parts
Valve cage cooling water leaks. This is up to a week with parts

Catastrophic failures
Inter-gear brackets cracking, if this is not found will destroy the gear chain and possibly the engine. The problem is these brackets are no longer made and would be a special order or find a second hand one. (engine could be out of service could be over a year).

A failure to the piston crown will have the engine out of service for a long period, it could take more than a year to source parts to repair or it could destroy the engine beyond repair.

Conclusions
Mirrlees no longer exists as an engine manufacturer and is owned by MAN Diesel.
MAN, never informed Yukon Energy of the closure of the Ontario office or any procedure for purchasing parts.

These engines are over 45 years of age and Mirrlees-experienced service engineers are not stationed in Canada. This will have a higher cost to provide service engineers in the future.

Stocking of parts are no longer in Canada and delivery of parts in a timely manner and cost are a major concern.

Brown Boveri VTR turbo chargers for these engines are no longer made and no parts are stored in Canada. The only suppler I could find on line was aftermarket parts in Europe.

NTPC in Yellowknife had to salvage parts from Yukon Energy to finish their overhaul.
Exhaust valve cages loaned to NTPC in Yellowknife took over three years to replace.

The use of aftermarket parts is not recommended, Yukon Energy tried this already and cost a lot of money for parts that did not meet Mirrlees specifications.

We tried to phone the Ontario service office for a time estimate for delivery of parts, only to find the office was closed
This is the contact information we were given for MAN was from NTPC:

Vancouver:
Najibul Ansari 1-604-365-4023 email: najibul.ansari@ca.man.eu
Riseley D'Souza [mailto:Riseley.DSouza@ca.man.eu]

Halifax:
Charlie Balogh 1-902-402-6445 email: charlie.balogh@ca.man.eu

24/7 emergency contacts:

Spare parts AUG engines: +49 821 322 1799
Spare parts TC: +49-821-322-4030
Spare parts 2 stroke engines: +45 4019 3501
Spare parts Holeby engines: +45 4014 4045

Technical Service AUG engines: +49 821 322 1499
Technical Service 2 Stroke engines: +45 2048 9440
Technical Service Holeby engines: +45 4014 4045
Technical Service TC (radial type): +49 821 322 4020
Technical Service TC (Axial type): +49 821 322 4010

Due to the age of the units, FD1 and WD3 are considered to be “end of life” and would require major work and operating methods to extend life. Even if this work is carried out equipment obsolescence will result in difficulty of obtaining parts at reasonable cost. The loss or OEM technical support compromises the life extension of these units. A major failure would result in an extended outage on the unit, and a cost prohibitive repair. YEC should replace the units.

Appendix 4.8
Generation Adequacy Evaluation
(Karki, 2017)

Generation Adequacy Evaluation of the Yukon Energy Corporation Power System Incorporating Major Power Delivery Constraints

Prepared By

Rajesh Karki, Ph.D., P.Eng.

February 23, 2017

EXECUTIVE SUMMARY

This report presents adequacy evaluation studies of the Yukon Energy Corporation (YEC) electric power system considering major capacity delivery constraints. The results of the studies carried out to develop a suitable reliability model for the existing YEC system are presented. The developed model was integrated in a software tool named YESREL which is a modified version of WAFSREL [1]. A number of case studies were also conducted using the YESREL program.

The Whitehorse, Aishihik and Faro (WAF) sub-systems were the major components of the YEC system in 2005, when a study [2] was carried out to recommend a reliability criterion of LOLE = 2 hours/year for capacity planning. The 2005 study showed that the capacity constraint imposed by the line L171, that interconnects the Aishihik hydro plant, had significant impact on the overall adequacy of the WAF system, and was therefore incorporated in the reliability model. A reliability software WAFSREL [1] then developed included this model in reliability evaluation of the WAF system. Another reliability study [3] was carried out in 2011 after the Mayo and Dawson (MD) sub-systems were integrated to the WAF system. The study recommended that the WAFREL software that was developed for the WAF system should be upgraded in response to the system changes in the WAF-MD system.

This report consists of 5 sections. Section 1 provides introduction to the work in this project. Section 2 presents the generation and load data of the WAF-MD system. The total system capacity of 131.21 MW was considered for the WAF-MD system. The total effective winter capacity was reduced to 109.61 MW as the Whitehorse and Mayo hydro plants during the winter season are limited to 24.5 MW and 9.0 MW respectively due to seasonal hydrological constraints. Generating unit forced outage rate of 1%, 4% and 15% were used respectively for the hydro, diesel and natural gas units in the evaluation. Section 2 also presents results of basic generation adequacy evaluation of the WAF-MD system, in which the transmission lines are not considered. This approach is taken in LOLE evaluation of many large power systems, and LOLE of 0.1 days/year is often used as a capacity planning criterion. Using this criterion, the WAF-MD system can carry a peak load of

94.36 MW. An LOLE of 0.1 days/year was found be equivalent to LOLE of 0.5 hours/year for the WAF-MD system without considering transmission constraints. It should be noted that that the Aishihik hydro capacity limitation due to the line L171 was considered in the WAF system reliability criterion of LOLE = 2 hours/year.

The impact on the YEC adequacy of the major transmission line outages is analyzed and presented in Section 3. The studies show that the line L171 (connecting Ashihik) has the largest impact on the LOLE and LOEE results. The parallel lines L172 and the distribution lines connecting Takhini and Whitehorse also showed notable impact on the system indices. The lines L176, L174+L173 and L170 connect the Mayo hydro generation to the bulk system load at Whitehorse, and the impact of these lines increases with their proximity to Whitehorse area load. However, the lines L177 (connecting Dawson) and Line L178 (connecting Faro) have very little impact on the system indices, and therefore, need not be considered in the generation adequacy model of the system.

Five different generation adequacy models were developed for the WAF-MD system and presented in Section 4, based on the analyses of the results obtained in the Section 3 studies. The five generation adequacy models are arranged in the report in the order such that the amount of input data requirements and evaluation complexity increases from Models 1 to 5 in the list. In this order, the models also deviate further away from a basic generation capacity adequacy model or HLI (Hierarchical Level I) model towards a composite generation and transmission adequacy or HLII (Hierarchical Level II) model. LOLE evaluation was also done using a sixth model, the HLII model, and compared with the previous 5 different adequacy models. A comparative analyses of the results from the 6 different adequacy models suggest that the “Hydro Plants Interconnection Model” is a suitable generation adequacy model for the YEC system since it is relatively simple and provides reasonable results. This adequacy model was therefore incorporated in the program YESREL.

Section 5 presents results from selected case studies of potential future scenarios. The results show that the existing WAF-MD system can carry a peak load of 82.8 MW at the LOLE criterion of 2 hours/year. Including the mobile diesel units and YECL generation, the system can up to 91.4 MW of peak load. This would have reduced to 84.3 MW if the YEC had not installed the distribution

line to add redundancy to the line L172. As the system peak load is around 83 MW, the YEC/YECL system has adequate capacity to meet the short term load growth. This scenario will change in 2021 as two YEC diesel units (FD1 and WD3) retire. This will cause a capacity deficit as the YEC/YECL will only be able to carry a peak of 81.8 MW. If 25 MW capacity assistance can be provided through the Skagway line, the YEC/YECL system will be able to carry a peak load of 109.9 MW. When all the YEC diesel units retire in 2026, the YEC/YECL system will only be able to carry a peak load of 56.3 MW. Twining the line L171 will raise the peak load carrying capability to 71.2 MW. A firm purchase of 25 MW through the Skagway line will enable the system to carry a peak load of 85.3 MW. Additional generation capacity installation will be required to meet the LOLE criterion of 2 hours/year in the year 2026. Representative data taken from the CEA Equipment Reliability Information System have been used to supplement the data provided by YEC. It should be noted that the study results are highly dependent on the generating unit and transmission line failure and repair parameters used in the analyses.

TABLE OF CONTENTS

		Page
1.	Introduction	6
2.	Basic Adequacy Evaluation	8
	2.1 System Generation Data	9
	2.2 System Load Data	14
	2.3 System Evaluation and Models	17
	2.4 Selected Task 1 Studies	25
3.	Impact of Transmission Line Outage on Generation System Adequacy	30
	3.1 Major Transmission Line Data	31
	3.2 Local Load Data	34
	3.3 System Risk Evaluation Considering Line Outages	35
4.	Development of Generating System Adequacy Model Considering Major Delivery Constraints	39
	4.1 Analysis of Alternate Generation Adequacy Models	39
	4.2 Adequacy Evaluation Results from Alternate Models	44
	4.3 Comparative Analysis of Alternate Models	54
5.	Case studies considering Potential System Scenarios	58
	5.1 Considering Existing Generation Facilities	60
	5.2 Considering Unit Retirement Scenario in the Year 2021	64
	5.3 Considering Unit Retirement Scenario in the Year 2026	65
	References	67

1. INTRODUCTION

This report presents the results of generation system adequacy evaluation studies of the Yukon Energy Corporation (YEC) electric system considering the major power delivery constraints in order to assist with the update of their 20-Year Resource Plan. The University of Saskatchewan conducted a reliability evaluation of the Whitehorse-Ashihik-Faro (WAF) electric power system in 2005 [1], and developed a software tool named WAFSREL [2] that incorporates the generation adequacy model developed in the 2005 study. There have since been significant changes to the topology and the configuration of the YEC system. The northern Mayo-Dawson (MD) system was interconnected to the southern WAF system through the Carmacks-Stewart transmission line. The University of Saskatchewan conducted a reliability evaluation of the extended Whitehorse-Ashihik-Faro-Mayo-Dawson (WAF-MD) electric power system in 2011 [3], and indicated that the WAFSREL program required relevant modification to incorporate the changes in the YEC electric power system. There have been further changes to generation capacity at various locations in the WAF and MD systems. This report also includes investigative studies to determine an appropriate generation adequacy evaluation model of the YEC electric power system to incorporate in the modified software tool.

Probabilistic reliability evaluation techniques [4] will be used in the overall project to carry out a number of case studies, and analyze the results to recommend an appropriate generation adequacy model for the YEC system under the changed scenario. The basic elements in a capacity adequacy review are the installed generating capacity and the system load. The YEC system load is dominated by the Whitehorse area load. Transmission lines are not generally considered in the generation capacity adequacy evaluation. Specific transmission facility that connects the power system to a remotely located large generation plant with insignificant local load are however typically considered in generation adequacy study. This approach will also be considered in the study to consider the ability of the remote generation at Aishihik, Faro, Mayo and Dawson to deliver their capacity to the Whitehorse load through the respective transmission lines. The impacts of major transmission line constraints in delivering the system generation capacity to the Whitehorse area were assessed in the study.

The project was carried out in five tasks. The first task was to carry out a basic generating capacity adequacy assessment of the YEC system considering the existing generation and load data. The transmission constraints to deliver the power to the system load were not considered in this task. The work in this task provides a base case to conduct comparative studies done in the next task to evaluate the impact of transmission lines. The second task was to evaluate the YEC system using a conditional probabilistic approach to assess the impact of the forced outages of major transmission lines on the generating capacity adequacy. The results of Task 2 studies were analyzed to quantitatively compare the impacts on the system adequacy of the individual transmission lines in order to assess their significance in the development of the system capacity adequacy model. The third task is to incorporate the constraints of all major transmission lines in the generating capacity adequacy evaluation of the YEC system, and determine an appropriate generation adequacy model for the YEC system. A number of case studies will be carried out in Task 4 using the transmission line constrained generating capacity adequacy model developed in Task 3. The final task is to develop a graphical user interface software tool that incorporates the transmission line constrained generating capacity adequacy model developed in Task 3.

A wide range of indices have been developed to quantify the reliability of electric power systems. These indices are described in detail in [4]. The basic concepts used to obtain the results provided in this report are also discussed and illustrated in [4]. The Loss of Load Expectation (LOLE), the Loss of Energy Expectation (LOEE), and the Peak Load Carrying Capability (PLCC) are the most commonly used indices in generating capacity reliability evaluation. The LOLE is the expected number of days or hours in the specified period when the load exceeds the available generating capacity. It is the most widely used index. The LOEE is the expected energy not served as a result of system generating capacity inadequacy. The PLCC is the peak load that the power system can carry while meeting the adequacy criterion. A LOLE of 2 hours/year is the accepted criterion adopted by YEC for generation planning.

2. BASIC ADEQUACY EVALUATION

This section presents a description of the relevant data, evaluation models and results obtained from a basic generating capacity adequacy assessment of the current YEC system using the conceptual reliability model [4] shown in Figure 2.1.

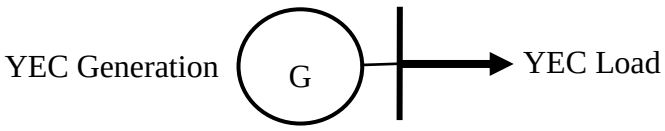


Figure 2.1: Basic Generation Adequacy Evaluation Model

The objective of the basic generation adequacy evaluation is to assess if an electric power system has sufficient generation facilities to meet the projected system demand within acceptable risk. This study does not consider the ability of the transmission system to deliver the power to the system load. A system generation model is created in the form of a discrete probability distribution by combining all the generating units in the system. A system load model is developed from the annual load profile of the entire power system. The line losses are included in the system load. The generation model and the load model are convolved to obtain quantitative risk indices. The loss of load expectation (LOLE) and the loss of energy expectation (LOEE) are the two important generation adequacy indices that will be used to quantify the level of system reliability. The peak load carrying capability (PLCC) of the generating system at the LOLE criterion of 2 hours per year will also be evaluated in the study. The results obtained from this study will be used to benchmark and compare the results obtained from the studies in the subsequent tasks.

2.1 System Generation Data

The YEC system generation data used in the study is shown in Table 2.1. The maximum continuous rating (MCR), generation type, location of the generation plants, and the total plant capacity are shown in the table.

Table 2.1: YEC System Generation Data

Location	Unit Type	Unit ID	MCR (MW)	Plant Capacity (MW)	
				Summer	Winter
Whitehorse	Hydro	WH1	5.8	38.0	24.5
		WH2	5.8		
		WH3	8.4		
		WH4	20		
	Diesel	WD3	4.5	15.0	15.0
		WD4	2.5		
		WD5	2.5		
		WD6	2.5		
		WD7	3.0		
	Natural Gas	WG1	4.4	8.8	8.8
		WG2	4.4		
Aishihik	Hydro	AH1	15	37.0	37.0
		AH2	15		
		AH3	7		
Faro	Diesel	FD1	4.0	6.8	6.8
		FD7	2.8		
Mayo	Hydro	MH1	2.55	11.6	9.0
		MH2	2.55		
		MBH1	5.0		
		MBH2	5.0		
	Diesel	FD2	0.85	2.55	2.55
		FD3	0.85		
		FD4	0.85		
Dawson	Diesel	DD1	0.72	5.96	5.96
		DD2	0.92		
		DD3	0.92		
		FD5	1.0		
		DD5	1.4		
		FD6	1.0		

The total MCR in the above table is 131.21 MW. The total effective summer and winter capacities are 125.71 MW and 109.61 MW respectively. The winter season was considered to consist of the months from November to March, with the remaining months grouped into the summer category. The effective capacity of the Whitehorse and Mayo hydro plants during the winter season is limited to 24.5 MW and 9.0 MW respectively due to seasonal hydrological constraints. The effective capacity of the Whitehorse and Mayo hydro plants during the summer season is limited to 38.0 MW and 11.6 MW respectively due to water spilling requirements.

Table 2.2 shows an analysis of the forced outage rate (FOR) [4] data provided by YEC on all of their generating units. The generating units have been classified into 4 groups based on their types and sizes in the analysis. A five-year average FOR is calculated for each classification using the YEC data.

The FOR is the expected probability that the generating unit will not be available for service due to random failure, and is calculated using Equation 2.1 [5]. The utilization forced outage probability (UFOP) [4] is the appropriate parameter to represent the unavailability of a peaking unit that is only operated during the peak hours of the day. The UFOP is calculated using Equation 2.2 [5].

$$\text{FOR} = \frac{\text{FO} + \text{FEMO} + \text{FEPO}}{\text{FO} + \text{FEMO} + \text{FEPO} + \text{O} + \text{O(FD)} + \text{O(SD)}} \text{ x } 100 \qquad (2.1)$$

$$\text{UFOP} = \frac{\text{f(FO} + \text{FEMO} + \text{FEPO)}}{\text{f(FO} + \text{FEMO} + \text{FEPO)} + \text{O} + \text{O(FD)} + \text{O(SD)}} \text{ x } 100 \qquad (2.2)$$

Where f = demand factor $= \dfrac{\frac{1}{r} + \frac{1}{T}}{\frac{1}{r} + \frac{1}{T} + \frac{1}{D}}$,

and the durations,

FO = forced outage
FEMO = forced extension of maintenance outage

FEPO = forced extension of planned outage
O = operating
O(FD) = operating under a forced derating
O(SD) = operating under a scheduled derating
r = average repair time of the unit
D = average in-service time per occasion of demand
T = average reserve shutdown time between periods of need

Table 2.2: Analysis of YEC Generating Unit FOR Data

Unit ID	MCR (MW)	2015	2014	2013	2012	2011	Average
Large Hydro Units (with High Operating Factor)							
AH1	15	0.05%	-	-	0.19%	0.06%	0.88%
AH2	15	0.08%	0.01%	0.02%	-	0.01%	
AH3	7	0.58%	-	-	1.69%	-	
WH3	8.4	0.06%	0.83%	-	0.79%	0.04%	
WH4	20	0.02%	9.46%	-	-	0.16%	
Small Hydro Units							
MBH1	5	1.96%	0.07%	1.02%	1.25%	2.18%	0.85%
MBH2	5	-	0.02%	1.73%	4.13%	-	
MH1	2.55	-	-	-	0.%	-	
MH2	2.55	0.03%	0.07%	0.%	-	-	
WH1	5.8	0.02%	0.83%	-	1.88%	0.01%	
WH2	5.8	-	0.83%	0.01%	1.03%	0.01%	
Diesel Units							
DD1	0.72	0.15%	-	-	-	-	3.72%
DD2	0.92	-	-	-	17.62%	7.3%	
DD3	0.92	-	0.01%	-	-	-	
DD5	1.4	0.55%	0.01%	-	2.78%	0.21%	
FD2	0.85	0.33%	0.01%	-	-	-	
FD3	0.85	-	0.01%	-	-	6.6%	
FD4	0.85	-	-	-	-	2.44%	
FD1	4	0.25%	2.21%	12.4%	3.9%	7.22%	
FD7	2.8	0.25%	0.34%	0.%	24.6%	8.3%	
WD3	4.5	0.59%	-	-	0.6%	1.67%	
WD4	2.5	1.38%	-	-	-	0.01%	
WD5	2.5	1.4%	0.%	0.01%	-	24.18%	
WD6	2.5	1.48%	0.15%	0.%	0.03%	9.54%	
WD7	3	2.67%	-	-	-	-	
Natural Gas Units							
WG1	4.4	0.18%	-	-	-	-	0.64%
WG2	4.4	1.1%	-	-	-	-	

Table 2.3 shows the relevant FOR and UFOP data from the CEA-ERIS 2014 Generation Equipment Status Annual Report [5].

Table 2.3: CEA-2014 Generation Forced Outage Data [5]

Size & Operating Factor	Hydro Unit, FOR	Combustion Turbine, UFOP
Small units	9.70% (5-23 MW, 607.5 uy)	47.14% (10-24 MW, 12.8 uy)
All sizes	5.03%, (2290.8 uy)	15.31%, (165.2 uy)
Op. Factor below 10%	95.92%	19.95%, (106.9 uy)
Op. Factor 11-20%	64.49%	16.29%, (5.0 uy)
Op. Factor 21-30%	24.69%	8.44%, (24.4 uy)
Op. Factor 61-70%	1.23% (37.2 uy)	
Op. Factor 71-80%	2.08% (65.2 uy)	
Op. Factor 81-90%	1.40%, (669.8 uy)	
Op. Factor above 90%	0.61%, (366.5 uy)	

Note: uy = units years

The YEC generation system includes hydraulic units, diesel engine units and natural gas combustion turbine units. The CEA report does not include diesel engine units. The YEC data for the diesel unit FOR was obtained from a population of 38 units years of data, and are used in the study. A review of YEC data and CEA data shown Tables 2.2 and 3.3 indicate that the YEC hydro unit FOR data are within the range of the CEA data for hydro units with high operating factors. As most YEC hydro units have high operating factors, the average of the actual YEC data is used in this study. There is very little YEC data on the forced outage of natural gas units. The CEA data for small combustion turbine units is skewed by the full outage of 3 units reported in the year 2014. The CEA UFOP data considering all operating factors and sizes of combustion turbine units calculated from a sample of 165.2 unit years are, therefore, used as representative data for natural gas combustion turbine in this study. Table 2.4 shows the generating unit FOR data used in the 2011 YEC report [3], the average FOR data obtained from actual YEC data collection, and the

FOR data used in the current reliability study. The FOR data used in this study are shown in the last column of Table 2.4.

Table 2.4: FOR Data for YEC Generating Units

Generating Unit	FOR (%)		
	2011 Study Data [3]	YEC Actual Data	Data for this study
Hydro	3.0	0.9	1.0
Diesel	10.0	3.7	4.0
Natural Gas	N/A	0.6	15.0

2.2 System Load Data

Historical data on the total chronological hourly generation to meet the system load for the past five years were provided by YEC, and is shown in Figure 2.2.

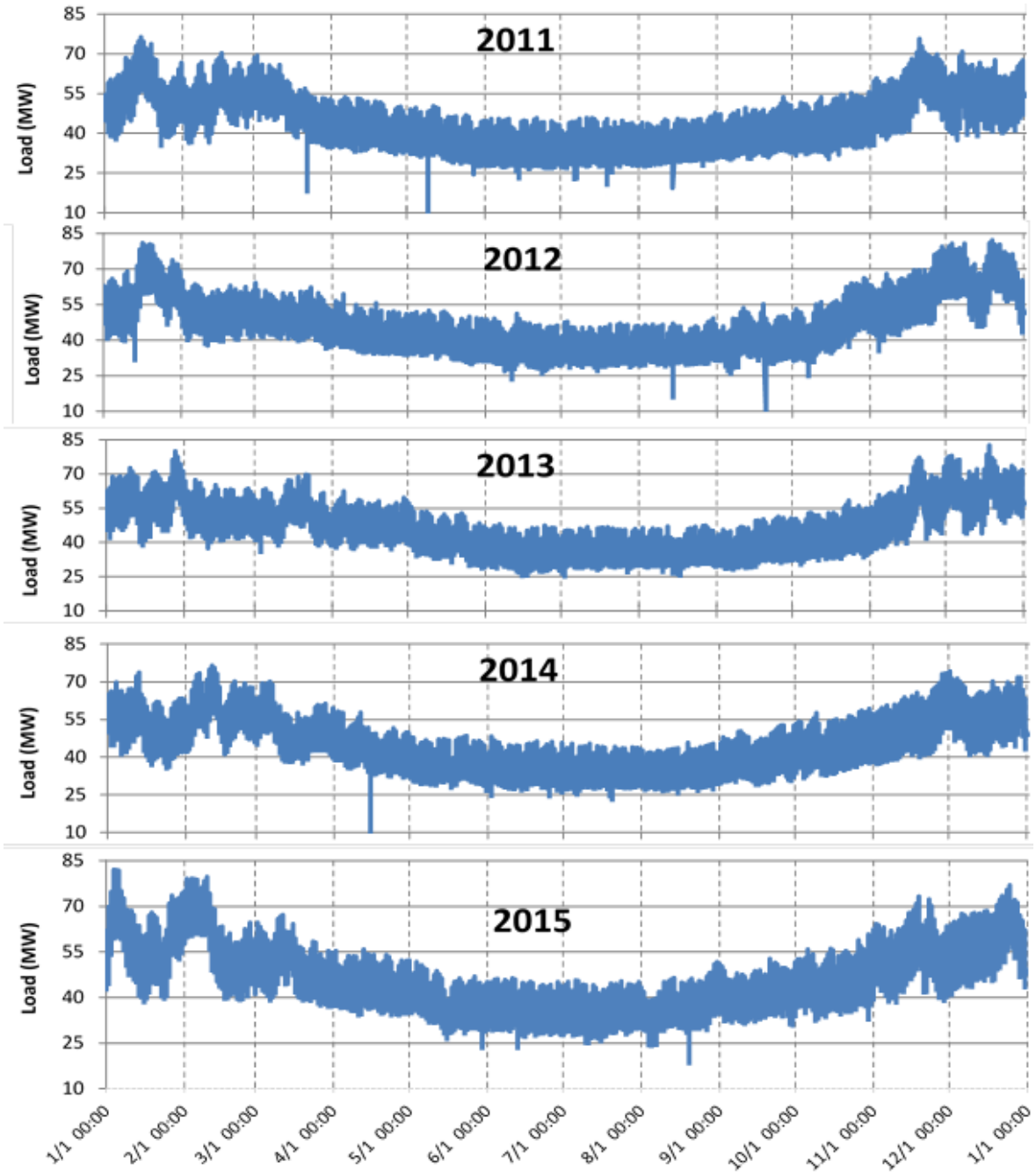


Figure 2.2: YEC Hourly Generation Data, 2011 – 2015

The sudden drops in generation in Figure 2.2 likely indicate data associated with loss of load events, and are therefore replaced by interpolated data. Figure 2.3 shows the modified chronological load data for the past 5 years.

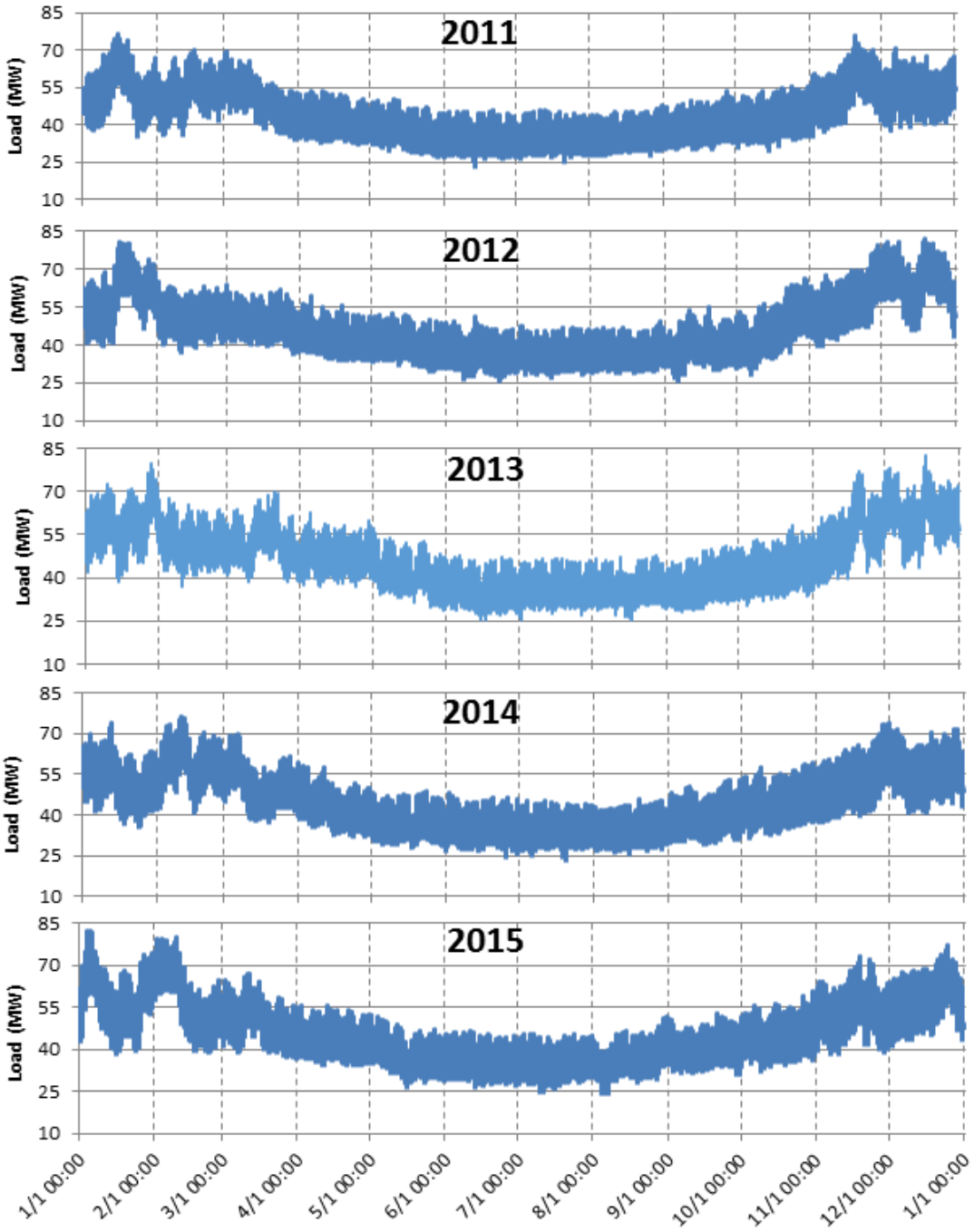


Figure 2.3. YEC Hourly Load Data for 2011-2015

The chronological load data were sorted in the decreasing order and expressed in per unit of the corresponding peak loads of the year to create the annual load duration curve (LDC) for each year. Data for the extra day in the leap year were not considered in the load model. Table 2.5 shows the annual peak load and the load factor for each year. Figure 2.4 shows the annual LDC for the 5 years. The average LDC was obtained by averaging the 5 LDC load points expressed in per unit of their respective peak loads that are arranged in the decreasing order. The average LDC can be used as a representative load model in reliability studies for system planning. The average LDC is also shown in the figure.

Table 2.5: Annual Peak Load and Load Factor

	2011	2012	2013	2014	2015	Average LDC
Load Factor	60.1%	58.9%	58.2%	60.8%	57.9%	58.3%
Peak Load (MW)	76.34	82.24	82.69	76.52	82.06	-

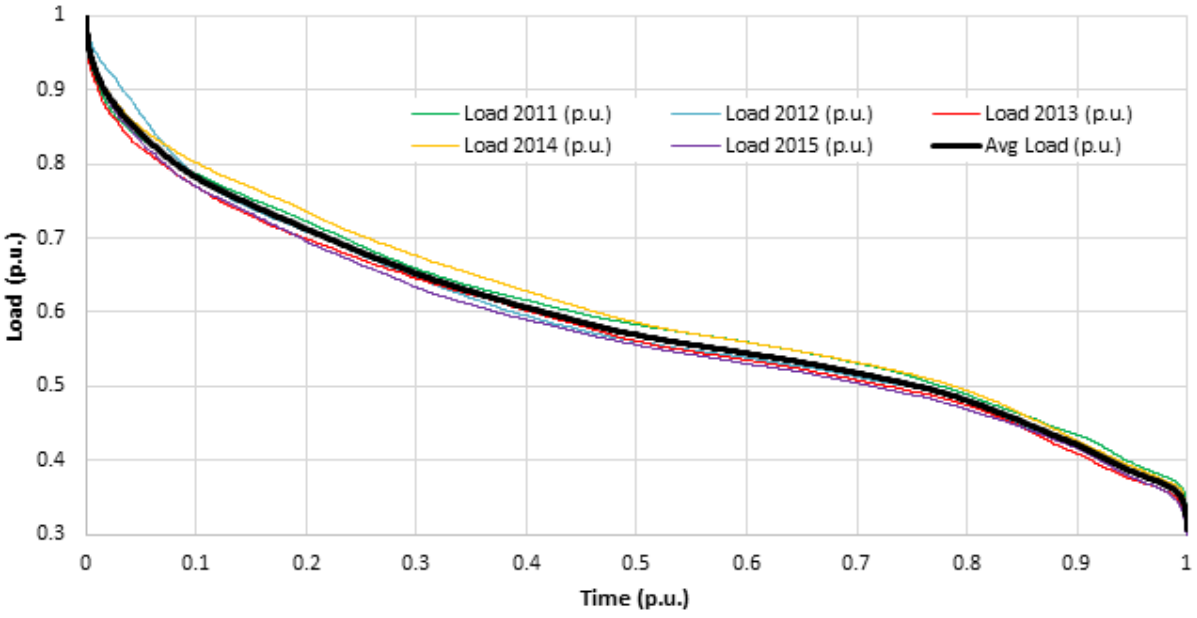


Figure 2.4. Annual Load Duration Curves, 2011 - 2015

2.3 System Evaluation and Models

A basic generating capacity adequacy evaluation was initially conducted for the YEC system using the model in Figure 2.1 without considering the seasonal capacity limitations of the Whitehorse and Mayo hydro plants. The generating unit data shown in the 4th and 5th columns of Table 2.1, and the outage data shown in the last column of Table 2.4 were used to create the overall system generation model. The annual LDCs were used as the system load model. The system LOLE were calculated for a range of peak loads using the average and the five LDCs for each of the past years. The LOLE results are shown in Table 2.6 and Figure 2.5.

Table 2.6: System LOLE Obtained Using the Load Models for the Different Years

Peak Load (MW)	LOLE (h/yr) with Load Model from Year					
	2011	2012	2013	2014	2015	Average
74.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
76.34	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000
78.00	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000
80.00	0.0001	0.0002	0.0001	0.0001	0.0001	0.0001
82.06	0.0002	0.0004	0.0001	0.0002	0.0002	0.0002
84.00	0.0003	0.0007	0.0002	0.0004	0.0004	0.0004
86.00	0.0006	0.0015	0.0005	0.0008	0.0008	0.0008
88.00	0.0012	0.0030	0.0009	0.0017	0.0016	0.0015
90.00	0.0023	0.0060	0.0019	0.0033	0.0033	0.0030
92.00	0.0046	0.0120	0.0036	0.0064	0.0063	0.0059
94.00	0.0085	0.0220	0.0067	0.0120	0.0116	0.0110
96.00	0.0153	0.0387	0.0120	0.0213	0.0202	0.0196
98.00	0.0267	0.0644	0.0209	0.0368	0.0343	0.0336
100.00	0.0442	0.1046	0.0358	0.0618	0.0570	0.0562
102.00	0.0741	0.1708	0.0604	0.1027	0.0961	0.0932

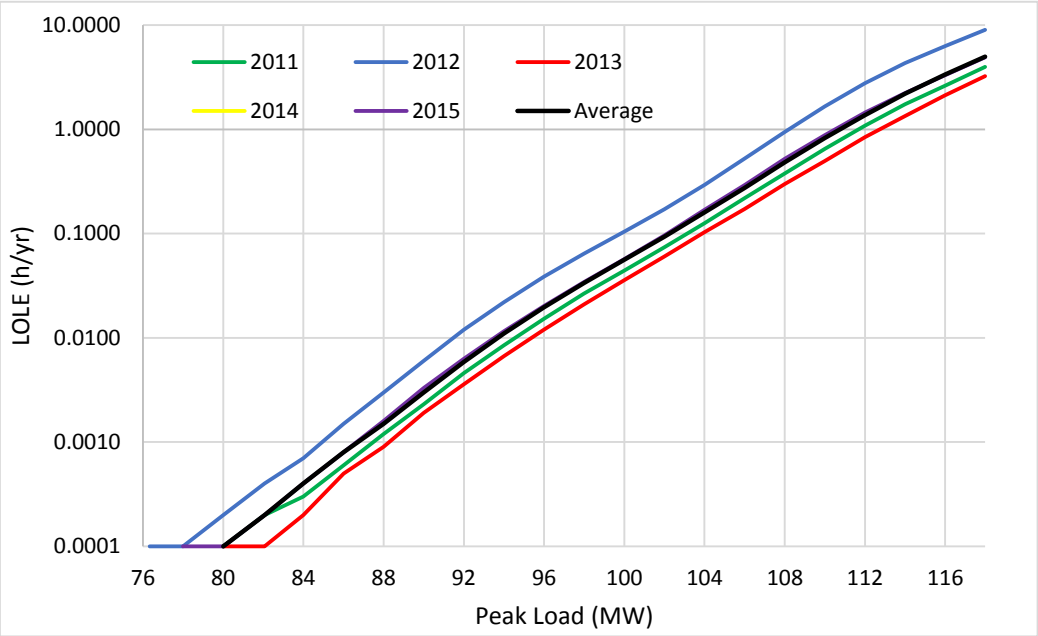


Figure 2.5: System LOLE Obtained Using the Load Models for the Different Years

A comparison of the LOLE results shown in Table 2.26 and Figure 2.5 indicates that there is insignificant difference in the results obtained using the 2015 load model and the average load model. The 2015 load model can therefore be used instead of the average load model in adequacy study. It should however be noted that the above results do not consider the seasonal hydro capacity constraints, which can have significant impact on the LOLE and LOEE indices.

It was shown in the 2011 report [3] that the reliability indices calculated for the winter period were practically the same as those calculated for the entire year, since the summer indices were insignificant relative to the annual indices. A comparative adequacy study similar to the one discussed above using the load models for the different years was next carried out for the winter period recognizing the seasonal hydro capacity limitations. The 5 months between the months of November and March were considered in the winter period. The generating unit data shown in the 4th and 6th columns of Table 2.1 were used to create the overall system generation model in this case. The winter LDCs were used as the system load model. Figure 2.6 shows the winter LDC for the 5 years. The average winter LDC is also shown in the figure.

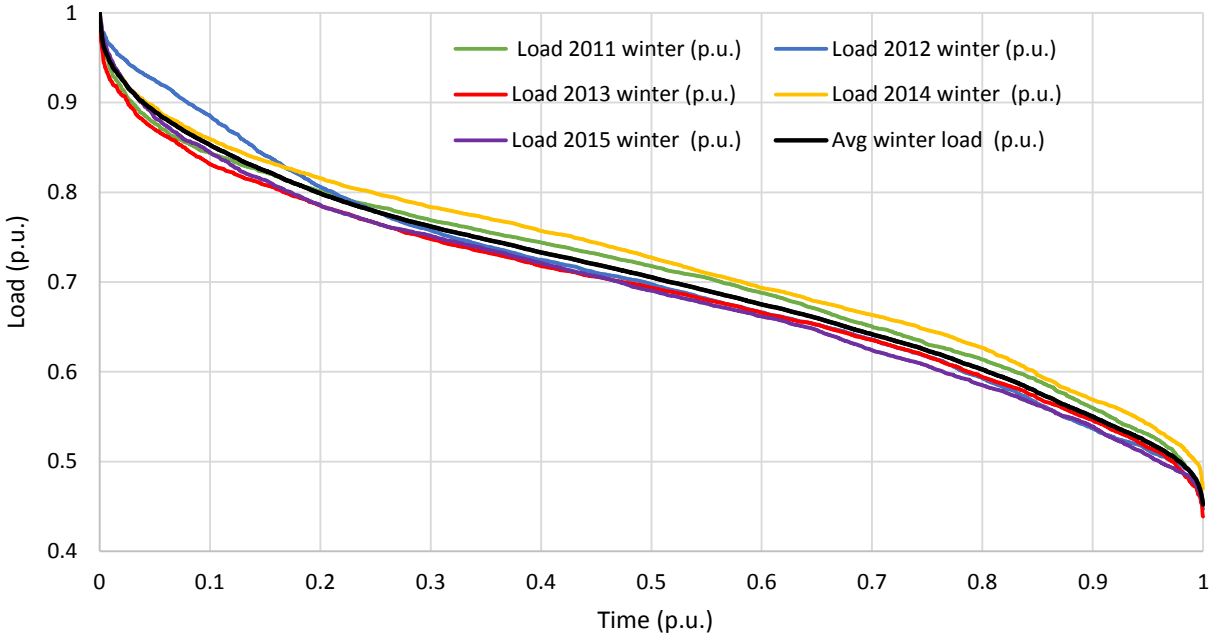


Figure 2.6. Winter Load Duration Curves, 2011 - 2015

The system LOLE and LOEE were calculated for the range of peak loads using the average winter LDC and the five winter LDCs for each of the past years. The results are shown in Table 2.7 and 2.8 respectively. The results shown in bold font are the system LOLE and LOEE obtained from HL-I generation adequacy evaluation in the past five years assuming that the same amount of system capacity existed in the past five years. The system LOLE and LOEE are also shown as a function of the system peak loads in Figures 2.6 and 2.7 respectively.

Table 2.7: Winter LOLE Obtained Using the Winter Load Models for the Different Years

Peak Load (MW)	LOLE (h/yr) with Load Model from Year					
	2011	2012	2013	2014	2015	Average
74.00	0.0003	0.0008	0.0002	0.0004	0.0004	0.0003
76.34	**0.0008**	0.0021	0.0006	0.0011	0.0011	0.0010
76.52	0.0008	0.0023	0.0006	**0.0012**	0.0012	0.0011
78.00	0.0015	0.0042	0.0012	0.0021	0.0021	0.0020
80.00	0.0031	0.0083	0.0025	0.0045	0.0043	0.0041
82.06	0.0063	0.0158	0.0052	0.0088	**0.0084**	0.0082
82.24	0.0067	**0.0167**	0.0054	0.0094	0.0089	0.0086

Table 2.7 Continued..

Peak Load (MW)	LOLE (h/yr) with Load Model from Year					
	2011	2012	2013	2014	2015	Average
82.69	0.0078	0.0193	**0.0063**	0.0110	0.0103	0.0100
84.00	0.0119	0.0283	0.0095	0.0164	0.0154	0.0150
86.00	0.0222	0.0518	0.0180	0.0308	0.0292	0.0281
88.00	0.0435	0.1026	0.0347	0.0601	0.0587	0.0544
90.00	0.0851	0.2132	0.0663	0.1186	0.1165	0.1077
92.00	0.1686	0.4443	0.1330	0.2445	0.2475	0.2211
94.00	0.3306	0.9074	0.2589	0.4684	0.4702	0.4298
96.00	0.6215	1.6439	0.4854	0.8869	0.8643	0.8106
98.00	1.1111	2.8445	0.8620	1.5365	1.4583	1.4230
100.00	1.8836	4.5430	1.4896	2.5907	2.3792	2.3610
102.00	3.0270	6.9955	2.4571	4.1931	3.7970	3.8259

Table 2.8: Winter LOEE Obtained Using the Winter Load Models for the Different Years

Peak Load (MW)	LOEE (MWh/yr) with Load Model from Year					
	2011	2012	2013	2014	2015	Average
74.00	0.455	1.409	0.353	0.672	0.743	0.626
76.34	**1.479**	4.392	1.153	2.156	2.301	2.009
76.52	1.611	4.767	1.256	**2.349**	2.501	2.187
78.00	3.178	9.172	2.467	4.584	4.776	4.265
80.00	7.34	20.55	5.7	10.502	10.625	9.738
82.06	16.105	43.287	12.631	22.866	**22.478**	21.157
82.24	17.184	**46.042**	13.506	24.383	23.93	22.553
82.69	20.179	53.601	**15.94**	28.611	27.948	26.419
84.00	31.788	82.361	25.383	44.982	43.453	41.366
86.00	61.946	155.231	49.45	87.25	83.278	79.845
88.00	119.32	293.757	96.635	168.256	162.524	153.31
90.00	231.97	578.792	186.271	327.567	321.692	297.742
92.00	459.246	1170.738	367.208	650.56	654.127	592.165
94.00	915.212	2406.732	714.218	1291.858	1306.969	1181.117
96.00	1783.406	4754.472	1385.115	2512.84	2532.747	2308.01
98.00	3357.635	8934.562	2591.212	4729.239	4667.780	4353.359
100.00	6027.934	15814.727	4731.525	8474.082	8208.876	7802.765
102.00	10405.983	26430.469	8253.050	14621.479	13840.248	13426.747

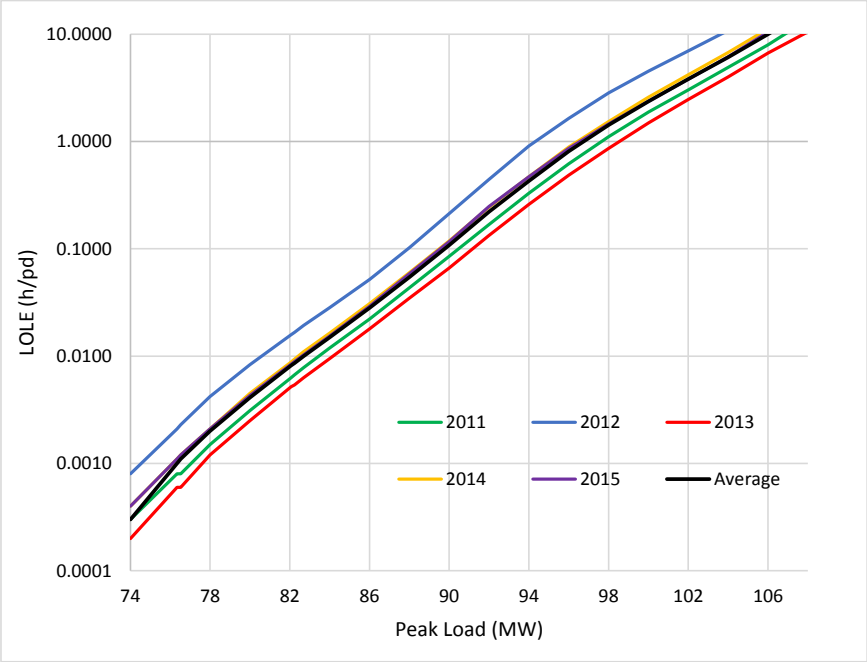


Figure 2.6: Winter LOLE Obtained Using the Winter Load Models for the Different Years

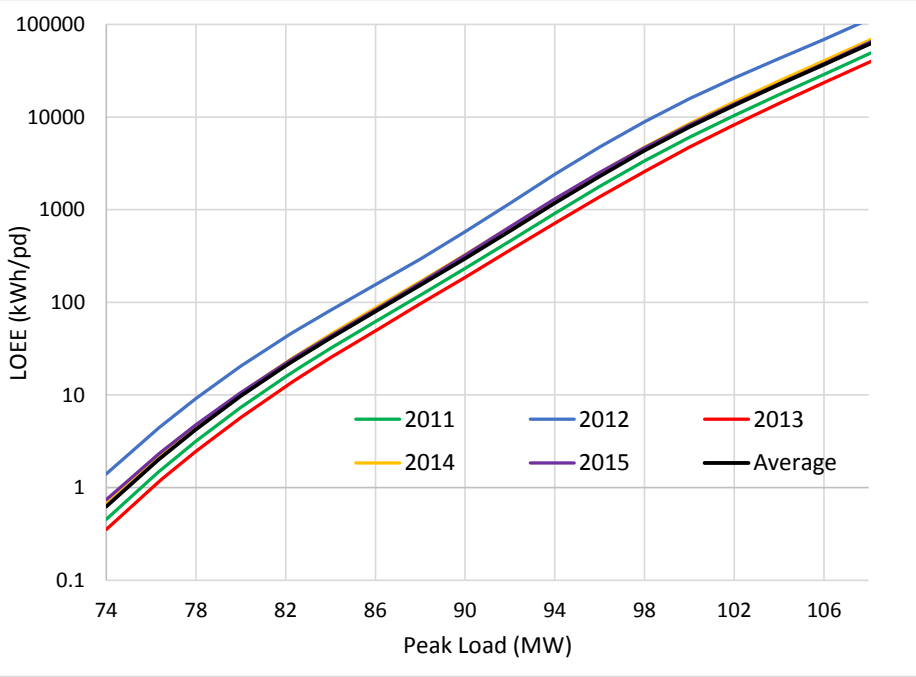


Figure 2.7: Winter LOEE Obtained Using the Winter Load Models for the Different Years

A comparison of the LOLE and LOEE results shown in Figures 2.6 and 2.7 indicates that there is insignificant difference in the results obtained using the 2015 winter load model and the average winter load model. The 2015 load shape can therefore be used as a representative load profile for the YEC adequacy study.

It should be noted from the comparison of the LOLE results in Tables 2.5 and 2.6 that the system LOLE are substantially increased when winter capacity limitations are incorporated in the evaluation. An annual assessment done without considering seasonal capacity limitations result in highly optimistic LOLE indices. It is therefore necessary to carry out period analysis that recognizes the seasonal capacity constraints of the hydro plants.

A period analysis was next carried out considering the seasonal hydro capacity constraints. A study year was divided into two periods; (1) winter period from November to March and (2) summer period between April to October. Separate generation and load models were created for each period. The winter and summer load models obtained from the 2015 load data were used in the study, and are shown in Figure 2.8. The reliability indices calculated for each period were then aggregated to obtain the overall annual indices. The results are shown in Table 2.9.

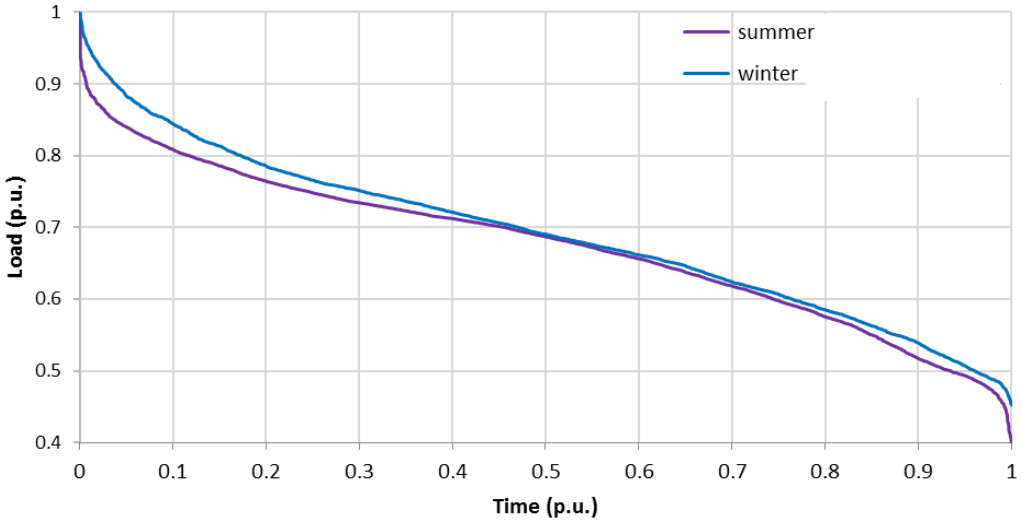


Figure 2.9: Winter and Summer Load Models in Per Unit of their Respective Peaks

Table 2.9: LOLE and LOEE Results from Period Analysis

Peak Load (MW)	LOLE (h/pd)				LOEE (MWh/pd)			
	Summer	Winter	Annual	Error	Summer	Winter	Annual	Error
74	0.0000	0.0004	0.0004	0.00%	0.0000	0.0007	0.0007	-0.13%
76	0.0000	0.0010	0.0010	0.00%	0.0000	0.0020	0.0020	-0.25%
78	0.0000	0.0021	0.0021	0.00%	0.0000	0.0048	0.0048	-0.35%
80	0.0000	0.0043	0.0043	0.00%	0.0000	0.0106	0.0107	-0.46%
82	0.0001	0.0082	0.0083	-1.20%	0.0001	0.0220	0.0221	-0.56%
84	0.0001	0.0154	0.0155	-0.65%	0.0003	0.0435	0.0437	-0.64%
86	0.0002	0.0292	0.0294	-0.68%	0.0006	0.0833	0.0839	-0.72%
88	0.0005	0.0587	0.0592	-0.84%	0.0012	0.1625	0.1638	-0.75%
90	0.0009	0.1165	0.1174	-0.77%	0.0024	0.3217	0.3241	-0.75%
92	0.0018	0.2475	0.2493	-0.72%	0.0048	0.6541	0.6589	-0.72%
94	0.0032	0.4702	0.4734	-0.68%	0.0091	1.3070	1.3161	-0.69%
96	0.0061	0.8643	0.8704	-0.70%	0.0172	2.5327	2.5499	-0.67%
98	0.0109	1.4583	1.4692	-0.74%	0.0321	4.6678	4.6999	-0.68%
100	0.0194	2.3792	2.3986	-0.81%	0.0582	8.2089	8.2671	-0.70%
102	0.0338	3.7970	3.8308	-0.88%	0.1042	13.8402	13.9445	-0.75%
104	0.0564	6.1686	6.2250	-0.91%	0.1818	22.9164	23.0981	-0.79%
106	0.0940	10.4473	10.5413	-0.89%	0.3123	37.8679	38.1802	-0.82%

It can be observed from Table 2.9 that the winter LOLE and LOEE are proximately equal to the annual LOLE and LOEE, and the error between the winter and annual indices as shown in the table are insignificant for all practical purposes. The LOLE and LOEE results are also shown in Figures 2.10 and 2.11 respectively. The peak load carrying capability (PLCC) of the YEC system at a LOLE criterion of 2.0 h/yr was also calculated using the period analysis. The PLCC considering both the summer and winter periods was found to be 99.22 MW. The PLCC obtained using only the winter models was 99.25 MW. It can therefore be concluded that the winter indices obtained using the winter generation and load models can be used to represent the annual indices in generation adequacy evaluation of the YEC system.

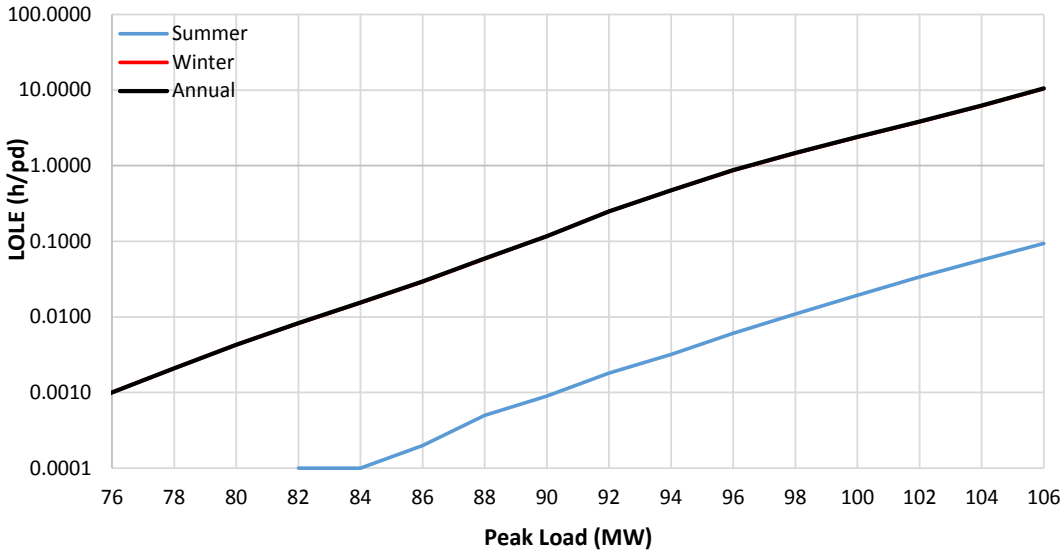


Figure 2.10: Summer, Winter and Annual System LOLE

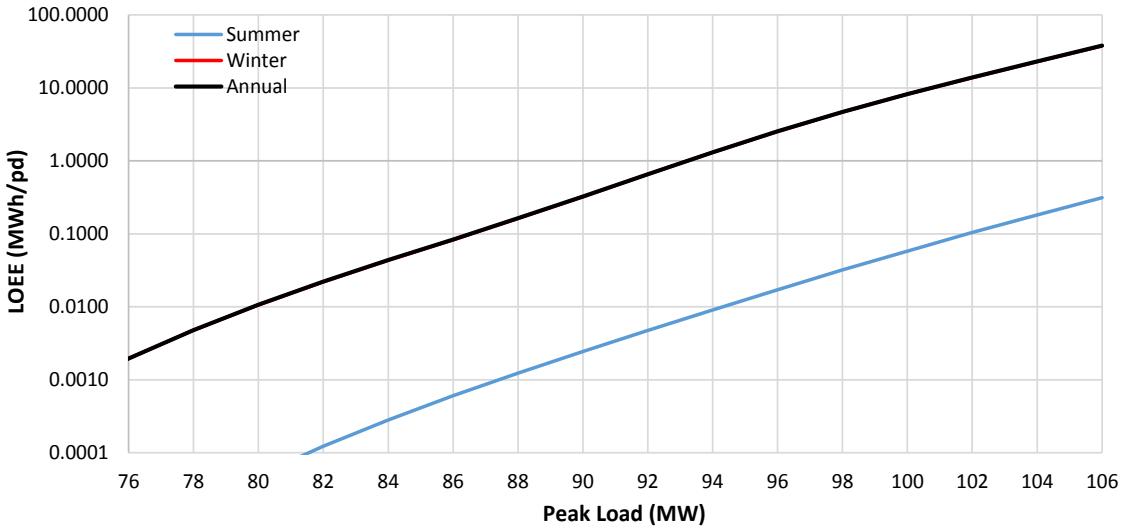


Figure 2.11: Summer, Winter and Annual System LOEE

It should be noted that the adequacy evaluation results presented in this section do not consider the transmission system. This is the typical approach in large power systems that have balanced transmission networks. In such systems, an LOLE of 0.1 days per year is the recommended reliability criterion in capacity planning. A daily peak load variation curve (DPLVC) is used as the load model instead of the LDC when evaluating the LOLE in days per year. A DPLVC curve is obtained by sorting the daily peaks in the decreasing order, and the load model is shown in Figure 2.12. Using the LOLE of 0.1 days per year as the criterion, the PLCC of the YEC system was evaluated, and found to be 94.36 MW. The LOLE in hours per year is 0.52 h/yr at the peak load of 94.36 MW.

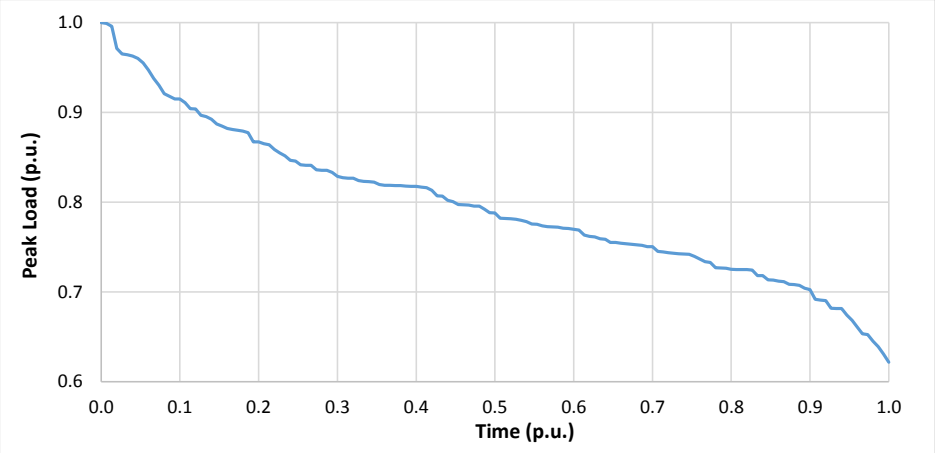


Figure 2.12: Year 2015 Winter DPLVC

2.4 Selected Task 1 Studies

As noted earlier, many large power systems conduct generation adequacy evaluation during generation planning, and these studies do not normally consider the transmission system. This type of evaluation is carried out in Task 1 using generating unit data from Table 2.1 and the forced outage data in the last column of Table 2.4. The hydro plant capacity limited by the winter water

conditions as shown in the 6th column of Table 2.1 are used in the evaluation. The 2015 winter LDC is used as the load model which includes the local loads and the line losses. The system LOLE and LOEE for a range of peak loads are shown in Table 2.9.

A FOR of 15% was used in the adequacy study based on the CEA data [5]. A study was also done assuming the Whitehorse natural gas units have the same FOR as the diesel generating units, which is 4%. The LOLE and LOEE results for a range of peak loads can be compared in Table 2.10. A comparison of the LOLE results is also shown in Figure 2.13.

Table 2.10: Impact of Natural Gas Unit FOR on Task-1 LOLE and LOEE Results

Peak Load (MW)	LOLE (h/yr)		LOEE (MWh/yr)	
	FOR=15%	FOR=4%	FOR=15%	FOR=4%
74	0.0004	0.0001	0.743	0.215
76	0.0010	0.0004	1.962	0.663
78	0.0021	0.0010	4.776	1.880
80	0.0043	0.0023	10.625	4.790
82.06	0.0084	0.0049	22.478	11.581
84	0.0154	0.0092	43.453	24.161
86	0.0292	0.0162	83.278	47.343
88	0.0587	0.0299	162.524	89.069
90	0.1165	0.0569	321.692	167.778
92	0.2475	0.1240	654.127	330.894
94	0.4702	0.2563	1306.969	673.851
96	0.8643	0.5405	2532.747	1396.100
98	1.4583	0.9747	4667.780	2793.316
100	2.3792	1.6655	8208.876	5250.518
102	3.7970	2.5858	13840.248	9172.959
104	6.1686	4.0635	22916.385	15253.594
106	10.4473	6.4940	37867.875	24757.285
108	17.5478	10.8929	63699.516	40629.656
110	29.6536	19.4732	106803.742	67901.023

The difference in PLCC using the two different FOR data for the natural gas units can be seen in Figure 2.13. The difference in PLCC at the LOLE criterion of 2 hours per year is 1.56 MW. The system PLCC results are shown in Table 2.11. The system PLCC at the LOLE criterion of 0.1 days per year is also shown in the table.

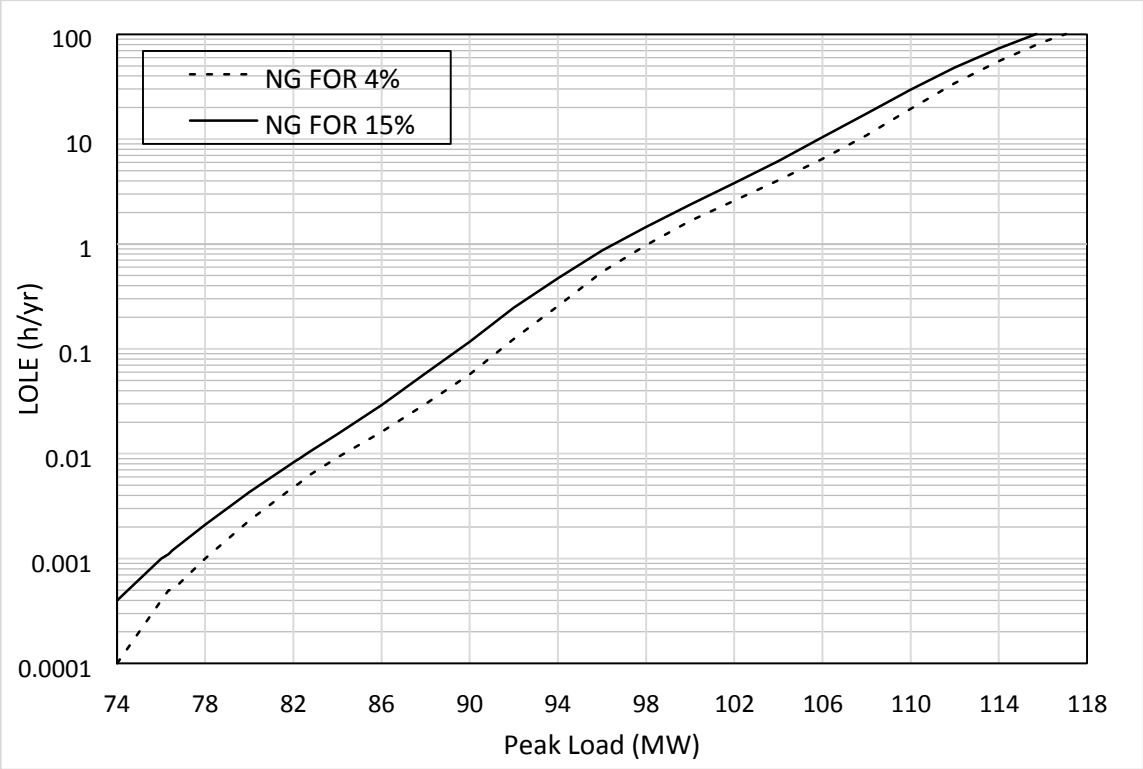


Figure 2.13: Comparison of the System LOLE Using Different FOR Data for the Natural Gas Units

Table 2.11: Comparison of System PLCC Using Different FOR Data for the Natural Gas Units

LOLE Criterion	PLCC (MW)	
	FOR=15%	FOR=4%
2.0 h/yr	99.2487	100.8139
0.1 d/yr	94.3608	95.5425

The adequacy studies includes the YEC generation data shown in Table 2.1. A Task 1 generation adequacy study was also carried out including the ATCO/YECL diesel generating units shown in Table 2.12 in addition to the data in Table 2.1. The FOR of 4% is used in the adequacy study for the ATCO diesel generating units. The system PLCC at LOLE criteria of 2 hours per year and 0.1 days per year are shown in Table 2.13. The system LOLE and LOEE for a range of peak loads are shown in Table 2.14 considering two different FOR for the natural gas units in Whitehorse, i.e. 4% and 15%.

Table 2.12: ATCO/YECL Generating Unit Data Included in the Study

Unit ID	MCR (kW)
CD1	1280
TD1	1200
RD1	800
HD1	1400
Pelly G1	220
Pelly G2	480
Pelly G3	240
Stewart G1	120

Table 2.13: System PLCC When ATCO Generating Units are Included in the Evaluation

LOLE Criterion	PLCC (MW)	
	NG FOR=15%	NG FOR=4%
2.0 h/yr	105.1858	106.8131
0.1 d/yr	100.0501	101.3319

Table 2.14: Task 1 LOLE and LOEE Results Including the ATCO Generating Units

Peak Load (MW)	LOLE (h/yr)		LOEE (MWh/yr)	
	NG FOR=15%	NG FOR=4%	NG FOR=15%	NG FOR=4%
78	0.0002	0.0001	0.300	0.076
80	0.0004	0.0002	0.858	0.262
82.06	0.0011	0.0005	2.283	0.818
84	0.0023	0.0011	5.259	2.171
86	0.0045	0.0025	11.459	5.412
88	0.0086	0.0051	23.393	12.393
90	0.0161	0.0095	45.852	25.798
92	0.0313	0.0169	88.345	49.812
94	0.0630	0.0317	173.976	93.821
96	0.1294	0.0635	347.416	179.075
98	0.2635	0.1356	709.247	359.650
100	0.4959	0.2799	1404.438	736.778
102	0.8959	0.5741	2694.632	1527.906
104	1.4964	1.0209	4894.991	2998.211
106	2.4134	1.6859	8505.274	5516.752
108	3.8869	2.6182	14269.631	9487.579
110	6.3514	4.1186	23615.104	15661.521
112	10.8700	6.7181	39305.117	25506.936
114	18.2479	11.4256	66277.711	42149.414
116	30.8129	20.7405	111452.039	71426.867
118	49.0267	35.4309	186063.719	123988.352
120	73.6220	56.5360	299618.188	209177.094

The 8 ATCO generating units in Table 2.12 have a total generating capacity of 5.74 MW. A comparison of the PLCC results in Tables 2.11 and 2.14 shows that the increase in PLCC due to the consideration of the ATCO units is 5.69 MW at the LOLE criterion of 0.1 days per year. The increase in PLCC at the LOLE criterion of 2 hours per year is 5.94 MW. These values are calculated considering 15% FOR of natural gas units at Whitehorse. The local peak loads served by the ATCO generating units must be considered in assessing the peak load that can be carried by the system.

3. IMPACT OF TRANSMISISON LINE OUTAGE ON GENERATING SYSTEM ADEQUACY

This section presents reliability studies on the impacts of the forced outages of the major transmission lines on the YEC generation system adequacy. The major transmission lines linking the YEC generation plants to the bulk system load at Whitehorse is shown in Figure 3.1.

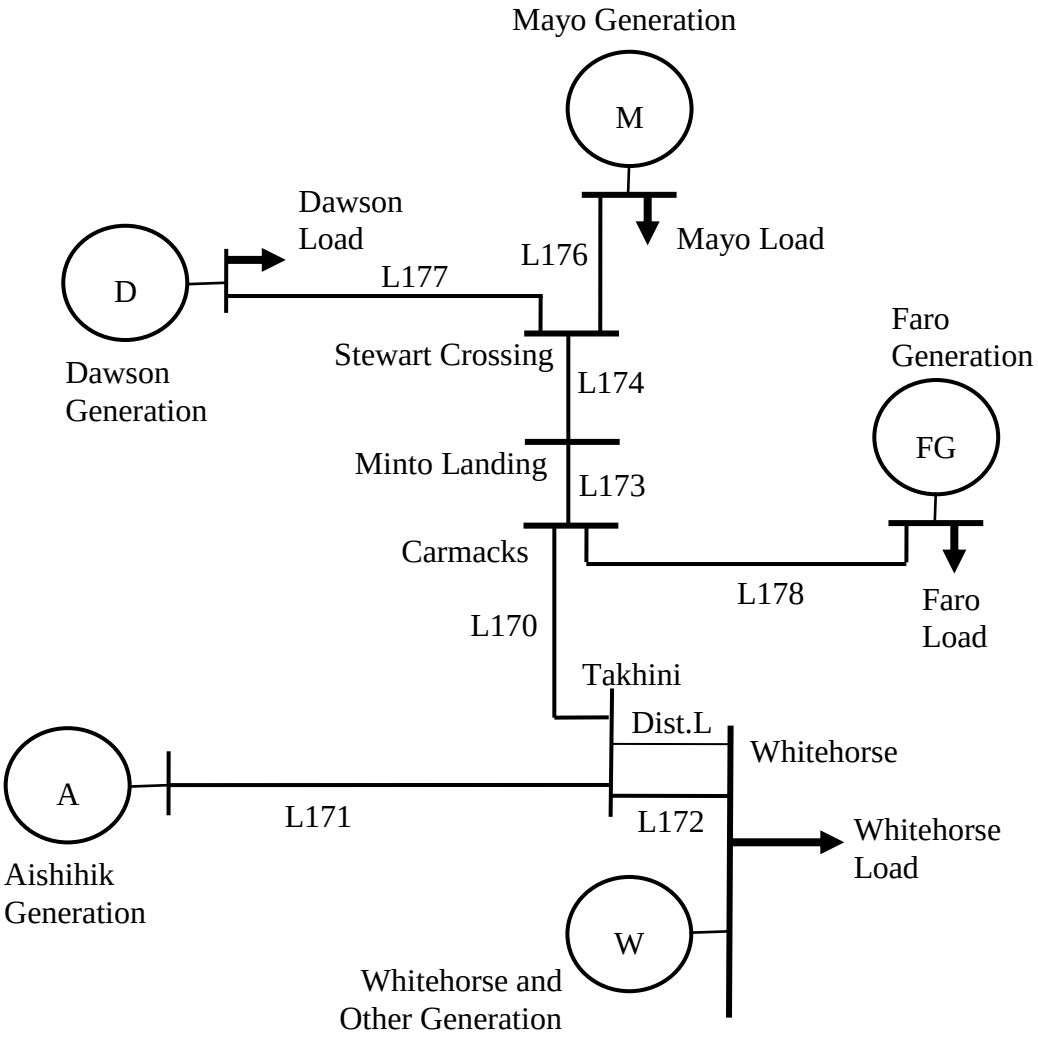


Figure 3.1: YEC Major Transmission Lines and Generation Plants

The impact of individual line segments on the ability of the YEC generation to satisfy the bulk load at the Whitehorse area is evaluated, and the resulting LOLE, LOEE and PLCC indices are calculated and compared with the base case in which the transmission system is not considered. The objective of the studies is to identify the major line segments that significantly affect the generation adequacy indices, and therefore, need to be considered in the development of the generation adequacy model of the YEC system.

3.1 Major Transmission Line Data

Table 3.2 shows the major YEC transmission system data that are used in the study. It should be noted that the line ID numbers have changed since the work done in the 2011 report [3].

Table 3.2: YEC Major Transmission System Data

Line Segment		Line Length (km)	Volt. Rating (kV)	Structure Type
Stations	Line ID			
Dawson – Stewart Crossing	L177	172	69	wood, single pole
Mayo – Stewart Crossing	L176	52	69	wood, single pole
Stewart C. – Minto Landing	L174	95	138	wood, double pole
Minto Landing - Carmacks	L173	71	138	wood, double pole
Faro - Carmacks	L178	190	138	wood, double pole
Carmacks - Takhini	L170	152	138	wood, double pole
Ashihik - Takhini	L171	130	138	wood, double pole
Takhini - Whitehorse	L172	25	138	wood, double pole
Distribution line parallel to L172		17	34.5	wood, single pole

All the transmission lines listed in Table 3.2 are capable of transferring the maximum power generated at the generation plants. The 34.5 kV distribution line parallel to L172 has a maximum load carrying capability of 19.6 MW, considering the overload protection setting at 20 MVA during the outage of line L172, and a power factor of 0.98.

The unavailability parameter for the 34.5 kV - 69 kV wood single pole and 138 kV wood double pole transmission lines were calculated using the 2014 CEA [6] data shown in Tables 3.3 and 3.4 respectively.

Table 3.3: CEA 2014 Transmission Line Data for < 110 kV, Wood Single-pole Structure

Outage Type	Failure Rate (failures/year)	Mean Down Time (hours)	Unavailability (%)
Sustained	3.0548/100 km	19.0	-
Transient	3.4406/100 km	-	-
Station	0.1614	-	0.146

Table 3.4: CEA 2014 Transmission Line Data for 110 – 149 kV, Wood Double-pole Structure

Outage Type	Failure Rate (failures/year)	Mean Down Time (hours)	Unavailability (%)
Sustained	0.9782/100 km	21.4	-
Transient	0.9087/100 km	-	-
Station	0.1295	-	0.085

Table 3.5 shows a sample calculation of the unavailability data for line L171 using the CEA data in Table 3.4. The sustained and transient failure rate for the 130 km lines are 1.27166 (i.e. 0.9782*130/100) and 1.18131 failures per year respectively.

Table 3.5: Transmission Line L171 Unavailability Calculation

Line and outage Component	Failure rate (failures/year)	Mean Down Time (hours)	Unavailability	
			(hours/year)	(%)
Sustained	1.27166	21.4	27.21352	0.3107
Transient	1.18131	0	0	0
Station (one end)	0.1295	-	-	0.085
Station (other end)	0.1295	-	-	0.085
			Total	0.4807

Table 3.6 shows the unavailability of all the major lines in the YEC system using the CEA 2007 [3] and CEA 2014 outage statistics for comparison.

Table 3.6: YEC Major Transmission System Unavailability Data

Line Segment (Note old line ID in brackets)	Line length (km)	Unavailability (%)	
		CEA 2007 data [3]	CEA 2014 data
L177 (L174W)	172	1.1827	1.4316
L176 (L174E)	52	0.5225	0.6365
L173+L174 (L173)	166	0.2237	0.5667
L178 (L170B)	190	0.2476	0.6240
L170 (L170A)	152	0.2267	0.5332
L171	130	0.2028	0.4807
L172	25	0.0984	0.2297
Distribution line parallel to L172	17	-	0.4046

Table 3.7 and Table 3.8 show the line losses in the major transmission lines for peak load and typical load scenarios that were obtained from load flow studies done by YEC. The data has been analyzed to obtain line losses as a percentage of the line loading for the major transmission lines. The losses in the distribution line between Takhini and Whitehorse at full loading is 443 kW.

Table 3.7: YEC Major Transmission Losses at Peak Load Scenario

Line Segment	Length (km)	Loading (kW)	Line Losses		
			(kW)	% of loading	%/100km
L177	172	4958	99	2.00%	1.16%
L176	52	9037	268	2.97%	5.70%
L174	95	4597	41	0.89%	0.94%
L173	71	981	5	0.51%	0.72%
L178	190	3276	67	2.05%	1.08%
L170	152	1606	96	5.98%	3.93%
L171	130	27079	1185	4.38%	3.37%
L172A	10	2227	2	0.09%	0.90%
L172B	15	25591	136	0.53%	3.54%
Total Losses at Peak Load			1899		

Table 3.8: YEC Major Transmission Losses at Typical Load Scenario

Line Segment	Length (km)	Loading (kW)	Line Losses		
			(kW)	% of loading	%/100km
L177	172	2381	35	1.47%	0.85%
L176	52	6970	149	2.14%	4.11%
L174	95	4225	29	0.69%	0.72%
L173	71	686	9	1.31%	1.85%
L178	190	7641	31	0.41%	0.21%
L170	152	4282	158	3.69%	2.43%
L171	130	24752	1010	4.08%	3.14%
L172A	10	2911	1	0.03%	0.34%
L172B	15	17454	62	0.36%	2.37%

3.2 Local Load Data

The local loads at the major generation plants at Dawson, Mayo and Faro that occurred in the year 2015 are shown in Table 3.9. The Elsa Keno load is combined with the Mayo load considering that they will be served by Mayo generation. The Minto Mine and Pelly loads are mainly served by the respective local diesel generation, and they will have little impact on the transmission lines or the ability of the overall system to meet the main system load. The Minto Mine and Pelly generation and loads are therefore not considered in the reliability evaluation model. The Haines Junction load is primarily met by the local diesel generation, and therefore, will not impact the ability of the system to meet the bulk load at Whitehorse through the line L171. The Haines Junction load is therefore lumped with the Whitehorse load in the reliability model.

Table 3.9: Local Loads at Major Generation Plants

Locations	Dawson	Mayo + Elsa Keno	Faro
Load (MW)	3.62	1.48 + 0.38 = 1.86	2.12

3.3 System Risk Evaluation Considering Line Outages

A conditional probability approach is used to evaluate the impact of a transmission line segment on the generating system adequacy. The generating system risk indices (i.e. LOLE and LOEE) are evaluated for the two conditions of the line segments being available and unavailable due to forced outage, and resulting risk index is calculated using Equation 3.1. The local loads isolated due to the outage of the line segment, and the corresponding line losses are subtracted from the bulk system load at the Whitehorse area when evaluating the risk indices for the condition that the line segment is on forced outage.

$$LOLE = (LOLE \mid L_out) \times U_L + (LOLE \mid L_in) \times (1 - U_L) \quad (3.1)$$

Where U_L is the unavailability of the line segment L, and LOLE|L_out and LOLE|L_in are the system LOLE given the line segment L is forced out and available respectively.

Equation 3.2 is used to calculate the system LOLE and LOEE when evaluating the impact of the parallel lines (i.e. L172 and the distribution line, DL) between Takhini and Whitehorse. Given the condition that the line L172 is out and the distribution line is available to transfer a maximum capacity of 19.6 MW to Whitehorse, the local loads at Mayo, Dawson and Faro are subtracted from the generation capacity model before passing it through the distribution line to Whitehorse. The line losses are proportionally reduced when considering this condition that has only 19.6 MW transfer capability.

$$LOLE = (LOLE \mid \text{both lines out}) \times U_{L172}.U_{DL} + (LOLE \mid L172_out) \times U_{L172}(1-U_{DL}) + (LOLE \mid DL_out \text{ OR no line outages}) \times (1-U_{L172}) \quad (3.2)$$

Figure 3.2 shows the system LOLE as a function of the annual peak load considering the impact of the major transmission lines illustrated in Figure 3.1. The LOLE was calculated considering the impact of one transmission line at a time, except for the parallel lines between Takhini and Whitehorse indicated as L172+DL in the figure. Also, the lines L173 and L174 were combined and considered as a single line and indicated as L174+L173 in the figure. The base case results are

also shown which does not consider the impact of the transmission lines. Figure 3.3 shows a similar graph for system LOEE.

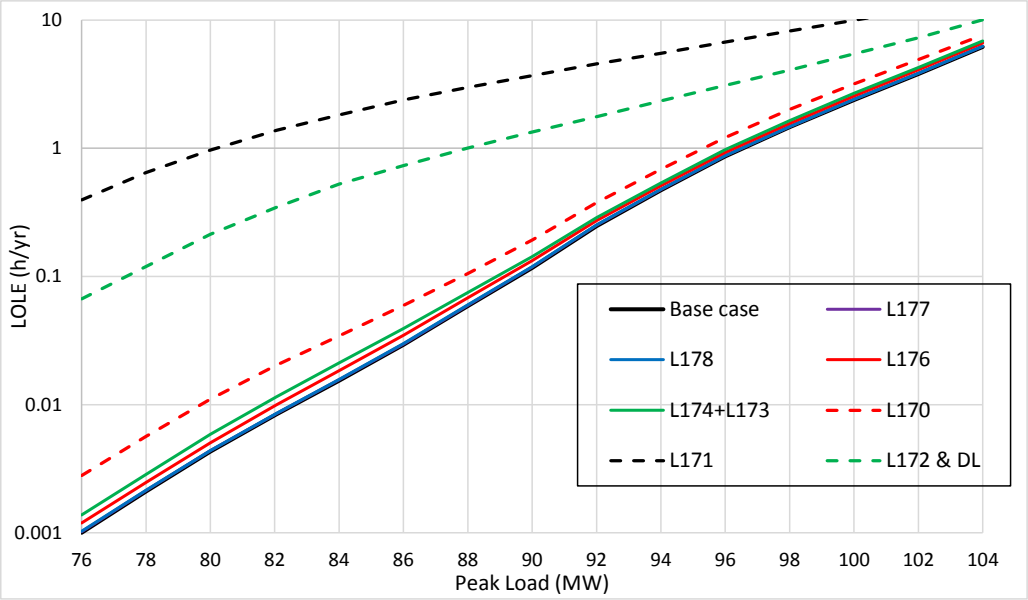


Figure 3.2: Impact of Individual Line Outage on the System LOLE

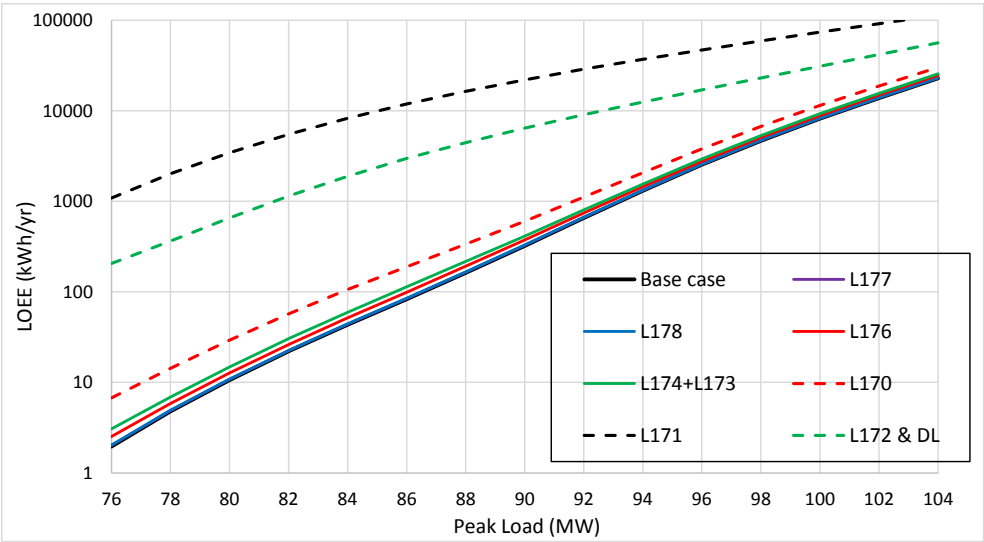


Figure 3.3: Impact of Individual Line Outage on the System LOEE

The LOLE and LOEE results for the different cases were compared with the Base Case results to assess the impacts of the different line segments on the system indices. It can be seen from Figure 3.2 that the different transmission line segments have varying impacts on the system LOLE. The lines are arranged in increasing order of their impacts on the system LOLE below:

L177 (connecting Dawson)
L178 (connecting Faro)
L176
L174+L173
L170
L172 parallel with Distribution Line
L171 (connecting Ashihik)

Figure 3.2 shows that the impacts of the lines L177 (connecting Dawson) and Line L178 (connecting Faro) have very little impact on the system LOLE as the results are almost the same as that obtained for the Base Case that does not consider the impact of the transmission lines. These lines therefore do not need to be considered in the generation adequacy model of the YEC system. The line L171 (connecting Ashihik) has the largest impact on the LOLE results. The impact of the parallel lines L172 and the distribution lines connecting Takhini and Whitehorse also have significant impact on the system indices. These line segments should therefore be considered in the generation adequacy model of the system. The lines L176, L174+L173 and L170 connect the Mayo hydro generation to the bulk system load at Whitehorse, and the impact of these lines increases with their proximity to Whitehorse area load. Similar observation can be noted from the LOEE results in Figure 3.3.

Redundancy in a transmission system can significantly improve its reliability, and this can be achieved by adding parallel transmission lines. It should be noted that the distribution line between Takhini and Whitehorse provides redundancy to the line L172. The load carrying capability of the distribution line, however, restricts its reliability contribution to the overall system. A study was carried out considering 2 different cases to analyze the reliability impact of the parallel lines

between Takhini and Whitehorse. Case 1 assumes that the distribution line was not installed and L172 is the only line to connect Takhini to Whitehorse. Case 2 is the actual scenario with 19.6 MW capacity of the distribution line in parallel to L172. Figure 3.4 shows the system LOLE for the 2 cases as a function of the system peak load. It should however be noted that all the other transmission lines are assumed to be 100% reliable and have no transfer restrictions in these studies. The results for the Base Case (that does not consider transmission constraints) and the case that considers only the impact of L171 alone are shown in the figure for comparison.

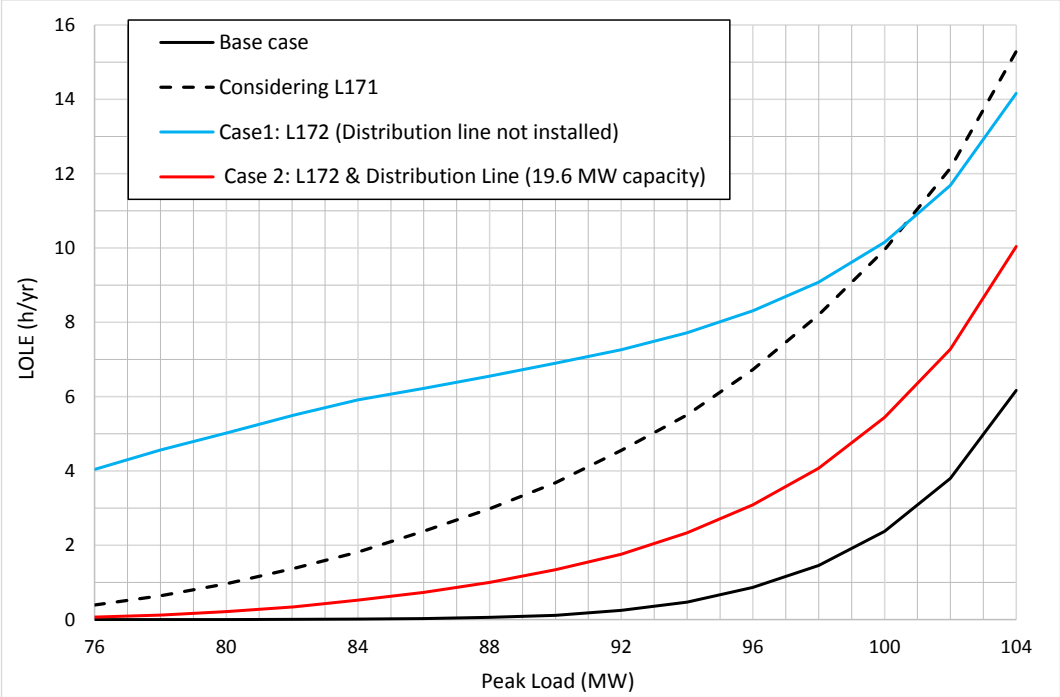


Figure 3.4: Impact of Line L172 Redundancy on the System LOLE

It can be seen from Figure 3.4 that the impact of the line L172 on the system LOLE was much greater than that of the line L171 prior to the commissioning of the distribution line between Takhini and Whitehorse. The figure shows that there has been a significant improvement in system reliability due to the distribution line between Takhini and Whitehorse despite the capacity transfer capability restriction of 19.6 MW. It can also be seen in the figure that the impact of the parallel lines between Takhini and Whitehorse would be negligible, and the LOLE results would be very close to the Base Case results if there was no restriction on the transfer capability of the distribution lines.

4. DEVELOPMENT OF GENERATING SYSTEM ADEQUACY MODEL CONSIDERING MAJOR DELIVERY CONSTRAINTS

This section presents the development of a generating system adequacy model for the YEC considering the capacity delivery constraints imposed by the major transmission lines. The results of the generation system adequacy impacts of the individual transmission lines presented in Section 3 were analyzed to develop five different models for YEC generation adequacy evaluation. The details of the five models are described in following sub-sections.

This section illustrates results from reliability studies conducted using the different adequacy models, and presents comparative analysis to determine an appropriate generation adequacy model for the YEC electric power system.

4.1 Analysis of Alternate Generation Adequacy Models

The following five different models were developed for the YEC generation adequacy evaluation based on the analysis of the results presented in Section 3. The order of the five models listed below is arranged such that the amount of input data requirements and evaluation complexity increases from Items 1 to 5 in the list.

1. Basic Generation Adequacy Model
2. WAFSREL Model
3. Extended WAFSREL Model
4. Hydro Plants Interconnection Model
5. Generation-Transmission Model

The first model or the Basic Generation Adequacy Model only considers the ability of the overall system generating capacity to meet the system load, and does not consider the transmission system. The analyses in Section 2 were done using this model. This model is shown in Figure 4.1.

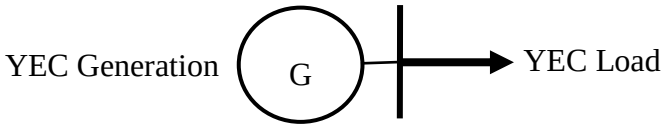


Figure 4.1: Basic Generation Adequacy Model

The LOLE and LOEE results shown in Figures 3.2 and 3.3 from comparative studies of the transmission line impacts on system adequacy clearly shows that the line L171 has the largest impact on these indices. The second model, i.e. the WAFSREL Model, considers the line L171 in the adequacy model, and is shown in Figure 4.2. The WAFSREL program [2] was developed based on this model which considers the ability of the Ashihik hydro generation capacity and its delivery through line L171 to the YEC system. The generation capacity at Whitehorse, Faro, Mayo and Dawson are also considered but their delivery constraints are not considered in this model.

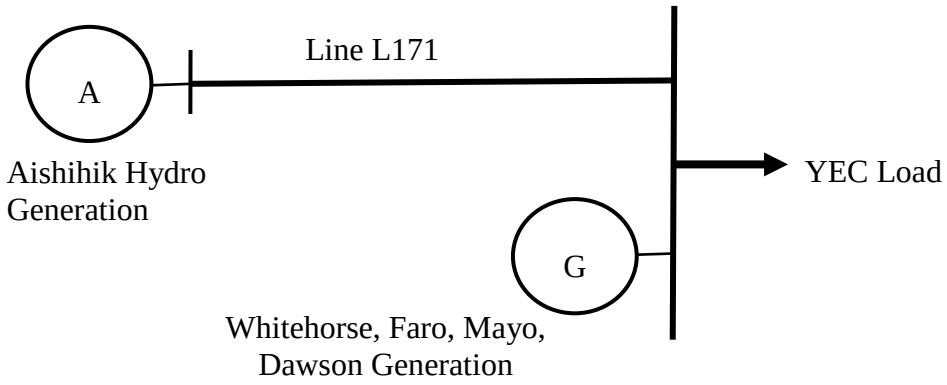


Figure 4.2: WAFSREL Model

The comparative LOLE and LOEE results in Figures 3.2 and 3.3 show that the parallel lines between Takhini and Whitehorse have the second largest impact on the adequacy indices after the line L171. The third model, i.e. the Extended WAFSREL Model shown in Figure 4.3 includes the line L171 and the parallel lines between Takhini and Whitehorse in the adequacy model. The delivery constraints of the Whitehorse, Faro, Mayo and Dawson generation are not considered in this model.

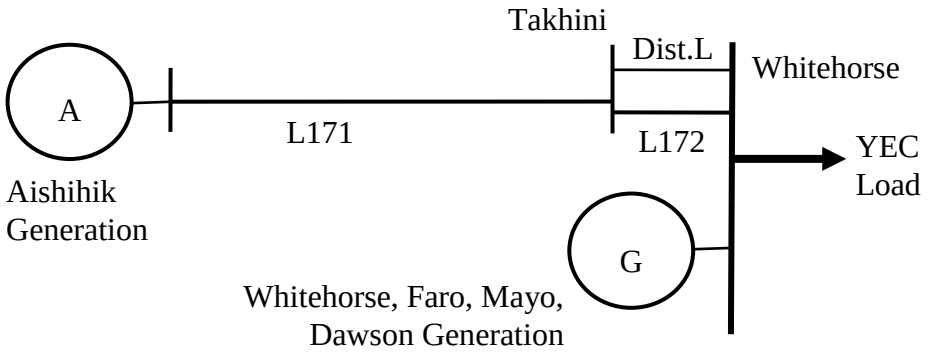


Figure 4.3: Extended WAFSREL Model

The comparative results in Figures 3.2 and 3.3 show that the transmission lines L176, L174, L173 and L170 delivering the Mayo hydro generation to the YEC system load have reasonable impact on the system LOLE and LOEE. The fourth model, i.e. the Hydro Plants Interconnection Model, considers the delivery constraints on the hydro generation from Aishihik and Mayo to serving the YEC system load, and is shown in Figure 4.4. The transmission lines L171, L176, L174, L173, L170, and the parallel lines (L172 and the distribution line between Takhini and Whitehorse) that are responsible for delivering generating capacity from Ashihik and Mayo hydro plants are considered in this model. The delivery constraints of diesel generation at Faro, Mayo and Dawson are not considered in this model. The assumption is that the diesel generation mainly meet their own local loads and have very little impact on their delivery to the rest of the YEC system.

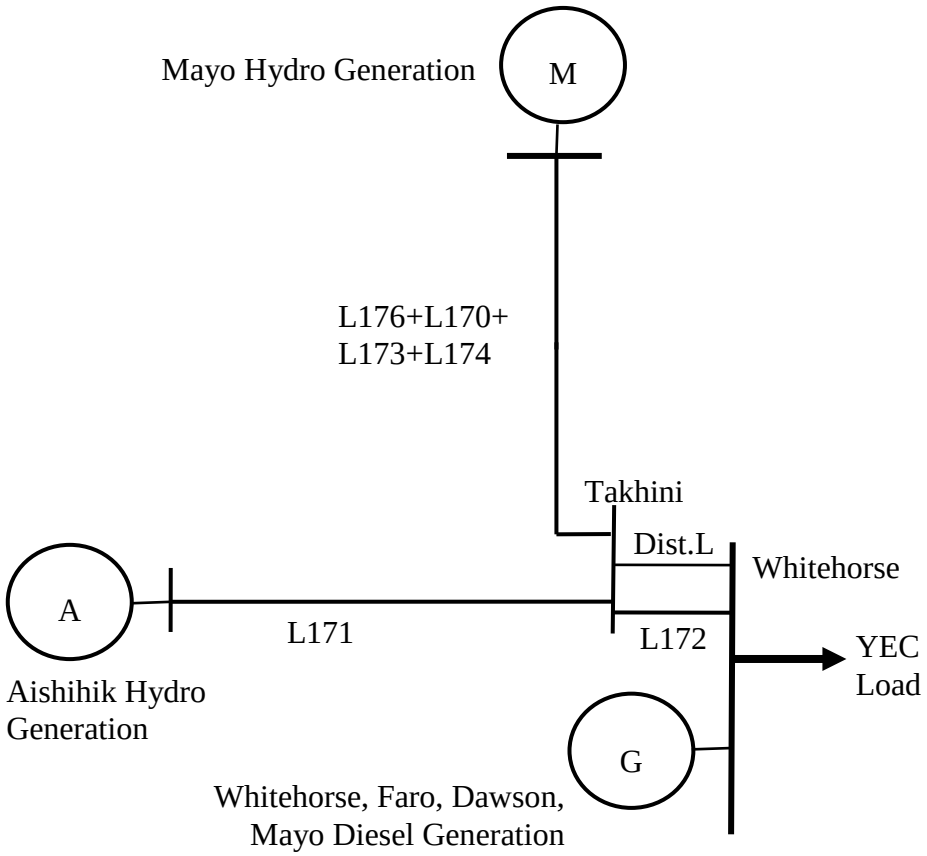


Figure 4.4: Hydro Plants Interconnection Model

The fifth model, or the Generation-Transmission Model considers the transmission constraints of the hydro plants in Ashihik and Mayo, and the diesel plants in Faro, Dawson and Mayo in serving the main system load at Whitehorse after satisfying their respective local loads at Faro, Mayo and Dawson. This model is shown in Figure 4.5.

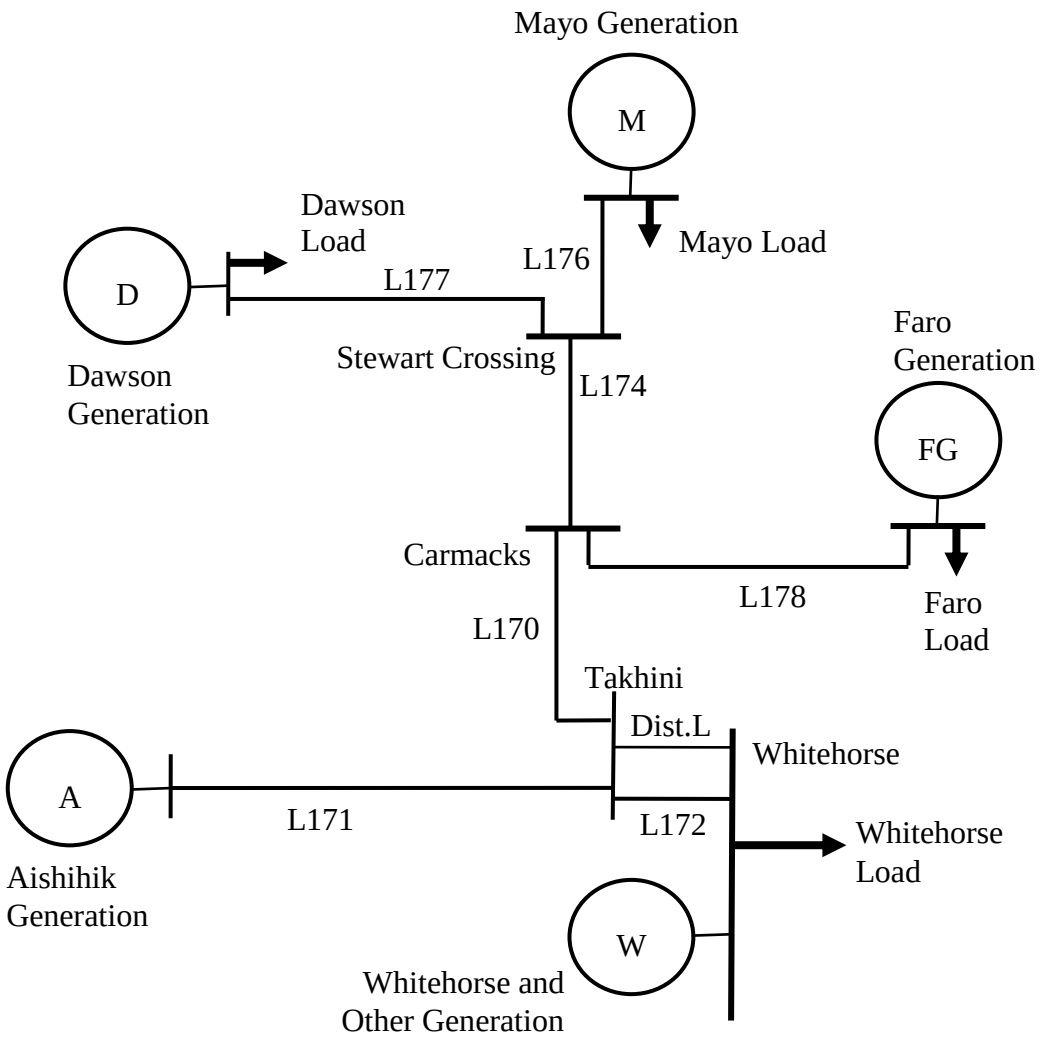


Figure 4.5: Generation-Transmission Model

4.2 Adequacy Evaluation Results from Alternate Models

The five adequacy models described in the previous sub-section are analyzed using generating unit data provided in Table 2.1 and the forced outage data shown in the last column of Table 2.4. The studies presented in Section 2 clearly show that the reliability indices calculated for the winter period were practically the same as those calculated for the entire year, since the summer indices were insignificant relative to the annual indices. The 5 months between the months of November and March were considered in the winter period. The hydro plant capacity limited by the winter water conditions as shown in the 6th column of Table 2.1 are used in the evaluation. A detailed analysis of the YEC load data for the past five years presented in Section 2 shows that the 2015 load model can be used instead of the average load model in adequacy studies. The 2015 winter LDC used as the load model in the following studies is shown in Figure 2.6 and Figure 2.9.

An evaluation of the YEC generation adequacy was first conducted using Model 1, the Basic Generation Adequacy Model. All the generating units listed in Table 2.4 were combined and convolved together to create the overall system generation model. The load model includes the local loads and the line losses. The system LOLE and LOEE were calculated for a range of peak loads. The results are shown in Table 4.1. It can be noted that the LOLE is 0.0084 hours per year at the system peak load of 82.06 MW. The peak load carrying capability (PLCC) is found to be 99.25 MW at the LOLE criterion of 2 hours per year when the system is represented by a basic generation adequacy model.

Table 4.1: LOLE and LOEE Results Using Model 1, the Basic Generation Adequacy Model

Peak Load (MW)	LOLE (h/yr)	LOEE (MWh/yr)
76.00	0.001	0.0020
78.00	0.0021	0.0048
80.00	0.0043	0.0106
82.06	*0.0084*	*0.0225*
84.00	0.0154	0.0435
86.00	0.0292	0.0833
88.00	0.0587	0.1625
90.00	0.1165	0.3217
92.00	0.2475	0.6541
94.00	0.4702	1.3070
96.00	0.8643	2.5327
98.00	1.4583	4.6678
100.00	2.3792	8.2089
102.00	3.797	13.8402
104.00	6.1686	22.9164
106.00	10.4473	37.8679
108.00	17.5478	63.6995
110.00	29.6536	106.8037
112.00	48.2345	179.4020
114.00	73.3794	291.5454
116.00	106.3985	457.0664

The evaluation method for Model 2, or the WAFSREL model consists of developing a winter capacity model for the Aishihik hydro plant, moving the capacity model through the transmission line L171 considering the line unavailability, and creating a tie-line constrained capacity model for the Aishihik hydro plant shown in Table 4.2. The transmission line unavailability data shown in the last column of Table 3.6 is used to incorporate the unavailability of the line L171 in this model.

Table 4.2: Tie-line (L171) Constrained Aishihik Hydro Capacity Model

Capacity (MW)	Probability
37	0.96563477
30	0.00975389
22	0.01950777
15	0.00019705
7	0.00009852
0	0.00480800

The model in Table 4.2 is then combined with the generation model that includes Whitehorse, Faro, Mayo and Dawson generation as shown in the model diagram of Figure 4.2. The overall generation system is then convolved with the winter load model to obtain the system LOLE and LOEE indices. The load model includes the local loads and the line losses. The results are shown in Table 4.3. It can be noted that the LOLE is 1.6131 hours per year at the system peak load of 82.06 MW when the system is represented by the WAFREL model, and the PLCC is 83.60 MW at the LOLE criterion of 2 hours per year.

Table 4.3: LOLE and LOEE Results Using Model 2, the WAFSREL Model

Peak Load (MW)	LOLE (h/yr)	LOEE (MWh/yr)
76.00	0.5183	1.5429
78.00	0.8136	2.7522
80.00	1.1894	4.5467
82.06	*1.6131*	*7.1156*
84.00	2.1179	10.2818
86.00	2.6931	14.4412
88.00	3.3093	19.5618
90.00	4.0615	25.7731
92.00	4.9137	33.2534
94.00	5.9141	42.1817
96.00	7.1566	52.9000
98.00	8.5885	65.7743
100.00	10.3129	81.1949
102.00	12.4845	99.7989
104.00	15.5179	122.8235
106.00	20.4168	152.6036
108.00	28.116	194.0624
110.00	40.7508	253.4741
112.00	59.7554	342.9590
114.00	85.2351	472.4052
116.00	118.5495	655.5268
118.00	158.5265	903.0183
120.00	204.8483	1224.7960

The third model, i.e. the Extended WAFSREL model consists of developing a winter capacity model for the Aishihik hydro plant, moving this model through the transmission line L171 to obtain the L171-constrained capacity model shown in Table 4.2. This model is then moved through the parallel lines between Takhini and Whitehorse considering their line unavailability and power transfer capability. The resulting tie-line constrained capacity model for the Aishihik hydro plant is shown in Table 4.4. The distribution line between Takhini and Whitehorse was considered to have a maximum power transfer capability of 19.6 MW. The transmission line unavailability data shown in the last column of Table 3.6 is used.

Table 4.4: Tie-line (L171, L172 and DL) Constrained Aishihik Hydro Capacity Model

Capacity (MW)	Probability
37	0.96341671
30	0.00973148
19.6	0.00227603
15	0.00019705
7	0.00009852
0	0.00481724

The capacity model in Table 4.4 is then combined with the generation model for Whitehorse, Faro, Mayo and Dawson. The generation model thus obtained is convolved with the system load model which includes the local loads and the line losses. The resulting system LOLE and LOEE indices are shown in Table 4.5. It can be seen that the LOLE is 1.6166 hours per year at the system peak load of 82.06 MW, and the PLCC is 83.58 MW at the LOLE criterion of 2 hours per year. It should be noted that the results obtained from this model are very close to that obtained using the WAFREL model.

Table 4.5: LOLE and LOEE Results Using Model 3, the Extended WAFSREL Model

Peak Load (MW)	LOLE (h/yr)	LOEE (MWh/yr)
76.00	0.5193	1.5459
78.00	0.8152	2.7575
80.00	1.1918	4.5556
82.06	*1.6166*	*7.1300*
84.00	2.1234	10.3037
86.00	2.7024	14.4762
88.00	3.3267	19.6199
90.00	4.0948	25.8770
92.00	4.9751	33.4433
94.00	6.0242	42.5296
96.00	7.3353	53.5122
98.00	8.8569	66.7976
100.00	10.689	82.8068
102.00	12.9871	102.2087
104.00	16.1685	126.2703
106.00	21.2256	157.3395
108.00	29.1113	200.3690
110.00	41.9219	261.6570
112.00	61.0922	353.2863
114.00	86.7837	485.1655
116.00	120.2845	670.9936

The evaluation method of model 4, i.e. the Hydro Plants Interconnection Model, considers the delivery constraints on the hydro generation from Aishihik and Mayo to serving the YEC system load as shown in Figure 4.4. The approach is to develop a winter constrained generation model for the Mayo hydro plants and then move the developed model through the transmission lines L176, L174, L173 and L170 to the Takhini station. The line-constrained Mayo hydro capacity model is shown in Table 4.6.

Table 4.6: Tie-line (L176, L174, L173 and L170) Constrained Mayo Hydro Capacity Model

Capacity (MW)	Probability
0	0.0172343061
2550	0.0000019459
5000	0.0000019459
5100	0.0000963209
7550	0.0003852835
9000	0.9822801978

The model in Table 4.6 is convolved with the L171- constrained Aishihik hydro capacity model in Table 4.2. The probability distribution of the resulting capacity model is shown in Figure 4.6. The left graph shows the entire probability distribution, whereas, the right graph excludes the maximum capacity state of 46 MW which has a probability of 94.8524%. The spikes in the right graph show the capacity and corresponding probability resulting from first order contingencies.

The combined model is further moved through parallel lines (L172 and the distribution line between Takhini and Whitehorse) to the Whitehorse load point. The probability distribution of the capacity model, thus obtained, is shown in Figure 4.7. It can be seen that the probability of getting the maximum capacity state of 46 MW is 94.6345%. A comparison between the right plots of Figure 4.6 and 4.7 shows that there is a new spike in Figure 4.7 due to the 19.6 MW capacity limit of the distribution line between Takhini and Whitehorse. This model is then combined with Whitehorse, Faro, Dawson, and Mayo diesel generation to get the overall generation model, which is convolved with the winter load model at Whitehorse that includes the line losses and the local loads. The results for the system LOLE and LOEE for a range of peak loads are shown in Table 4.7.

It can be seen that the LOLE is 1.7603 hours per year at the system peak load of 82.06 MW, and the PLCC is 82.94 MW at the LOLE criterion of 2 hours per year. The results obtained from this model provide slightly pessimistic results when compared to the WAFREL or the extended WAFSREL models. Although the YEC generation system is presently adequate based on the WAFREL, extended-WAFSREL or the Hydro Plants Interconnection Model, a capacity expansion should be considered if load growth is expected in the near future.

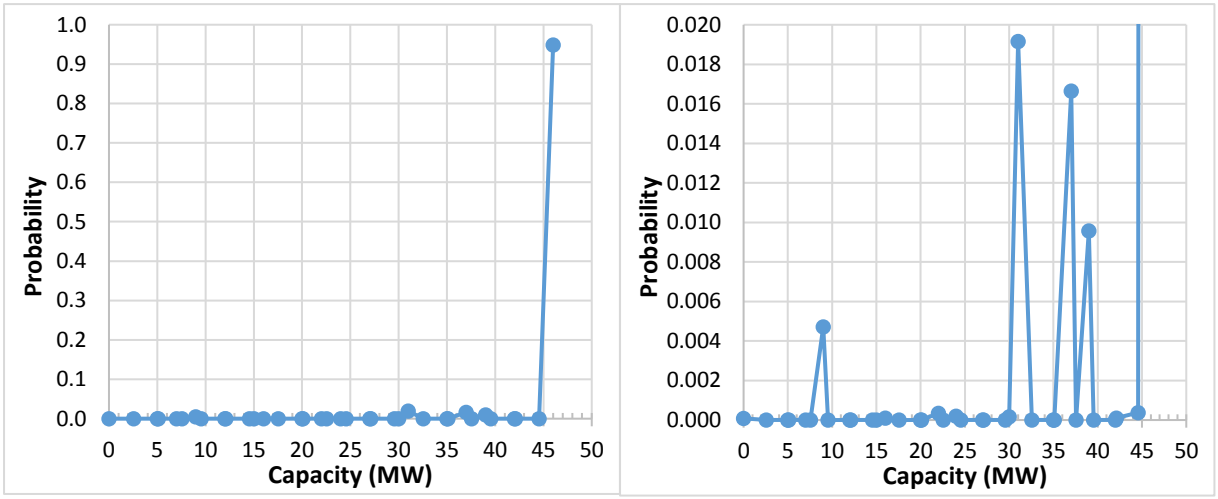


Figure 4.6: Line-Constrained Aishihik and Mayo Capacity Model at Takhini
(Left: entire distribution, Right: excluding maximum capacity state)

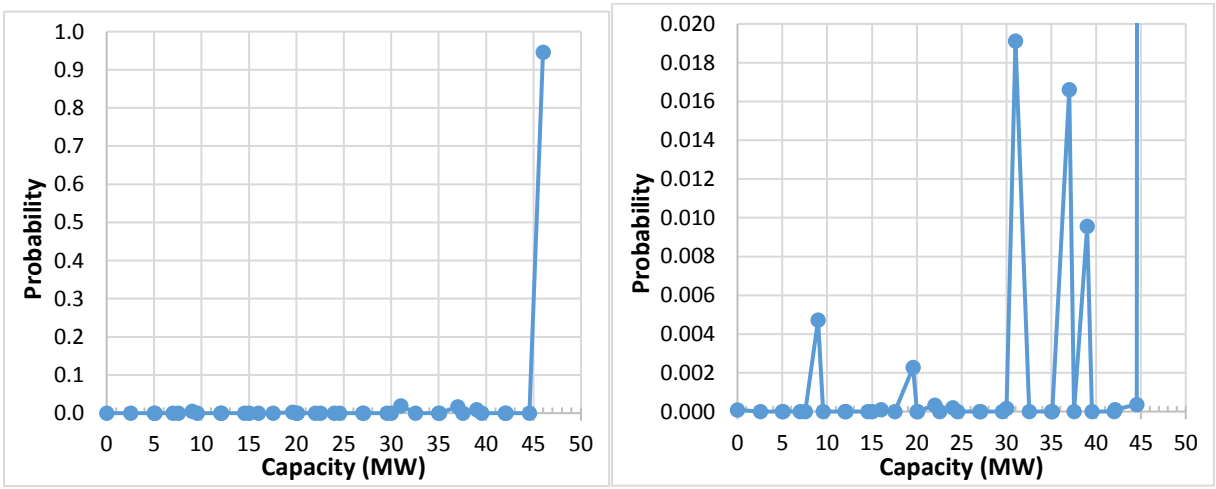


Figure 4.7: Line-Constrained Aishihik and Mayo Capacity Model at Whitehorse
(Left: entire distribution, Right: excluding maximum capacity state)

Table 4.7: LOLE and LOEE Results Using Model 4, the Hydro Plants Interconnection Model

Peak Load (MW)	LOLE (h/yr)	LOEE (MWh/yr)
76.00	0.574	1.8270
78.00	0.8869	3.1440
80.00	1.2901	5.0835
82.06	*1.7603*	*7.8681*
84.00	2.3347	11.3352
86.00	3.0139	15.9654
88.00	3.7775	21.7741
90.00	4.6896	28.9422
92.00	5.7444	37.6978
94.00	6.9891	48.2821
96.00	8.5144	61.0756
98.00	10.3303	76.6043
100.00	12.4881	95.3899
102.00	15.2863	118.2471
104.00	19.0767	146.7254
106.00	24.8661	183.3830
108.00	33.6123	233.2990
110.00	47.2875	302.8763
112.00	67.3836	404.2252
114.00	93.7284	547.1602
116.00	128.022	745.2783

The fifth model, or the Generation-Transmission Model considers the transmission constraints of the hydro plants in Ashihik and Mayo, and the diesel plants in Faro, Dawson and Mayo in serving the main system load at Whitehorse after satisfying their respective local loads at Faro, Mayo and Dawson. The capacity reserve models are first created for Faro, Mayo and Dawson by subtracting the respective loads from the generation models developed for these generating plants. The YEC

data indicates that the system peak load does not coincide with the peak loads at the Faro, Mayo or Dawson areas. The evaluation therefore does not consider the correlation of the loads at these locations with the system peak load, and the load model is represented by the average load at these locations when developing the reserve capacity models. The local peak load data shown in Table 3.9 was used in the evaluation, and the system winter load factor was considered to obtain the average load.

The reserve capacity models developed for the Dawson and Mayo sites are moved through the respective transmission lines L177 and L176 to Stewart Crossing. The resulting capacity model at Stewart Crossing incorporates the line losses and unavailability of the lines L176 and L177. The line losses at the different generation capacity levels in the multi-state capacity model are estimated using the line losses per unit loading data provided in Table 3.7. The unavailability data is provided in the last column of Table 3.6. The capacity model thus obtained at Stewart Crossing is then similarly moved through lines L174+L173 to Carmacks, and the capacity model is modified by incorporating the line losses and unavailability data of the line L174 and L173. This model is then combined with the modified reserve capacity model from Faro through the line L178. This evaluation procedure can be visualized by referring to the model diagram in Figure 4.5. The combined capacity model developed at Carmacks is then moved through line L170 to Takhini, and combined with the L171-constrained Aishihik generation model shown in Table 4.2. The resulting capacity model is further moved through the parallel lines (L172 and the distribution line between Takhini and Whitehorse) and combined with the Whitehorse generation model to create the overall system generation model. This system generation model is convolved with winter load model at Whitehorse that excludes the transmission line losses and the local loads at Faro, Mayo and Dawson. The system risk indices for this model are shown in the Table 4.8. The system PLCC is 82.54 MW.

Table 4.8: LOLE and LOEE Results Using Model 5, the Generation-Transmission Model

Peak Load (MW)				LOLE (h/yr)	LOEE (MWh/yr)
Local	Line Losses	Whitehorse	Total		
6.96	1.91	67.13	76.00	0.5614	1.8022
7.14	1.96	68.89	78.00	0.8688	2.9196
7.33	2.01	70.66	80.00	1.2817	4.6012
7.51	*2.07*	*72.48*	*82.06*	*1.8137*	*7.0902*
7.69	2.12	74.19	84.00	2.3964	10.2603
7.87	2.17	75.96	86.00	3.1316	14.5108
8.06	2.22	77.73	88.00	3.964	19.8972
8.24	2.27	79.49	90.00	4.8885	26.5327
8.42	2.32	81.26	92.00	5.9701	34.6093
8.61	2.37	83.03	94.00	7.1629	44.262
8.79	2.42	84.79	96.00	8.5875	55.7602
8.97	2.47	86.56	98.00	10.2407	69.4049
9.16	2.52	88.32	100.00	12.231	85.6582
9.34	2.57	90.09	102.00	14.542	104.9272
9.52	2.62	91.86	104.00	17.2417	127.826
9.71	2.67	93.62	106.00	20.6084	155.1726
9.89	2.72	95.39	108.00	24.969	188.2346
10.07	2.77	97.16	110.00	31.4755	229.46
10.26	2.82	98.92	112.00	40.7816	283.7845
10.44	2.87	100.69	114.00	53.5562	355.3313
10.62	2.92	102.46	116.00	73.3625	453.0799

4.3 Comparative Analysis of Alternate Models

Table 4.9 shows the system PLCC and Figures 4.8 and 4.9 show the LOLE and LOEE for the different alternate models for comparison. The PLCC is evaluated at the LOLE criterion of 2 hour per year.

Table 4.9: System PLCC for the Different Adequacy Models

Adequacy Model	PLCC (MW) at LOLE = 2 h/yr
Basic Generation Adequacy Model	99.25
WAFSREL Model	83.60
Extended WAFSREL Model	83.58
Hydro Plants Interconnection Model	82.94
Generation-Transmission Model	82.54

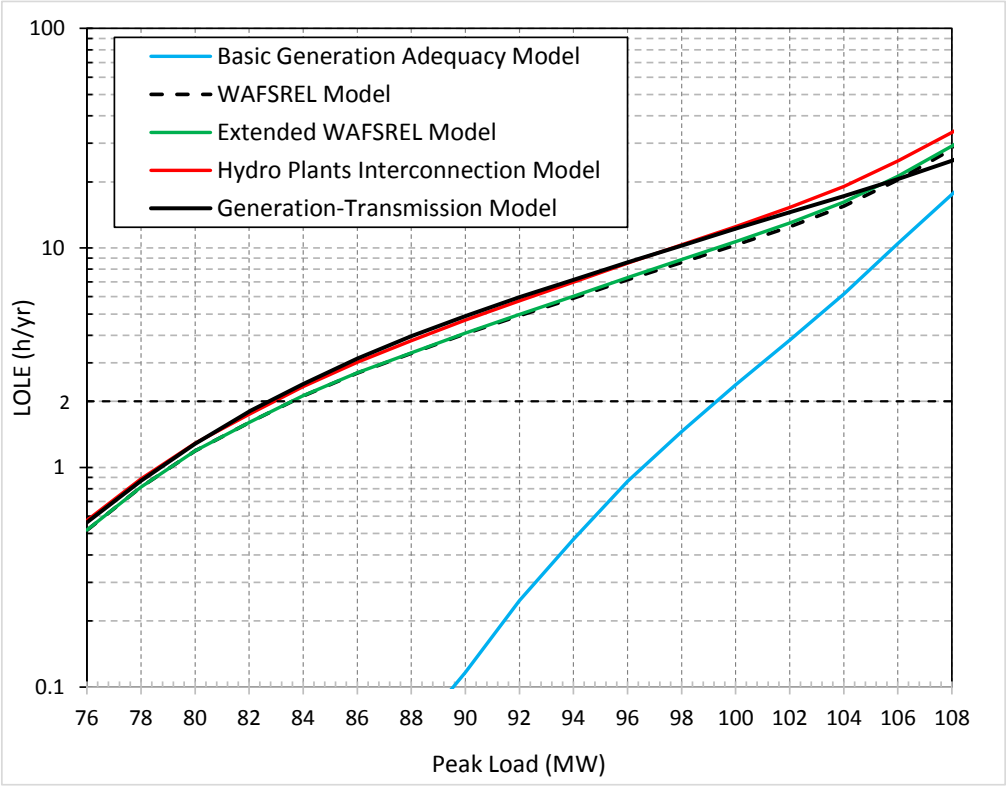


Figure 4.8: System LOLE for the Different Adequacy Models

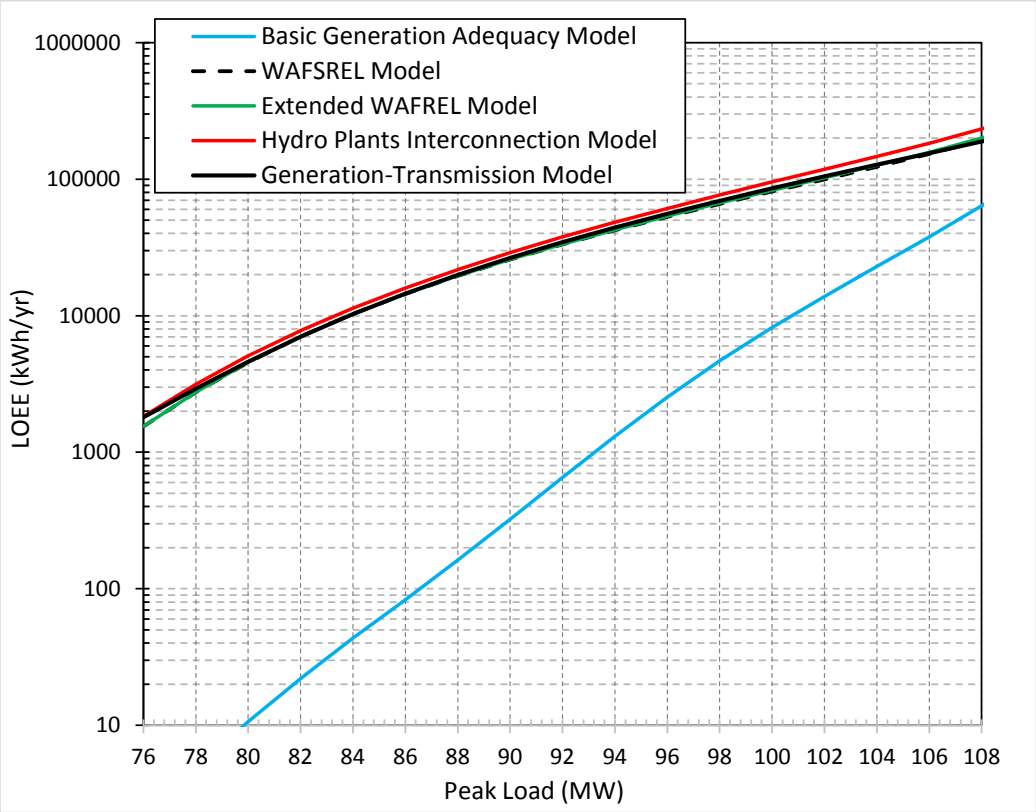


Figure 4.9: System LOEE for the Different Adequacy Models

A comparison of the LOLE results in Figure 4.8 indicates that the "Basic Generation Adequacy Model" that does not consider transmission system provides highly optimistic results. There is insignificant difference in the LOLE and PLCC results obtained from the "WAFSREL" and the "Extended WAFREL" models. The results from these two models are slightly more optimistic than that obtained from the "Hydro Plants Interconnection" and the "Generation-Transmission" models. The LOLE and PLCC results obtained from the "Hydro Plants Interconnection" and the "Generation-Transmission" models are very close for all practical purposes. It should be noted that the results become more pessimistic as the evaluation model includes more transmission system.

A composite generation and transmission system reliability evaluation, also known as HLII (Hierarchy Level II) study [4], was also carried out on the YEC electric system incorporating the locational impacts of the generation plants, transmission lines and load points considering the network in Fig. 4.5. A contingency enumeration approach [4] was applied to determine the

probabilities of energy curtailment at the different load points, and the transmission losses were evaluated based on the power flow. Since the Expected Energy Not Supplied (EENS) or the LOEE is the most widely used HLII reliability index, this index was calculated for each load point and aggregated to obtain the system EENS. Fig. 4.10 compares the EENS obtained from the HLII evaluation with the LOEE values obtained using the 5 different generation adequacy (or HLI) models.

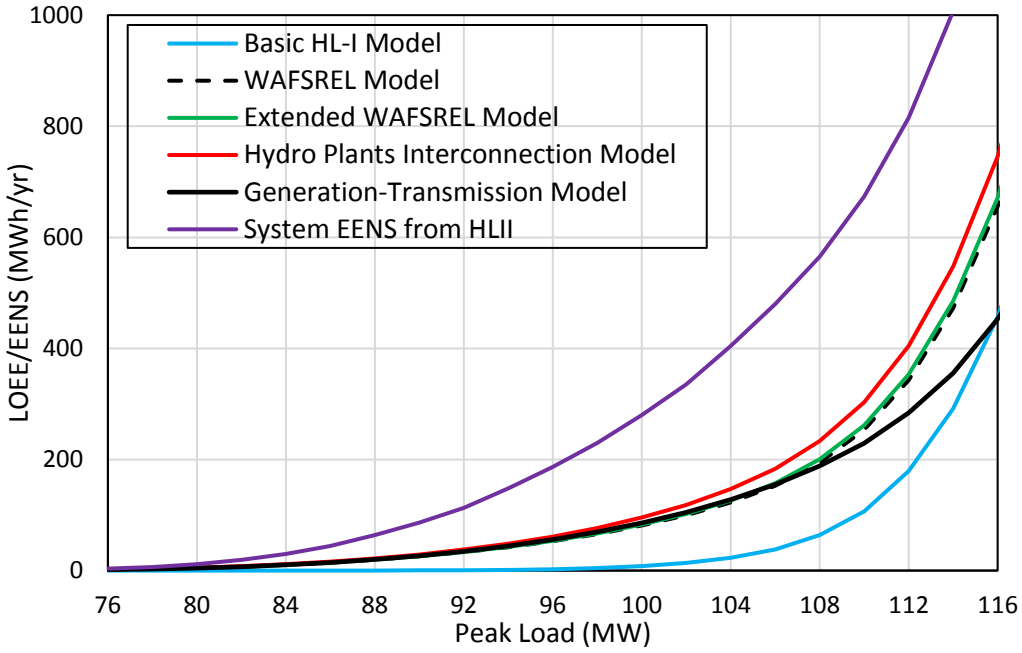


Figure 4.10: System LOEE/EENS Obtained from HLII and the 5 Different HLI Adequacy Models

As noted earlier, the order of the five generation adequacy or HLI models described above are arranged such that the amount of input data requirements and evaluation complexity increases from Models 1 to 5 in the list. In this order, the models also deviate further away from a basic generation capacity adequacy model towards a composite generation and transmission adequacy or HLII model. It should be noted that the objective of reliability study in generation capacity planning is to assess the generation system's ability to meet the system demand over the planning horizon considering only the major capacity delivery constraints, and not the entire transmission system. It should also be noted that the capacity planning criterion of LOLE of 2 hours per year

was determined by conducting comparative studies [1] of the previous YEC firm capacity criterion using the WAFSREL model.

It can be seen from Figure 4.10 that the LOEE/EENS plots for all the models, except the Generation-Transmission Model, increase with similar slopes as the system peak load increases. The Generation-Transmission model provides highly optimistic results at high peak loads since it is assumed in this model that the local generation provides support to the Whitehorse load only after satisfying their respective local loads. This results in the local load points being highly reliable and also reduced constraints on power delivery. It should be noted that the Generation-Transmission model assumes the local loads to increase in the same proportional to the system load, similar to that assumed in the HLII model. The "Generation-Transmission Model" is also more complex than the "Hydro Plants Interconnection Model", and requires more input data, such as, losses in the individual lines at different loading levels, correlation between local loads and the load at Whitehorse, the priority of the local loads and the Whitehorse load, etc. A comparative analyses of the results from the 5 different HLI models suggest that the "Hydro Plants Interconnection Model" is a suitable generation adequacy model for the YEC system since it is relatively simple and provides the least optimistic results among the five HLI models based on LOEE, and comparable results to the "Generation-Transmission Model" at reasonable peak load levels.

5. CASE STUDIES CONSIDERING POTENTIAL SYSTEM SCENARIOS

This section presents results from different case studies that are assumed to be likely system scenarios in the future. The evaluation was carried out with the recommended generating system adequacy evaluation model, i.e. Hydro Plants Interconnection Model. It is expected that two of the existing YEC system diesel units, FD1 and WD3, will retire in the year 2021, and all of the remaining diesel units in the YEC system will retire in the year 2026. The impact of these unit retirements on the generation system adequacy has been evaluated and presented in this section. This section also presents study results with and without considering the YECL hydro and diesel generating units in the Yukon electric system adequacy. The YEC system also has four mobile diesel units with a total capacity of 435 kW. Their impact on the system adequacy is carried out in the study. It is likely that the YEC system can benefit from capacity assistance through the proposed Skagway-Whitehorse transmission line. The adequacy impact of the assistance through this interconnection is also analyzed and presented in this section. It should be noted that the existing capacity of the distribution line parallel to L172 is considered to be 19.6 MW in the studies presented in the previous sections of this report. This section also includes results from case studies carried out to analyze the impact of upgrading this line. The reliability impact of twining the line L171 is also presented.

The generation data of the YECL Fish Lake hydro units is shown in Table 5.1 with a total capacity of 1295 kW. The unit ID and MCR of YECL Diesel units are shown in Table 2.12. The total diesel capacity is 5740 kW. The total YECL capacity considered in this study is therefore 7035 kW. The unavailability of the hydro and diesel units are assumed to be the same as that of YEC units. The FOR of 4% is used in the adequacy study for the YECL diesel generating units. Table 5.2 shows the unit ID, MCR and FOR of the mobile diesel units of YEC. The FOR of 4% is used for these diesel units as well.

Table 5.1: YECL Hydro Generating Unit Data

Unit ID	MCR (kW)	FOR (%)
Fish Lake #1	815	1
Fish Lake #2	480	1

Table 5.2: Mobile Diesel Generating Unit Data Included in the Study

Unit ID	MCR (kW)	FOR (%)
YM2	150	4
YM3	125	4
YM4	35	4
YM5	125	4

The Skagway-Whitehorse transmission line is rated at 138 kV. The line is considered to have a length of 170 km, and mainly supported by wood double pole tower structure. The unavailability of the line is calculated to be 0.5762%. The calculation of the line unavailability is shown in Table 5.3, using the 2014 CEA [6] data shown in Table 3.4.

Table 5.3: Proposed Skagway-Whitehorse Transmission line Unavailability Calculation

Line and outage component	Failure rate (failures/year)	Mean down time (hours)	Unavailability	
			(hours/year)	(%)
Sustained	1.66294	21.4	35.586916	0.4062
Transient	1.54479	0	0	0
Station (one end)	-	-	-	0.085
Station (other end)	-	-	-	0.085
			Total	0.5762

The Skagway-Whitehorse Transmission line is proposed to have a load carrying capability of 25 MW. The capacity assistance to the YEC electric system through this line is modeled as an equivalent 2-state generating unit with 25 MW capacity, and a FOR of 0.6%.

5.1 Considering Existing Generation Facilities

An adequacy study was carried out considering all the existing generation facilities, i.e. the YEC generating units listed in Table 2.1, YECL diesel and hydro generating units listed in Table 2.12 and 5.1, and the YEC mobile generating units listed in Table 5.2. The total winter generating capacity in this case is 116.278 MW. The system LOLE and LOEE as a function of the system peak load are shown in Table 5.4. The LOLE and LOEE results are also on shown graphically in Fig. 5.1 and 5.2 respectively.

Table 5.4: LOLE and LOEE Results Obtained Considering All Existing Generation

Peak load(MW)	LOLE(h/yr)	LOEE(MWh/yr)
76	0.0539	127.828
78	0.1099	276.769
80	0.2037	562.556
82	0.3580	1076.232
84	0.5783	1931.139
86	0.861	3235.328
88	1.2239	5110.522
90	1.6550	7678.792
92	2.1665	11043.630
94	2.7855	15356.630
96	3.4928	20784.520
98	4.3078	27450.560
100	5.2743	35577.480
102	6.4064	45410.010
104	7.8489	57343.260
106	9.5918	71917.620
108	11.7347	89728.600
110	14.5850	111758.500
112	18.6151	139684.100
114	24.9623	176714.900
116	34.2808	227841.400

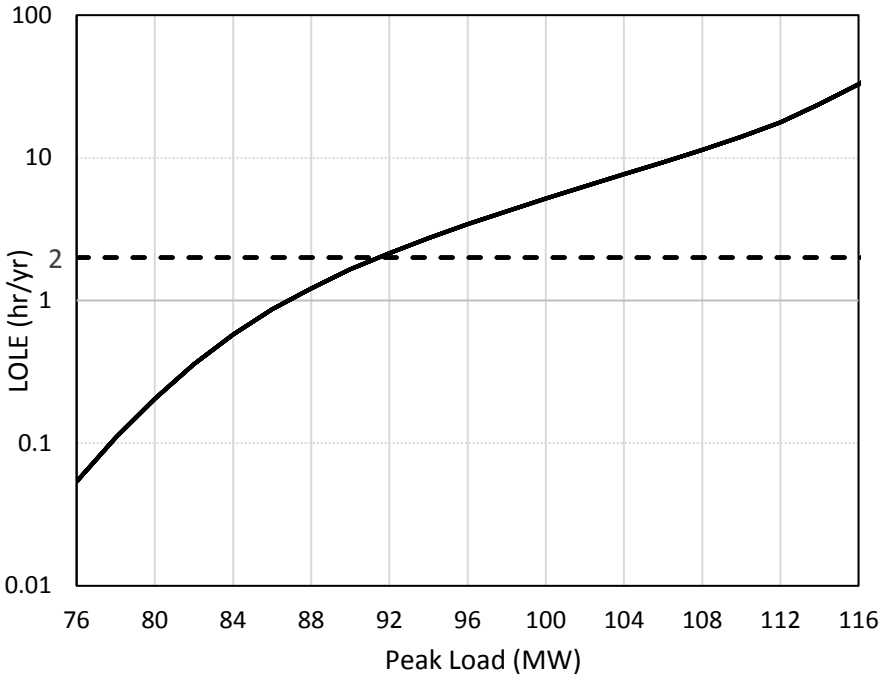


Figure 5.1: System LOLE Considering All Existing Generation

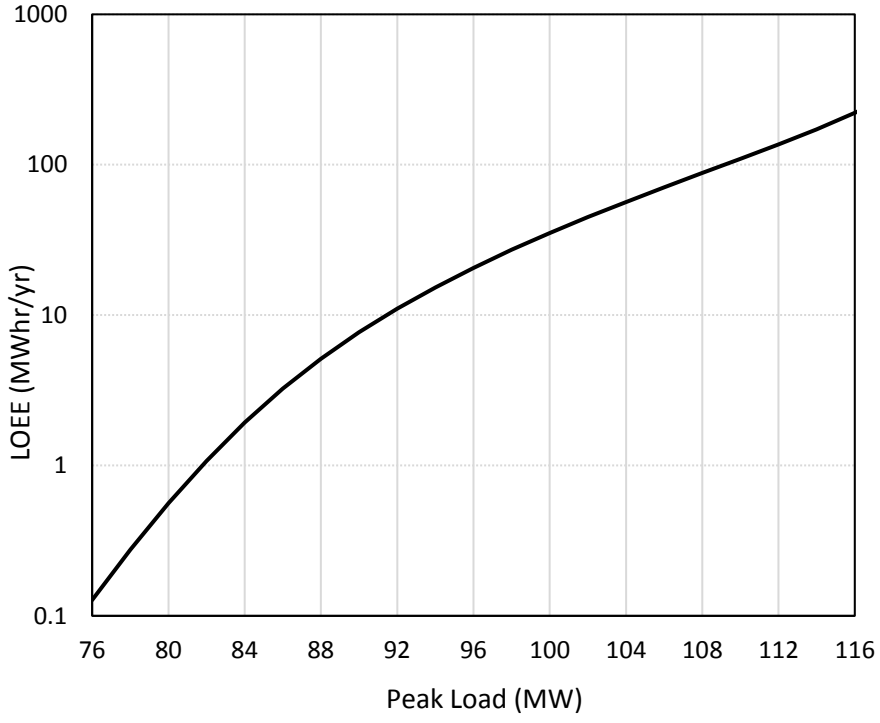


Figure 5.2: System LOEE Considering All Existing Generation

The impact of the mobile generation and the YECL generation on the overall YEC system adequacy was also analyzed. Fig. 5.3 shows the contribution of the mobile generation and the YECL generation on the system LOLE as a function of the system peak load.

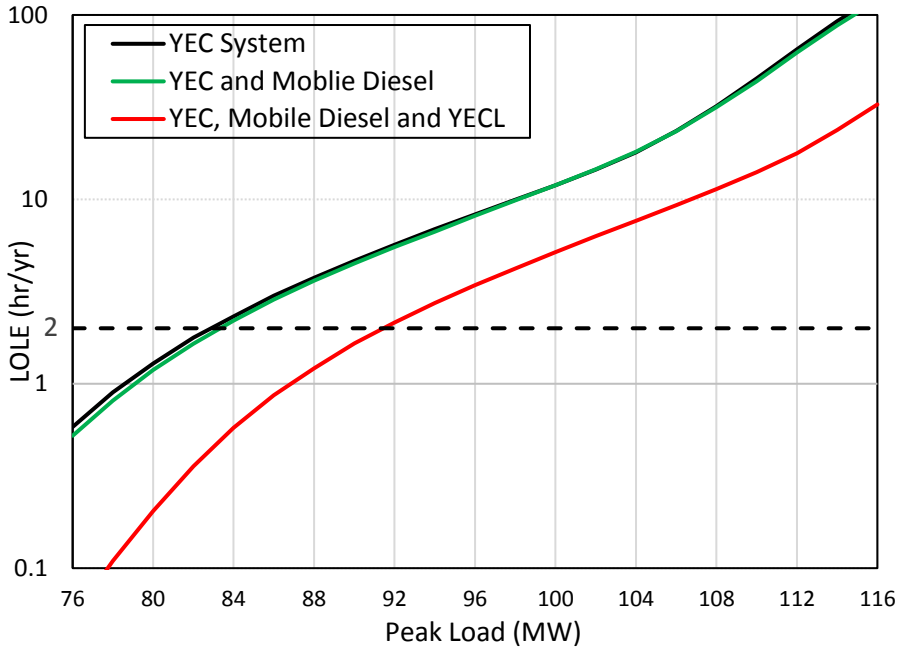


Figure 5.3: Impact of Mobile and YECL Generation on the System LOLE

The YECL and mobile generation enables the YEC electric system to carry an increased load. The peak load carrying capability of the YEC system while maintaining a reliability criterion of LOLE = 2 hours/year was evaluated, and the impact of the mobile and the YECL generation on the system PLCC is shown in Table 5.5.

Table 5.5: Impact of Mobile and YECL Generation on the System PLCC at the LOLE Criterion of 2 hours/year

Generating Units Considered	PLCC (kW)
YEC Generation listed in Table 2.1	82811.5
Plus mobile units listed in Table 5.2	83336.7
Plus YECL units listed in Table 2.12 and Table 5.1	91391.3

The YEC has improved the reliability of its electric system by adding redundancy to the line L172 with a parallel distribution line. An evaluation was done to quantify the reliability impact of the parallel line addition in terms of the increase in peak load carrying capability of the system while considering all the existing generation facilities. Table 5.6 shows the increase in PLCC (IPLCC) due to the distribution line is 7072 kW. A further upgrade of this line by increasing its load transfer capability can only increase the PLCC of the system by 342 kW.

Table 5.6: Impact of the Distribution Line Addition and its Upgrade on the System PLCC at the LOLE Criterion of 2 hours/year Considering All Existing Generation

Study Cases	PLCC (kW)	IPLCC (kW)
Before addition of the distribution line	84319.4	-
With the line addition (19.6 MW transfer capacity)	91391.3	7071.9
Upgrade the line (no transfer capacity restriction)	91733.3	342

5.2 Considering Unit Retirement Scenario in the Year 2021

It is expected that two of the YEC system diesel units FD1 and WD3 will retire in the year 2021. The system PLCC at the LOLE criterion of 2 hours/year with the retirement of the two diesel units are shown in Table 5.7. The table shows the results for the following case studies:

i. Considering only YEC generating units listed in Table 2.1
ii. Considering YEC generation, YECL generation and the mobile generating units
iii. Considering all the generation in Case ii and the assistance from the Skagway-Whitehorse transmission line
iv. Considering all the generation in Case ii and the upgrade of the distribution line between Takhini and Whitehorse
v. Considering all the generation in Case ii and twining the line L171 between Aishihik and Takhini

Table 5.7: System PLCC at LOLE criterion of 2 hours/year for different scenarios assumed for the Year 2021 after the retirement of units FD1 and WD3

Study Cases	PLCC (MW)
i. YEC generation only	73.1831
ii. YEC, YECL and mobile generation	81.8042
iii. All generation and assistance from Skagway line	109.9031
iv. All generation and upgrade of the distribution line	82.0146
v. All generation and twining line L171	95.1002

5.3 Considering Unit Retirement Scenario in the Year 2026

It is expected that all the diesel units of within the YEC system will retire in the year 2026. The system PLCC at the LOLE criterion of 2 hours/year with the retirement of all the YEC diesel units are shown in Table 5.8. The table shows the results for the following case studies:

i. Considering only YEC generating units listed in Table 2.1
ii. Considering only YEC generating units and YECL units listed in Tables 2.12 and 5.2.
iii. Considering all the generation in Case ii and the assistance from the Skagway-Whitehorse transmission line
iv. Considering all the generation in Case ii and the upgrade of the distribution line between Takhini and Whitehorse
v. Considering all the generation in Case ii, assistance from the Skagway-Whitehorse transmission line and the upgrade of the distribution line between Takhini and Whitehorse
vi. Considering all the generation in Cases ii and twining the line L171 between Aishihik and Takhini
vii. Considering all the generation in Cases ii, assistance from the Skagway-Whitehorse transmission line, and twining the line L171 between Aishihik and Takhini

Table 5.8: System PLCC at LOLE criterion of 2 hours/year for different scenarios assumed for the Year 2026 after the retirement of all YEC diesel units

Study Cases	PLCC (MW)
i. YEC generation only	48.1696
ii. YEC and YECL generation	56.3378
iii. All generation and assistance from Skagway line	85.3039
iv. All generation and upgrade of the distribution line	56.3733
v. All generation, assistance from Skagway line, and upgrade of the distribution line	85.5520
vi. All generation and twining line L171	71.2489

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Appendix 5.1 Greenhouse Gas Emission Life Cycle Assessment of Resource Options (ArcticCan Energy Services 2016)

ArticCan
ENERGY SERVICES

FINAL REPORT

LIFECYCLE ASSESSMENT FOR ENERGY RESOURCE OPTIONS IN YUKON TERRITORY

Prepared for Yukon Energy Corporation
2 Miles Canyon Rd
Whitehorse YT Y1A6S7
Attention: Shannon Mallory

By Anastassia Manuilova, P.Eng.
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September 6, 2016

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September 6, 2016

Yukon Energy Corporation
2 Miles Canyon Rd
Whitehorse YT Y1A6S7
Attention: Shannon Mallory, Environmental Coordinator

Re: Lifecycle Assessment for Energy Resource Options in Yukon Territory

Dear Ms. Mallory:

Please find attached the Final Report. If you have any questions or comments regarding the report, please contact me at (306) 502-5005 or amanuilova@articcanenergy.com.

Yours sincerely,

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TABLE OF CONTENTS

TABLE OF CONTENTS 3
ABBREVIATIONS 5
1 EXECUTIVE SUMMARY 6
2 INTRODUCTION 12
3 STUDY GOAL AND SCOPE 14
3.1 Objectives and Intended Application 14
3.2 Systems Function and Functional Unit 14
3.3 Description of Energy Resource Pathways and System Boundaries 15
3.3.1 System Description: Biomass Gasification Plant 16
3.3.2 System Description: Municipal Solid Waste (MSW) Waste to Energy Plant 17
3.3.3 System Description: Biogas Plant 19
3.3.4 System Description: Geothermal Power Plant 20
3.3.5 System Description: Wind Plant 22
3.3.6 System Description: Solar Plant 23
3.3.7 System Description: Pumped Storage 23
3.3.8 System Description: Small Hydroelectricity Plant 25
3.3.9 System Description: Battery Storage 26
3.3.10 System Description: Thermal Diesel Plant 27
3.3.11 System Description: Thermal LNG Plant 28
3.3.12 System Description: New Transmission Line (Whitehorse-Skagway) 29
3.3.13 System Description: Gladstone Diversion Project 30
3.4 Data Quality, Data Sources and Assumptions 31
3.4.1 Uncertainty 31
3.5 Life Cycle Assessment Methodology 33
3.5.1 Life Cycle Inventory and Life Cycle Impact Assessment Analyses 34
3.5.2 Results Interpretation 37
4 GREENHOUSE GAS EMISSIONS ASSESSMENT RESULTS 38
4.1 Life Cycle Inventory 38
4.2 Results 38

4.2.1 Comparison of GHG Emissions from Energy Production Pathways for 20 Year GWP 40
4.2.2 Comparison of GHG Emissions from Energy Production Pathways for 100 Year GWP 40
4.2.3 Analysis of Biogenic CO_2 Emissions 40
4.3 Contribution Analysis 48
4.3.1 Biomass Gasification 48
4.3.2 Waste to Energy MSW 49
4.3.3 Biogas 51
4.3.4 Geothermal 52
4.3.5 Wind 53
4.3.6 Solar 54
4.3.7 Pumped Storage Hydro Power Plant 55
4.3.8 Small Hydro 56
4.3.9 Energy Storage: Lithium Ion Batteries 57
4.3.10 Thermal-Diesel 58
4.3.11 Thermal-LNG 59
4.3.12 New Transmission Line 61
4.3.13 Water Diversion Project 62
4.4 Fixed and Variable Emissions Analysis 63
4.5 Sensitivity Analysis 65
4.5.1 Wind 65
4.5.2 Battery Storage 66
4.5.3 Biomass Gasification 67
4.5.4 LNG Combustion Emissions 68
4.5.5 Transmission Line Capacity 69
5 CONCLUSIONS AND RECOMMENDATIONS 70
REFEENCES 72
APPENDIX A: LIFE CYCLE INVENTORY – SUPPORTING INFORMATION 78

ABBREVIATIONS

AD	Anaerobic Digester
API	American Petroleum Institute (API)
C	Carbon
CAPP	Canadian Association of Petroleum Producers
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2e	Carbon dioxide equivalent
GHG	Greenhouse Gas
GWP	Global Warming Potential
HHV	Higher Heating Value
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
LCA	Life Cycle Assessment
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
Mm^3	Million Cubic Meters
MSW	Municipal Solid Waste
N_2O	Nitrous Oxide
ORC	Organic Rankine Cycle
WRGS	Whitehorse Rapids Generating Station
WTE	Waste-to-Energy

1 EXECUTIVE SUMMARY

There is an increase in concern around the world regarding environmental issues, including the use of natural resources, water, soil and air quality, deforestation, pollution, and emissions. The performance of products, services and processes in terms of its environmental impact has become a key global focal point for policy makers and industry leaders alike. As such, a critical analysis of negative environmental impacts that result from human activity must be performed. One of the most common analytical tools to weigh such impacts is the life cycle assessment (LCA). The purpose of the LCA is to examine and evaluate the overall environmental impact of using a certain product or implementing a certain technology by considering all stages of its life, from raw materials acquisition, to production, transportation, application, energy generation, recycling, and disposal, i.e., from "cradle to grave."

The results of an LCA can assist decision makers in choosing the most appropriate process or product that has the least environmental impact. LCAs are used in conjunction with other factors, such as performance, cost and feasibility, to assist in the selection of a process or product. With careful selection of the system boundaries, the LCA benefits end-users by exposing the environmental impacts that may be transferred from one medium to another, or from one life cycle stage to another, that may otherwise go unnoticed and unaccounted for.

Yukon Energy Corporation decided to perform a comparative LCA study of various energy resource options as part of their 2016-2035 Resource Plan. The goal of this study is to determine the amount of greenhouse gas (GHG) emissions that would be generated from 13 preselected energy resource options that are available to Yukon Energy for future use, which include both renewable and non-renewable resources. The pathways analysed are as follows:

1. Biomass gasification (combined heat and power, CHP)
2. Waste to energy (municipal solid waste alone and with biomass conventional combustion CHP plant)
3. Biogas (generated from organic waste)
4. Geothermal
5. Wind
6. Solar
7. Pumped storage hydro power plant
8. Small hydro power plant
9. Energy storage (lithium ion batteries)
10. Thermal – diesel
11. Thermal – LNG
12. New transmission line
13. Water diversion project

Included in the study is an analysis of energy storage in the form of batteries as well as the construction of a new transmission line. These options are modelled separately as they may form a part of another energy production pathway.

Each resource option is analyzed for GHG emissions using the Global Warming Potential (GWP) for both the 20 year and 100 year time horizon. The GWP factors without feedback are taken from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5). The significant

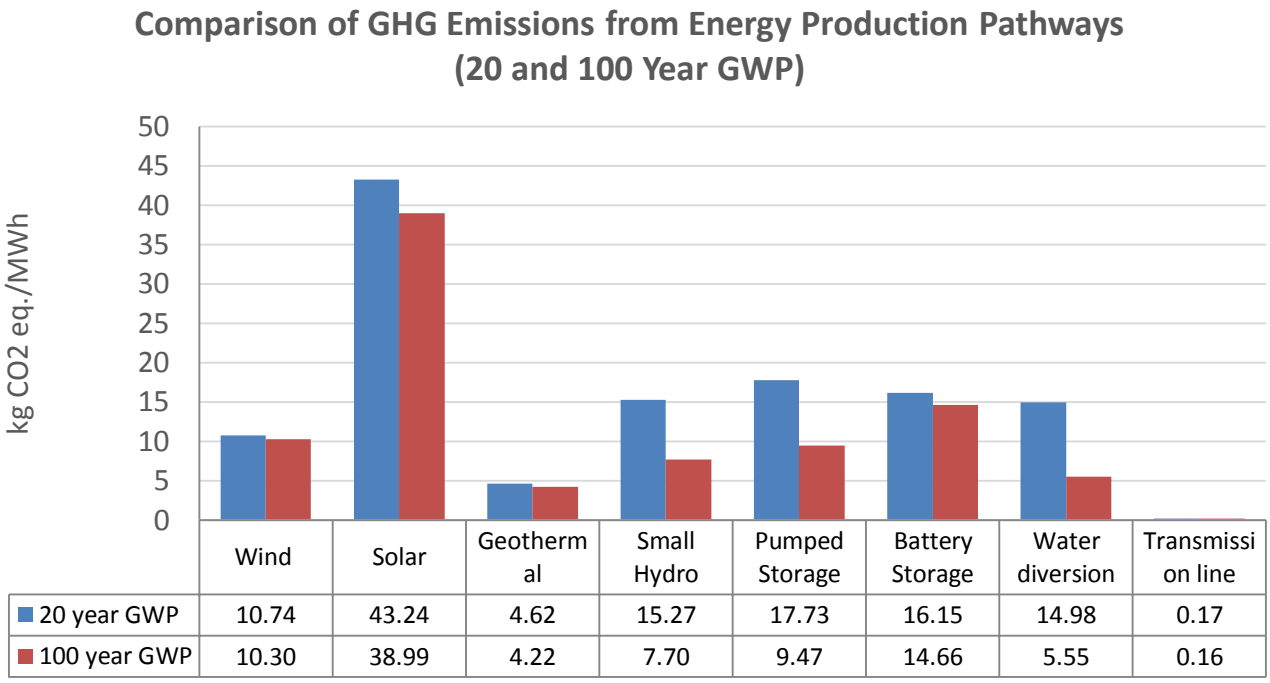
difference among the two GWP values is seen in methane emissions (84 and 28 for the 20 year and 100 year time horizons, respectively), which affects GHG emissions results when analyzing resource options that generate significant amounts of methane. Results from estimating the GHG emissions for both time horizons can illustrate immediate and future emissions concentrations released into the atmosphere. This can assist decision makers in deciding which energy resource scenario best addresses their short-term and long-term climate strategy.

This study is based on LCA principles and includes a definition of the system boundary, selection of relevant data (site-specific where possible and North American or European data when Canadian data were unavailable), and calculations of total GHG emissions for each energy resource per functional unit. The functional unit selected is MWh of energy delivered to the grid. In the battery storage and transmission line scenarios, the results are also presented per MWh of energy stored and MWh-km, respectively, to accommodate the appropriate energy source addition in future environmental studies.

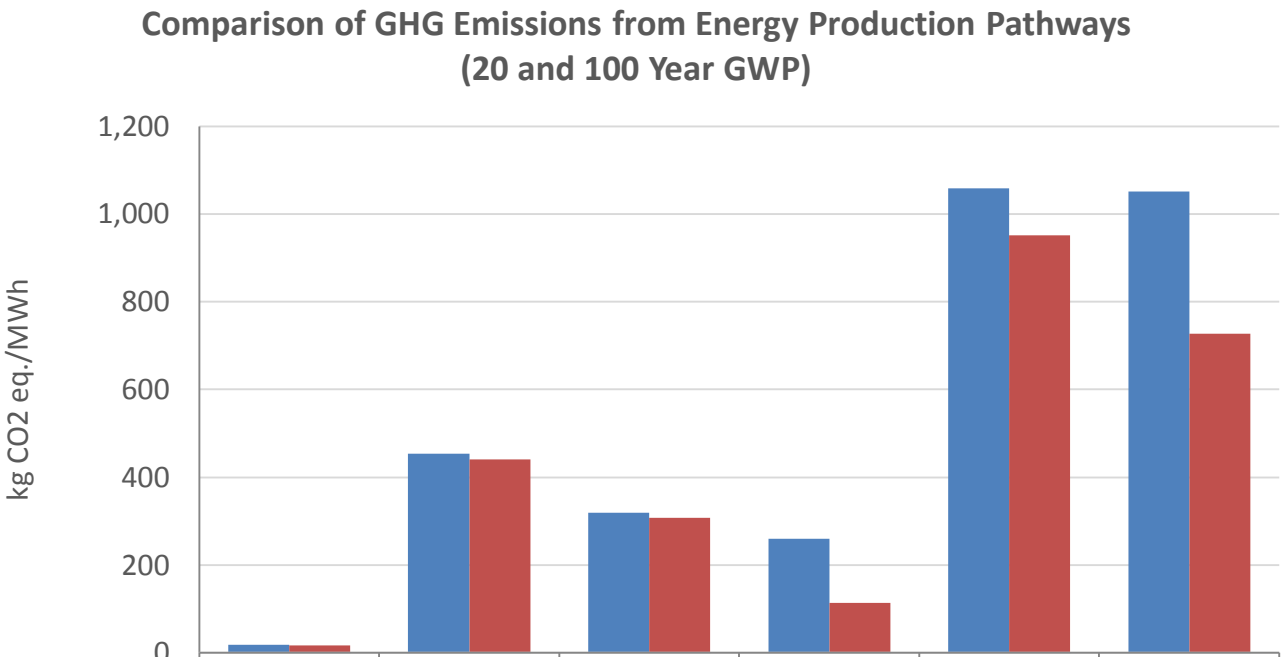
Results in kg of CO_2e/MWh of energy delivered for both the 20 and 100 year GWPs are presented in Figure E.1. Certain pathways (biogas, biomass gasification, waste to energy, small hydro, pumped storage and water diversion) have biogenic CO_2 emissions due to biomass combustion and/or decomposition. Since it is planned to utilize various biomass waste (e.g. dead trees, logging residues, and sawmill residues) as a source of biomass in biomass gasification and waste to energy pathways and municipal organic wastes in biogas pathway, one can argue in support of carbon neutrality of these pathways and exclude the biogenic CO_2 emissions from the total life cycle emissions. The biogenic CO_2 emissions in small hydro, pumped storage and water diversion scenarios originate from biomass decomposition after land inundation. Biomass decomposition is a slow process that lasts several years during which forest may be re-grown in other parts of the territories and recapture CO_2 from the atmosphere. Moreover, the inundated area represents a small fraction of the territories' forest reserves. Therefore, one may consider the emitted CO_2 to be carbon neutral.

The overall results indicate that the diesel and LNG pathways are the greatest GHG emitters with 1,059 and 1,051 kg CO_2e/MWh emitted for the 20 year time horizon, respectively, and 951 and 728 kg CO_2e/MWh emitted for the 100 year time horizon, respectively. The next highest emitters are waste to energy (MSW and MSW + biomass) and biogas pathways. The smallest GHG emitters for both time horizons are solar (approximately 40 kg CO_2e/MWh), followed by biomass gasification, pumped storage, small hydro, water diversion, battery storage, wind, and geothermal (all with less than 18 kg CO_2e/MWh). The 170 km of new transmission line produces just over 0.17 kg CO_2e/MWh for the 20 year and 0.16 CO_2e/MWh for the 100 year time horizon.

Wind, solar, geothermal, battery storage, transmission line, biomass gasification, and waste to energy produce emissions that are almost the same for both the 20 and 100 year time horizons. However, the most notable differences come from the analysis of biogas, diesel, liquefied natural gas (LNG), and hydro projects. These energy resource options emit significant amounts of methane; therefore, their overall GHG emissions vary between the 20 year and 100 year time horizons: (260 kg CO_2e/MWh versus 114 kg CO_2e/MWh for biogas, respectively; 1,059 kg CO_2e/MWh versus 951 kg CO_2e/MWh for diesel, respectively; and 1,051 kg CO_2e/MWh versus 728 kg CO_2e/MWh for LNG, respectively). Methane emissions in biogas pathway originate mainly from anaerobic digestion and waste storage processes, while in the diesel pathway they originate from crude oil extraction. Methane emissions in hydro energy pathways come from biomass decomposition after land inundation.

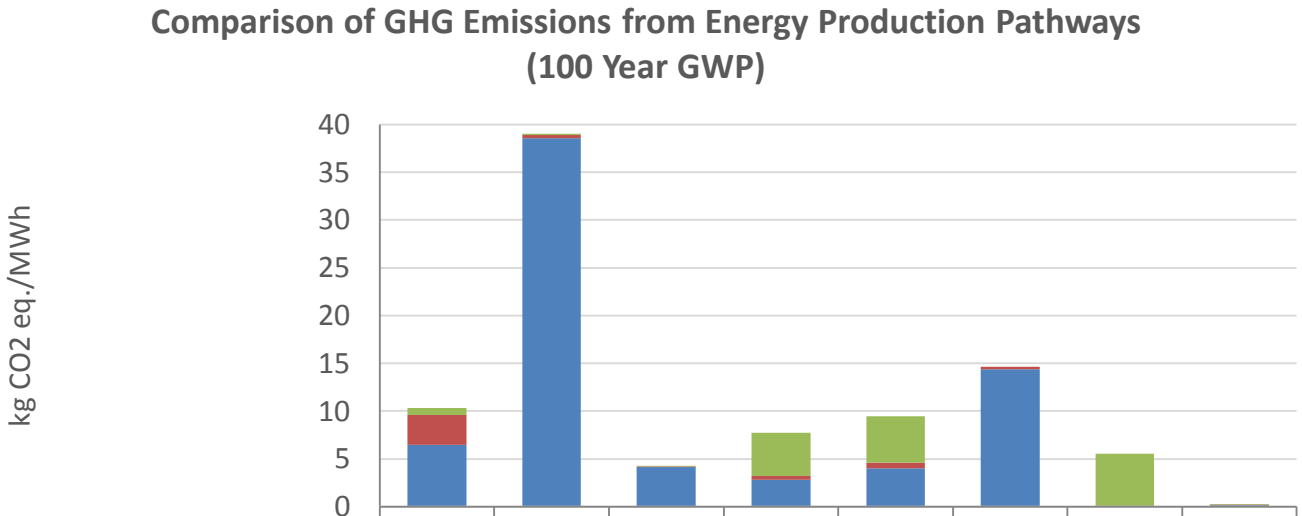


	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
20 year GWP	10.74	43.24	4.62	15.27	17.73	16.15	14.98	0.17
100 year GWP	10.30	38.99	4.22	7.70	9.47	14.66	5.55	0.16

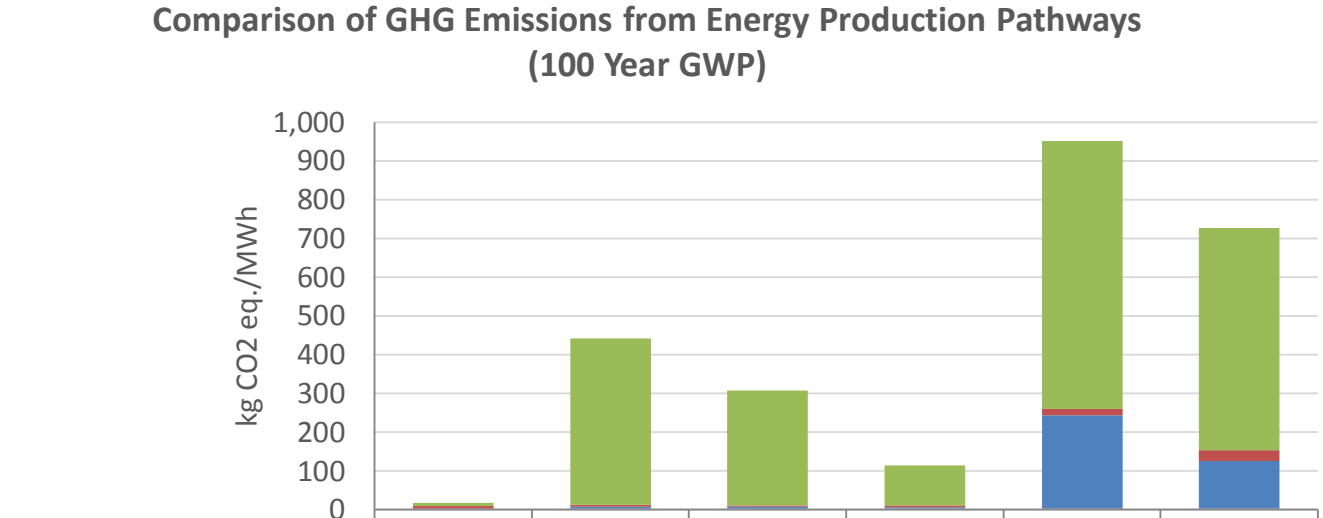


	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
20 year GWP	17.72	453.67	319.32	259.60	1058.91	1050.76
100 year GWP	17.20	441.40	307.06	113.77	951.11	727.68

Figure E.1. Comparison of GHG emissions from energy production pathways (biogenic CO_2 emissions excluded)



	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
Operation	0.71	0.10	0.01	4.48	4.88	0.00	5.43	0.0304
Transport of Materials & Fuel	3.09	0.33	0.10	0.41	0.58	0.28	0.00	0.0027
Materials and Fuel Acquisition, Production and Construction	6.49	38.56	4.11	2.81	4.01	14.38	0.12	0.1251



	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
Operation	8.51	429.37	295.35	103.30	690.43	574.23
Transport of Materials & Fuel	6.90	3.83	3.51	4.65	16.23	28.01
Materials and Fuel Acquisition, Production and Construction	1.79	8.20	8.20	5.83	244.45	125.45

Figure E.2. GHG Emissions from Energy Production Pathways - Contribution Analysis (biogenic CO_2 emissions excluded)

Analysis of the results includes a contribution analysis to determine the contribution each life cycle process has on the total GHG emissions and a sensitivity analysis whereby the effects on the final results by changing parameters are considered. The results of contribution analysis are shown in Figure E.2.

It is seen that operation of the energy generating plant is by far the most significant in terms of GHG emissions in biogas, waste to energy, diesel, and LNG pathways. For wind, solar, geothermal, transmission line and battery storage pathways, the majority of GHG emissions originate from upstream life cycle stages (e.g. materials extraction, components manufacturing). Diesel and LNG thermal plants also had notable GHG emissions contributions from fuel extraction and production life cycle stages.

The fixed and variable GHG emissions are shown in Table E.1. The fixed emissions are emissions associated with power plant and infrastructure construction and include raw materials acquisition, transportation, site preparation, and construction of the plant and transmission line. In the diesel, LNG, biomass gasification and waste to energy pathways, the emissions related to diesel, LNG, biomass and MSW transportation are considered variable emissions. The fixed emissions are expressed in tonnes CO_2e per facility, while variable emissions that originate from power plant operations are expressed in kg CO_2e/MWh.

Table E.1. Fixed and variable GHG emissions from energy production pathways (20 and 100 year GWP)

Energy Production Pathway	Fixed GHG emissions tonnes CO_2e		Variable GHG emissions kg CO_2e/MWh		Variable GHG emissions (biogenic CO_2 excluded) kg CO_2e/MWh	
	20 year GWP	100 year GWP	20 year GWP	100 year GWP	20 year GWP	100 year GWP
Biomass Gasification	679.1	651.7	769.3	768.9	14.53	14.14
Waste to energy: MSW	7,775	7,496	699.8	687.9	444.4	432.5
Waste to energy: MSW + biomass	7,775	7,496	666.0	654.1	310.1	298.2
Biogas	420.9	404.1	1151.2	1005.8	249.1	103.7
Geothermal	6,647	6,077	0.0230	0.0145	0.0230	0.0145
Wind	3,641	3,499	0.7379	0.7108	0.7379	0.7108
Solar	6,726	6,067	0.1284	0.0988	0.1284	0.0988
Pumped storage	16,294	16,098	18.77	10.56	13.09	4.88
Small hydro	6,704	6,630	17.31	9.77	12.02	4.48
Battery storage	904.5	820.9	0.00	0.00	0.00	0.00
Thermal - Diesel	675.2	649.1	1058.48	950.70	1058.48	950.70
Thermal - LNG	1,065	1,023	1050.09	727.04	1050.09	727.04
New transmission line (170km)	29,498	27,284	0.0324	0.0304	0.0324	0.0304
Water diversion project	237.8	223.2	21.30	11.99	14.86	5.43

The sensitivity analysis reveals that the choice of the technology and location of the manufacturing facilities (e.g. in North America versus oversees) can significantly impact the total life cycle emissions in

the case of renewable energy sources where upstream life cycle stages are the largest contributors to the total life cycle GHG emissions.

The technology pathways that can potentially support other energy generation options such as small hydro are geothermal, as well as wind and solar coupled with battery storage. Hydro options, in turn, make it feasible to utilize other renewable sources. Pumped storage offers operational flexibility, since it can immediately respond to fluctuations in the demand for electricity. The flexibility and storage capacity of hydro options make them efficient and economical in supporting the use of intermittent sources of renewable energy, such as solar and wind, especially if these energy options are not coupled with battery storage. The waste to energy option has a potential to displace some fossil fuel-based sources, such as diesel and LNG, especially if the produced heat is utilized to make the technology economically viable. However, the waste to energy pathway produces a significant amount of fossil GHG emissions due to MSW combustion.

In summary, this LCA reveals the environmental impacts related to climate change for various energy options for renewable and non-renewable resources which can be used for enhanced decision making and improved strategies regarding long term energy planning for the Yukon Territory.

2 INTRODUCTION

Yukon Energy Corporation is committed to providing long-term, sustainable and reliable energy options for its customers. As part of the long term resource planning process (Resource Plan 2016-2035), Yukon Energy is in the process of evaluating different resource options for energy production. The goal of this study is to estimate greenhouse gas emissions (GHG) from the life cycle of different energy generation options. At the conclusion of this study, a detailed energy sources assessment of the overall GHG emissions associated with each energy source, including fossil fuels and several renewable energy production pathways, are presented. A final analysis of the contributions to the Global Warming Potential (GWP) from each resource option over a 20 year and 100 year timeframe is given. This will allow Yukon Energy to employ best management practices and make informed decisions in planning for future energy developments.

The study follows the current state-of-the-science practices with regard to LCA and is based on ISO 14040 principles and guidelines. Specifically, ISO 14040 and 14044 (2006) standards are applied to determine the key GHG contributors for each life cycle stage of the energy production technologies. Table 1 represents the energy resources pathways that are compared in this study. The studied projects are used as proxy for potential similar projects that may be implemented by Yukon Energy.

Table 1. Energy Resources Pathways

#	Resource option and location	Installed capacity	Annual energy (net)	Impacted area & Transmission line
1	Biomass gasification (Combined Heat and Power, CHP) Haines Junction	Gross power 0.5MW_e Net power 0.369 MW_e, 1,150 kW_{th}	2,585 MWh_e/yr 8,059 MWh_{th}/yr	Brownfield
2	Waste to Energy Municipal Solid Waste (MSW) with biomass conventional combustion (CHP) Whitehorse landfill	1.6MW_e (Scenario 1: 23,750 tonnes MSW/year Scenario 2: 16,100 tonnes MSW per year and 7,650 tonnes biomass per year)	9,975 MWh_e/yr 23,700 MWh_{th}/yr	Brownfield
3	Biogas Whitehorse landfill	185kW (second 100kW unit added in 2020)	885.9 MWh_e/yr	Brownfield
4	Geothermal McArthur Springs	7MW_e gross or 5.5MW_e net (3.86 MW_e taking into account the losses and decrease in production of 3% per year)	48.2 GWh_e/yr	Greenfield 42 km x 30 m of 138kV line
5	Wind Mount Sumanik	6MW_e	14.558 GWh_e/yr	Greenfield (impact area 100 ha) 7.6 km x 30 m of 138kV line
6	Solar Whitehorse Copper	5MW_e	5.2 GWh_e/yr	Brownfield
7	Pumped storage Moon Lake	20.2MW_e	54 GWh_e/yr	Greenfield Inundation area 352.4 ha

#	Resource option and location	Installed capacity	Annual energy (net)	Impacted area & Transmission line
				2.6 km x 30 m of 138kV line
8	Small hydro Drury Creek	8.1MW_e	31.7 GWh_e/yr	Greenfield Inundation area 190 ha 0.5 km x 30 m of 138kV line
9	Energy storage – lithium ion batteries Takhini Substation	8MW_e	2.8 GWh_e/yr 5hr discharge time	Greenfield/Brownfield 0.42 ha cleared area footprint
10	Thermal-diesel Takhini Substation	5MW_e	39.42 GWh_e/yr	Greenfield/Brownfield 4.5-5.5 ha of cleared area footprint
11	Thermal-LNG Takhini Substation	5MW_e,	39.42 GWh_e/yr	Greenfield/Brownfield 6.5 ha of cleared area footprint
12	New transmission line Whitehorse to Skagway	443 MW reliable transfer capacity	N/A	Greenfield/ Brownfield 170 km of 230kv line and 68 km of an existing 34.5kv line (306 ha plus 102 ha of cleared area footprint)
13	Enhancement – Gladstone Water diversion	Would utilize existing hydro unit capacity	29.7 GWh_e/yr	Partial greenfield Inundation area 220 ha

The following issues are examined in this study:

- The amount of the greenhouse gas emissions originating from different energy production technologies that could potentially be implemented in the Yukon,
- Contribution of each life cycle stage to the environmental impact through the determination of an environmental “hot spot” (i.e. any life cycle stage with the highest GHG emissions) in the life cycle of each technology, and
- The technology pathways that either support other energy generation options (e.g. hydro) and/or have the potential to displace another energy source (e.g. fossil fuel-based sources, such as diesel fuel).

The report consists of the following parts:

Chapter 3 – Goal and Scope Definition;

Chapter 4 – Greenhouse Gas Assessment results;

Chapter 5 – Conclusions and Recommendations.

3 STUDY GOAL AND SCOPE

This section of the report provides a general description of the energy systems under study, definition of the system boundaries, and the functional unit. Data quality, assumptions, limitations and GHG assessment methodology are also discussed.

3.1 OBJECTIVES AND INTENDED APPLICATION

The project has the following objectives:

- Using the "cradle-to-grave" approach, develop greenhouse gas emission inventories associated with different energy production pathways in the Yukon Territory,
- Inform decision-makers of the overall contribution of the different technology pathways to the Global Warming impact,
- Rank the energy generation technologies based on their greenhouse gas emissions,
- Provide comparative study results with recommendations on which technology pathways support other energy generation options (e.g. hydro) and which ones have a potential to displace another energy source (e.g. fossil fuel-based sources, such as diesel fuel), and
- Provide input into the evaluation of energy resource options against technical, financial, social and environmental attributes.

The results of this study are intended for the internal use by Yukon Energy to assist with the long term resource planning process (Resource Plan 2016-2035). Results of the LCA study may be made public by Yukon Energy.

3.2 SYSTEMS FUNCTION AND FUNCTIONAL UNIT

The main function of the system under study is to produce energy. In order to compare the environmental footprints of the various energy production scenarios considered in this study, a common functional unit is selected – a unit that provides a reference to which the input and output data are normalized. The functional unit best suited for this study is **MWh of energy delivered to the grid**.

The GHG emissions per MWh of energy delivered to the grid are obtained by dividing the life cycle inventory data (e.g. plant construction data) by total net energy output of the power plant during its lifetime.

The lithium-ion battery storage (scenario #9) LCA is limited to the manufacturing of the battery and site preparation, including materials extraction, production of materials, battery assembly, transportation, and land clearing. The results are presented per MWh of energy stored.

Analysis of the transmission line (scenario #12) is limited to the construction of the line itself, including materials, transportation, and change in land use. The LCA does not consider the potential proximity of the transmission line to the point of energy production or the type of energy source being used. These results are given per MWh-km such that future environmental assessments may include the appropriate energy resource option at that time (transmission line results per MWh-km are presented in section 4.2.12). The results per MWh-km are then used to estimate the environmental impact of 170km of new transmission line.

3.3 DESCRIPTION OF ENERGY RESOURCE PATHWAYS AND SYSTEM BOUNDARIES

This section provides a description of the systems under study and their system boundaries. The system boundary defines the unit processes to be included in the system.

The "cradle-to-grave" approach is applied, which includes the life cycle activities from resource extraction and production of materials through to the generation of electrical energy at the generating station, as well as all transportation stages (Figure 1). Downstream stages (decommissioning, recycling and site remediation) are excluded from the analysis. Exclusion of these activities is a common practice where it is expected that these processes contribute to less than 1% of total impact from the energy resource life cycle[1].

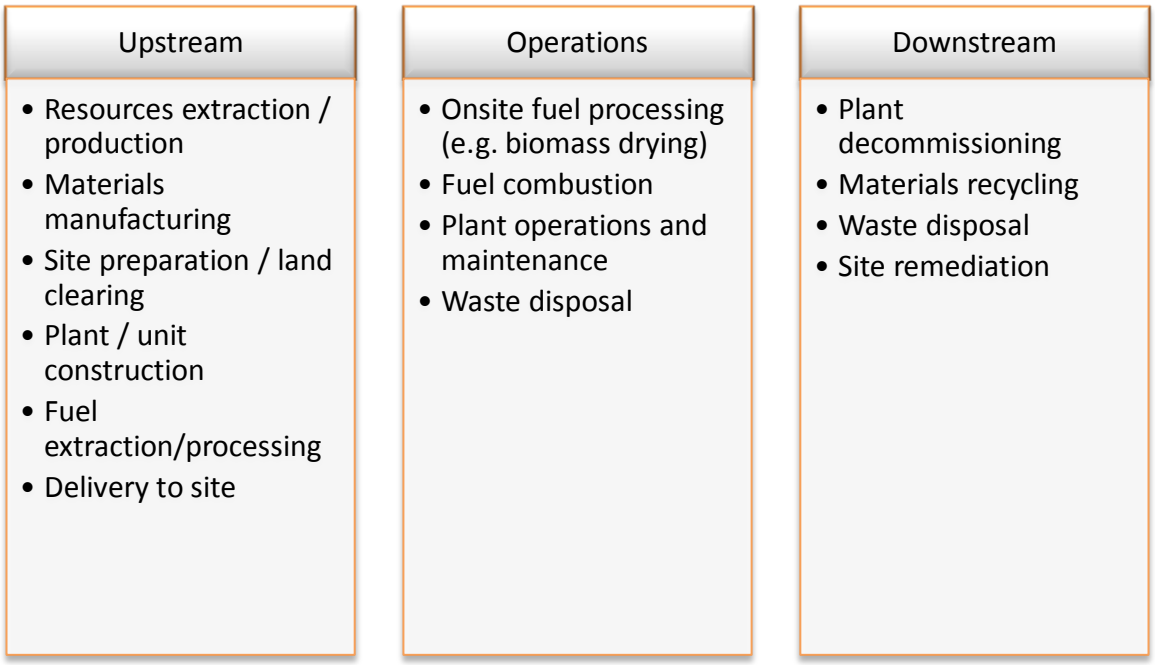


Figure 1. Generalized Life Cycle Stages of an Energy Generation Technology

Most of the processes included in the system boundaries occur in Yukon or Western Canada. However, some unit processes may occur in other Canadian provinces, the US and worldwide. Life Cycle Inventory supporting information that includes a description of all data sources used in the analysis is presented in Appendix A.

[1] Baumann, H. and Tillman, A. (2004) The Hitch Hiker's Guide to LCA. Studentlitteratur AB, Lund, Sweden.

3.3.1 System Description: Biomass Gasification Plant

The biomass gasification combined heat and power plant (CHP) with a 0.5 MW_e and 1,150 kW_{th} capacity was chosen to be located in the centre of Haines Junction[2]. The potential project includes two 250 kW_e biomass gasification units that will be supplied by Community Power Corporation (CPC). The plant is expected to produce 2,585 MWh_e net and 8,059 MWh_{th} energy annually. The biomass supply would be primarily sawmill and forest harvesting residues, as well as dead trees from the spruce beetle infestation.

The system boundary is presented in Figure 2 with a description following in Table 2.

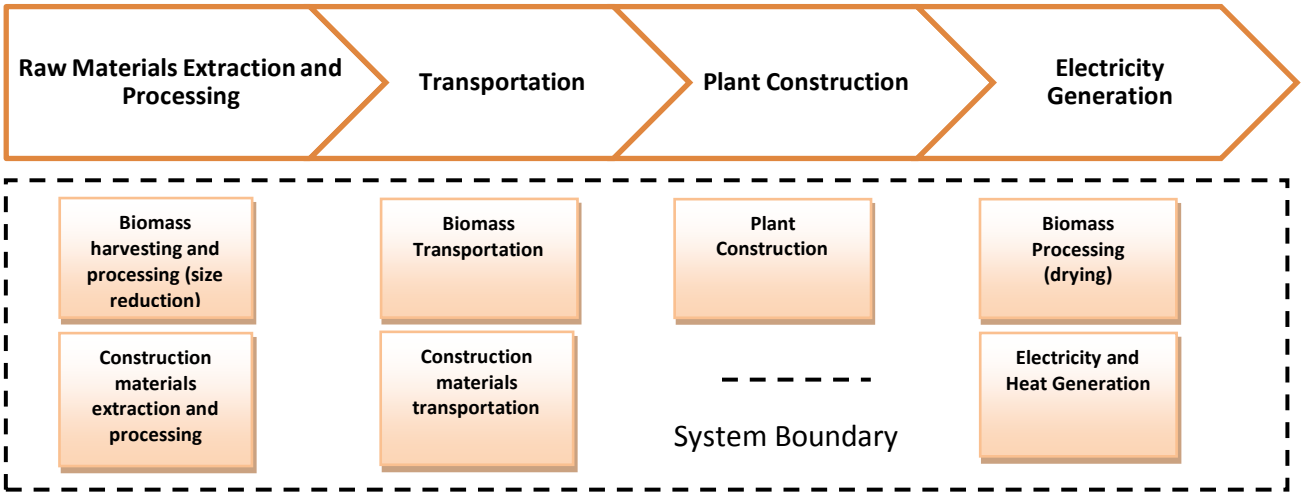


Figure 2. System Boundary of Biomass Gasification Electricity Generation

Table 2. Description of Biomass Gasification Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	<u>Biomass harvesting and processing</u> Sawmill and forest harvesting residues, dead trees from the spruce beetle infestation. Required feedstock: • Oven dry tonnes – 3,000 tonnes/year • With 15% moisture content – 3,789 tonnes/year • Forest harvesting residues: 1,603 tonnes/year • Sawmill residues – 2,190 tonnes/year Biomass processing includes size reduction in the field. <u>Construction materials extraction and processing</u> Raw materials extraction and production of construction materials (steel, aluminum, concrete, etc.)
Transportation	<u>Biomass transportation</u> Sawmill residues are transported 50km by truck, 9t payload Forest harvesting residues - 70km by truck, 9t payload

[2] Stantec. (2013). Front End Engineering Design (FEED) Study. Yukon Bioenergy Demonstration project in Haines Junction, Yukon. Final FEED Report. June 7, 2013.

Life Cycle Activity	Description
	Construction materials transportation Transportation by truck, 22t payload (assumed average distance of 2,400 km)
Plant Construction	Location: Whitehorse landfill Brownfield – no site preparation included
Electricity Generation	Biomass processing Biomass processing includes drying to 15% moisture content Electricity generation 1-Stage Downdraft Gasifier (BioMax), 2xIC Engines, 2 x 250 kW_e Annual energy production (net): • 2,585 MWh_e -682 kWh_e/tonne of biomass • 8,059 MWh_{th} – 2,127 kWh_{th}/tonne of biomass Waste disposal Disposal of waste (e.g. ash) is excluded from analysis
End of life	Lifetime: 20 years

In the CHP plant, heat and electricity are generated simultaneously from the same input of fuel. This increases the plant efficiency and reduces GHG emissions per MWh of energy produced. Although, the produced electricity is more valuable than heat, no allocation of GHG emissions to electricity and heat separately is performed as the goal of the project is to assess total GHG emissions produced by the CHP plant.

3.3.2 System Description: Municipal Solid Waste (MSW) Waste to Energy Plant

For this analysis, a municipal solid waste (MSW) conventional combustion waste to energy (WTE) facility with nominal design capacity of 25,000 tonnes per year has been chosen for evaluation. The actual annual throughput is 95% of the total design capacity or 23,750 tonnes year. In order to maximize the facility efficiency, a CHP plant is selected. The CHP plant will generate up to 4MW of heat and 1.6 MW of electricity. Approximately 16,100 tonnes of MSW and 7,650 tonnes of wood biomass per year until 2035 would be required[3].

The operating life of the WTE facility is assumed to be 25 years (to year 2040). It is likely that the WTE facility will operate longer (if there is waste still available), and the landfill will continue to accept waste/ash past 2040.

Two scenarios are modelled:

1. 2015 feedstock: MSW (16,100 tonnes) + biomass (7,650 tonnes) conventional combustion, and
2. 2035 feedstock: MSW (23,750 tonnes) conventional combustion.

The system boundary is presented in Figure 3 with a description following in Table 3.

Similar to the biomass gasification pathway, no allocation of GHG emissions to electricity and heat is performed.

[3] Morrison Hershfield. (2012). Waste to Energy Updated design Basis and Business Case Analysis. April 24, 2012.

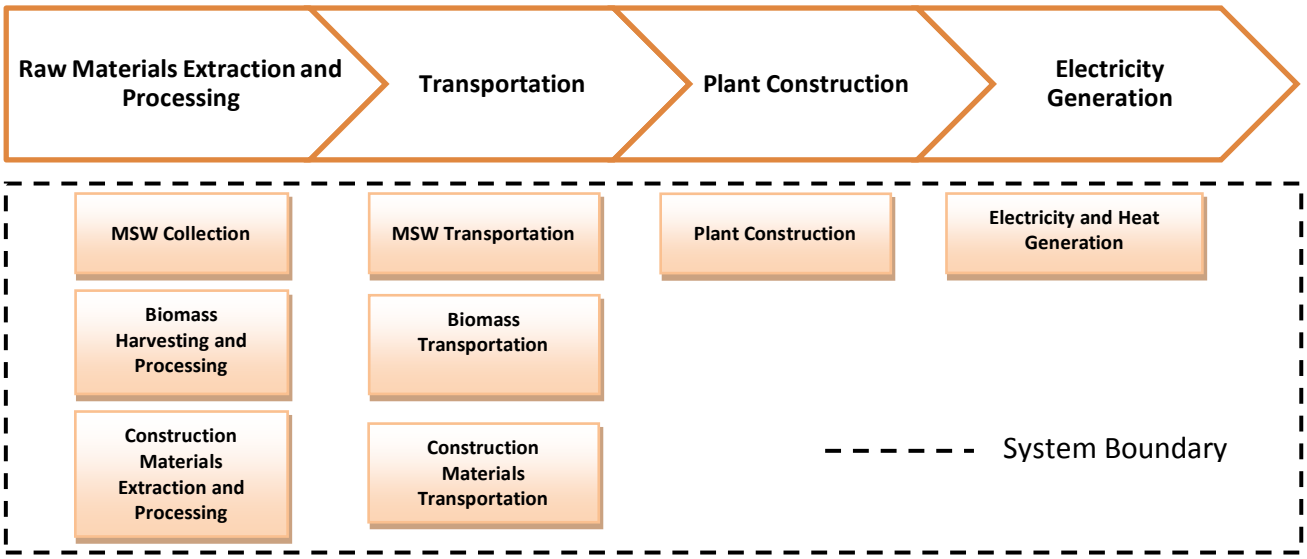


Figure 3. System Boundary of MSW Waste to Energy Electricity Generation

Table 3. Description of MSW Waste to Energy Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	MSW Collection MSW generated within Whitehorse and surrounding communities, used tires, waste oil and abattoir waste Biomass Harvesting and Processing (in Scenario 1 only) Biomass as a supplement fuel during winter (7,650 tonnes/year) Sources: Forest harvesting residues and sawmill residues Biomass processing includes size reduction in the field Construction materials extraction and processing Raw materials extraction and production of construction materials (steel, aluminum, concrete, etc.)
Transportation	MSW transportation 8-9 truckloads of waste per day (truck payload 9t); approximate distance 16 km Biomass transportation Sawmill residues are transported 50km by truck, 9t payload Forest harvesting residues - 70km by truck, 9t payload Construction materials transportation Transportation by truck, 22t payload (assumed average distance of 2,400 km)
Plant Construction	Location: Whitehorse landfill Brownfield (min 2 ha)– no site preparation included
Electricity Generation	Technology (EcoWaste Solutions): Controlled-air two stage conventional combustion WTE facility capacity: 25,000 tonnes/year Annual throughput: 23,750 tonnes/year (95% of total design capacity) Weighted HHV (Higher Heating Value): 14.45 GJ/tonne MSW

Life Cycle Activity	Description
	Electricity production (net): 9,975 MWh_e/year Heat production (net): 23,700 MWh_{th}/year Total electricity produced (net): • 420 kWh_e per tonne of MSW or MSW + biomass (10% electrical efficiency) • 998 kWh_{th} per tonne of MSW or MSW + biomass <u>Waste disposal</u> Disposal of waste (e.g. ash) is excluded from analysis
End of life	Lifetime: 25 years

3.3.3 System Description: Biogas Plant

The site identified for the biogas plant is the Whitehorse Municipal Landfill near the composting site. A dry (high solids) garage style anaerobic digester will be used to treat Whitehorse residential and commercial organic waste and produce electricity and heat. The produced heat will be used on-site to heat the digester to 35°C. Some of the produced electricity will be used internally to operate the digester. Initially, one 100 kW_e unit will be installed and the second 100 kW_e unit will be added in 5 years (2020)[4].

The system boundary is presented in Figure 4 with a description following in Table 4.

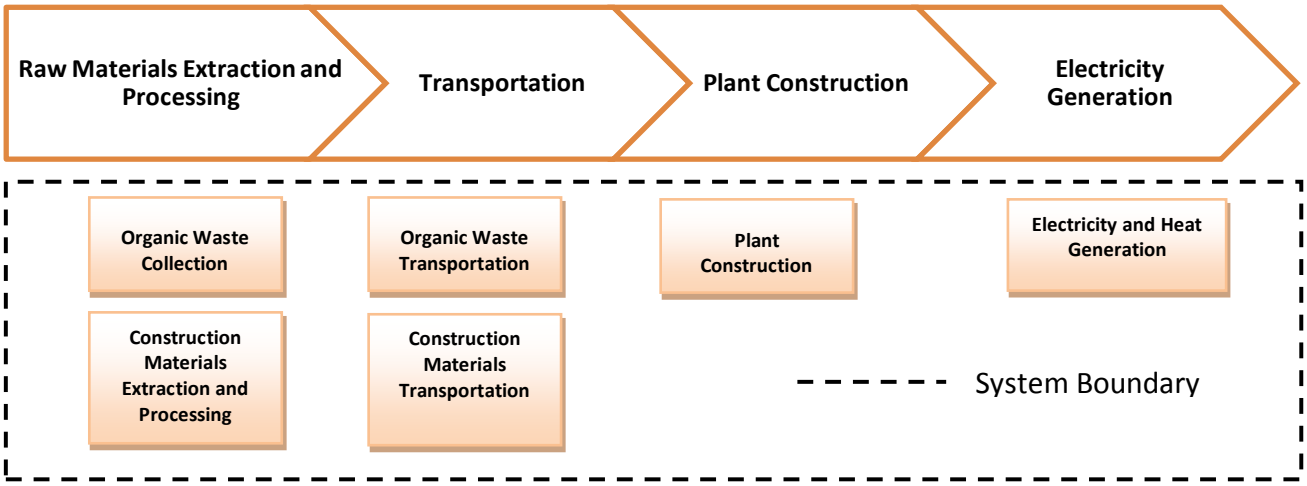


Figure 4. System Boundary of Biogas Electricity Generation

[4] WSP. (2016). Biogas Plant in Whitehorse. Feasibility Study, Whitehorse, Yukon. January 2016.

Table 4. Description of Biogas Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	Organic waste collection Food waste, green yard waste, dry yard waste Construction materials extraction and processing Raw materials extraction and production of construction materials (steel, aluminum, concrete, etc.)
Transportation	Organic waste transportation Approximate distance: 16 km, truck payload 9 tonnes Construction materials transportation Transportation by truck, 22t payload (assumed average distance of 2,400 km)
Plant Construction	Location: Whitehorse landfill Brownfield – no site preparation included
Electricity Generation	Dry garage style anaerobic digester CHP unit Capacity: 185 kW_e (takes into account addition of a second 100 kW unit in 2020) Electric efficiency: 35% Thermal efficiency: 40% (heat production 28.7%, internal heat use 11.3%) Energy loss: 25% Electric output: 56kW_e (33kW_e in April and 100 kW_e in August) Thermal output: 64 kW_{th} (37 kW_{th} in April and 114 kW_{th} in August) Total electricity produced (net): 885.9 MWh_e/yr
End of life	Lifetime: 20 years

3.3.4 System Description: Geothermal Power Plant

McArthur Springs, in Northeast Yukon, was chosen as a geothermal power plant location. The site is located approximately 42 km East of Highway #2 southeast of Stewart Crossing, and approximately 75 km south of Mayo. The net capacity of the plant is 5.5MW[5]. The plant is estimated to produce water at 160°C using a binary cycle Organic Rankine Cycle (ORC) system.

The capacity of a geothermal reservoir decreases over time; thus, a constant decrease of 3% per year has been assumed. The net electricity output of the plant is 48.2 GWh_e/yr taking into account the losses and decrease in production output of 3% per year.

The system boundary is presented in Figure 5 with a description following in Table 5.

[5] KGS. (2016). Geothermal Review and Site Inventory. Draft Report – Rev. A. KGS Group. May 2016.

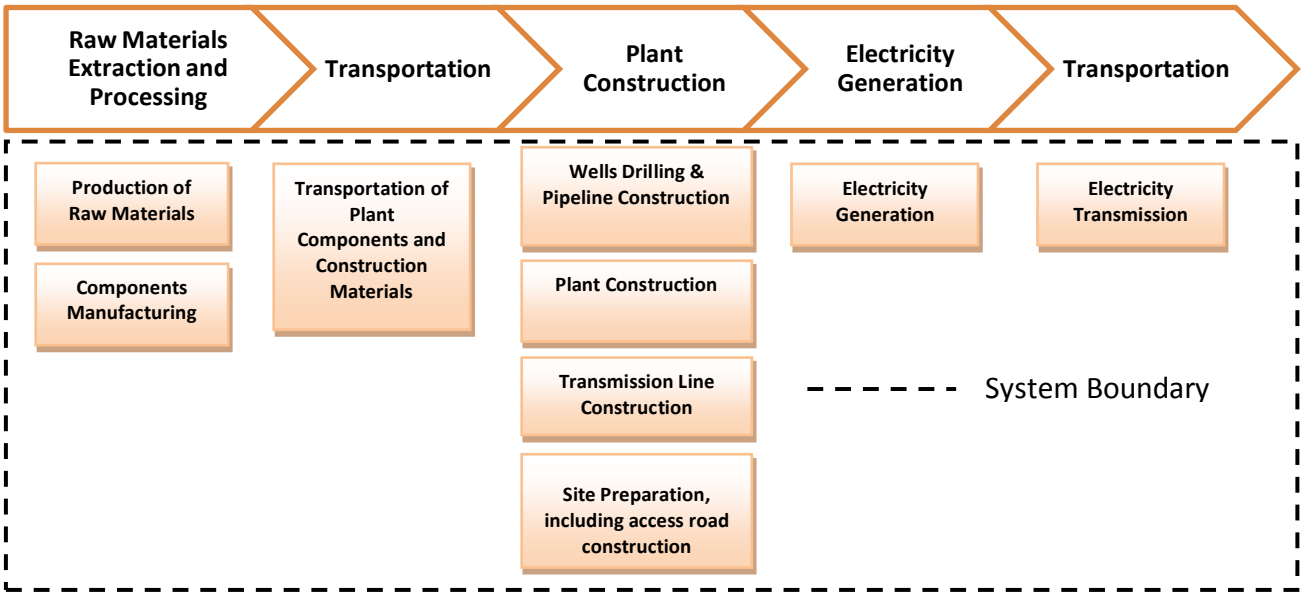


Figure 5. System Boundary of Geothermal Electricity Generation

Table 5. Description of Geothermal Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	Raw materials for plant construction are extracted and processed. Construction materials (aggregates) are assumed to be sourced locally (within 15 km of the site).
Components Manufacturing and Transportation	Power generation and transmission line components are manufactured and transported 2,400km by truck, 22t payload.
Plant Construction	Greenfield site 2 production and 1 injection wells are drilled approximately 1 km apart. Wells are equipped with line-shaft pumps, located in a small building. Pipeline construction to connect the wells to the power plant, access road, wells, and transmission line construction are included in the assessment. One exploration well drilling is included.
Electricity Generation	Binary Organic Rankine Cycle (ORC) geothermal plant with 70% efficiency. Net electricity output: 48.2 GWh_e/yr
Electricity transmission	Produced electricity is transported from MacArthur through 42km of 138kV transmission line.
End of life	Lifetime: 30 years

3.3.5 System Description: Wind Plant

The site chosen for proposed wind power plant is Mount Sumanik in southern Yukon. Mount Sumanik, a large, broad hill complex equipped with Lidar for ongoing wind resource assessment study, is located immediately west of Whitehorse[6]. A three-turbine, 6 MW wind farm with 27% capacity factor is studied.

The system boundary is presented in Figure 6 with a description following in Table 6.

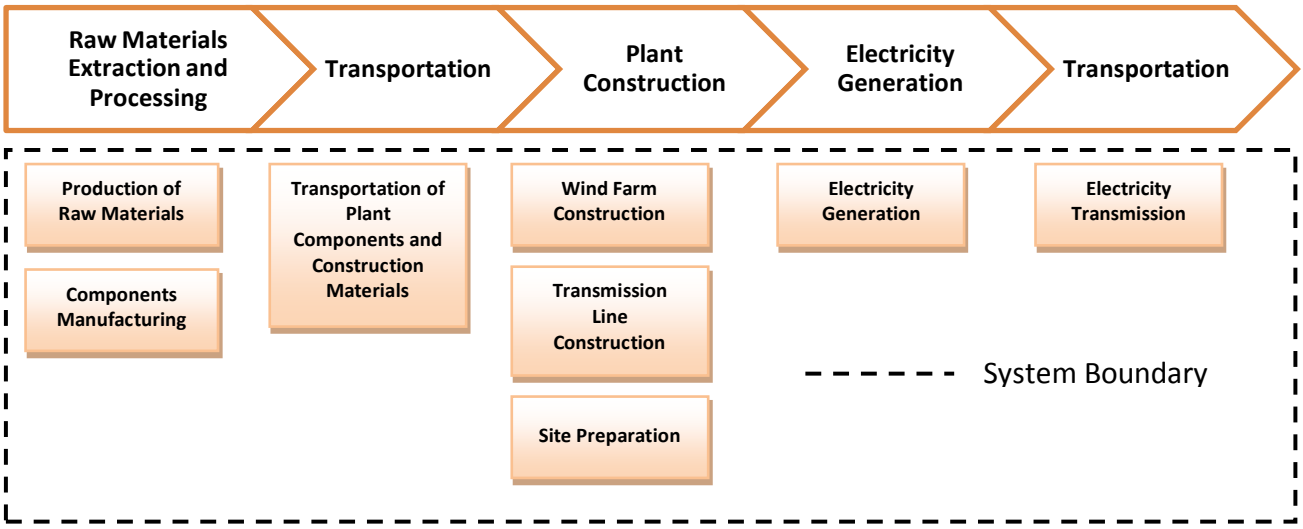


Figure 6. System Boundary of Wind Electricity Generation

Table 6. Description of Wind Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	Raw materials for plant construction (i.e. concrete, steel, etc.) are extracted and processed.
Components Manufacturing and Transportation	It is assumed that wind turbines are manufactured in Denmark. Turbine transport by sea – 5,578 km (Denmark – Montreal) Turbine transport by road – 5,560 km (Montreal – Whitehorse) Transmission line components are transported 2,400km by truck, 22t payload.
Plant Construction	Greenfield site This stage includes construction and installation of the plant at Mount Sumanik and construction of 7.6km transmission line. Total road, transmission line, and wind farm area is 100 ha.
Electricity Generation	Three Vesta V-90 2MW turbines with 27% capacity factor or similar turbines. Gross annual energy production: 16.45 GWh_e/yr; Net (88.5% of theoretical gross output): 14.558 GWh_e/yr
Electricity transmission	Produced electricity is transported to Whitehorse through 7.6km transmission line
End of life	Plant lifetime: 25 years

[6] CBER Ltd., ENVINT Consulting, V3 Energy, LLC. (2016). Yukon Wind Site Inventory. Draft Report. May 16, 2016.

3.3.6 System Description: Solar Plant

A 5 MW photovoltaic solar farm is chosen to be located at the old Whitehorse Copper Mine site near Whitehorse[7]. It is a brownfield site and has an established road access.

The system boundary is presented in Figure 7 with a description following in Table 7.

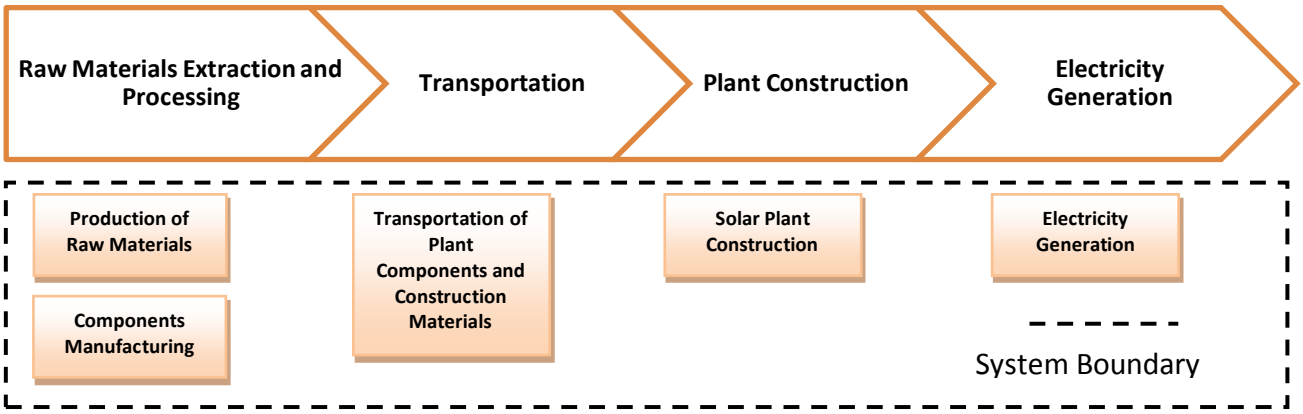


Figure 7. System Boundary of Solar Electricity Generation

Table 7. Description of Solar Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	Raw materials for plant construction (i.e. concrete, steel, etc.) are extracted and processed.
Components Manufacturing and Transportation	Solar PV components (e.g. module, racking, inverter) are manufactured in Japan and transported to Vancouver by sea (7,664 km) and then from Vancouver to Whitehorse 2,400km by truck, 22t payload.
Plant Construction	Brownfield, no site preparation or access road construction is included. Solar PV system is assembled in Whitehorse Copper.
Electricity Generation	Panasonic HIT 330W n-type silicon modules produce electricity at 20% efficiency. Net electricity production: 5.2 GWh_e/yr
End of life	Lifetime: 30 years

3.3.7 System Description: Pumped Storage

The Tutshi-Moon pumped storage project with a capacity of 20.2MW and 54 GWh energy storage is located between Tutshi and Moon Lakes in BC (110 km from Whitehorse and 18 km south of the BC-Yukon border) [8]. This is a greenfield site with the proposed inundation area of 352.4 ha. The site is 2.6 km away from the transmission line.

The system boundary is presented in Figure 8 with a description following in Table 8.

[7] Solvest Inc. Solar Site Inventory. Draft report for RFP #2015-058.
[8] Knight Piésold Ltd. (2016). Based on data from Yukon Energy Corporation Pumped-Storage Assessment, Preliminary Assessment. April 14, 2016.

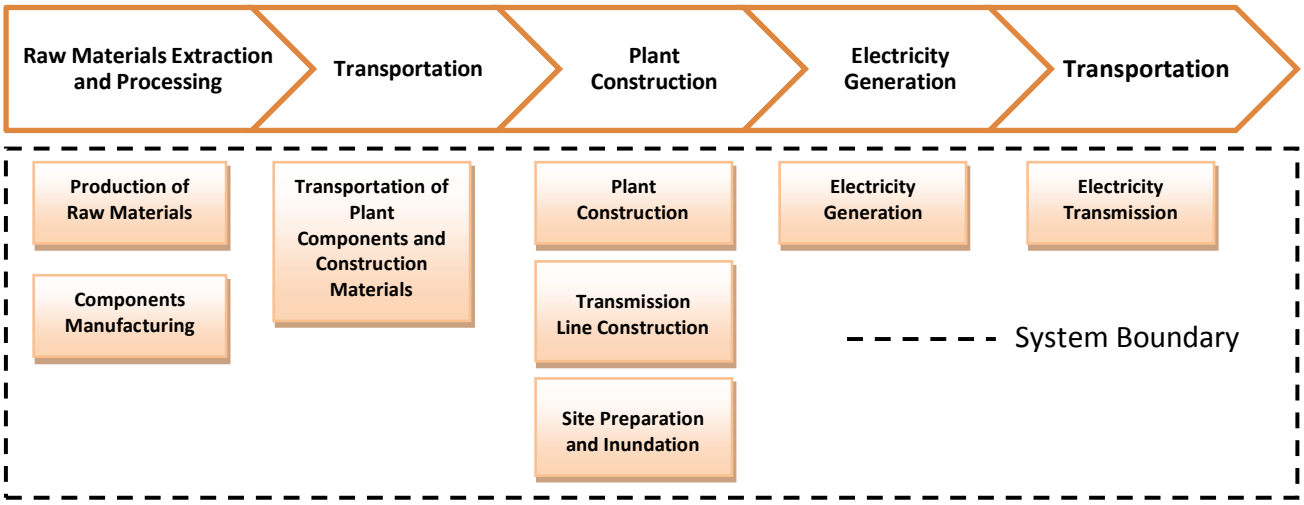


Figure 8. System Boundary of Pumped Storage Electricity Generation

Table 8. Description of Pumped Storage Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	Raw materials for plant construction (i.e. concrete, steel, etc.) are extracted and processed.
Components Manufacturing and Transportation	Plant components are manufactured and transported 2,400km by truck. Equipment manufacturing (motor-generator, transformer, pump-turbine, pressure pipes, etc.) is included in the system boundaries.
Plant Construction	This stage includes construction and installation of the plant and transmission line construction. The main components of the plant are: diversion, dam, spillway, reservoir, intake penstock, substation, and powerhouse with equipment[9]. The concrete dam construction is modelled. The site specifications are as follows: • Upper Reservoir Area (ha): 610 • Lower Reservoir Area (ha): 5600 • Penstock Length (km): 5.8 • 2m wide and 300m long gated concrete spillway • Inundation area is 352.4 ha • Greenfield site
Electricity Generation	Power house (contains a turbine and generator unit, most likely a vertical axis Pelton turbine), located at Tutshi Lake. Net electricity production: 54 GWh/yr
Electricity Transmission	Once electricity is produced, it moves to 2.6 km transmission line (138 kV).
End of life	The lifetime of the plant is 65 years.

[9] Midgard Consulting Inc. (2015). Moon Lake – Pumped Storage, Conceptual Study Report. December 14, 2015.

3.3.8 System Description: Small Hydroelectricity Plant

The Drury Lake project is a small hydro with storage power station with an installed capacity of 8.1 MW[10]. The proposed station location is on Drury Creek between Drury Lake and Little Salmon Lake, in the Yukon River watershed. The site is approximately 170 km north of Whitehorse and is situated within 1 km of the Robert Campbell Highway and the existing Yukon Integrated Grid transmission line.

The system boundary is presented in Figure 9 with a description following in Table 9.

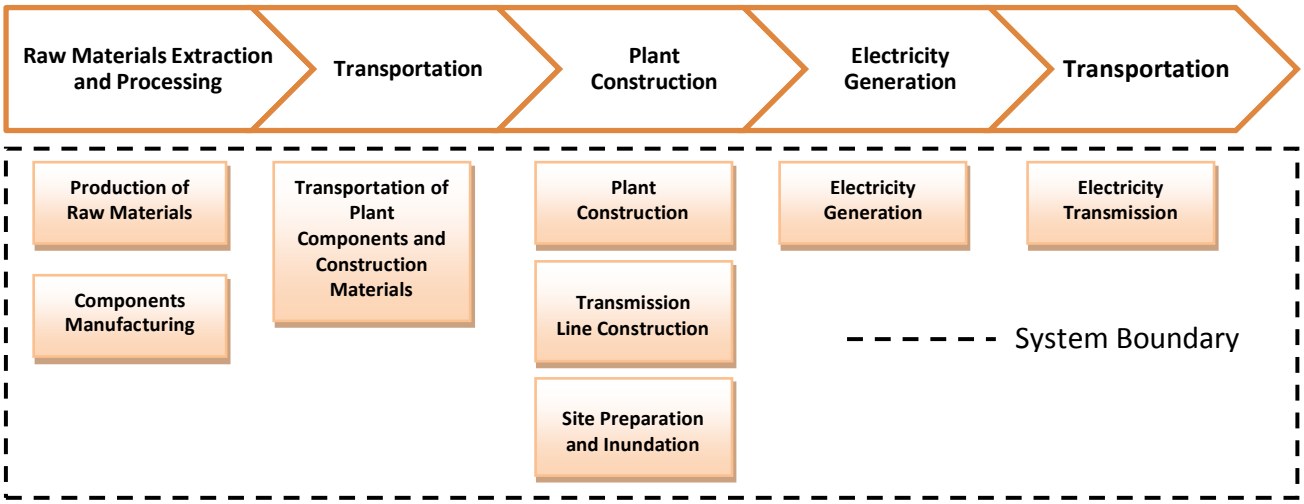


Figure 9. System Boundary of Pumped Storage Electricity Generation

Table 9. Description of Small Hydroelectricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	Raw materials for plant construction (i.e. concrete, steel, etc.) are extracted and processed.
Components Manufacturing and Transportation	Plant components are manufactured and transported 2,400km by truck. Equipment manufacturing is included in the system boundaries.
Plant Construction	This stage includes construction and installation of the plant and transmission line. Plant specification: • 5km of access roads. • Concrete Faced Rockfill Dam (CFRD) or earthfill control dam at the outlet of Drury Lake to provide 5m of storage (operating storage of 135 Mm^3). The concrete dam construction is modelled. The dam would be constructed with an Instream Flow Requirement (IFR) discharge system and a spillway to Drury Creek for flood water management. • Intake weir across Drury Creek, approximately 4 km downstream of the lake outlet. • 4.8 km penstock located on the south side of Drury Creek, comprising 3.6 km of low pressure pipe (LPP) and 1.2 km of high

[10] Knight Piésold Ltd. (2016). Based on data from Yukon Energy Corporation Small Hydroelectric Projects, Screening Assessment. April 22, 2016.

Life Cycle Activity	Description
	pressure pipe (HPP). • Powerhouse and substation at the edge of Drury Creek, upstream of the Robert Campbell Highway and the river mouth at Little Salmon Lake. • 0.5 km of 138 kV transmission line
Electricity Generation	Net electricity production: 31.7 GWh_e/yr
Electricity Transmission	Once electricity is produced, it moves to 0.5 km transmission line, to the existing grid (Yukon Integrated Grid).
End of life	The lifetime of the plant is 65 years.

3.3.9 System Description: Battery Storage

For this portion of the study, a lithium-ion battery was chosen for the analysis. The battery's capacity is 8 MW with 5 hours discharge time[11]. The energy storage system will be treated as a separate substation and the anticipated location is near the S164 Takhini 138 kV / 34.5 kV substation. The energy storage system will connect to the 34.5 kV system (not included in the current analysis). By connecting to the relatively low transmission line voltage of 34.5 kV, the need for a second step-up transformer is avoided.

The system boundary of the battery storage pathway is presented in Figure 10.

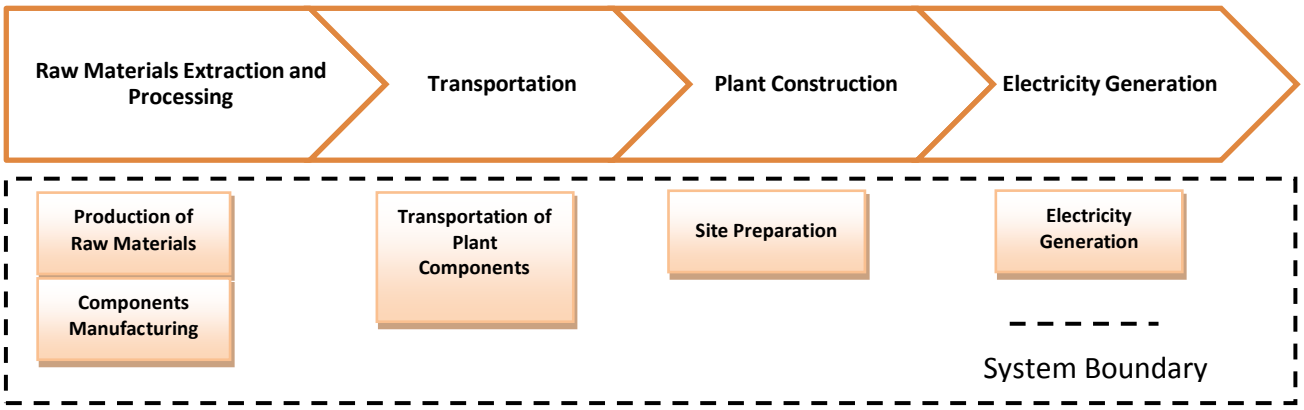


Figure 10. System Boundary of Battery Storage

Table 10. Description of Battery Storage by Life Cycle Stage

Life Cycle Activity	Description
Production of Raw Materials	Raw materials for battery manufacturing are extracted and processed.
Components Manufacturing and Transportation	Battery components are manufactured and transported to the plant location: California to Alaska by sea – 3,226 km Alaska to Whitehorse -1,133 km by truck, 22t payload

[11] TransGrid Solutions Inc. (2016). Evaluation of Energy Storage Technologies. April 18, 2016.

Life Cycle Activity	Description
Plant Construction	Equipment Two (2) PCS Modules packaged in two 40' trailers. Each module includes the following: • Two (2) 2 MW inverters with AC and DC circuit breakers; thermal management; control and protection • Two (2) 2000 kVA padmount transformers : 35 kV : 454 VAC • One (1) MUC (Multiple Unit Control) Greenfield/Brownfield The site preparation includes clearing of 4,200 m^2 (0.42 ha) area
Electricity Generation	Electricity is stored in the battery cell and released when needed. Annual energy storage: 2,780 MWh_e
End of life	Project lifetime: 20 years Battery lifetime: 10-15 years

3.3.10 System Description: Thermal Diesel Plant

The thermal diesel energy production pathway is based on previous LCA studies[12],[13]. The crude oil comes from Alaska North Slope and Alberta and is refined at Puget Sound refinery in Washington State, US. The crude oil is transported to the refinery via ocean freighter. The diesel fuel is transported from Puget Sound refinery to Skagway, Alaska via ocean freighter and from Skagway to Whitehorse via truck transport. A Caterpillar diesel engine (CAT Continuous 3300 generator) with electrical efficiency of 41.6% is used to generate electricity at the plant. The proposed diesel plant will be based at Takhini Substation outside of Whitehorse. The plant capacity is $5MW_e$ and annual net electricity production is 39.42 GWh/yr.

The system boundary is presented in Figure 11 with a description following in Table 11.

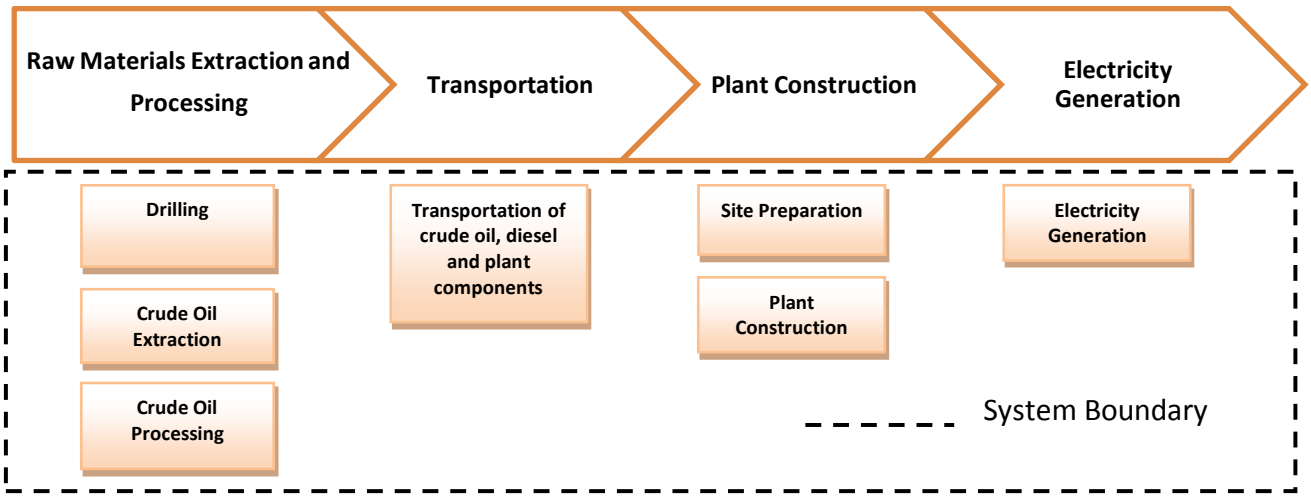


Figure 11. System Boundary of Diesel Electricity Generation

[12] Pembina. (2013). LNG for Yukon Energy Power Generation. A Life Cycle Emissions Inventory. The Pembina Institute. July 2013.
[13] (S&T)^2 Consultants Inc. (2014). Amended Lifecycle Analysis of Diesel and LNG Power Production. March 17, 2014.

Table 11. Description of Diesel Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Extraction of Raw Materials	Crude oil is extracted from Alaska's North Slope and Alberta and transported to Puget Sound refinery via ocean vessel.
Processing and Transportation	Crude oil is refined into diesel fuel and other refined petroleum products. Diesel fuel is transported from Puget Sound refinery to Skagway, AK via ocean barge and from Skagway to Whitehorse via truck transport.
Electricity Generation	Diesel is combusted for power in a CAT Continuous 3300 generator operating at 41.6% efficiency. Net electricity production: 39.42 GWh/yr
Plant Construction	Greenfield/Brownfield Includes 4.5-5.5 ha of land clearing.
End of life	Lifetime: 20 years

3.3.11 System Description: Thermal LNG Plant

Three LCA studies on thermal LNG pathway have been conducted in the period from 2013 to 2014. These are ICF Marbek, 2013[14], Pembina, 2013[12] and (S&T)[2] Consultants Inc., 2014[13]. An analysis of the studies with the focus on upstream emissions from LNG is given in Appendix A.11. The uncertainty of methane emissions estimates is discussed in section 3.4.1.

The LNG comes from the Fortis BC LNG facility at Tillbury Island in Delta, BC. Tillbury has been in operation since 1971 and can liquefy 120,000 cubic meters (4,500 GJ) of natural gas per day. The facility uses electricity to drive the liquefaction process. The energy requirement is 0.5 kWh/kg of LNG (0.039 joules of power per joule of LNG). The LNG is transported from Tillbury to Whitehorse via truck transport. The proposed thermal LNG plant will be based at Takhini Substation outside of Whitehorse. The plant capacity is $5MW_e$ and annual net electricity production is 39.42 GWh/yr. The system boundary is presented in Figure 12 with a description following in Table 12.

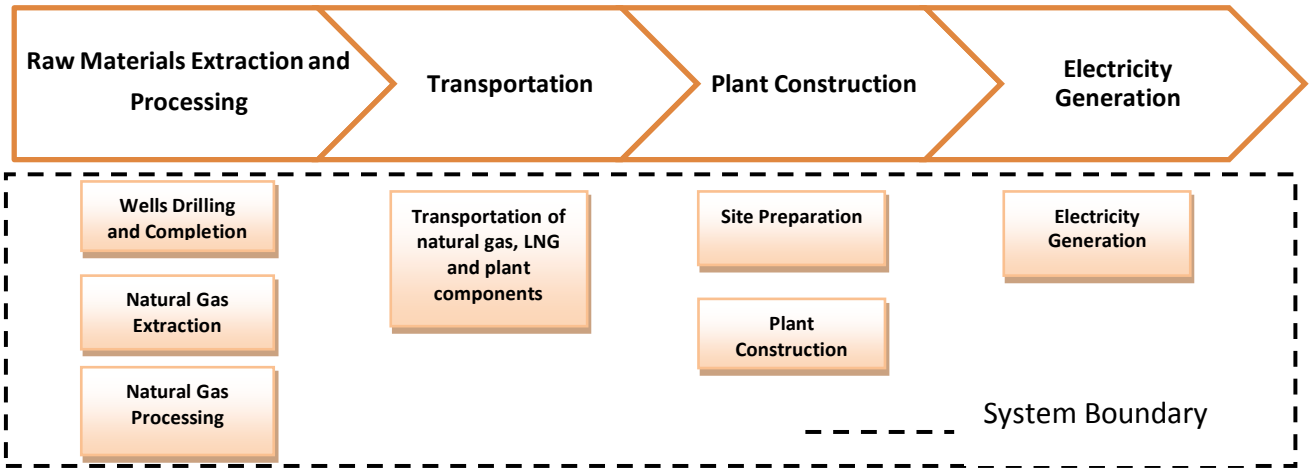


Figure 12. System Boundary of LNG Electricity Generation

[14] ICF Marbek (2013). Yukon Power Plant Fuel Life Cycle Analysis. Final Report. July 2, 2013.

Table 12. Description of Diesel Electricity Generation by Life Cycle Stage

Life Cycle Activity	Description
Extraction of Raw Materials	Natural gas comes from conventional gas fields predominantly in Northeast BC (some NW Alberta natural gas) and delivered to the Fortis BC Tillbury facility from Spectra at Huntington Gate by pipeline.
Processing and Transportation	LNG is treated to remove impurities and liquefied. LNG is transported 5,440 km round trip by truck.
Electricity Generation	LNG is vapourized and combusted to produce power in a Jenbacher generator operating at 46.3% efficiency (47% @ 90% load). Net electricity production: 39.42 GWh/yr
Plant Construction	Greenfield/Brownfield Includes 6.5 ha of land clearing
End of life	Lifetime: 20 years

3.3.12 System Description: New Transmission Line (Whitehorse-Skagway)

A new electric 230kV transmission line, 170 km in length, will be constructed from Whitehorse Generating Station to Skagway. The electricity will be generated at Whitehorse Rapids Generating Station (WRGS) and delivered to the Town of Skagway, Alaska or in the winter generated in Skagway and delivered to Whitehorse. From the WRGS, the corridor follows Highway 1 southeast for 17 km to Carcross Cutoff (the junction of Highways 1 and 2). From Carcross Cutoff, the corridor follows Highway 2 southward, through the town of Carcross for 77 km, to the BC-Yukon border. Once in BC, the corridor continues along Highway 2 for an additional 56 km to the BC-Alaska border. In Alaska, the corridor continues along the same highway (now named Highway 98) for an additional 21 km to Skagway, Alaska. Sixty-eight km of 15m wide 34.5 kV distribution line from Whitehorse to Carcross[15] is included in the analysis.

The full life cycle of Whitehorse-Skagway transmission line is considered. The system boundary is presented in Figure 13.

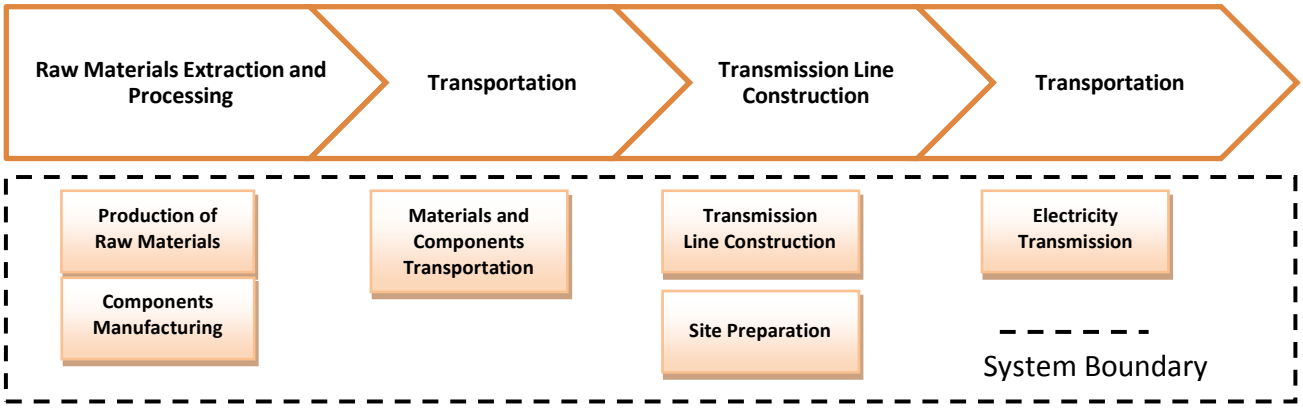


Figure 13. System Boundary of Whitehorse-Skagway Transmission Line

[15] Midgard Consulting Inc. (2016). Yukon Energy Corporation Transmission Options Evaluation. June 2, 2016.

Table 13. Description of Whitehorse-Skagway Transmission Line by Life Cycle Stage

Life Cycle Activity	Description
Production of Raw Material	Raw materials for transmission line construction (i.e. concrete, wood, copper, etc.) are extracted and processed.
Components Manufacturing and Transportation	Transmission line components are manufactured and transported 2,400 km by truck, 22t payload.
Transmission Line Construction	This stage includes site clearing and installation of the transmission line (poles, transmission towers, etc.). Transfer Capacity: 443 MW, 230 kV transmission line Transmission Conductor: Hawk 477 MCM 102 km line, 30m wide right of way clearing and 68 km of an existing 34.5kv line (306 ha plus 102 ha of cleared area footprint)
Electricity Transmission	3880.7 GWh/yr (100% reliable capacity) Transmission Voltage: 230 kV
End of life	Lifetime: 55 years

3.3.13 System Description: Gladstone Diversion Project

The Gladstone Diversion project has been used as a proxy for a potential diversion project. The project will give some additional storage to an existing generating Station. A dam and channels will be constructed on the Gladstone Lake across the divide between the Gladstone Creek and Isaac Creek watershed. This will increase the diverted drainage basin area. The project will utilize capacity of existing hydro units.

The system boundary is presented in Figure 14 with a description following in Table 13.

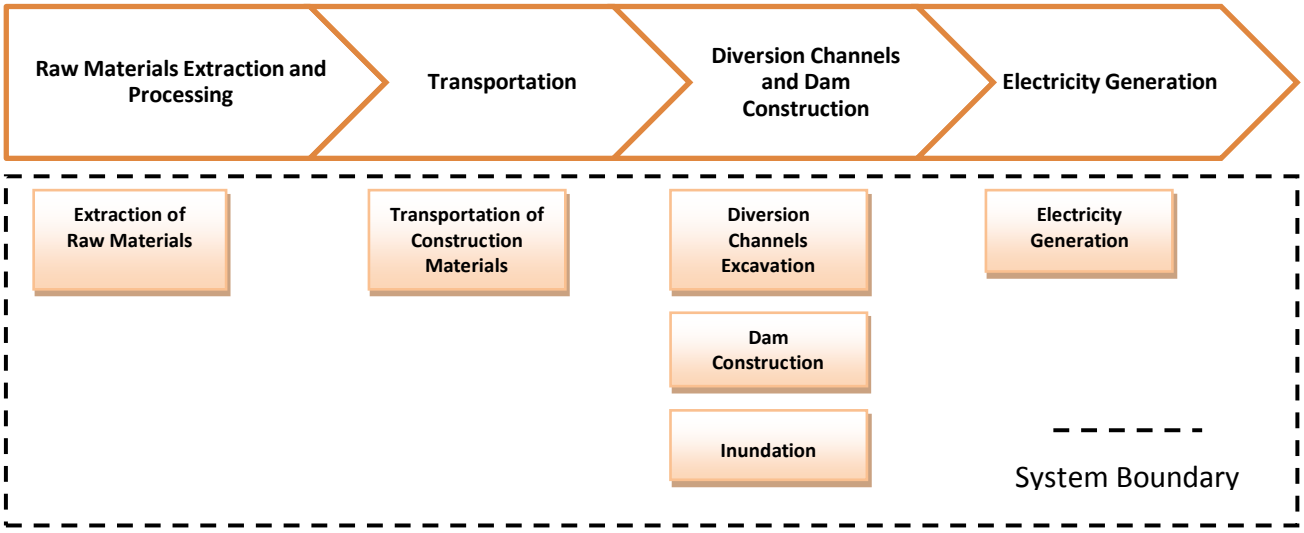


Figure 14. System Boundary of the Gladstone Diversion Project

Table 14. Description of Water Diversion Project by Life Cycle Stage

Life Cycle Activity	Description
Raw Materials Extraction and Processing	Raw materials (gravel, sand) for dam construction are sourced locally
Transportation	Transport distance: 15 km by truck, 22 t payload
Diversion Channels and Dam Construction	Partial greenfield site with inundation area of 220 ha This stage includes diversion channels excavation and dam construction.
Electricity Generation	Net electricity production: 29.7 GWh_e/yr - the project would utilize existing hydro units.
End of life	The lifetime of the project is 24 years. 65 years lifetime is modelled to compare results to other hydro power scenarios.

3.4 DATA QUALITY, DATA SOURCES AND ASSUMPTIONS

Data quality requirements specify the characteristics of the data needed for the study. Description of data quality, sources and assumptions is important to understand the reliability of the study results and properly interpret the outcome of the study[16].

Several different methods of data collection were available, such as personal interaction, previous LCA studies and technical reports prepared for Yukon Energy, and both peer-reviewed and un-reviewed published literature.

The majority of the data used in this project is specific to Yukon and Western Canada. In the absence of the Western Canadian data, information was drawn from other Canadian sources, followed by North American and European sources and, finally, from pre-existing life cycle databases, most notably the Ecoinvent library and GaBi database. The Ecoinvent library is a European database considered to be the most comprehensive and up-to-date inventory currently available[17]. Canadian data was directly substituted into the Ecoinvent library where possible, and the default European data remained when Canadian data was unavailable.

More information on life cycle inventory data, assumptions and data sources can be found in Appendix A: Life Cycle Inventory Supporting Information.

3.4.1 UNCERTAINTY

The quality and reliability of LCA results depend on the quality of data used in the inventory analysis. It is therefore important to identify sources of uncertainty in the inventory data and understand how they affect the results of the study.

Materials and equipment manufacturing locations

The study evaluates potential energy resource options available to Yukon Energy. The studied scenarios are based on the results of feasibility studies conducted for each resource option. A specific

[16] ISO - International Organization for Standardization (2006) 14040. (2006). Environmental Management - Life cycle assessment - Principles and Framework.
[17] Ecoinvent Centre. (2009). Swiss Centre for Life Cycle Inventories Website. http://www.ecoinvent.ch/.

technology or manufacturer is not always identified in the feasibility study. Thus, several assumptions were made and a sensitivity analysis was conducted on selected parameters, such as technology choice (e.g. battery storage pathway) and plant components manufacturing location (e.g. wind pathway).

The manufacturing locations of power plant components are also unknown. It is therefore assumed that most of the materials (e.g. steel, concrete, iron) and plant components are produced in Canada and transported 2,400km by truck to the power plant location.

Power plant construction data

Moreover, site specific data such as plant construction data (e.g. area of land to be cleared, type of dam, excavation area, quantities of construction materials) is available only for some of the pathways.

The power plant construction data in the waste to energy pathways originates from Spath and Mann[18] and is representative of a North American power plant. Small hydro and pumped storage power plant construction data is based on Flury and Frischknecht, 2012[19] and represents a mix of North American and European small hydro and pumped storage power plants. The data is obtained per MWh of energy produced; if the emissions data expressed per MWh is converted back to the total GHG emissions from plant construction using the total energy output of the plant over plant's lifetime, it increases the uncertainty of the results. Site specific data need to be obtained to better understand GHG emissions from power plants construction. It is recommended to update this data when site specific data become available.

Diesel and LNG combustion data

GHG emissions from diesel and LNG combustion are estimated based on emissions factors, not specific operating data, which was not available at the time of the study. The emissions factors are derived from GHGenius 4.03 that are based on the US EPA non-road model for large diesel and natural gas engines. The Jenbacher natural gas engine has up to 2.5% of the methane in the exhaust emissions, while the EPA non-road emission model uses a methane emissions factor of approximately 2.8%[13]. A sensitivity analysis is performed to better understand an effect of different emissions factors on the results.

Upstream emissions in LNG pathway

The accuracy of methane emissions from natural gas extraction, processing, transportation, and storage is an area of concern. Significant differences exist among data reported by industry. The application of correct emissions factors in order to estimate methane emissions is therefore challenging. The 2006 IPCC Guidelines suggests a range of +/-100% uncertainty when applying their values to estimate natural gas methane emissions.

Many emissions in the oil and gas industry are unintentional and do not necessarily correlate with default emissions factors; rather, they are dependent on the operation and condition of the specific equipment itself. The method in which data are collected, various modelling techniques, and the location where the data are collected contribute to the variability. When emissions factors are

[18] Spath, P.L. and Mann, M. K. (1997). Life Cycle Assessment of a biomass Gasification Combined-Cycle System. NREL. December 1997.
[19] Flury, K. and Frischknecht, R. (2012). Life Cycle Inventories of Hydroelectric Power Generation. ESU- Services. Commissioned by Öko-Institute e.V.

unavailable, studies and assessments are forced to use generic emissions factors, regardless of the range of uncertainty. Therefore, understanding the inherent uncertainty is key to applying emissions factors in life cycle assessments. This report used the Canadian data from CAPP, 2004[20] and GHGenius v4.03. A detailed discussion and an overview of the latest research on the LNG upstream emissions are given in section A.11 of the report.

3.5 LIFE CYCLE ASSESSMENT METHODOLOGY

Life cycle assessment (LCA) is a method for examining the environmental effects of a product or process across its lifespan. It is a "cradle-to-grave" analysis in which complex systems are broken down into elementary flows. The flows are then grouped and categorized based on the effects they have on the environment.

This LCA study follows the general principles set forth by the International Organization for Standardization (ISO) in ISO 14040[15] and ISO 14044[21] for conducting and reporting LCA studies and examines GHG emissions only. The ISO 14040 LCA framework consists of four steps (Figure 15):

1. Definition of goal and scope;
2. Inventory analysis;
3. Impact assessment; and
4. Interpretation of results.

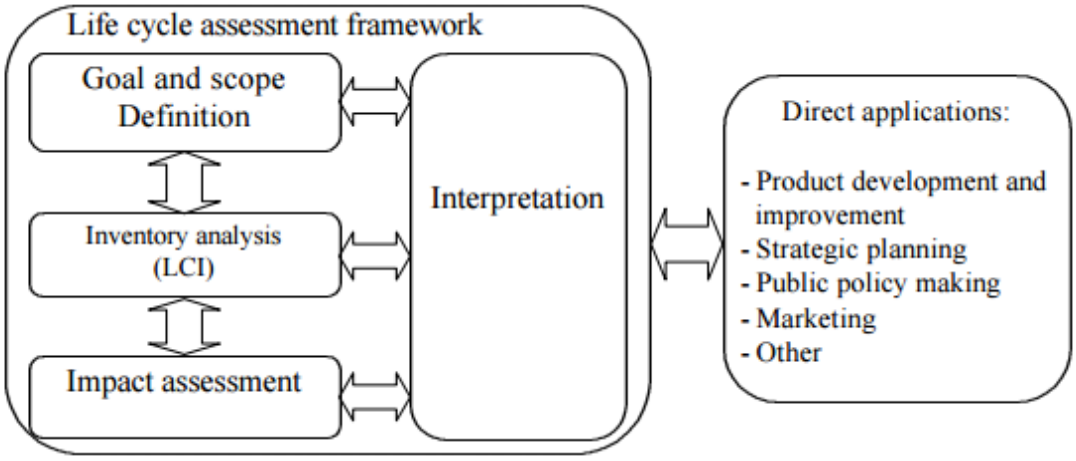


Figure 15. LCA phases

[20] CAPP. (2004). A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H_2S) Emissions by the Upstream Oil and Gas Industry.

[21] ISO - International Organization for Standardization 14044. (2006). Environmental Management – Life Cycle Assessment - Requirement and Guidelines.

3.5.1 Life Cycle Inventory and Life Cycle Impact Assessment Analyses

The second phase of the LCA is life cycle inventory analysis where the energy use and raw material inputs and environmental releases associated with each stage of the life cycle are grouped and quantified.

In the life cycle impact assessment phase the Global Warming Potential (GWP) factors are applied to the life cycle inventory data to calculate the global warming impact of each energy resource pathway. The results are presented as carbon dioxide equivalents (CO_2e). The GWP factors (without feedback) based on the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) are used to quantify GHG emissions (Table 15).

Table 15. Greenhouse Gases

GHG	Life time[22]	GWP time horizon (IPPC AR5)	
		20 years	100 years
Carbon dioxide (CO_2)		1	1
Methane (CH_4)	12.4	84	28
Nitrous oxide (N_2O)	121	264	265
HFC-23	222	10,800	12,400
HFC-134a	13.4	3,710	1,300
CF_4 (PFC)	50,000	4,880	6,630
Sulphur hexafluoride (SF_6)	3,200	17,500	23,500
Nitrogen trifluoride (NF_3)	500	12,800	16,100

3.5.1.1 Methane Global Warming Potential over 20- and 100-year time horizon

This study recognizes the importance of short-term and long-term mitigation strategies for the release of GHG emissions. To fully understand the environmental impact of each energy source under analysis, both the 20-year and 100-year time horizon are applied. The analysis quantifies and evaluates the released emissions and their respective levels of radiative forcing relative to the CO_2 reference gas.

A GWP for a particular GHG is determined by the gas's ability to absorb certain types of radiation and the length of time the gas remains in the atmosphere.

GWP values are currently reported for time scales of 20 and 100 years by the IPCC. They are regularly updated as newer modelling techniques are developed and as GHG lifetimes and absorption efficiencies are revised[23]. The GWP values are relative to the reference gas CO_2, which has a GWP set to one, regardless of the time period it is reported for. GWPs quantify the amount of radiated energy that will be absorbed by one ton of gas, compared to one ton of CO_2. Hence, larger GWP values indicate a greater warming effect compared to CO_2 for the chosen time horizon under investigation.

[22] The lifetime of a greenhouse gas refers to the approximate amount of time for the atmospheric pollutant to return to its natural level as a result of either being converted to another chemical compound or being taken out of the atmosphere via a sink.

[23] Boucher, O., Friedlingstein, P. Collins, B., and Shine, K.P. (2009). The indirect global warming potential and global temperature change potential due to methane oxidation. *Environ. Res. Lett*. 4, 044007.

LCA standard practice is to use GWPs with a predetermined time horizon regardless of when the emissions occurred[24]. However, the lack of available information on the application of different GWP time scales in LCAs increases the level of uncertainty in the calculated emissions[25]. For example, LCA studies have not focused on the use of different time horizons despite it being a well known factor in the analysis of biofuels, which contribute to methane emissions[26,27]. As well, the choice of timeframe in which to analyze the GHG is somewhat arbitrary. In a 2009 study, data showed that the most optimum GWP time horizon to correlate methane emissions with equivalent CO_2 emissions using to historical temperature data was 44 years[28]. Interestingly, the data could not provide any particular time horizon where N_2O emissions accurately corresponded with historical data. As well, GWP values are weighted equally across the entire time period regardless of any change in their absorption efficiency during that time period[29]. Therefore, analysis with multiple time horizons can provide additional insight into the short and long term environmental effects caused by various GHGs.

The choice of time scale used to report GWP values can significantly affect the actual GWP value due to the varying atmospheric lifespan of each greenhouse gas. The most widely accepted time scale is 100 years, which adequately represents most GHGs due to their significantly long lifetime (Table 14 – GWP for 20 and 100 years). That is, the reported GWP value does not change considerably for the different time scales. It is the most commonly used metric for comparing GHGs and was used under the Kyoto Protocol[30].

Greenhouse gases with shorter lifetimes that are in the order of decades rather than centuries or millennia can have a GWP value that increases by a factor of three for the 20 year time horizon versus the 100 year time horizon. Specifically, methane (CH_4) emissions typically last approximately one decade before being oxidized into CO_2. Additionally, methane's higher energy absorption is significantly greater than CO_2. Over 100 years, it is 28 more times effective at trapping heat compared to CO_2, but over 20 years, it is 84 times more potent at retaining heat. The impact of methane's shorter lifetime and greater ability to trap energy is revealed in its GWP value. Comparatively, CF_4, which has a 50,000 year lifetime, has a lower 20-year GWP value than the 100-year value. Therefore, examining global warming potential effects over shorter timeframes will be included in order to address the immediate effects of methane on global temperatures.

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[24] Peters, G.P., Aamaas, B., Lund, M.T., Solli, C., and Fuglestvedt, J. S. (2011). Alternative "Global Warming" Metrics in Life Cycle Assessment: A Case Study with Existing Transportation Data. *Environ Sci Technol*. 45, 8633-8641.

[25] Levasseur, A., Lesage, P., Margni, M., Deschenes, L., and Samson, R. (2010). Considering time in LCA: Dynamic LCA and its application to global warming assessments. *Environ. Sci. Techno*l. 44: 3169-3174.

[26] Kendall, A., Chang, B., and Sharpe, B. (2009). Accounting for Time-Dependent Effects in Biofuel Life Cycle Greenhouse Gas Emissions Calculations. *Environ. Sci. Technol*. 43: 7142–7147.

[27] Cherubini, F., Peters, G. P., Berntsen, T., Strømman, A. H., and Hertwich, E. (2011). CO_2 emissions from biomass combustion for bioenergy: Atmospheric decay and contribution to global warming. *GCB Bioenergy*. 3: 413–426.

[28] Tanaka, K., O'Neill, B.C., Rokityanski, D., Obersteiner, M., and Tol, R.S.J. (2009). Evaluating global warming potentials with historical temperatures. *Climatic Change*. 96:443-466.

[29] Shoemaker, J., and Schrag, D. (2013). The danger of overvaluing methane's influence on future climate change. *Climatic Change*. 120:903-94.

[30] Reisinger, A., Meinshausen, M., Manning, M., and Bodeker, G. (2010). Uncertainties of global warming metrics: CO_2 and CH_4, *Geophys Res Lett.* 37, L14707.

In this study, the application of the 20 year time horizon for GWP values, in addition to the 100 year time horizon, prioritizes gases with shorter lifetimes rather than focusing on longer-term impacts from GHGs[31]. Carbon dioxide, and many other GHGs, remains in the atmosphere longer than methane by factors greater than 100. The rationale for addressing short term GHG impacts, such as methane emissions, is that it allows additional time to implement more effective means to regulate and reduce CO_2 emissions that ultimately have longer term effects and are necessary for overall climate stabilization. Given that methane is the second most prominent human-induced GHG present in the atmosphere with a short lifespan, a decrease in current CH_4 emissions will reduce anthropogenic-induced warming relatively quickly as the results can be seen in the subsequent few decades, whereas the effects of reduced CO_2 emissions will not be seen for centuries[32,33]. Due to its short lifespan, methane has become an appealing objective for climate mitigation strategies.

The hypothesis that a reduction in methane concentrations will have a significant positive impact on the overall atmospheric burden is supported by the 20 year time horizon in LCA studies. It is suggested that the immediate benefit of reducing short lived GHGs will help avoid the 2^0C increase in the temperature threshold, or the so-called "tipping point" in climate change[34,35]. Moreover, recent studies have shown that the GWP for methane increases substantially for the 20 year time horizon when interactions with aerosols are considered in the calculations[36,37]. A 2015 study on the LCA of biofuels revealed that the choice of GWP timeframe by which to analyze the carbon footprint should be carefully considered, rather than simply choosing the standard 100 year time horizon[38]. The analysis showed that the methane emitted through biogas use had a greater carbon footprint for the 20 year timeframe compared to the 100 year time horizon.

This study recognizes the importance of short-term and long-term mitigation strategies for the release of GHG emissions. To fully understand the environmental impact of each energy source under analysis,

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[31] Forster, P., Ramaswamy, V., Artaxo, P., Berntsen, T, Betts, R, Fahey, D.W., Haywood, J., Lean, J., Lowe, D.C., Myhre, G., Nganga, J., Prinn, R., Raga, G., Schulz, M., and Dorland, R.V. (2007). Changes in atmospheric constituents and in radiative forcing. paper presented at the climate change 2007: the physical science-basis. Contribution of Working Group 1 to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

[32] Intergovernmental Panel on Climate Change (IPCC) (2007). Climate Change 2007: The Physical Science Basis, edited by S.Solomon et al., Cambridge Univ. Press, Cambridge, U.K.

[33] Intergovernmental Panel on Climate Change (IPCC) (2009), Meeting Report of the Expert Meeting on the Science of Alternative Metrics, 75 pp., IPCC WGI Tech. Support Unit, Bern.

[34] Shindell, D, Kuylenstierna, J.C.I., Vignati, E., van Dingenen, R., Amann, M., Klimont, Z., Anenberg, S.C., Muller, N., Janssens-Maenhout, G., Raes, F., Schwartz, J., Faluvegi, G., Pozzoli, L., Kupiainen K., Hoglund-Isaksson, L., Emberson, L., Streets, D., Ramanathan, V., Hicks, K., Oanh, N.T.K., Milly, G.,Williams M, Demkine, V., and Fowler, D. (2012). Simultaneously mitigating near-term climate change and improving human health and food security. *Science.* 33:183–189.

[35] Howarth, R., Santoro, R., and Ingraffea, A. (2012). Venting and leaking of methane from shale gas development: response to Cathles et al. *Climatic Change*. 113:537–549.

[36] Shindell, D.T., Faluvegi, G., Koch, D.M., Schmidt, G.A., Unger, N., and Bauer, S.E. (2009). Improved attribution of climate forcing to emissions. *Science* 326(5953):716–718.

[37] Howarth RW, Santoro R, Ingraffea A (2011). Methane and the greenhouse-gas footprint of natural gas from shale formations. *Climatic Change*. 106:679–690.

[38] Pfister, S. and Scherer, L. (2015). Uncertainty analysis of the environmental sustainability of biofuels. Energy, *Sustainability and Society*. 5:30.

both the 20-year and 100-year time horizon are applied. This information is critical to stakeholders in order to make an informed decision as they prepare for future energy scenarios.

3.5.2 RESULTS INTERPRETATION

In the final stage of the LCA, results of the impact assessment phase are interpreted and presented. Two major analyses in determining the validity of the results are conducted:

- Contribution analysis - a measure of the effect each process has on the complete environmental profile of the life cycle. The processes that make up the largest portions of the total impact assessment are then subjected to rigorous data quality checks and sensitivity analyses, and
- Sensitivity analysis - determines the effect of changing parameters and assumptions on the final results. It is essential to determine whether the final results are resistant to small changes through the life cycle.

4 GREENHOUSE GAS EMISSIONS ASSESSMENT RESULTS

4.1 LIFE CYCLE INVENTORY

Life cycle inventory models have been developed to quantify and compare GHG emissions for the 13 scenarios under study. Detailed descriptions of the life cycle inventory data used in this study are presented in Appendix A: Life Cycle Inventory Supporting Information.

4.2 RESULTS

The results are presented per MWh of energy delivered, including the transmission line results that are converted to MWh by multiplying the results in kg CO_2e/MWh-km by the transmission line length of 170km. The contribution analysis results are grouped into three categories:

1. Materials and Fuel Acquisition, Production and Construction
2. Transport of Materials and Fuel, and
3. Operation.

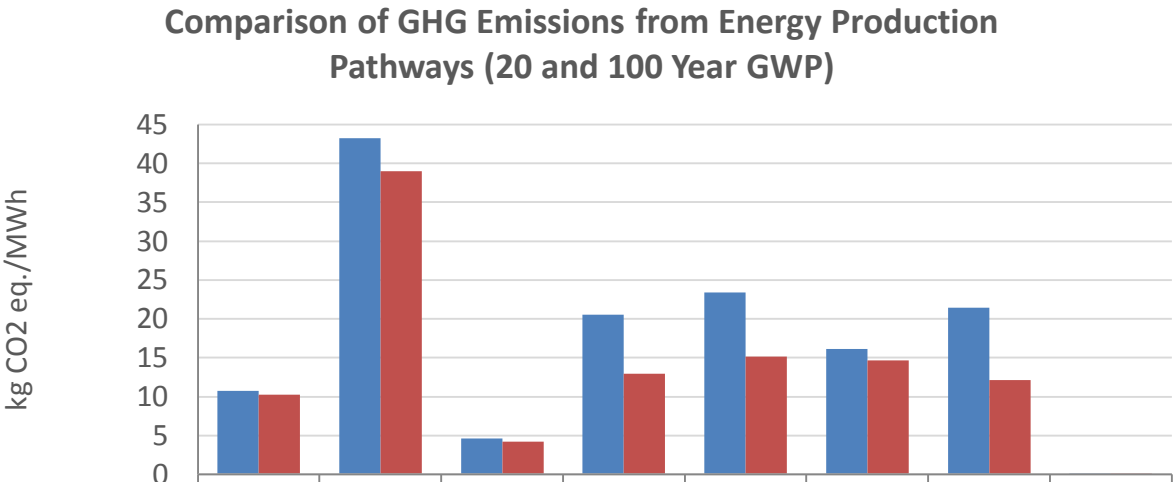
Materials and fuel acquisition, production and construction include raw materials for plant construction acquisition, processing, components manufacturing, site preparation, and plant and transmission line construction. In the diesel pathway, crude oil extraction (includes leakage, vented and flared emissions), diesel production, crude oil and diesel storage, and power plant construction (extraction and processing of raw materials, site preparation) are included in this stage.

Transport of materials and fuels include transportation of raw materials and components, as well as transportation of fuel such as biomass, MSW, diesel, and LNG.

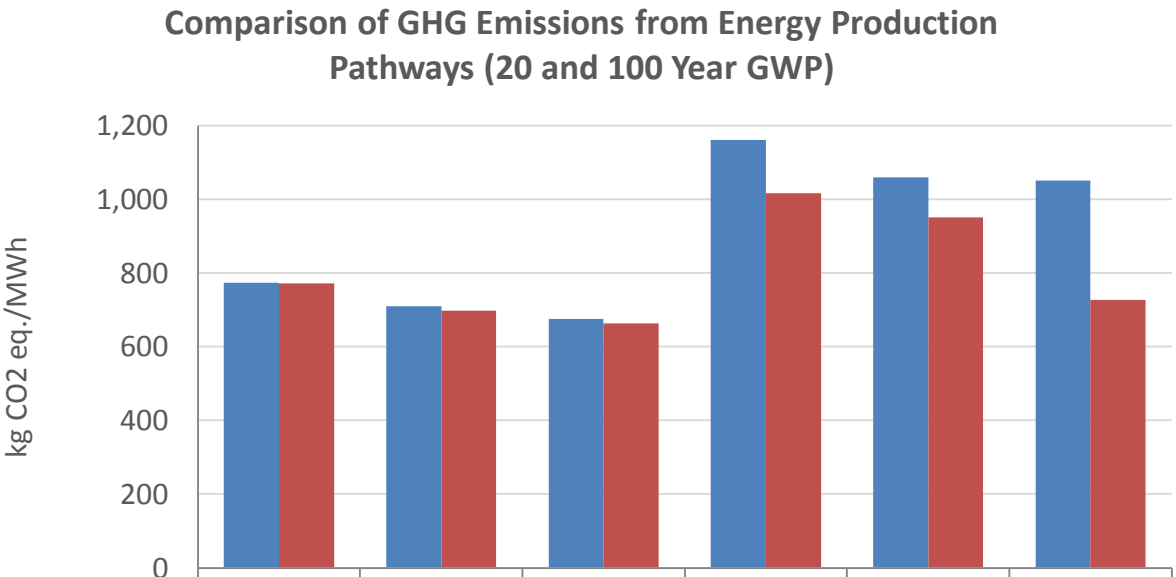
Operation category includes onsite fuel processing (e.g. biomass drying), fuel combustion, plant operations and maintenance, as well as yearly right of way clearing in the transmission line pathway. In the hydro pathways, emissions from land inundation are also included in the operation category.

A comparison of total GHG emissions (including biogenic CO_2) produced by all resource options under consideration for the 20 and 100 year GWP time horizons is presented in Figure 16. The resource options can be grouped into three categories of emitters: those producing GHGs just over 1,000 kg CO_2e/MWh, resources producing well over 600 kg CO_2e/MWh, and those that produce GHGs below 45 kg CO_2e/MWh. In the first category, the top three overall GHG emitters are biogas, diesel and LNG, where each pathway produces more than 1,000 kg CO_2e/MWh. However, it should be noted that biogas pathway has biogenic CO_2 emissions included in the operation stage. More information on accounting for biogenic CO_2 emissions can be found in the next section (4.2.3). Biomass gasification produces 772 kg CO_2e/MWh, and MSW and MSW with biomass combustion produce around 700 kg CO_2e/MWh. Both plants are combined heat and power plants that have higher efficiencies due to produced heat utilization. Last, the remaining resources (geothermal, wind, solar, battery storage, transmission line, small hydro, pumped storage and water diversion) produce approximately 43 kg CO_2e/MWh or less.

In most of the scenarios, except for the biogas, LNG and hydro options, the GHG emissions among the two time horizons are similar. The difference in GHG emissions for the biogas, LNG and hydro options for the 20 year and 100 year time horizons is due to the larger amounts of methane produced and the significantly larger difference between the two GWPs, as previously discussed.



	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
20 year GWP	10.74	43.24	4.62	20.56	23.41	16.15	21.43	0.17
100 year GWP	10.30	38.99	4.22	12.99	15.15	14.66	12.10	0.16



	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
20 year GWP	772.49	709.08	675.24	1161.71	1058.91	1050.76
100 year GWP	771.97	696.81	662.98	1015.88	951.11	727.68

Figure 16. Comparison of total GHG emissions (including biogenic CO_2) from energy production pathways (20 and 100 year GWP)

4.2.1 Comparison of GHG Emissions from Energy Production Pathways for 20 Year GWP

The contribution analysis results for the 20 year time horizon presented in Figure 17 reveal that wind, geothermal, transmission line, battery storage and solar energy options GHG emissions come primarily from materials acquisition, production and construction rather than operation of the plant. It is also seen that operation of the energy generating plant is by far the most significant in terms of GHG emissions in biogas, biomass gasification, waste to energy, diesel, and LNG pathways. The hydro power pathways' GHG emissions originate mainly from the operation life cycle stage due to land inundation. The CO_2 emissions from land inundation are considered biogenic and further discussed in section 4.2.3 of the report.

4.2.2 Comparison of GHG Emissions from Energy Production Pathways for 100 Year GWP

Figure 18 compares GHG emissions under the 100 year time horizon for all resource pathways. The trends are nearly identical to the results shown in Figure 17 for the emitted GHGs under the 20 year time horizon. Overall, total GHG emissions are lower when applying the 100 year GWP. This is expected due to the lower GWP for methane for the 100 year time horizon.

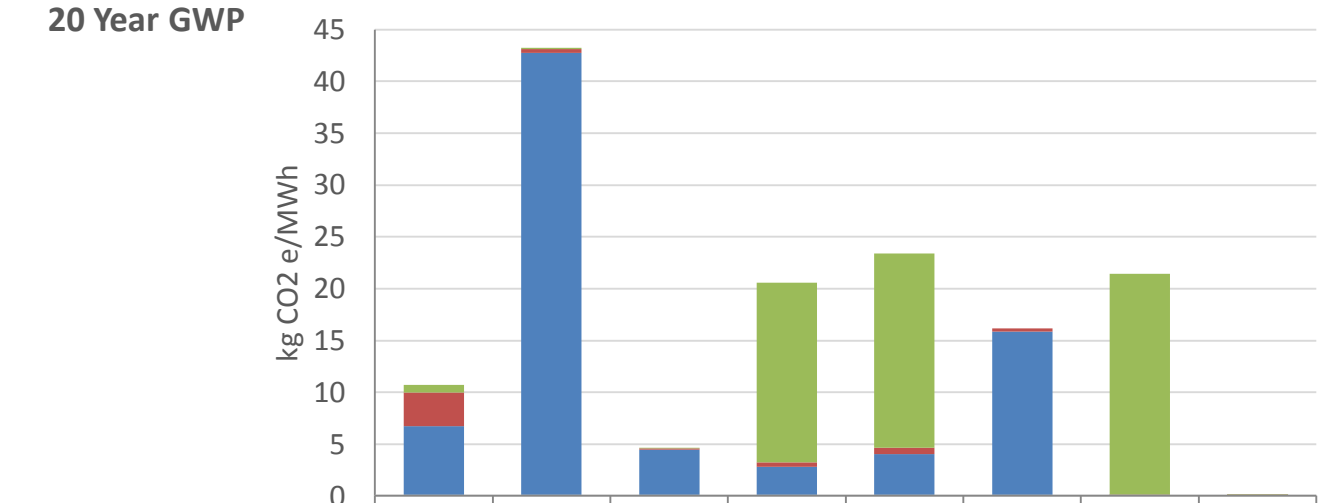
In the 100 year GWP scenario, there is only one energy resource option (biogas) that is greater than 1,000 kg CO_2e/MWh. After biogas, diesel and LNG were the next highest emitters, similar to the results using the 20 year GWP. However, while biogas, diesel and LNG were calculated to have less GHG emissions for the 100 year GWP, LNG emitted significantly less compared to the calculated value using the 20 year GWP. The remaining energy resource options produced approximately 40 kg CO_2e/MWh or lower, in a similar manner to the calculated GHG emissions under the 20 year time horizon.

4.2.3 Analysis of Biogenic CO_2 Emissions

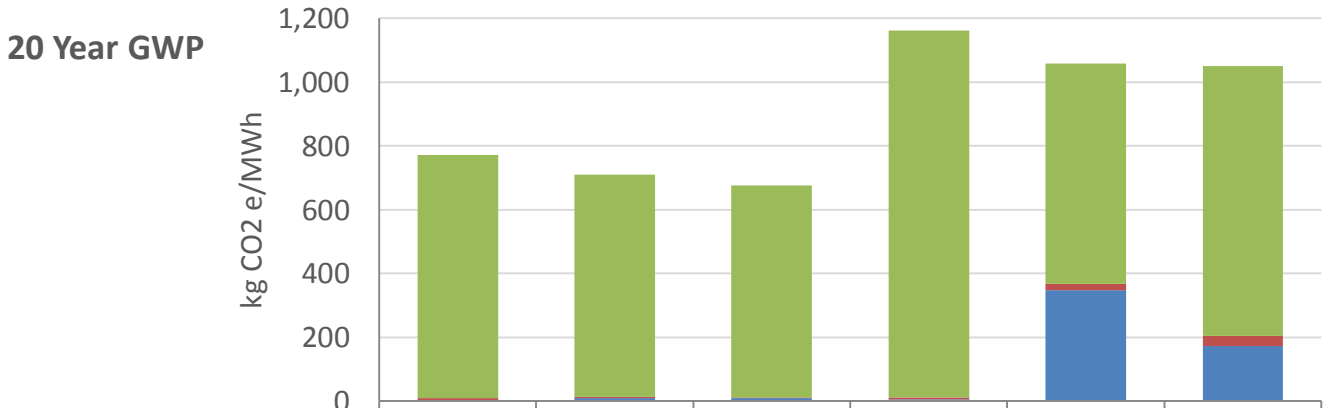
Biogenic CO_2 emissions are those that relate to either the natural carbon cycle or the use of biological material to produce energy, through processes such as combustion, fermentation, digestion and decomposition. Bioenergy is often assumed to be "carbon-neutral". This is due to photosynthesis sequestering CO_2 from the atmosphere in the biogenic material in a short timeframe[39]. However, according to the EPA Science Advisory Board's Biogenic Carbon Emissions Panel, biomass energy does not necessarily guarantee carbon neutrality[40]. In some cases, the production, processing and combustion of biomass can be done in a carbon neutral manner; however, it should not always be assumed that carbon neutrality will be the case unless a complete life cycle assessment of production and consumption cycle of the feedstock is performed.

[39] EPA. Office of Atmospheric Programs, Climate Change Division. (2011). Accouting Framework for Biogenic CO2 Emissions from Stationary Sources. https://www3.epa.gov/climatechange/Downloads/ghgemissions/Biogenic-CO2-Accounting-Framework-Report-Sept-2011.pdf

[40] Voegele, E. (2014). EPA releases updated biogenic emissions framework. http://biomassmagazine.com/articles/11234/epa-releases-updated-biogenic-emissions-framework

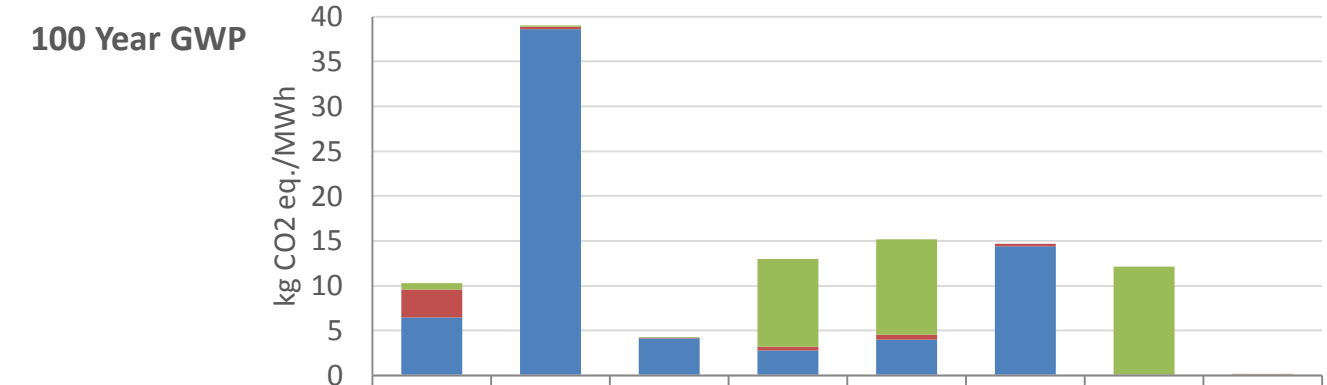


	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
Operation	0.74	0.13	0.02	17.31	18.77	0.00	21.30	0.0324
Transport of Materials & Fuel	3.29	0.35	0.10	0.44	0.61	0.30	0.0003	0.0027
Materials and Fuel Acquisition, Production and Construction	6.72	42.76	4.49	2.82	4.03	15.85	0.12	0.1355

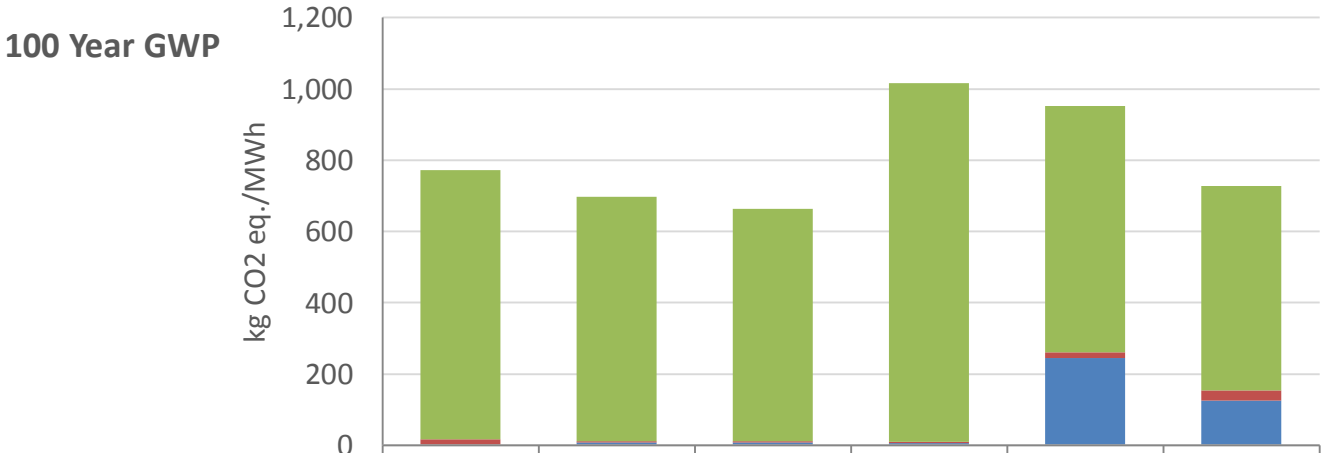


	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
Operation	763.30	696.52	663.01	1150.81	692.29	846.86
Transport of Materials & Fuel	7.34	4.08	3.74	4.93	18.22	31.44
Materials and Fuel Acquisition, Production and Construction	1.84	8.49	8.49	5.97	348.40	172.47

Figure 17. Contribution analysis of GHG emissions (including biogenic CO_2) from energy production pathways (20 year GWP)



	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
Operation	0.71	0.10	0.01	9.77	10.56	0.00	11.99	0.0304
Transport of Materials & Fuel	3.09	0.33	0.10	0.41	0.58	0.28	0.00	0.0027
Materials and Fuel Acquisition, Production and Construction	6.49	38.56	4.11	2.81	4.01	14.38	0.12	0.1251



	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
Operation	754.77	684.78	651.27	1005.41	690.43	574.23
Transport of Materials & Fuel	15.41	3.83	3.51	4.65	16.23	28.01
Materials and Fuel Acquisition, Production and Construction	1.79	8.20	8.20	5.83	244.45	125.45

Figure 18. Contribution analysis of GHG emissions (including biogenic CO_2) from energy production pathways (100 year GWP)

The recent study of using forest wood for energy in Massachusetts, US examined the carbon-neutrality and showed that using wood to produce energy results in an initial "carbon debt", because burning wood releases more CO_2 into the atmosphere per unit of energy than fossil fuels[41]. However, when forests grow back and recapture CO_2 from the atmosphere, the "carbon dividend" is realized. The length of time it takes to get carbon dividends depends on the type of biomass used to produce energy, the fossil fuel that biomass replaces, the bioenergy combustion technology and the forest management practices. For example, using forest biomass in district heating in Massachusetts can provide carbon dividends within 10 to 20 years.

The biomass feedstock used in this study consists of forest logging residues, dead trees, and sawmill residues. Since the waste material is used as biomass feedstock, one can argue in support of carbon neutrality of the studied pathways.

Biogenic CO_2 Originating from Studied Pathways

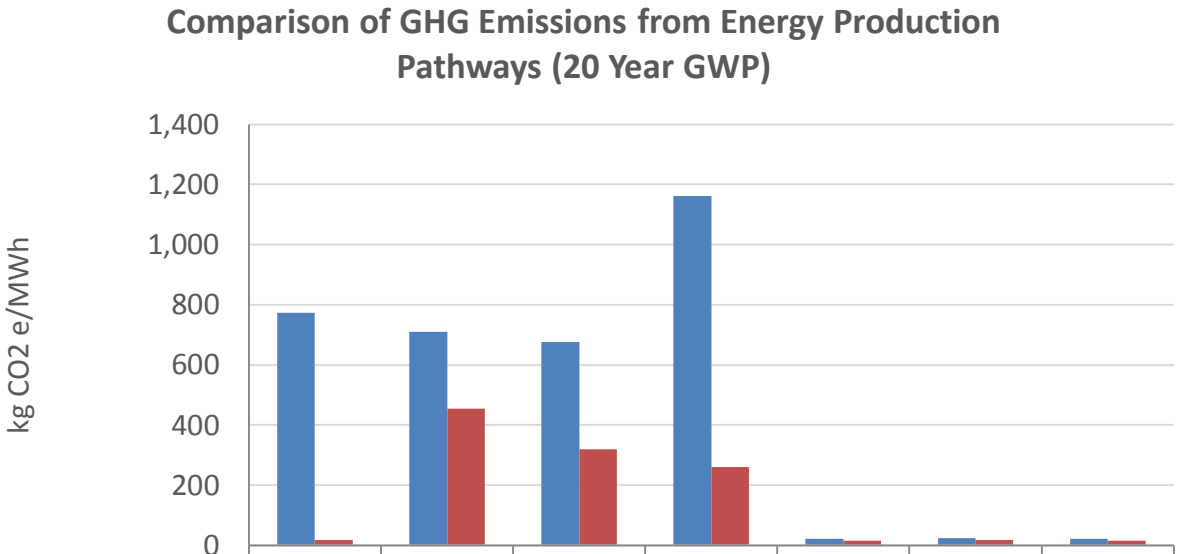
The biomass gasification, biogas, waste to energy (MSW and MSW & biomass combustion) and hydro (small hydro, pumped storage and water diversion) scenarios have biogenic emissions that originate from operations stage. A comparison of total GHG emissions with the results where biogenic CO_2 emissions are excluded is presented in Figure 19. The results that exclude biogenic CO_2 emissions are further presented in Figures 20 - 22.

Biogenic CO_2 emissions in the biogas and biomass gasification pathways originate from biogas combustion and biomass gasification life cycle stages, while fossil emissions come from raw materials acquisition, transportation and plant construction stages. If biogenic CO_2 emissions are excluded, it results in significantly lower life cycle emissions (260 and 114 kg CO_2e/MWh for biogas and 17.72 and 17.20 kg CO_2e/MWh for biomass gasification over the 20 and 100 year time horizons, respectively).

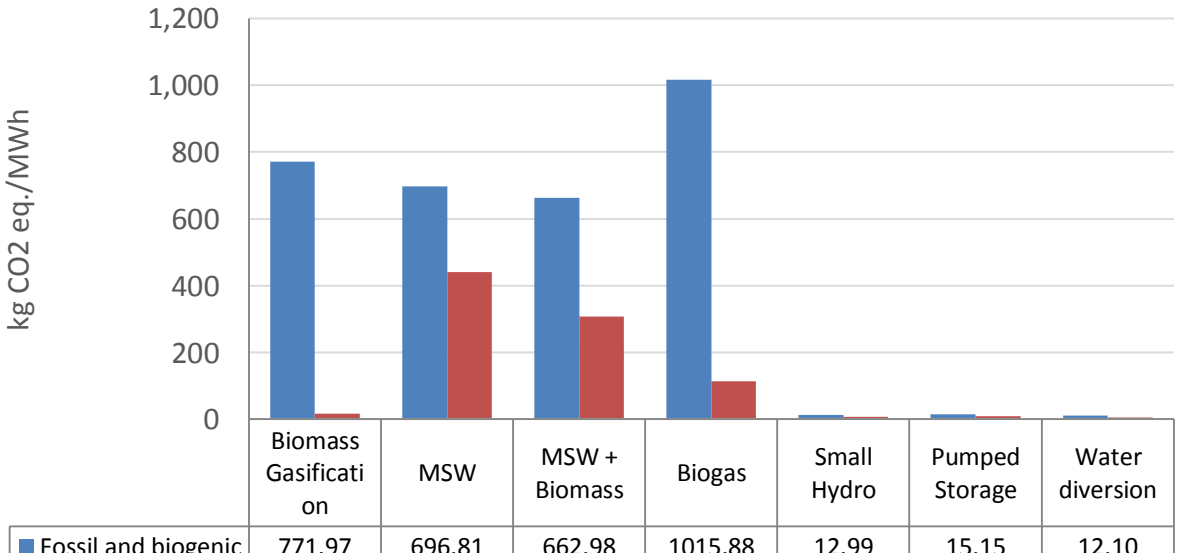
While GHG emissions from fossil sources are quite small in the biogas and biomass gasification scenarios, waste to energy pathways (MSW and MSW with biomass combustion) have notable fossil GHG emissions. This is due to higher quantities of waste in the MSW that contribute to fossil GHG emissions as well as fossil GHG emissions originating from plant construction and MSW collection. Paper, wood waste, and organics in the MSW are assumed to contribute to the biogenic CO_2 emissions. All other groups of waste contribute to fossil CO_2 emissions.

In the hydro pathways (pumped storage, small hydro, water diversion), after exclusion of biogenic CO_2 emissions that originate from biomass decomposition after land inundation, the GHG emissions are significantly lower, especially for the 100 year time horizon.

[41] MCCS. (2010). Biomass Sustainability and Carbon Policy Study. Natural Capital Initiative, Manomet Center for Conservation Sciences, Brunswick ME, USA.

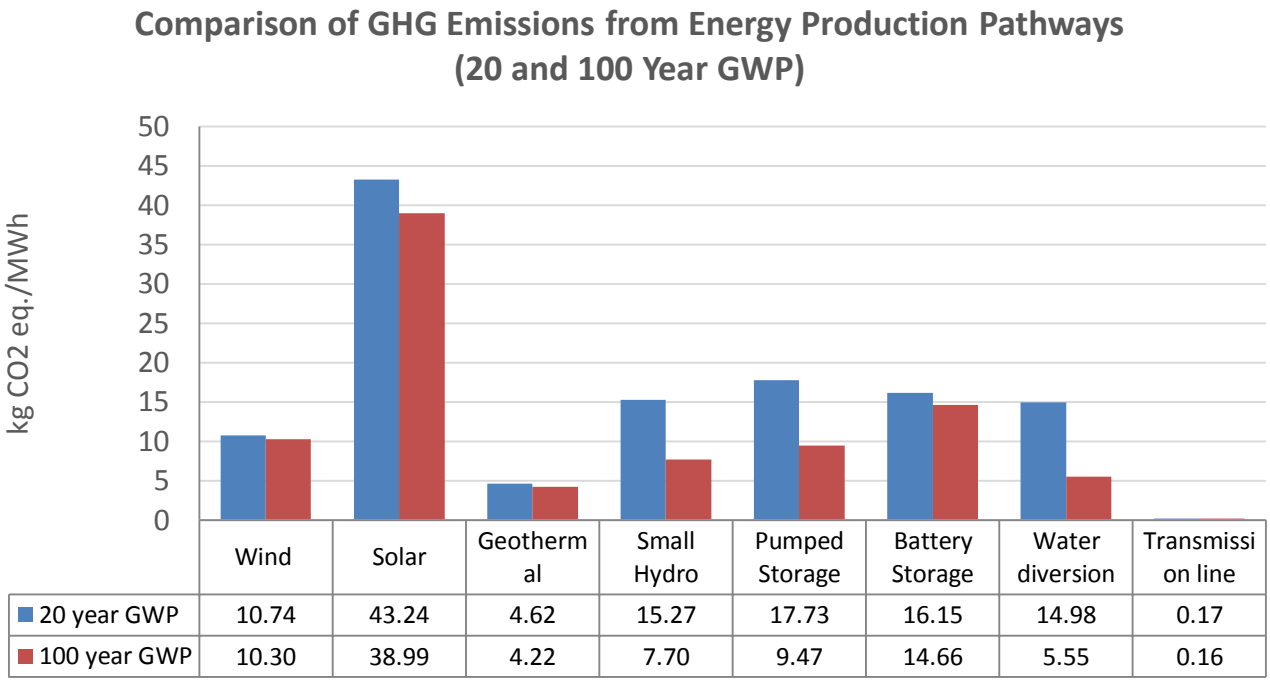


	Biomass Gasification	MSW	MSW + Biomass	Biogas	Small Hydro	Pumped Storage	Water diversion
Fossil and biogenic	772.49	709.08	675.24	1161.71	20.56	23.41	21.43
Fossil	17.72	453.67	319.32	259.60	15.27	17.73	14.98

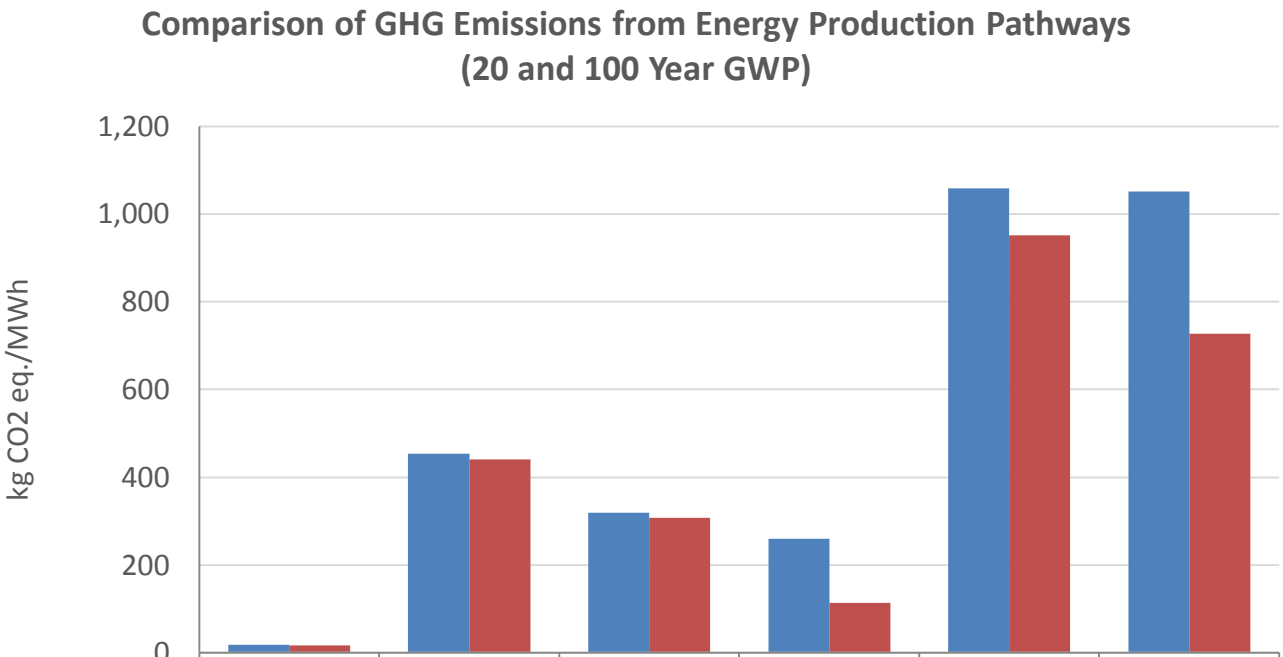


	Biomass Gasification	MSW	MSW + Biomass	Biogas	Small Hydro	Pumped Storage	Water diversion
Fossil and biogenic	771.97	696.81	662.98	1015.88	12.99	15.15	12.10
Fossil	17.20	441.40	307.06	113.77	7.70	9.47	5.66

Figure 19. Comparison of total GHG emissions with results where biogenic CO_2 is excluded

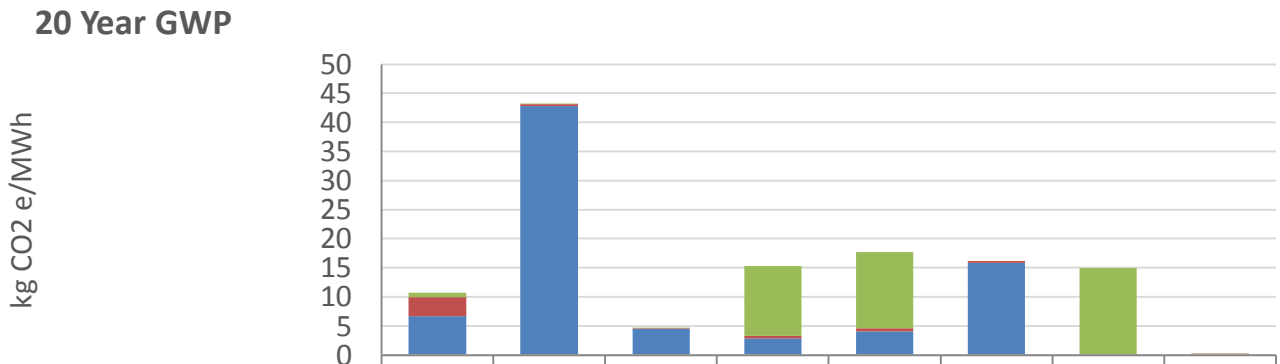


	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
20 year GWP	10.74	43.24	4.62	15.27	17.73	16.15	14.98	0.17
100 year GWP	10.30	38.99	4.22	7.70	9.47	14.66	5.55	0.16

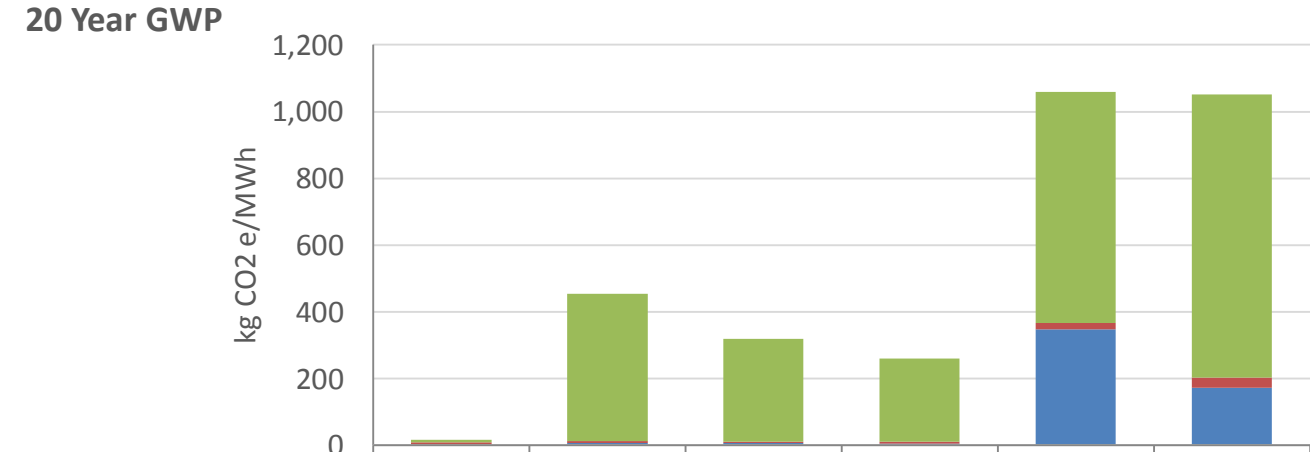


	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
20 year GWP	17.72	453.67	319.32	259.60	1058.91	1050.76
100 year GWP	17.20	441.40	307.06	113.77	951.11	727.68

Figure 20. Comparison of GHG emissions from energy production pathways (biogenic CO_2 emissions excluded)

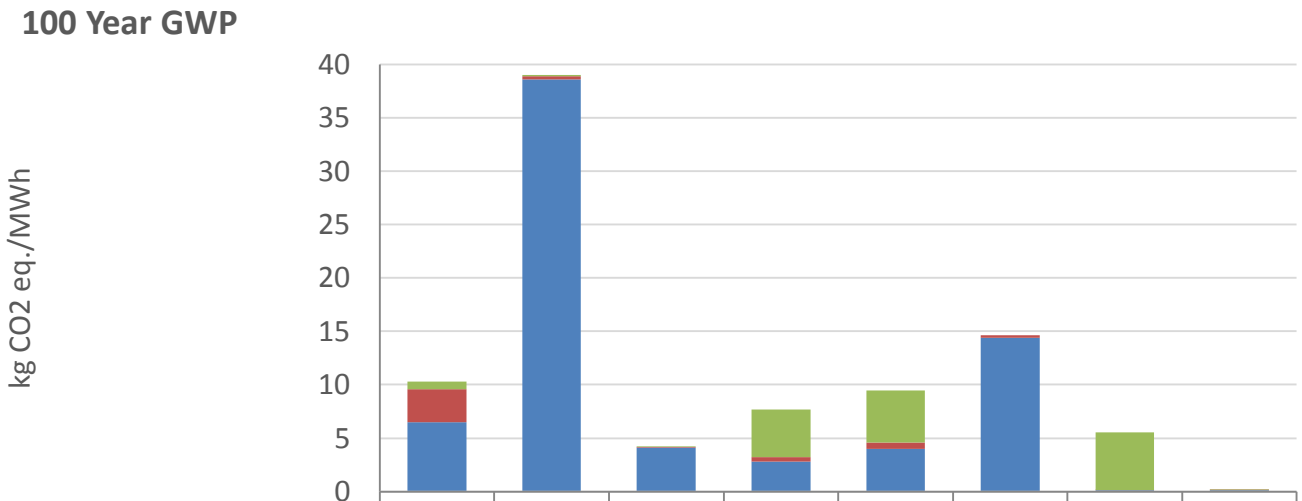


	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
Operation	0.74	0.13	0.02	12.02	13.09	0.00	14.86	0.0324
Transport of Materials & Fuel	3.29	0.35	0.10	0.44	0.61	0.30	0.0003	0.0027
Materials and Fuel Acquisition, Production and Construction	6.72	42.76	4.49	2.82	4.03	15.85	0.12	0.1355

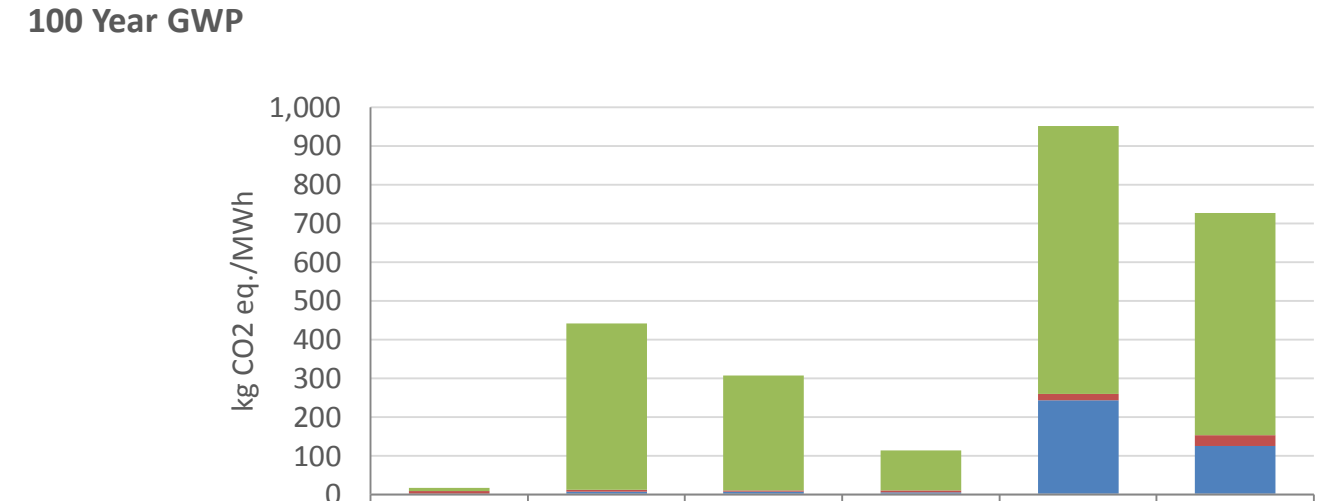


	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
Operation	8.53	441.11	307.09	248.70	692.29	846.86
Transport of Materials & Fuel	7.34	4.08	3.74	4.93	18.22	31.44
Materials and Fuel Acquisition, Production and Construction	1.84	8.49	8.49	5.97	348.40	172.47

Figure 21. GHG emissions from energy production pathways - contribution analysis, 20 year GWP (biogenic CO_2 emissions excluded)



	Wind	Solar	Geothermal	Small Hydro	Pumped Storage	Battery Storage	Water diversion	Transmission line
Operation	0.71	0.10	0.01	4.48	4.88	0.00	5.43	0.0304
Transport of Materials & Fuel	3.09	0.33	0.10	0.41	0.58	0.28	0.00	0.0027
Materials and Fuel Acquisition, Production and Construction	6.49	38.56	4.11	2.81	4.01	14.38	0.12	0.1251



	Biomass Gasification	MSW	MSW + Biomass	Biogas	Diesel	LNG
Operation	8.51	429.37	295.35	103.30	690.43	574.23
Transport of Materials & Fuel	6.90	3.83	3.51	4.65	16.23	28.01
Materials and Fuel Acquisition, Production and Construction	1.79	8.20	8.20	5.83	244.45	125.45

Figure 22. GHG emissions from energy production pathways - contribution analysis, 100 year GWP (biogenic CO_2 emissions excluded)

4.3 CONTRIBUTION ANALYSIS

Contribution analysis is a measure of the effect each process has on the complete environmental profile of the life cycle. The impact each process or life cycle stage has on the total life cycle GHG emissions is identified and discussed below.

4.3.1 BIOMASS GASIFICATION

The biomass gasification is a CHP plant. The total amount of electricity and heat produced from the plant is considered in the calculations. No allocation of emissions to electricity or heat was performed.

Figure 23 presents GHG emissions from biomass gasification in Haines Junction. The total GHG emissions are 771.97 kg CO_2e/MWh based on the 100 year GWP. The primary source of emissions is the operation of the plant, which contributes to almost 99% of the total emissions with 97.7% coming from biogenic CO_2 emissions. The remaining 1.1% of emissions are produced from materials acquisition, transportation of materials and biomass, and plant construction.

According to current GHG accounting protocols and standards, biogenic CO_2 emissions should be accounted and reported separately from all other GHG emissions[42]. The biomass combustion is considered carbon-neutral and biogenic CO_2 emissions are reported separately from other emissions (Table 16).

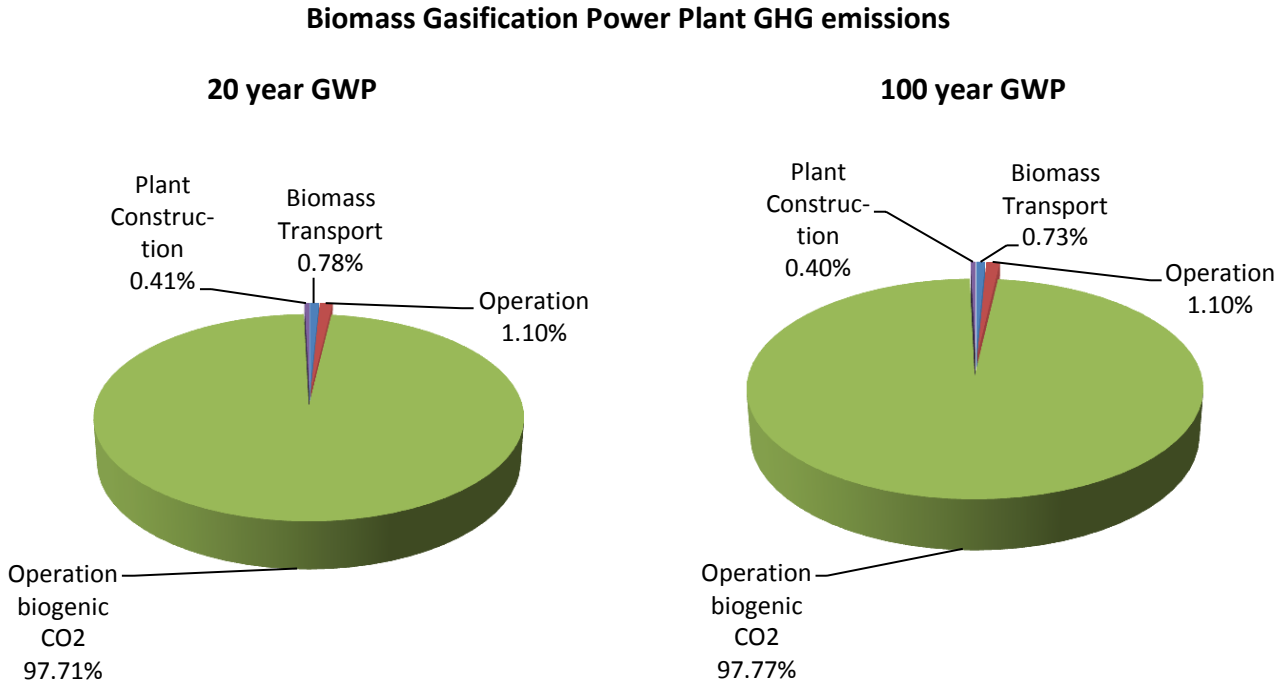


Figure 23. Biomass Gasification Power Plant GHG emissions (20 and 100 year GWP)

[42] Greenhouse Gas Accounting Protocol (2016). http://www.ghgprotocol.org/

Table 16. Biomass Gasification Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Bio	N_2O	SF_6	CH_4				
Materials Acquisition	1.7673	0.0000	9.29E-06	2.71E-13	0.0008	1.8388	0.24	1.7928	0.23
Materials Transportation	1.2247	0.0000	9.77E-06	5.36E-13	1.47E-03	1.3511	0.17	1.2685	0.16
Biomass Transportation	5.4245	0.0000	0.0001	2.37E-12	0.0065	5.9921	0.78	5.6268	0.73
Operation	8.1754	754.77	0.0012	0.0000	0.0004	763.30	98.81	763.28	98.87
Total	**16.5919**	**754.77**	**0.0013**	**3.18E-12**	**0.0092**	**772.49**	**100**	**771.97**	**100**

4.3.2 WASTE TO ENERGY MSW

There are two scenarios considered for the MSW combustion power plant.

Scenario 1: MSW & Biomass Conventional Combustion

Scenario 1, which is based on a combined combustion of 16,100 tonnes of waste and 7,650 tonnes of biomass, is presented in Figure 24. The amount of emitted GHGs is 675.24 kg CO_2e/MWh based on the 20 year GWP, with plant operation accounting for nearly all of the GHGs (98%) for both time horizons. Nearly 53% of the GHGs from operations originate from biogenic CO_2. The remaining 1.8% of GHGs is produced by transportation of materials and plant construction.

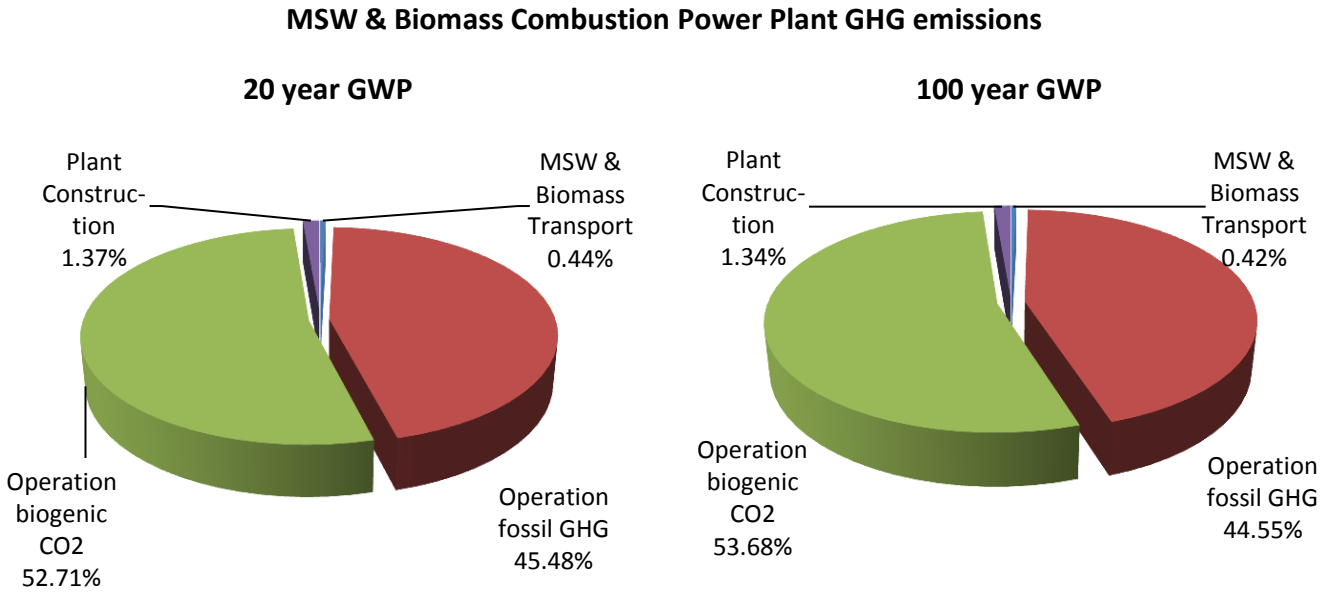


Figure 24. MSW & Biomass Combustion Power Plant GHG emissions (20 and 100 year GWP)

Table 17. MSW & Biomass Combustion Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Materials Acquisition	8.0435	0.0000	4.99E-05	7.62E-11	0.0051	8.4856	1.26	8.1997	1.24
Materials Transportation	0.6799	0.0000	5.43E-06	2.97E-13	8.18E-04	0.7501	0.11	0.7043	0.11
Biomass Transportation	2.7055	0.0000	3.70E-05	1.18E-12	0.0033	2.9891	0.44	2.8066	0.42
Operation	282.05	355.92	0.0280	0.0000	0.2101	663.01	98.19	651.27	98.23
Total	**293.48**	**355.92**	**0.0281**	**7.77E-11**	**0.2193**	**675.24**	**100**	**662.98**	**100**

Scenario 2: MSW Conventional Combustion

In Scenario 2 (Figure 25), where 23,750 tonnes of MSW are combusted, the amount of GHG emissions is slightly higher at 709 kg CO_2e/MWh based on the 20 year GWP. The source of the GHGs is divided among the pathways in the same manner as Scenario 1, with operations accounting for 98% of GHG emissions for both GWPs under consideration. The biogenic CO_2 contributes to over 36% of total GHG emissions from operations.

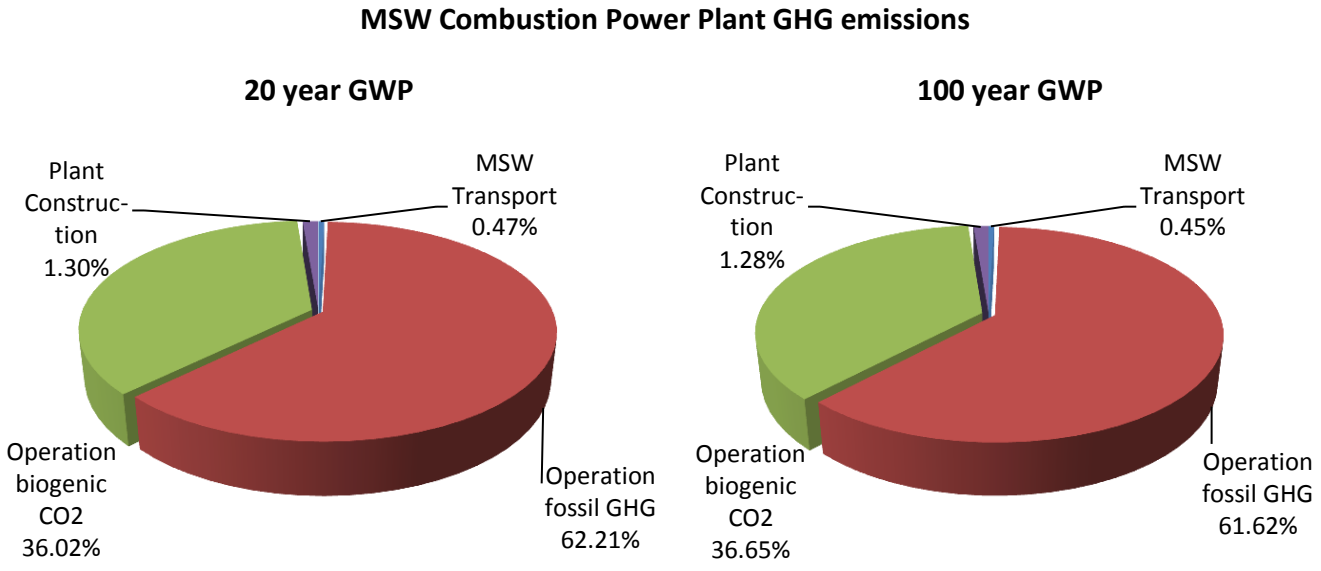


Figure 25. MSW Combustion Power Plant GHG emissions (20 and 100 year GWP)

Table 18. MSW Combustion Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Materials Acquisition	8.0435	0.0000	4.99E-05	7.62E-11	0.0051	8.4856	1.20	8.1997	1.18
Materials Transportation	0.6799	0.0000	5.43E-06	2.97E-13	8.18E-04	0.7501	0.11	0.7043	0.10
Biomass Transportation	3.0135	0.0000	4.14E-05	1.32E-12	0.0036	3.3288	0.47	3.1260	0.45
Operation	416.07	255.41	0.0280	0.0000	0.2101	696.52	98.23	684.78	98.27
Total	**427.81**	**255.41**	**0.0281**	**7.78E-11**	**0.2196**	**709.08**	**100**	**696.81**	**100**

4.3.3 BIOGAS

Results of the biogas resource option located at the Whitehorse landfill are shown in Figure 26. The biogas power plant (AD operation) produces a large amount of methane emissions. As such, the amount of GHGs produced over a 20 year timeline versus 100 years is significantly different due to the difference in the GWPs. Calculations using the 20 year GWP show the plant releasing 1,162 kg CO_2e/MWh whereas only 1,016 kg CO_2e/MWh are released based on the 100 year GWP. The combustion of biogas (CHP operation) releases 902.11 kg CO_2e/MWh of biogenic CO_2.

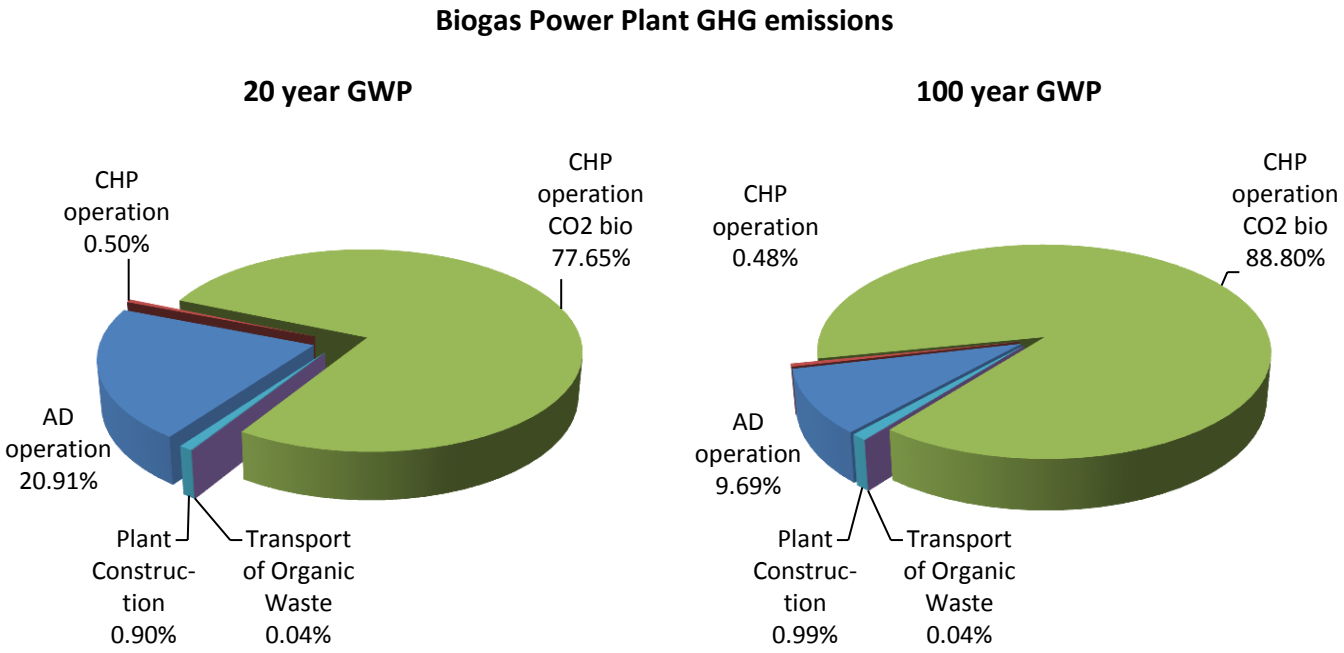


Figure 26. Biogas Power Plant GHG emissions (20 and 100 year GWP)

Table 19. Biogas Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Materials Acquisition	5.7469	0.0000	3.06E-05	9.31E-13	2.52E-03	5.9663	0.51	5.8254	0.57
Materials Transportation	4.0962	0.0000	3.27E-05	1.79E-12	4.93E-03	4.5189	0.39	4.2429	0.42
AD Operation	18.7826	0.0000	0.0281	0.0000	2.5800	242.92	20.91	98.47	9.69
CHP Operation	0.0000	902.11	0.0164	0.0000	0.0173	907.89	78.15	906.94	89.28
Waste Transportation	0.4050	0.0000	5.38E-06	0.0000	4.04E-06	0.4067	0.04	0.4065	0.04
Total	**29.0306**	**902.11**	**0.0446**	**2.72E-12**	**2.6047**	**1161.71**	**100**	**1015.88**	**100**

4.3.4 GEOTHERMAL

Figure 27 shows the results for a geothermal plant that will be located at McArthur Springs with 4.6 kg CO_2e/MWh GHG emissions produced based on the 20 year GWP and 4.2 kg CO_2e/MWh based on the 100 year GWP. For both GWPs, plant and transmission line construction account for more than 99% of the emitted GHGs. The length of the transmission line in this pathway is 42 km and the line construction and operation accounts for 0.74% and 0.17% of the total impact in the 20 year scenario, respectively and 0.75% and 0.18% in the 100 year scenario, respectively (Table 20).

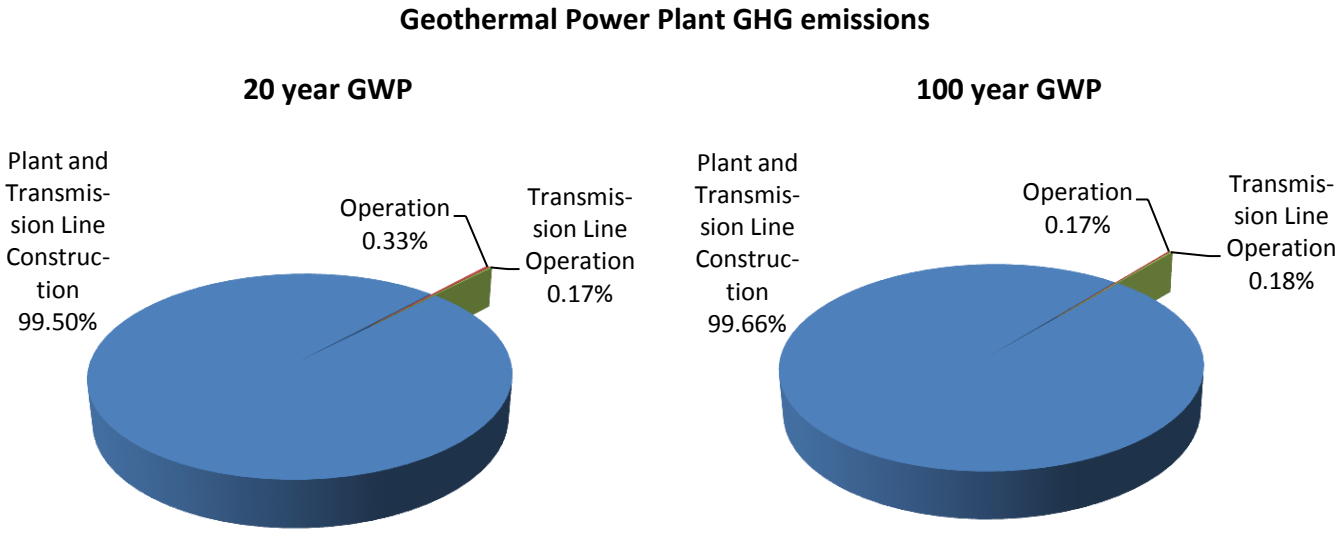


Figure 27. Geothermal Power Plant GHG emissions (20 and 100 year GWP)

Table 20. Geothermal Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh				Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Plant construction	3.9612	5.33E-05	2.59E-10	0.0070	4.5626	98.76	4.1711	98.91
Transmission line construction	0.0302	5.39E-07	2.61E-12	4.58E-05	0.0341	0.74	0.0316	0.75
Operation	0.0024	2.13E-06	0.0000	1.44E-04	0.0150	0.33	0.0070	0.17
Transmission line operation	0.0070	9.44E-07	2.60E-11	0.0000	0.0080	0.17	0.0075	0.18
Total	**4.0007**	**5.69E-05**	**2.88E-10**	**0.0072**	**4.6198**	**100**	**4.2171**	**100**

4.3.5 WIND

Figure 28 presents GHG emissions from wind power generation. The total GHG emissions are 10.7 kg CO_2e/MWh using the 20 year GWP. The majority of the emissions (62%) originate from plant and transmission line construction life cycle stages. The wind turbines are transported by sea freighter from Denmark to Montreal and then by truck to Whitehorse. This accounts for 30% of the total life cycle impact. Almost 7% of GHG emissions come from wind power plant operations and transmission line operations. Since the length of the transmission line is only 7.6km, most of GHGs from operations originate from wind plant operations. The difference in emissions between the two time horizons is very small.

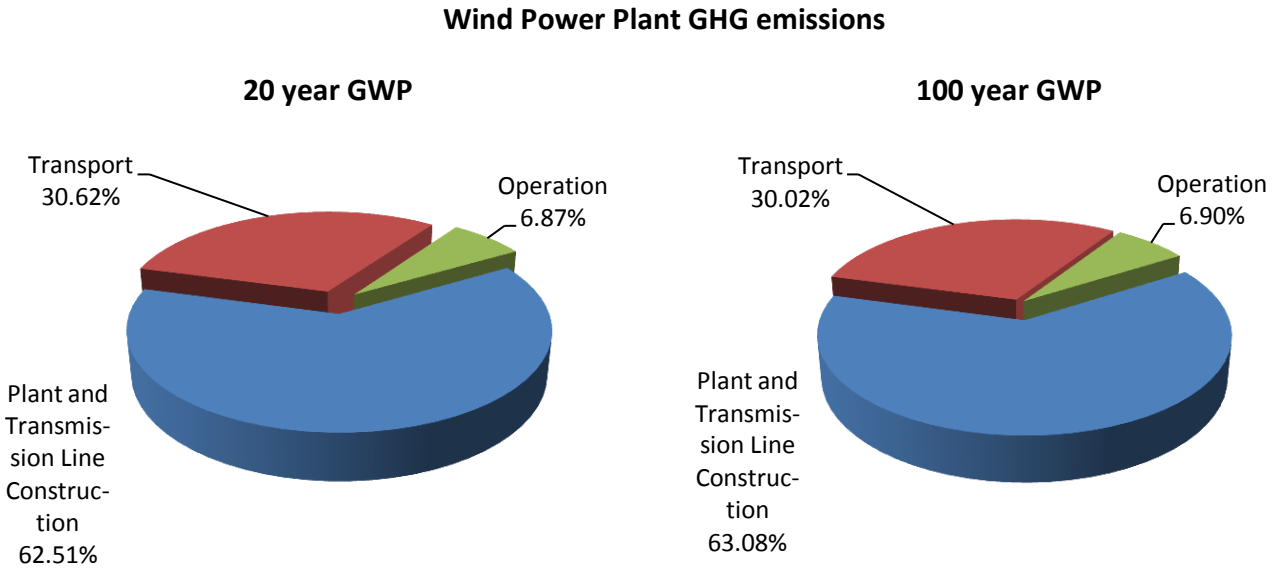


Figure 28. Wind Power Plant GHG emissions (20 and 100 year GWP)

Table 21. Wind Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh				Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Plant and Transmission Line Construction	6.3215	2.34E-04	7.37E-10	0.0040	6.7154	62.51	6.4942	63.08
Materials Transportation	2.9853	2.30E-05	1.29E-12	0.0035	3.2892	30.62	3.0907	30.02
Operation	0.6913	2.24E-05	4.71E-12	4.85E-04	0.7379	6.87	0.7108	6.90
Total	**9.9980**	**2.79E-04**	**7.43E-10**	**0.0080**	**10.7425**	**100**	**10.2956**	**100**

4.3.6 SOLAR

Results for the solar resource option are shown in Figure 29, where GHGs are mostly generated by PV panels manufacturing (93%) for both the 20 and 100 year GWPs. The Panasonic 330W panels are manufactured in Japan and transported to Vancouver by sea freighter and then to Whitehorse by truck. The amount of GHGs emitted is 43.24 kg CO_2e/MWh for the 20 year time horizon and 38.99 kg CO_2e/MWh for the 100 year time horizon.

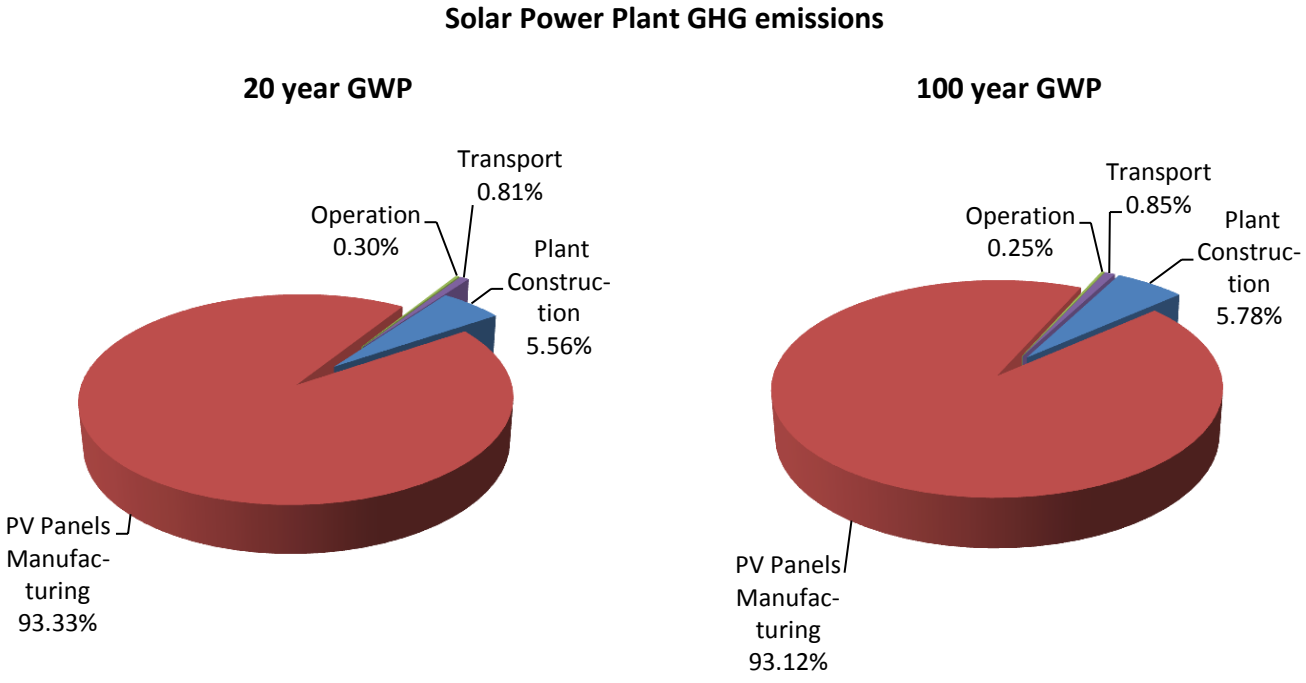


Figure 29. Solar Power Plant GHG emissions (20 and 100 year GWP)

Table 22. Solar Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh				Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Plant Construction	2.1678	4.14E-05	3.52E-08	2.66E-03	2.4028	5.56	2.2541	5.78
PV Panels Manufacturing	34.1087	6.42E-04	0.0000	0.0724	40.3605	93.33	36.3064	93.12
Operation	0.0836	1.65E-06	1.65E-13	5.27E-04	0.1284	0.30	0.0988	0.25
Transportation	0.3182	2.33E-06	1.39E-13	3.83E-04	0.3510	0.81	0.3296	0.85
Total	**36.6784**	**6.88E-04**	**3.52E-08**	**0.0760**	**43.2426**	**100**	**38.9888**	**100**

4.3.7 PUMPED STORAGE HYDRO POWER PLANT

Located at Moon Lake, pumped storage results are shown in Figure 30. The total GHG emissions are 23.41 kg CO_2e/MWh under the 20 year time horizon GWP factor, with 15.15 kg CO_2e/MWh for the 100 time horizon GWP. Nearly 70% of emissions came from the operation of the plant calculated using the 100 year GWP while 80% came from the 20 year GWP calculation. These emissions originated from biomass decomposition after land inundation. Biogenic CO_2 emissions from land inundation are shown separately and are 24% for the 20 year GWP and over 37% for the 100 year GWP. Plant and transmission line construction accounted for over 30% of GHG emissions using the 100 year GWP but only 19.83% for the 20 year GWP. The differences in distribution of GHG emissions over the 20 and 100 year time horizons are due to different methane GWP values.

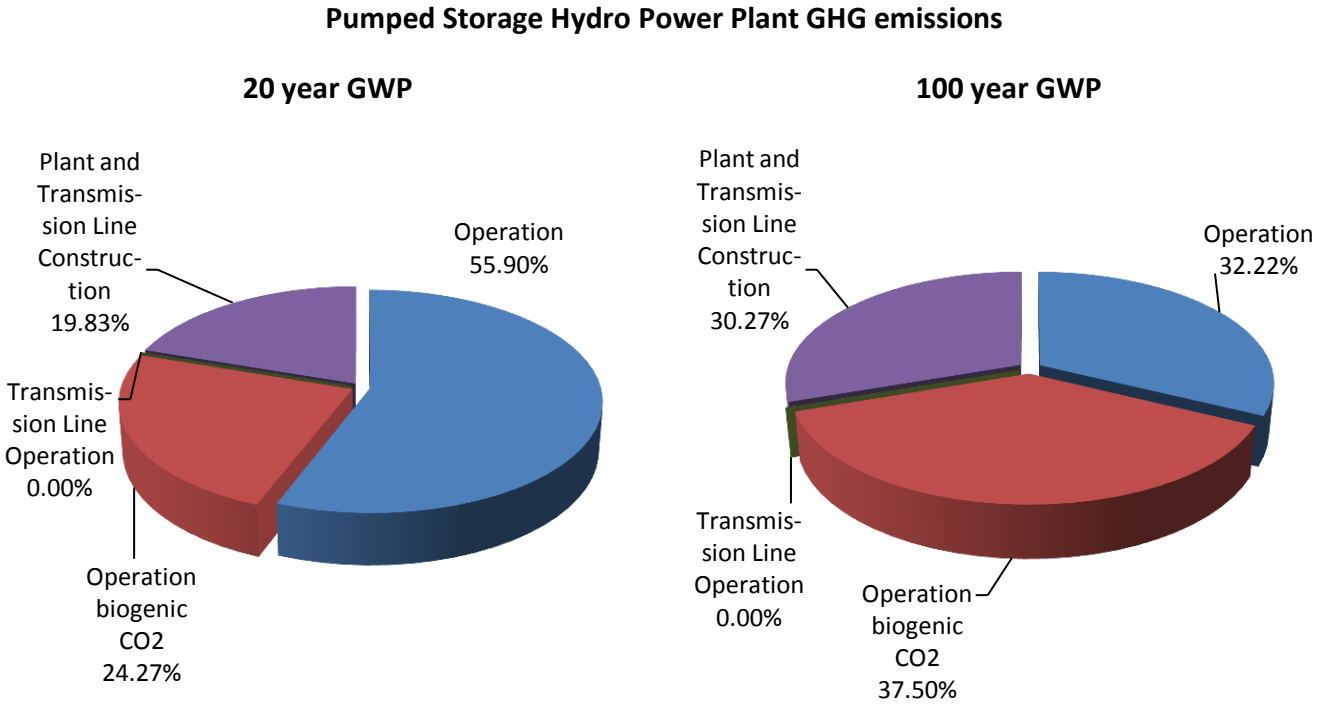


Figure 30. Pumped Storage Power Plant GHG emissions (20 and 100 year GWP)

Table 23. Pumped Storage Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Plant construction	4.5487	0.0000	2.96E-05	1.33E-12	9.93E-04	4.6400	19.82	4.5844	30.26
Transmission line construction	0.0019	0.0000	3.33E-08	1.62E-13	2.83E-06	0.0021	0.01	0.0020	0.01
Operation	0.0000	5.6814	0.0029	3.40E-10	0.1466	18.7682	80.17	10.5626	69.72
Transmission line operation	0.0004	0.0000	5.84E-08	1.61E-12	5.43E-07	0.0005	0.00	0.0005	0.00
Total	**4.5510**	**5.6814**	**0.0030**	**3.43E-10**	**0.1477**	**23.4108**	**100**	**15.1494**	**100**

4.3.8 SMALL HYDRO

The scenario of constructing a small hydro plant at Drury Creek generated 20.56 kg CO_2e/MWh for the 20 year GWP and nearly 12.99 kg CO_2e/MWh for the 100 year GWP. The results, shown in Figure 31, show that the largest difference is in plant operation, where 84% of emissions are calculated using the 20 year GWP and 75% calculated in the 100 year GWP. As with the pumped storage option, these emissions come from land inundation. The other two differences are similar to the pumped storage results in the above section: 16% versus 25% are attributed to plant and transmission line construction and transmission line operation for the 20 year versus 100 year GWP, respectively.

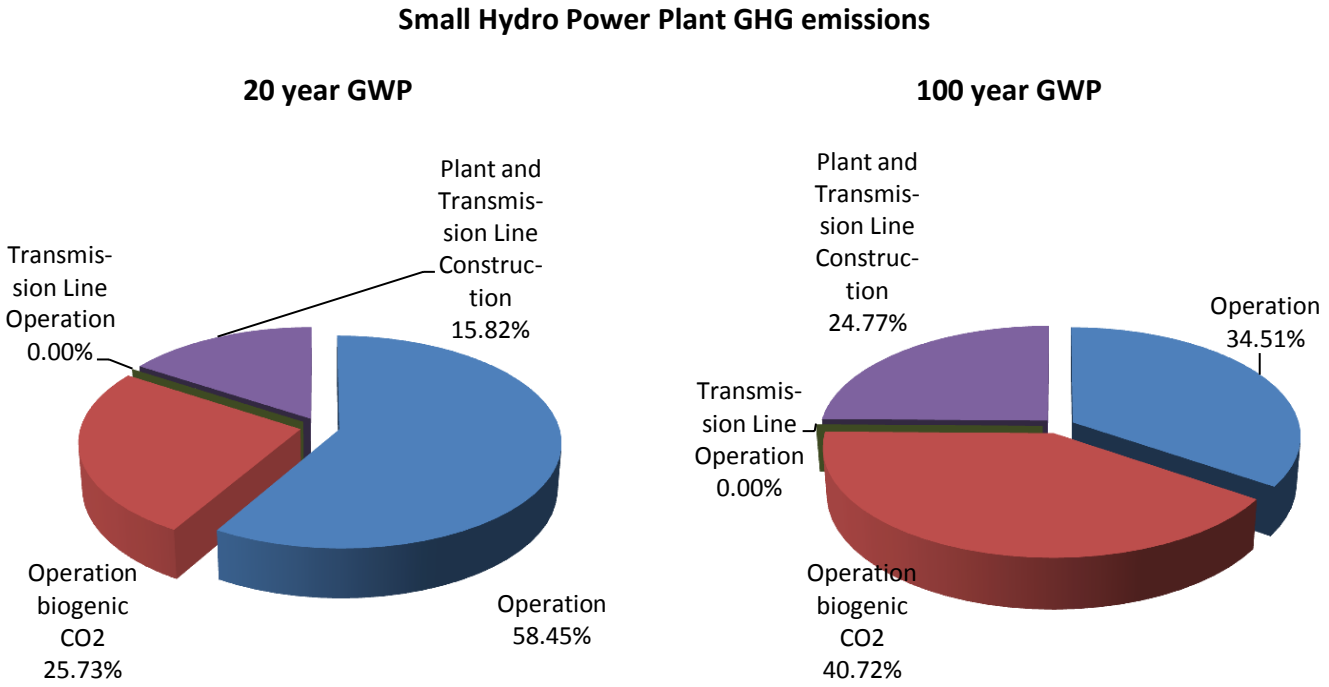


Figure 31. Small Hydro Power Plant GHG emissions (20 and 100 year GWP)

Table 24. Small Hydro Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Plant construction	3.1938	0.0000	2.10E-05	1.35E-12	6.44E-04	3.2534	15.82	3.2174	24.76
Transmission line construction	0.0004	0.0000	6.41E-09	3.11E-14	5.45E-07	0.0004	0.00	0.0004	0.00
Operation	0.0000	5.2904	0.0027	0.00E+00	0.1346	17.3101	84.18	9.7736	75.22
Transmission line operation	0.0001	0.0000	1.12E-08	3.10E-13	1.04E-07	0.0001	0.00	0.0001	0.02
Total	**3.1942**	**5.2904**	**0.0027**	**1.69E-12**	**0.1353**	**20.5640**	**100**	**12.9915**	**100**

4.3.9 Energy Storage: Lithium Ion Batteries

Lithium ion batteries were chosen as the preferred means to store energy and results are shown in Figure 32. The functional unit for this application is MWh of energy stored. Almost the entire amount of GHG emissions is from battery manufacturing (98%) for both time horizons (Table 25). The total GHG emissions are 16.15 kg CO_2e/MWh for the 20 year time horizon and 14.66 kg CO_2e/MWh for the 100 year time horizon.

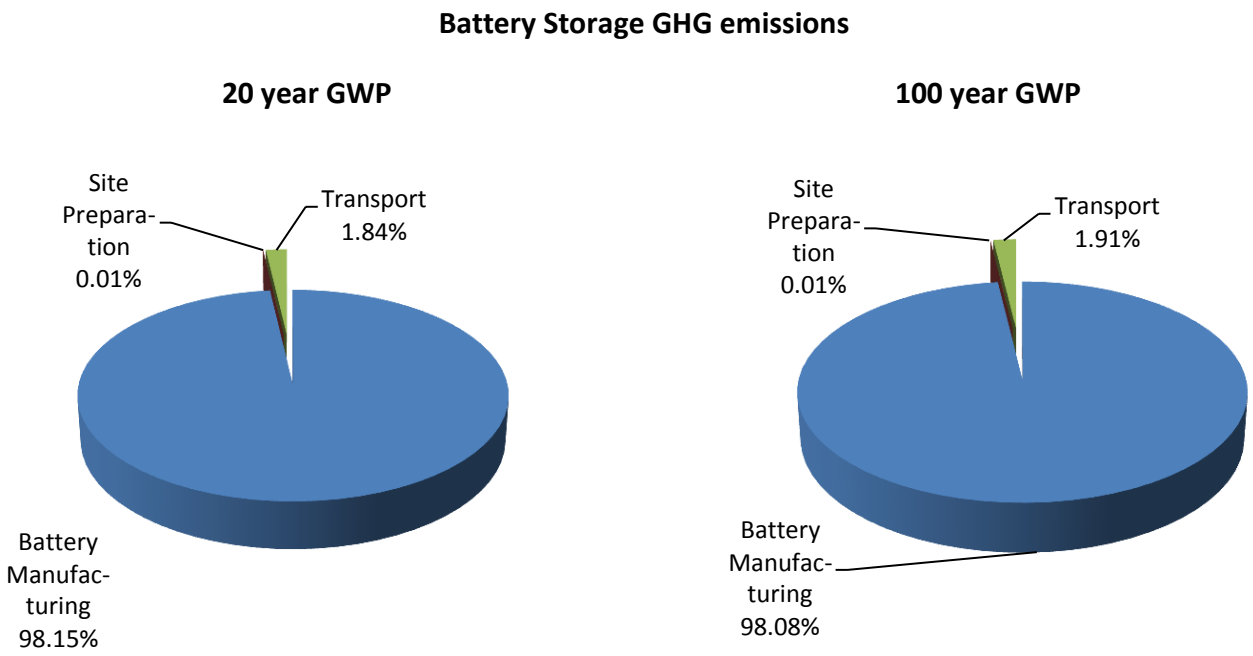


Figure 32. Lithium Ion Battery GHG emissions (20 and 100 year GWP)

Table 25. Lithium Ion Battery GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh						Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4	CF_4	C_2F_6				
Battery Manufac-turing	13.1879	2.48E-04	0.0000	0.0280	4.31E-05	5.9E-06	15.8520	98.15	14.3777	98.08
Site Prepara-tion	0.0017	2.61E-07	1.29E-17	1.22E-07	0.0000	0.0000	0.0018	0.01	0.0018	0.01
Opera-tion	0.2697	2.08E-06	1.18E-13	0.0003	0.0000	0.0000	0.2975	1.84	0.2793	1.91
Total	**13.4593**	**2.51E-04**	**1.18E-13**	**0.0283**	**4.31E-05**	**5.9E-06**	**16.1513**	**100**	**14.6588**	**100**

4.3.10 THERMAL-DIESEL

Figure 33 shows the results for a Diesel plant at Takhini Substation. Total GHG emissions are 1,058.91 kg CO_2e/MWh under the 20 year time horizon, where operations account for over 65%, extraction of resources accounts for nearly 19%, and fuel production and transportation accounts for over 15% of the produced GHGs. The remaining 0.04% comes from plant construction. A slightly smaller amount of GHGs were calculated using the 100 year GWP values, giving an estimate of 951.11 kg CO_2e/MWh. In this case, plant operation contributed to over 72% of the GHG emissions, fuel production and transportation accounted for 15%, and extraction of resources was only 12% - a 7% decrease compared to the 20 year time horizon. This is due to a lower GWP of methane emissions from crude oil extraction under the 100 year time horizon. Similar to the results from the 20 year time horizon, plant construction accounts for the remaining 0.04% of GHGs.

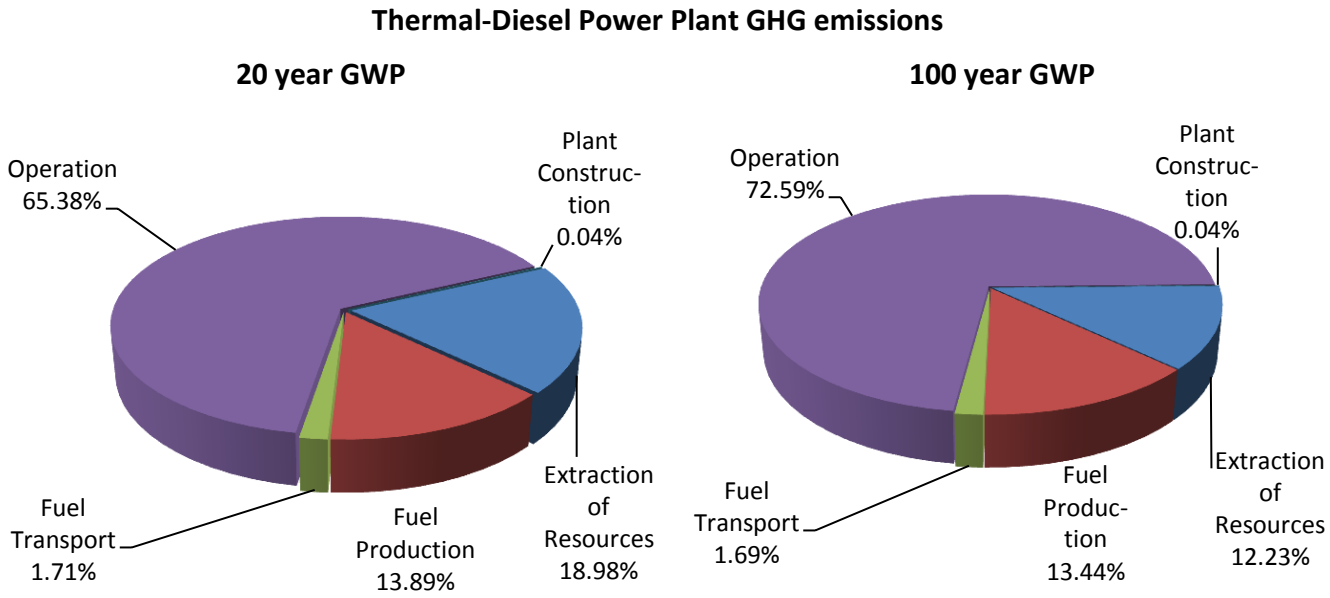


Figure 33. Thermal-Diesel Power Plant GHG emissions (20 and 100 year GWP)

Table 26. Thermal-Diesel Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh				Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Resource Extraction	73.3456	0.0024	0.0000	1.5124	201.02	18.98	116.33	12.23
Materials Acquisition	0.2608	1.34E-06	3.66E-14	0.0001	0.2723	0.03	0.2649	0.03
Materials Transportation	0.1416	1.98E-06	5.94E-14	1.64E-04	0.1559	0.01	0.1468	0.02
Fuel Production	116.69	0.0058	0.0000	0.3439	147.10	13.89	127.85	13.44
Fuel Transportation	14.9790	0.0004	0.0000	0.0353	18.06	1.71	16.09	1.69
Operation	620.30	0.2607	0.0000	0.0378	692.29	65.38	690.43	72.59
Total	**825.72**	**0.2693**	**9.60E-14**	**1.9297**	**1058.91**	**100**	**951.11**	**100**

Figure 33 show GHG emissions that originate from five life cycle stages. The processes included in each life cycle stage are described below.

- Resource Extraction - crude oil extraction, leakage, vented and flared gas emissions;
- Fuel Production – crude oil transport via ocean vessel, diesel production at the refinery, crude oil and diesel storage;
- Fuel Transportation – diesel fuel transport by ocean barge and truck to Yukon Energy;
- Plant Construction (includes materials acquisition and transportation) – extraction and processing of raw materials, transport of materials, site preparation;
- Operation – diesel fuel combustion.

4.3.11 THERMAL-LNG

Results for a thermal LNG plant located at the Takhini Substation are shown in Figure 34. In this scenario, an LNG power plant produces approximately one-third more GHGs when analyzed using the 20 year GWP values (1,050.76 kg CO_2e/MWh) in comparison to the 100 year GWP values (727.68 kg CO_2e/MWh). This is primarily due to the different methane GWP values. Extraction of resources (6.6% versus 4.9%), fuel production and transportation (12% versus 15%) and plant operation (81% versus 79%) are the primary differences in GHG emission for the 20 year versus 100 year time horizon, respectively. Using the 20 year GWP, GHG emissions were double for extraction of resources (70 kg CO_2e/MWh) and approximately one-third higher for plant operation (847 kg CO_2e/MWh).

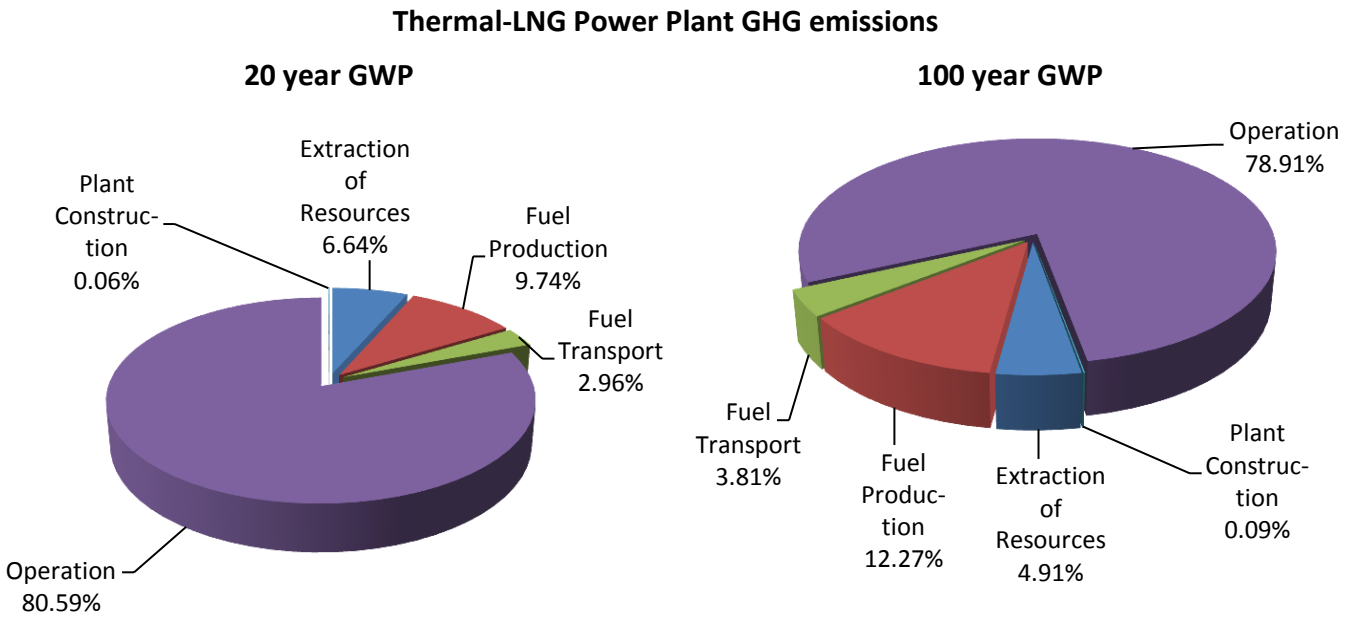


Figure 34. Thermal-LNG Power Plant GHG emissions (20 and 100 year GWP)

Figure 34 show GHG emissions that originate from five life cycle stages. The processes included in each life cycle stage are described below.

- Resource Extraction - natural gas extraction, leakage and flare emissions;
- Fuel Production – fuel processing (treatment & liquefaction), distribution by pipeline, fuel storage;
- Fuel Transport – LNG transport by truck to Yukon Energy;
- Plant Construction – extraction and processing of raw materials for plant construction, transport of materials , site preparation;
- Operation – LNG combustion.

Table 27. Thermal-LNG Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh				Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Resource Extraction	18.5317	9.02E-04	0.0000	0.6069	69.7494	6.64	35.7639	4.91
Material Acquisition	0.3641	1.96E-06	6.06E-14	0.0002	0.3775	0.04	0.3689	0.05
Material Transportation	0.2701	3.13E-06	1.15E-13	3.17E-04	0.2976	0.03	0.2798	0.04
Fuel Production	81.86	0.0035	0.0000	0.2327	102.34	9.74	89.31	12.27
Fuel Transportation	25.82	0.0008	0.0000	0.0609	31.14	2.96	27.73	3.81
Operation	433.18	0.0178	0.0000	4.8687	846.86	80.59	574.23	78.91
Total	**560.02**	**0.0231**	**1.76E-13**	**5.7697**	**1050.76**	**100.00**	**727.68**	**100.00**

4.3.12 New Transmission Line

Figure 35 and Table 28 present the results for the completion of a new 230 kV transmission line from Whitehorse to Skagway. It is assumed that the line operates at 100% reliable capacity (3880.7 GWh/yr). The functional unit for this scenario is MWh-km. Total GHG emissions per MWh-km are 0.001 kg CO_2e/MWh-km under the 20 year time horizon and 0.0009 CO_2e/MWh-km under the 100 year time horizon. Materials acquisition accounts for 78% of the GHGs in both scenarios. The line operation accounts for 19% of the total impact with the majority of impact originating from yearly vegetation clearing. The difference in results between the 20 year and 100 year time horizons is quite small.

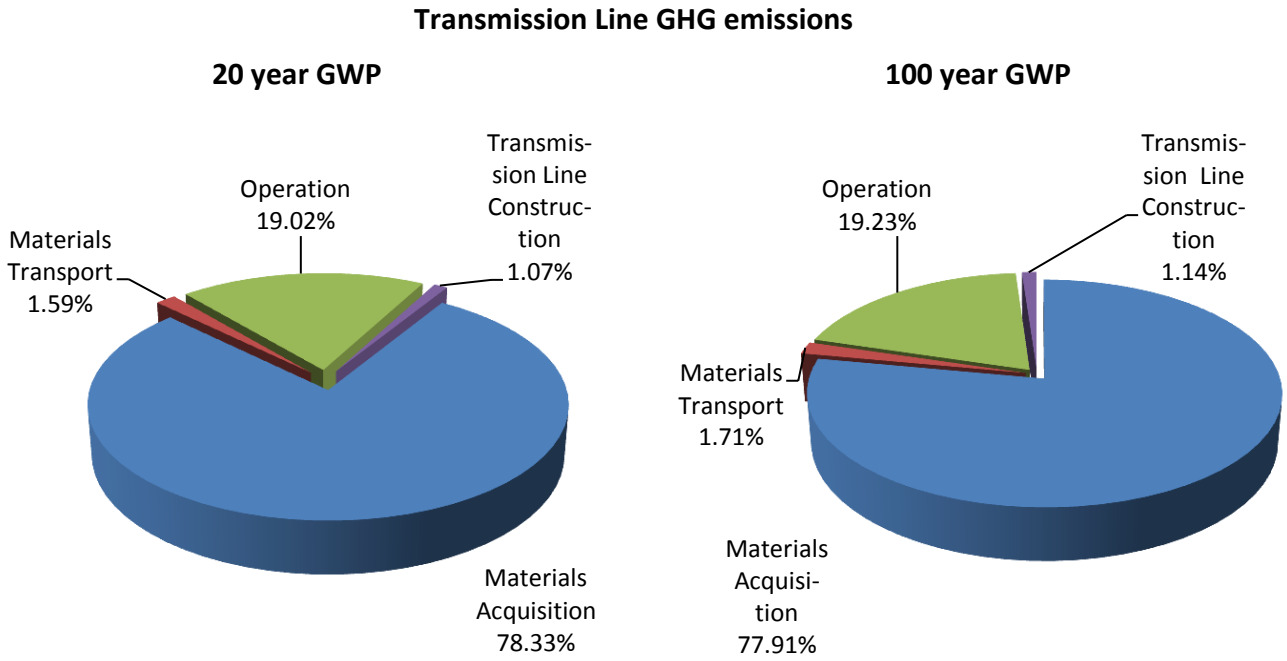


Figure 35. Transmission Line GHG emissions (20 and 100 year GWP)

Table 28. Transmission Line GHG emissions summary of results per MWh-km

Life Cycle Stage	Emissions, kg/MWh-km				Total, kg CO_2e/MWh-km (20 year GWP)	%	Total, kg CO_2e/MWh-km (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Materials Acquisition	6.91E-04	1.12E-08	6.22E-14	1.08E-06	7.8388E-04	78.33	7.2368E-04	77.91
Materials Transportation	1.59E-05	1.08E-10	1.21E-21	1.77E-10	1.5899E-05	1.59	1.5889E-05	1.71
Transmission Line Construction	1.02E-05	1.53E-09	0.00E+00	5.10E-10	1.0660E-05	1.07	1.0633E-05	1.14
Operation	0.000167	2.25E-08	6.20E-13	2.09E-07	0.000190	19.02	0.000179	19.23
Total	**0.000883**	**3.53E-08**	**6.82E-13**	**1.28E-06**	**0.001001**	**100**	**0.000929**	**100**

The total GHG emissions in MWh for a 170km transmission line are estimated by multiplying the MWh-km results in Table 28 by the length of the transmission line (170km). The results are shown in Table 29.

Table 29. Transmission Line GHG emissions summary of results per MWh

Life Cycle Stage	Emissions, kg/MWh				Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Materials Acquisition	0.1174	1.90E-06	1.06E-11	1.83E-04	0.1333	78.33	0.1230	77.91
Materials Transportation	0.0027	1.83E-08	2.05E-19	3.01E-08	0.0027	1.59	0.0027	1.71
Transmission Line Construction	0.0017	2.61E-07	0.0000	8.67E-08	0.0018	1.07	0.0018	1.14
Operation	0.0284	3.82E-06	1.05E-10	0.0000	0.0324	19.02	0.0304	19.23
Total	**0.1502**	**6.00E-06**	**1.16E-10**	**0.0002**	**0.1701**	**100**	**0.1579**	**100**

4.3.13 WATER DIVERSION PROJECT

Figure 36 and Table 30 present the results for the Water Diversion Project. Total GHG emissions for the 24 year project lifetime are 58.03 kg CO_2e/MWh-km under the 20 year time horizon and 32.78 CO_2e/MWh-km under the 100 year time horizon. The GHG emissions from operation originate from land inundation. These emissions are higher per MWh than in the small hydro and pumped storage pathways due to a shorter project life of 24 years, instead of 65 years in other pathways.

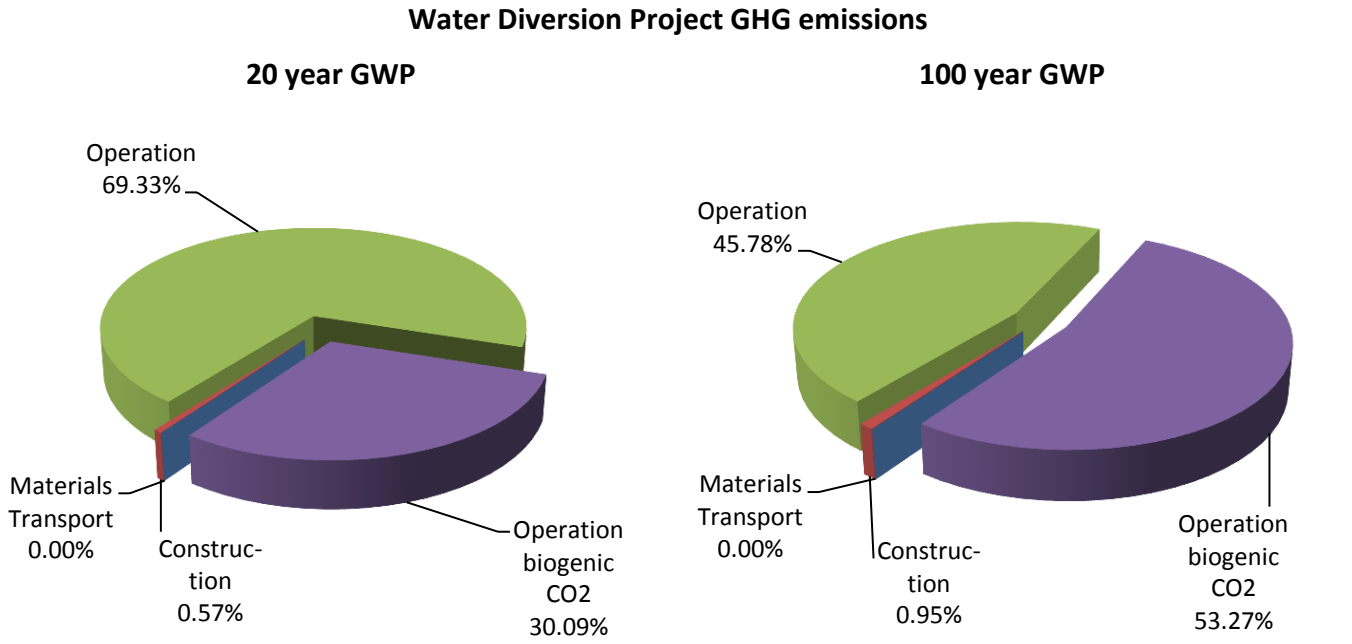


Figure 36. Water Diversion Project GHG emissions (20 and 100 year GWP)

Table 30. Water Diversion Project GHG emissions summary of results – 24 years lifetime

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Materials Transportation	6.94E-04	0.0000	5.54E-09	3.03E-16	8.35E-07	7.6521E-04	0.00	7.1847E-04	0.00
Construction	0.2917	0.0000	3.93E-05	1.29E-13	3.65E-04	0.3328	0.57	0.3124	0.95
Operation	0.0000	17.4614	11.5771	0.0000	0.4506	57.6924	99.43	32.4669	99.04
Total	**0.2924**	**17.4614**	**0.0090**	**1.29E-13**	**0.4510**	**58.0260**	**100**	**32.7800**	**100**

In order to compare the Water Diversion Project with other hydro options (small hydro and pumped storage), the results were normalized per project life of 65 years. The normalized results are shown in Table 31.

Table 31. Water Diversion Project GHG emissions summary of results – 65 years lifetime

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Materials Transportation	2.56E-04	0.0000	2.04E-09	1.12E-16	3.08E-07	2.8254E-04	0.00	2.6528E-04	0.00
Construction	0.1077	0.0000	1.45E-05	4.77E-14	1.35E-04	0.1229	0.57	0.1153	0.95
Operation	0.0000	6.4473	0.0033	0.0000	0.1664	21.3023	99.43	11.9884	99.04
Total	**0.1080**	**6.4473**	**0.0033**	**0.0000**	**0.1665**	**21.4255**	**100**	**12.1040**	**100**

4.4 FIXED AND VARIABLE EMISSIONS ANALYSIS

The fixed GHG emissions are emissions associated with power plant and infrastructure construction and include raw materials acquisition, transportation, site preparation, and construction of the plant and transmission line. In the diesel, LNG, biomass gasification and waste to energy pathways, the emissions related to diesel, LNG, biomass and MSW transportation are considered variable emissions. The fixed emissions are expressed in tonnes CO_2e per facility, while variable emissions that originate from power plant operations are expressed in kg CO_2e/MWh.

Table 32. Fixed and variable GHG emissions from energy production pathways (20 and 100 year GWP)

Energy Production Pathway	Fixed GHG emissions tonnes CO_2e		Variable GHG emissions kg CO_2e/MWh		Variable GHG emissions (biogenic CO_2 excluded) kg CO_2e/MWh	
	20 year GWP	100 year GWP	20 year GWP	100 year GWP	20 year GWP	100 year GWP
Biomass Gasification	679.1	651.7	769.3	768.9	14.53	14.14
Waste to energy: MSW	7,775	7,496	699.8	687.9	444.4	432.5
Waste to energy: MSW + biomass	7,775	7,496	666.0	654.1	310.1	298.2
Biogas	420.9	404.1	1151.2	1005.8	249.1	103.7
Geothermal	6,647	6,077	0.0230	0.0145	0.0230	0.0145
Wind	3,641	3,499	0.7379	0.7108	0.7379	0.7108
Solar	6,726	6,067	0.1284	0.0988	0.1284	0.0988
Pumped storage	16,294	16,098	18.77	10.56	13.09	4.88
Small hydro	6,704	6,630	17.31	9.77	12.02	4.48
Battery storage	904.5	820.9	0.00	0.00	0.00	0.00
Thermal - Diesel	675.2	649.1	1058.48	950.70	1058.48	950.70
Thermal - LNG	1,065	1,023	1050.09	727.04	1050.09	727.04
New transmission line (170km)	29,498	27,284	0.0324	0.0304	0.0324	0.0304
Water diversion project, 24 years lifetime	237.8	223.2	57.69	32.47	40.23	15.01
Water diversion project, 65 years lifetime	237.8	223.2	21.30	11.99	14.86	5.43

The site specific data for plant construction (e.g. area of land to be cleared, type of dam, excavation area, quantities of construction materials, energy generation technology) was available for wind, solar, geothermal, battery storage, transmission line, diesel, LNG, biomass gasification, biogas, and the water diversion pathway. The power plant construction data in the waste to energy pathway is representative of a North American power plant. Small hydro and pumped storage power plant construction data represents a mix of North American and European small hydro and pumped storage power plants. The plant construction data is obtained per MWh of energy produced; if the emissions data expressed per MWh is converted back to the total GHG emissions from plant construction using the total energy output of the plant over plant's lifetime, it increases the uncertainty of the results. Site specific data on construction material requirements need to be obtained to better understand GHG emissions from power plants construction in these pathways. It is recommended to update the fixed GHG emissions of waste to energy, small hydro and pumped storage when site and technology specific data become available.

4.5 SENSITIVITY ANALYSIS

A sensitivity analysis was performed to determine the effect of changing parameters and assumptions on the final results. As it was discussed earlier in section 3.4.1, a number of uncertainties in the life cycle inventory data are identified. For example, materials and equipment manufacturing locations are not known in the wind and battery storage pathways. However, it is expected that the equipment and materials manufacturing location will greatly affect the results of the study, since the GHG emissions originate mainly from the upstream life cycle stages in these pathways. The effect of these and other uncertainties (e.g. CHP plant efficiency, LNG combustion emission factors, and transmission line capacity) on the results of the study is assessed in this section. The results are presented below.

4.5.1 WIND

The wind pathway results presented in the section 4.3.5 are for a 3 turbine wind plant. The modelled wind turbines are Vesta V80 2 MW turbines manufactured in Denmark.

An alternative scenario was modelled to present results for an average mix of wind technologies currently in use in the U.S. This scenario assumes that 55% of wind turbine components are manufactured in China and then transported to Canada by sea freighter and truck. The remaining 45% of wind plant materials and components come from the U.S. Four (4) wind turbines with a capacity of 1.5 MW each are installed. The results of this scenario are shown in Figure 37 below.

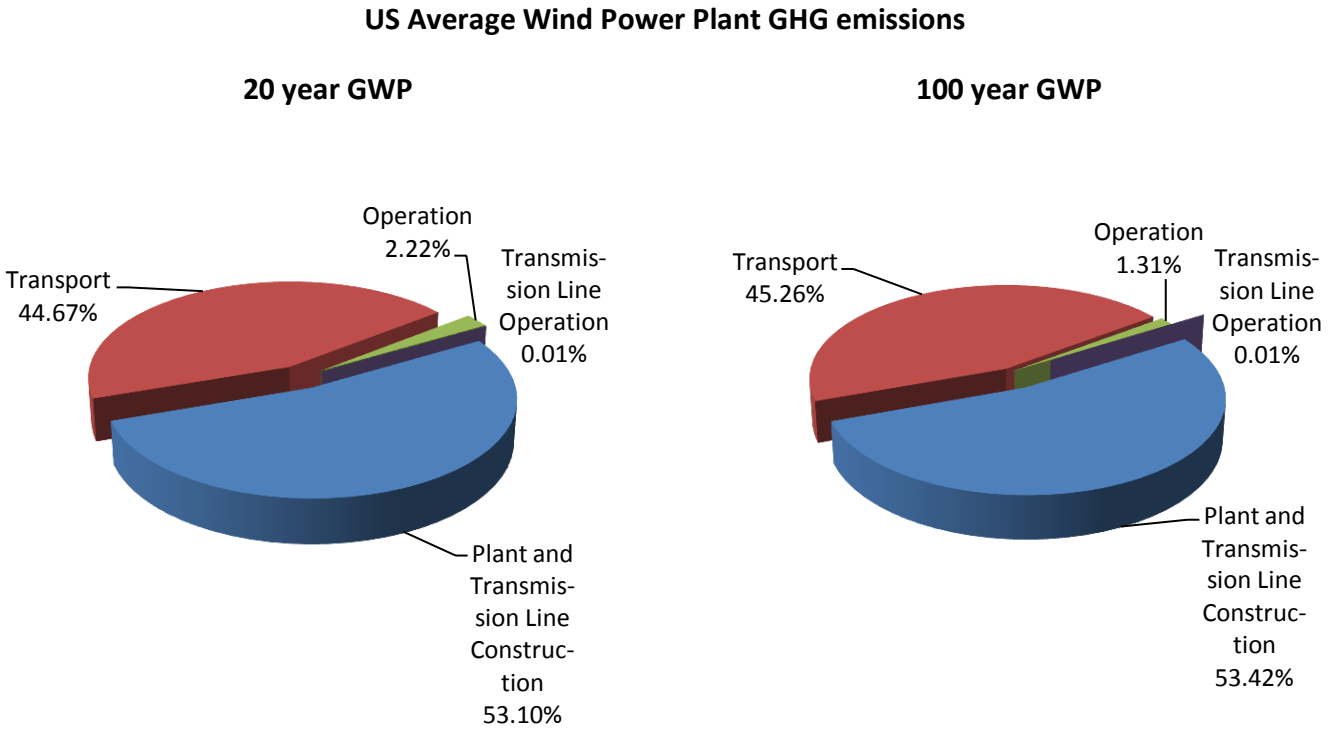


Figure 37. U.S. Average Wind Power Plant GHG emissions (20 and 100 year GWP)

Table 33. U.S. Average Wind Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh				Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	N_2O	SF_6	CH_4				
Plant and Transmission Line Construction	10.1515	3.03E-05	7.84E-10	4.05E-04	10.3069	53.10	10.2087	53.42
Materials Transportation	8.6400	7.15E-07	0.0014	3.67E-04	8.6710	44.67	8.6505	45.26
Operation	0.1440	6.17E-05	9.30E-11	0.0032	0.4315	2.22	0.2507	1.31
Transmission Line Operation	0.0013	1.71E-07	4.71E-12	1.59E-06	0.0014	0.01	0.0014	0.01
Total	**18.9367**	**9.29E-05**	**0.0014**	**0.0040**	**19.4109**	**100.00**	**19.1112**	**100.00**

As it can be seen from Tables 34, the total GHG emissions are significantly higher in the average U.S. wind plant scenario compared to the Vesta turbines manufactured in Denmark. This is due to the higher GHG emissions from transportation and turbine components manufacturing in China. The choice of the turbine manufacturer should be carefully considered when selecting wind turbines for the project, as wind turbines manufactured in Asia tend to have higher environmental impact.

Table 34. Wind scenarios comparison (100 year GWP)

Wind Plant	Total GHG, kg CO_2e/MWh (100 yr GWP)	Plant and Transmission Line Construction	Materials Transportation	Operation (plant and transmission line)
Baseline scenario 3 Vesta V80 2 MW turbines	10.33	6.49	3.09	0.71
Average U.S. wind plant Four 1.5MW turbines	19.11	10.21	8.65	0.25

4.5.2 BATTERY STORAGE

Two batteries from different manufacturers – UltraLife Corporation and SAFT Batteries were evaluated. A 1,000-kWh lithium-ion battery manufactured by SAFT is currently installed at the Wind and Storage Demonstration project site in the Cowessess First Nations, Saskatchewan[43]. A specific power density of different batteries varies significantly from one manufacturer to another. The UltraLife Corporation's battery has a specific power density of 149 W/kg and the SAFT Batteries' specific power density is 60 W/kg.

The effect from the number of batteries required for a 20-year plant lifetime was also modelled. The baseline scenario (UltraLife battery) described in the previous section assumes that 1.5 batteries are

[43] Natural Resources Canada. (2016). Wind and Storage Demonstration in a First Nations Community, Cowessess First Nation. http://www.nrcan.gc.ca/energy/funding/current-funding-programs/cef/4983

needed. The sensitivity scenario assessed the effect of battery's lifetime of 10 years. In this case, two batteries are required. The results for the 100 year GWP are presented in Table 35 below.

Table 35. Battery storage sensitivity analysis results (100 year GWP)

Battery manufacturer	Battery lifetime, years	Number of batteries	GHG, kg CO_2e/MWh (100 yr GWP)
UltraLife (baseline scenario)	15	1.5	14.66
Ultralife	10	2	19.44
Saft	15	1.5	35.64
Saft	10	2	47.48

A significant increase in GHG emissions from one type of the battery to another is observed. The Saft battery's specific power density is only 60 W/kg. This means that the weight of a 8MW battery (132 tonnes) is much higher compared to the UltraLife battery with the specific power density of 149 W/kg (53.6 tonnes). This results in higher GHG emissions from battery manufacturing and transportation life cycle stages.

4.5.3 BIOMASS GASIFICATION

An alternative scenario for biomass gasification was modelled. It assumes that only 1,283 MWh of heat per year will be delivered and consumed in Haines Junction compared to 8,059 MWh_{th}/yr in the baseline scenario. Table 36 presents GHG emissions from this scenario. The total GHG emissions are 1,678.26 kg CO_2e/MWh based on the 100 year GWP. The GHG emissions are significantly higher compared to the baseline scenario where more heat is utilized. This scenario has lower overall plant efficiency and thus, higher emissions.

Table 36. Biomass Gasification Power Plant GHG emissions summary of results

Life Cycle Stage	Emissions, kg/MWh					Total, kg CO_2e/MWh (20 year GWP)	%	Total, kg CO_2e/MWh (100 year GWP)	%
	CO_2	CO_2 Biogenic	N_2O	SF_6	CH_4				
Materials Acquisition	1.7673	0.0000	9.29E-06	2.71E-13	0.0008	1.8388	0.11	1.7928	0.11
Materials Transportation	1.2247	0.0000	9.77E-06	5.36E-13	1.47E-03	1.3511	0.08	1.2685	0.08
Biomass Transportation	5.4245	0.0000	0.0001	2.37E-12	0.0065	5.9921	0.36	5.6268	0.34
Operation	0.0000	1669.57	0.0000	0.0000	0.0000	1669.57	99.45	1669.57	99.48
Total	**8.4165**	**1669.57**	**0.0001**	**3.18E-12**	**0.0088**	**1678.75**	**100**	**1678.26**	**100**

A comparison of the two scenarios is shown in Table 37 below. The GHG emissions in the sensitivity analysis scenario are more than 2 times higher than in the baseline scenario. This is due to the lower efficiency of the CHP plant since only a small portion of produced heat is utilized.

Table 37. Biomass gasification scenarios comparison

Scenario	Total GHG, kg CO_2e/MWh (100 yr GWP)	Materials Acquisition	Materials Transportation	Biomass Transportation	Operation
Baseline scenario (65% electrical and heat production efficiency)	771.97	1.7928	1.2685	5.6268	763.28
Sensitivity analysis scenario (only 1,283 MWh of heat is utilized in Haines Junction)	1,678.26	1.7928	1.2685	5.6268	1,669.57

4.5.4 LNG COMBUSTION EMISSIONS

GHG emissions from LNG combustion are estimated based on emissions factors, not specific operating data that was not available at the time of the study. The emissions factor is derived from GHGenius 4.03 that is based on the US EPA non-road model for large natural gas engines. A sensitivity analysis is performed to better understand an effect of different emissions factors on the results.

Two different LNG combustion emissions factors are selected for the sensitivity analysis:

1. Canadian Energy Partnership for Environmental Innovation, CEPEI (Pembina, 2013):
    a. CO_2 emission factor – 49,300 ng/J NG combusted (4-stroke lean burn)
    b. CH_4 emission factor – 537 ng/J NG combusted (4-stroke lean burn)
2. 2016/2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, Ministry of Environment, May, 2016. Stationary fuel combustion emission factors are based on Environment Canada (2014). National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990-2012., and British Columbia (2014). British Columbia Greenhouse Gas Inventory Report 2012.
    a. CO_2 emission factor – 1.926 kg/m^3
    b. CH_4 emission factor – 0.000037 kg/m^3
    c. N_2O emission factor – 0.000035 kg/m^3

The results are presented in Table 38.

Table 38. LNG combustion emissions

Scenario	kg CO_2e/MWh (20 yr GWP)	kg CO_2e/MWh (100 yr GWP)
Baseline scenario, US EPA	846.86	574.23
CEPEI, Pembina 2013	734.06	500.24
2016/2017 B.C. Best Practices	390.49	390.08

The emissions factors selected for the baseline scenario are in the upper range of emissions and therefore conservative. Actual natural gas engine GHG emissions would likely be lower and will be based on actual operating conditions of the unit. The direct measurement of emissions from the unit is recommended to determine the precise emissions factor.

4.5.5 TRANSMISSION LINE CAPACITY

The GHG emissions from transmission line pathway are modelled using 80%, 60% and 40% transmission line capacity. The baseline scenario assumes that the transmission line operates at 100% of reliable capacity. It is expected that the actual transmission line capacity will vary over the life time of the transmission line. The results are presented in Table 39 below.

Table 39. 170 km transmission line capacity modelling

Scenario	GWh/yr	kg CO_2e/MWh (20 yr GWP)	kg CO_2e/MWh (100 yr GWP)
Baseline scenario, 100% reliable capacity	3880.7	0.1706	0.1582
80% capacity	3104.5	0.1784	0.1631
60% capacity	2328.4	0.2380	0.2175
40% capacity	1552.3	0.3561	0.3254

5 CONCLUSIONS AND RECOMMENDATIONS

The use of an LCA allows decision makers to better understand the impacts on human health and the environment that may not be traditionally seen when selecting an energy source. The results of this study illustrate the vast differences in GHG emissions generated by various energy resource technologies. Careful consideration is crucial in determining the most amenable resource option in light of current policies and climate change strategies. Cost, long-term access to the resources, land availability, and energy demand forecasts must be examined in conjunction with the LCA results. The LCA results provide a means to more fully understand the impacts of choices among energy options, including those impacts that occur outside the project location, which can ultimately lead to a more balanced approach.

This analysis provides insight into the estimated GHG emissions from several renewable and non-renewable energy resources. Key conclusions from this analysis are summarized below.

- The overall results indicate that the biogas pathway is the greatest GHG emitter with over 1,000 kg CO_2e/MWh of GHG emitted for both time horizons, if biogenic CO_2 is included. The next highest emitters are diesel and LNG pathways with 1,059 and 1,051 kg CO_2e/MWh emitted for the 20 year time horizon, respectively, and 951 and 728 kg CO_2e/MWh emitted for the 100 year time horizon, respectively. The smallest GHG emitters for both time horizons are solar (approximately 40 kg CO_2e/MWh), followed by pumped storage, small hydro, water diversion, battery storage, wind, and geothermal (all with less than 25 kg CO_2e/MWh). The 170 km of new transmission line produces 0.17 kg CO_2e/MWh for the 20 year and 0.16 CO_2e/MWh for the 100 year time horizon.
- Renewable energy resources (hydro, solar, wind and geothermal) produced significantly less amounts of GHG emissions per MWh. This may ultimately lead to the replacement of fossil thermal energy generation (diesel and LNG) in the long term, especially when these sources are coupled with battery storage technology and supported by hydro power. However, this must be considered in combination with a cost-benefit analysis.
- The application of 20 year and 100 year GWPs did not significantly change the results except for diesel, biogas, LNG and hydro options. This is due to the higher amounts of methane emissions since methane's GWP is three times higher in the 20 year time horizon scenario than it is for the 100 year time horizon. Methane emissions in biogas pathway originate mainly from anaerobic digestion and waste storage processes, while in the diesel pathway they originate from crude oil extraction. Methane emissions in hydro energy pathways come from biomass decomposition after land inundation. Wind, solar, geothermal, battery storage, transmission line, biomass gasification, and waste to energy produce emissions that are almost the same for both time horizons.
- The GHG emissions from biomass gasification, MSW conventional combustion, and MSW and biomass conventional combustion pathways strongly depend on the CHP plant efficiency and are reduced significantly (per MWh) when plants operate at higher efficiencies and all heat produced is utilized.
- Operations are the highest contributing life cycle stages to GHG emissions across all energy resources, except solar, wind, transmission line, battery storage and geothermal pathways

where materials acquisition, transportation, and plant construction (upstream life cycle stages) are the highest contributors. Diesel and LNG thermal plants also had notable GHG emissions contributions from upstream (fuel extraction and production) life cycle stages. Transmission line had 19% of GHG emissions from operation due to fuel consumption for yearly land clearing.

- Biogenic CO_2 emissions are reported separately as these emissions are considered carbon-neutral. The resource options that comprise biogenic emissions are biogas (902 kg biogenic CO_2/MWh), MSW (255 kg biogenic CO_2/MWh), combined MSW and biomass (356 kg biogenic CO_2/MWh), biomass gasification (755 kg biogenic CO_2/MWh), small hydro (5.29 kg biogenic CO_2/MWh), pumped storage (5.68 kg biogenic CO_2/MWh), and water diversion (17.46 kg biogenic CO_2/MWh and 6.45 kg biogenic CO_2/MWh for the 24 and 65 years lifetime, respectively).
- While GHG emissions from fossil sources are quite small for biogas and biomass gasification energy resources, waste to energy scenarios (MSW and MSW with biomass combustion) have notable fossil GHG emissions.
- The sensitivity analysis reveals that the choice of the technology and location of the manufacturing facilities (e.g. in North America versus oversees) can significantly impact the total life cycle emissions in the case of renewable energy sources where upstream life cycle stages are the largest contributors to the total life cycle GHG emissions.
- The technology pathways that may have a good potential to support other energy generation options such as small hydro are geothermal, as well as wind and solar coupled with battery storage. Hydro options, in turn, make it feasible to utilize other renewable sources. Pumped storage offers operational flexibility, since it can immediately respond to fluctuations in the demand for electricity. The flexibility and storage capacity of hydro options make then efficient and economical in supporting the use of intermittent sources of renewable energy, such as solar and wind, especially if these energy options are not coupled with battery storage. The waste to energy option has a potential to displace some fossil fuel-based sources, such as diesel and LNG, especially if produced heat is utilized to make the technology economically viable. However, the waste to energy pathway was found to produce a significant amount of fossil GHG emissions due to MSW combustion.
- The fixed GHG emissions originate from the plant construction (materials acquisition, transportation, components manufacturing, site clearing, etc.), while variable emissions come from the operation life cycle stage. The fixed emissions remain constant; however, variable emissions vary with power plant energy output. If power plant runs only occasionally (e.g. diesel and LNG power plants), the variable emissions are minimal.
- Site specific data on construction material requirements need to be obtained to better understand fixed GHG emissions from power plants construction in the waste to energy, small hydro, and pumped storage pathways. It is recommended to update fixed GHG emissions in these pathways when site and technology specific data become available.

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APPENDIX A: LIFE CYCLE INVENTORY – SUPPORTING INFORMATION

A.1 Scenario 1: Biomass Gasification

Table 1.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Concrete Steel Aluminum	Athena, 2005 GaBi Professional database (region: Canada)
Available biomass	Wood residues, spruce (left at the landing, in the harvest block and standing dead) – 5,600 tonnes/yr Sawmill residues – 2,000 tonnes/yr	Stantec, 2013[44]
Required biomass (based on net energy production)	Oven dry tonnes – 3,000 tonnes/year With 15% moisture content – 3,789 tonnes/year • Forest harvesting residues: 1,603 tonnes/year • Sawmill residues – 2,190 tonnes/year	Stantec, 2013
Biomass collection	Diesel consumption: 2.37 L/tonne Average collection distance is 100 km	Jones et al. 2010[45]
Size reduction by mobile wood chipper (roadside chipping)	Diesel consumption: 1.7 L/tonne of biomass	Jones et al., 2010
Transport of wood residues to the plant	Forest harvesting residues – 70km, truck, 9t payload Sawmill residues – 50 km, truck, 9t payload	Stantec, 2013
Transport of construction materials	2,400 km by truck, 22t payload	
Plant construction	No site preparation included – brownfield site 37.4 x 36.4 pre-engineered building (steel) +foundation (concrete) 2 x 250 kVA wood gasification generators <u>Plant Materials Requirements:</u> • Concrete: 6.2387 kg/MWh electricity produced • Steel: 1.7345 kg/MWh electricity produced	Stantec, 2013 Yukon Energy, 2016a[46] Stantec, 2016a[47]

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[47] Stantec. (2016a). Basis of Design (BOD). Thermal Energy Plant Study. Stantec Consulting LTD. June 2, 2016.

Process	Assumptions	Source
Biomass drying and gasification	Annual energy production (net): • 2,585 MWh_e -682 kWh_e/tonne of biomass • 8,059 MWh_{th} – 2,127 kWh_{th}/tonne of biomass Gasification and Energy Production GHG emissions (based on Nexterra Energy gasifier)[48] • CO_2 biogenic – 1,495.63 kg/tonne of biomass • CH_4 – trace only • N_2O – trace only	Stantec, 2016[49] Chan et al. (2008)[50]

A.2 Scenario 2: Municipal Solid Waste Combustion

Waste volumes potentially available to a WTE facility are presented in the Table below.

Table 2.1 Waste volumes potentially available to a WTE facility in Whitehorse[51]

Waste Stream	Current Diversion Rate		
	Annual Heating Value (GJ/yr)	Annual Waste Flow (tpy)	Weighted HHV (GJ/tonne)
MSW Generated within the City of Whitehorse	337,409	23,595	14.3
MSW Generated outside Whitehorse	35,231	2,669	13.2
Tires	8,970	299	30.0
Waste Oil	8,891	239	37.2
Abattoir Waste	500	250	2
Totals	***391,000***	***27,052***	***14.45****

** Annual Average HHV*

[48] Nexterra's gasifier emissions factors were used instead of the Community Power Corporation's (CPC) gasifier emissions factors. CPC couldn't be reached.
[49] Stantec. (2016). Biomass Technology Updated. January 15, 2016.
[50] Chan, B., Chan, B., and Young, C. (2008). Wood Pellet for UBC Boiler Replacing Natural Gas Based on LCA. UBC. April 11, 2008.
[51] Morrison Hershfield (2011). Waste to Energy Business Case Analysis (Final). Summary Report. Whitehorse, Yukon. September 6, 2011.

The City of Whitehorse MSW composition and heating values are shown in the Table 2.2.

Table 2.2. City of Whitehorse Waste Composition[52]

Material	Waste Composition Weighted Average (%)	Weight, Tonne/Year	Heat Content, Million BTU/Tonne
Paper	13.5	3545.64	6.7
Glass	1.3	341.43	0
Metal	6.7	1759.69	0
Plastic	9.1	2147.15	20.45
Organics	17.1	4491.14	5.2
Composite	9.3	2442.55	18.1
Wood Waste	15.3	4018.39	9.96
Inert Materials	2.3	604.07	0
Gypsum Wallboard	6.3	1654.63	0
Textiles	2.8	735.39	13.8
Rubber	0.4	105.06	26.86
Carpet and Underlay (PVC)	2.2	577.81	16.5
Electronic Waste	3.2	840.45	0
Personal Hygiene Products	2.5	656.60	7.51
Hazardous Waste	1.6	420.22	18.1
Biomedical Waste	0.5	131.32	18.1
Pet Waste	1.2	315.17	9.7
Fines	0.3	78.79	18.1
Fiberglass Insulation (Glass)	0.6	157.58	0
Other	3.7	971.77	18.1
MSW Total		**25994.86**	
Tires		299.00	
Waste Oil		239.00	
Abattoir Waste		250.00	
Total		**26782.86**	

Paper, wood waste, and organics are assumed to contribute to the biogenic CO_2 emissions. All other groups of waste contribute to fossil CO_2 emissions.

[52] Waste Composition Weighted Averages source: Walker & Associates (2010). City of Whitehorse Solid Waste Composition Study. Draft Report. Prepared for the City of Whitehorse.
Heat Content: Energy Information Administration (2007). Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy. U.S. Department of Energy, May 2007.

Table 2.3 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Concrete Steel Aluminum	Athena, 2005[53] GaBi Professional database (region: Canada)
Municipal Solid Waste and Biomass requirements	2015 feedstock: 16,100 tonnes MSW + 7,650 tonnes biomass 2035 feedstock: 23,750 tonnes MSW	Morrison Hershfield, 2012[54]
Biomass collection	Diesel consumption: 2.37 L/tonne Average collection distance is 100 km	Jones et al. 2010
Size reduction by mobile wood chipper (road side chipping)	Diesel consumption: 1.7 L/tonne of biomass	Jones et al., 2010
Transport of wood residues to the plant	Forest harvesting residues – 70km, truck, 9t payload Sawmill residues – 50km, truck, 9t payload	Stantec, 2013
Transport of MSW to plant	16km, truck, 9t payload	Morrison Hershfield, 2012
Transport of construction materials	Assumed 2,400 km by truck, 22t payload	GaBi database (region: Canada)
Plant construction	No site preparation included – brownfield site (2 ha) <u>Plant Materials Requirements</u> • Concrete: 22.3 kg/MWh electricity produced • Steel: 8.341 kg/MWh electricity produced • Aluminum: 0.065 kg/MWh electricity produced • Iron: 0.097 kg/MWh electricity produced	Morrison Hershfield, 2012 Spath and Mann, 1997[55]
Electricity Generation	Annual electricity production (net): 9,975 MWh_e/year Annual heat production (net): 23,700 MWh_{th}/year Energy production (net): • 420 kWh_e per tonne of MSW or MSW+biomass • 998 kWh_{th} per tonne of MSW or MSW+biomass The heat content of different groups of waste (Table 2.2) and the IPCC, 2006 MSW combustion emission	Morrison Hershfield, 2012

[53] Athena Institute. (2005). Cement and Structural Concrete Products: Life Cycle Inventory Update #2. Prepared by Athena Sustainable Materials Institute, Ottawa, Canada, 2005.
[54] Morrisson Hershfield. (2012). Waste to Energy Updated Design Basis and Business Case Analysis. April 24, 2012.
[55] Spath, P.L. and Mann, M. K. (1997). Life Cycle Assessment of a biomass Gasification Combined-Cycle System. NREL. December 1997.

Process	Assumptions	Source
	factors were used to estimate GHG emissions from waste combustion. MSW combustion emission factors Emissions factors, kg/TJ: CO_2 / CH_4 / N_2O Waste oil: 73300 / 30 / 4 MSW non biomass: 91700 / 30 / 4 Wood waste: 112000 / 30 / 4 Biomass: 100000 / 30 / 4	IPPC, 2006[56]

A.3 Scenario 3: Biogas Plant

The feedstock is residential and commercial organic waste collected in Whitehorse.

Organic waste characteristics are based on WSP, 2016[57].

Feedstocks	%TS	%VS	M³ Biogas/T VS	Density (KG/L)	Methane (%CH_4)
SSO from residential collection	36%	82%	600	0,9	60%
Green yard waste	31%	81%	380	0,8	55%
Dry yard waste	44%	86%	100	0,8	55%
SSO from ICI	23%	83%	600	0,9	60%

Note: %TS and %VS come from Wisconsin laboratory results and the other parameters come from the consultant's database.

TS – Total solid concentration, expressed as a fraction of the wet mass of the prepared feedstock.

VS – Volatile solid concentration, expressed as a function of the total solid mass.

Table 3.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Concrete Steel	Athena Institute, 2005
Collection and transport of organic waste	Organic waste transportation 16 km, truck, 9t payload 3.6144 tonnes of waste/MWh	WSP, 2016 (Based on mass balance - 2016)
Transport of construction materials	2,400 km by truck, 22t payload	Estimated

[56] IPPC. (2006). Incineration and Open Burning of Waste. Chapter 5. 2006 IPCC Guidelines for National Greenhouse Gas Inventories.
IPPC. (2006). Stationary Combustion. Chapter 2. 2006 IPCC Guidelines for National Greenhouse Gas Inventories.
[57] WSP (2016). Biogas Plant in Whitehorse. Feasibility Study. January 2016.

Process	Assumptions	Source
Plant construction	No site preparation included – brownfield site Plant construction (includes Anaerobic digester (AD) and CHP plant construction): Concrete: 21.4044 kg/MWh Steel: 5.2628 kg/MWh	EcoInvent, 2007[58] Whiting and Azapagic, 2014[59] Stantec, 2016a
Organic waste anaerobic digestion and electricity generation	Electric output: 56kWe (33kW$_e$ in April and 100 kW$_e$ in August) Thermal output: 64 kWt (37 kW$_t$ in April and 114 kW$_t$ in August) Total electricity produced (net): 885.9 MWh$_e$/yr Biogas heating value: 22 MJ/Nm^3 1 m^3 biogas = 2.135 kWh (electrical conversion efficiency = 35%) <u>AD plant emissions</u> CO_2 fossil 18.78 kg/MWh CH_4 (from AD plant) 2.58 kg/MWh N_2O 0.0282 kg/MWh <u>Biogas combustion emission factors (CHP)</u> CO_2 biogenic 1.926 kg/m^3 CH_4 0.000037 kg/m^3 N_2O 0.000035 kg/m^3	EcoInvent, 2007 Fusi et al., 2016[60] Ministry of Environment, BC (2016)[61]

[58] EcoInvent. (2007). Life Cycle Inventories of Bioenergy. Swiss Centre for Life Cycle Inventories.
[59] Whiting, A. and Azapagic, A. (2014). Life Cycle Environmental Impacts of Generating Electricity and Heat from Biogas Produced by Anaerobic Digestion. *Energy 70*, 181-193.
[60] Fusi, A., Bacenetti, J., Fiala, M. and Azapagic, A. (2016) Life Cycle Environmental Impacts of Electricity from Biogas Produced by Anaerobic Digestion. Fontiers in Bioengineering and Biotechnology, March 11, 2016.
[61] Ministry of Environment, BC. (2016). 2016/2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions. Including Guidance for Public Sectors Organizations, Local Governments and Community Emissions. Victoria, B.C., May, 2016.

A.4 Scenario 4: Geothermal Power Plant

A binary Organic Rankine Cycle (ORC) plant uses the high temperature steam and/or water from the production wells (called "geofluid") to heat a binary fluid, which most often is a hydrocarbon, with a low boiling point in a heat exchanger. The hydrocarbon fluid evaporates, producing the high-pressure vapour that is then expanded through a turbine. The turbine drives a generator to produce electric power.

Binary cycle power plants are closed-loop systems, and virtually nothing (except water vapor) is emitted to the atmosphere. The process diagram is shown in the Figure A.1.

After the geothermal fluid has heated the hydrocarbon fluid in the heat exchanger, it is reinjected into the reservoir through a reinjection well.

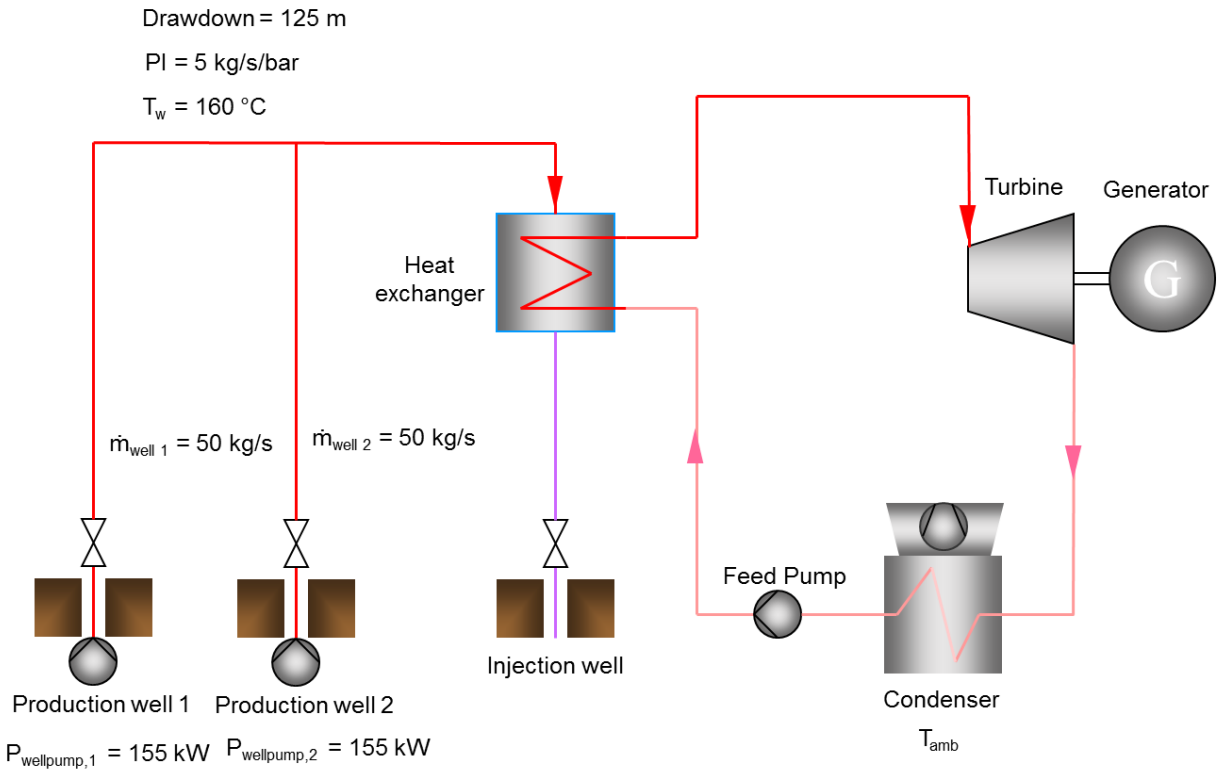

Figure A1. Organic Ranking Cycle Flowchart[62]

[62] KGS Group. (2016). Geothermal Review and Site Inventory. KGS Group, Winnipeg, Manitoba, May 2016.

Table 4.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, cast iron)	Athena, 2005 GaBi Professional database (region: Canada)
Transport of construction materials	2,400 km by truck, 22t payload	
Plant and transmission line construction	<u>Wells construction and installation (1.5km wells, including an exploration well)</u> Two production wells and one injection well would be located approximately 1 km apart. One exploration well will be drilled. • Steel, pipe welded: 0.566 kg/MWh • Cement: 0.373 kg/MWh • Diesel: 0.333 kg/MWh <u>Plant construction and installation</u> • Aluminum: 0.240 kg/MWh • Concrete: 2.385 kg/MWh • Cast Iron: 0.0222 kg/MWh • Steel, pipe welded: 1.200 kg/MWh • Diesel: 0.113 kg/MWh <u>Pipeline construction and installation (1,000m of piping)</u> • Diesel: 0.00162 kg/MWh • Steel, pipe welded: 1.85 kg/MWh • Cement: 0.456 kg/MWh <u>Greenfield site: Site preparation and access gravel road construction</u> Access road construction: • Diesel: 0.000232 kg/MWh • Gravel: 0.611 kg/MWh Site preparation: • Diesel: 800 L/km Transmission line construction (42 km of 138kV line)[63]	NETL, 2012[64] Sullivan et al., 2010[65] Yukon Energy, 2016[66]

[63] Refer to Scenario 12: Transmission Line for more information on line construction and operation.
[64] NETL. (2012). Role of Alternative Energy Sources: Geothermal Technology Assessment. National Energy technology Laboratory. U.S. Department of Energy. August 28, 2012.
[65] Sullivan, J.L., Clark, C.E., Han, J. and Wang, M. (2010). Life-Cycle Analysis Results of Geothermal Systems in Comparison to Other Power Systems. Argonne National Laboratory, Energy Systems Division, U.S. Department of Energy. August 2010.

Process	Assumptions	Source
Electricity Generation	Binary Organic Ranking Cycle (ORC) geothermal plant with 70% efficiency. Net electricity production: 48.2 GWh_e/yr	

A.5 Scenario 5: Wind Power Plant

The wind farm has a total capacity of 6 MW. Two different scenarios were modelled:

1. 4 wind turbines with a capacity of 1.5 MW each (sensitivity analysis scenario)
    a. Based on average wind farm technology used in the U.S.
    b. 55% of components are manufactured in China. The remaining 45% come from the U.S.
2. 3 wind turbines with a capacity of 2 MW each
    a. Based on Vesta V80 2 MW turbine manufactured in Denmark

Table 5.1 Data sources and assumptions for processes in the system boundaries – Scenario 1 – The U.S. average wind turbine

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, cast iron)	NETL, 2012a[67]
Transport of construction materials	It is assumed that 55% of wind farm components are manufactured oversees (China). The remaining 45% come from the US. Transmission line components are transported 2,400km by truck.	NETL, 2012a Estimated
Plant and transmission line construction	<u>Manufacture of Turbine Components</u> *Rotor (turbine rotor diameter 63m)* • Blades Glass fibers – 2,713 kg Carbon fibers – 399 kg Resin glue – 598kg Steel – 279 kg Electricity – 15,958 MJ • Hub Cast iron – 10,082 kg Electricity – 44,675 • Spinner, nose cone Glass fibers – 309.8 kg Resin glue – 464.7 kg	NETL, 2012a

[66] Yukon Energy. (2016). Diesel consumption for land clearing information provided by Shannon Mallory. July 2016.
[67] NETL. (2012a). Role of Alternative Energy Sources: Wind Technology Assessment. National Energy Technology Laboratory. U.S. Department of Energy. August 30, 2012.

Process	Assumptions	Source
	Electricity – 8,542 MJ *Nacelle* • Main Shaft and bearings Cold rolled steel – 5,241 kg Electricity – 445,491 MJ • Generator Cold rolled steel – 665 kg Copper – 3,574 kg Silicate – 1,759 kg Electricity – 1,361,570 MJ • Main frame Cast iron – 5,376 kg Cold rolled steel – 3,584 kg Electricity – 27,690 MJ • Nacelle cover Glass fibers – 2,153 kg Resin glue – 538.5 kg Electricity – 30,046 MJ *Tower* Cold rolled steel – 117,787 kg Electricity – 103,652 MJ <u>Plant construction</u> • Gravel road Diesel – 0.741 kg/m of gravel road Gravel – 2319.5 kg/ m of road • Switchyard and transformer Transformer – 105,000 kg/switchyard Mineral oil – 28,800 kg/switchyard Circuit breaker – 14,400 kg/switchyard Concrete – 690,000/ kg/switchyard <u>Greenfield site: Site preparation</u> • Diesel: 800 L/km Transmission line construction (7.6 km of 138kV line)	Yukon Energy, 2016
Electricity Generation	Net electricity production: 14.558 GWh_e/yr <u>Operation</u> Diesel – 0.000759 kg/MWh Lubrication oil – 0.0730 kg/MWh	NETL, 2012a

Table 5.2 Data sources and assumptions for processes in the system boundaries – Scenario 2 – Vesta V80 2 MW wind turbine

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, cast iron) Manufacturing of turbine in Denmark	Elsam, 2004[68]
Transport of construction materials	Turbine transport by sea – 5,578 km (Denmark – Montreal) Turbine transport by road – 5,560 km (Montreal – Whitehorse) Emissions from turbine transport CO_2 g/kWh CH_4 g/kWh N_2O g/kWh Transmission line components are transported 2,400km by truck.	Estimated
Plant and transmission line construction	Manufacture of Turbine Components Steel 223,140 kg/turbine Stainless steel 13,328 kg/turbine Cast iron 20,688 kg/turbine Glass fiber 21,507 kg/turbine Plastic 3,088 kg/turbine Cobber 2,816 kg/turbine Aluminum 1,678 kg/turbine Zinc 203 kg/turbine Concrete 805,000 kg/turbine Emissions from manufacturing CO_2 6.1 g/kWh CH_4 3.55E-03 g/kWh N_2O 2.06E-04 g/kWh Greenfield site: Site preparation • Diesel: 800 L/km Transmission line construction (7.6 km of 138kV line)	Elsam, 2004 Yukon Energy, 2016
Electricity Generation	Net electricity production: 14.558 GWh_e/yr Operation CO_2 0.69 g/kWh CH_4 4.83E-04 g/kWh N_2O 2.22E-05 g/kWh	Elsam, 2004

[68] Elsam. (2004). Life Cycle Assessment of offshore and onshore sited wind farms. Elsam Engineering A/S. October 20, 2004.

A.6 Scenario 6: Solar Power Plant

Table 6.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, cast iron)	NETL, 2012b[69]
Transport of construction materials	<u>Transport of solar panels</u> Fukuyama, Japan to Vancouver, BC – 7,664 km by sea Vancouver to Whitehorse – 2,400 km by truck, 22t payload	Estimated
Plant construction	Panasonic 330W panels; panel weight – 19 kg. Brownfield, no site preparation or access road construction is included • Plant construction and installation • PV module, array support, foundation, inverter, other components manufacturing and construction	NETL, 2012b Ito (2011)[70] Fthenakis and Kim (2010)[71]
Electricity Generation	<u>Operations</u> Diesel for fire pump engines and emergency generators – 0.02019 kg/MWh Gasoline for maintenance vehicles – 0.1005 kg/MWh Net electricity production: 5.2 GWh_e/yr	NETL, 2012b

[69] NETL (2012b). Role of Alternative Energy Sources: Solar Thermal Technology Assessment. National Energy Technology Laboratory. U.S. Department of Energy. August 28, 2012.
[70] Ito, M. (2011). Life Cycle Assessment of PV systems, Crystalline Silicon - Properties and Uses, Prof. Sukumar Basu (Ed.), ISBN: 978-953-307-587-7, InTech, http://www.intechopen.com/books/crystalline-silicon-properties-and-uses/life-cycle-assessment-of-pv-systems
[71] Fthenakis, V.M. and Kim, H.C. (2010). Photovoltaics: Life-cycle Analyses. *Solar Energy* 85, 1609-1628.

A.7 Scenario 7: Pumped Storage Hydro Power Plant

Table 7.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, cast iron)	Athena, 2005 GaBi Professional database (region: Canada)
Transport of construction materials	2,400 km by truck, 22 t payload	Estimated
Plant construction	<u>Greenfield site with inundation area of 354.2 ha</u> GHG emissions from inundation are estimated using IPPC, 2003 Tier 1 methodology: 5.68 kg CO_2/MWh 0.1466 kg CH_4/MWh 0.0029 kg N_2O/MWh <u>Plant Construction</u> Cement 3.42 g/kWh Gravel 29.8 g/kWh Reinforcing steel 0.06 g/kWh Steel for equipment 0.06 g/kWh Steel for tubes and anchors 0.14 g/kWh Copper 0.0099 g/kWh Explosives 0.02 g/kWh Diesel 0.0467 g/kWh Transmission line construction (2.6 km of 138kV line)	IPCC, 2003[72] Flury and Frischknecht, 2012[73]
Electricity Generation	Net electricity production: 54 GWh_e/yr	IEA, 2002[74]

Intergovernmental Panel on Climate Change Tier 1 approach to estimate GHG emissions from reservoirs (IPPC, 2003).

The IPCC has developed guidelines for estimating GHG emissions from flooded lands. The Tier 1 approach provides a simplified method for estimating GHG emissions. Only the first 10 years post-inundation are considered to be at the level estimated by the following equations. After 10 years, emissions are assumed to be negligible.

[72] IPPC (2003). *Good Practice Guidance for Land Use, Land-Use Change and Forestry*. J. Penman, M. Gytarsky, T. Hiraishi, T. Krug and D. Kruger (eds.). Institute for Global Environmental Strategies (IGES). 944 pp.
[73] Flury, K. and Frischknecht, R. (2012). Life Cycle Inventories of Hydroelectric Power Generation. ESU- Services. Commissioned by Öko-Institute e.V.
[74] IEA. (2002). Environmental and Health Impacts of Electricity Generation. A comparison of the Environmental Impacts of Hydropower with those of other Generation Technologies. The International Energy Agency – Implementing Agreement for hydropower Technologies and Programmes.

Equation 1: Tier 1 CO_2 Emissions from Flooded Lands

$$CO_{2\ emissions} = P * E(CO_2)_d * A_r$$

Where:

$CO_{2\ emissions}$ = total CO_2 emisisons from flooded lands, kg CO_2/yr;

P = period of emissions, usually 365 days for annual inventory estimates, d/yr;

$E(CO_2)_d$ = averaged daily diffusive emissions, with a default value of 15.5 kg CO_2 / ha /day;

A_r = total flooded surface area, ha.

Based on Equation 1, the Tier 1 CO_2 emissions for 354.2 ha of flooded area are 1,993,703 kg CO_2/yr or 5.68 kg CO_2/MWh.

Equation 2: Tier 1 CH_4 Emissions from Flooded Lands

$$CH_{4\ emissions} = P * E(CH_4)_d * A_r + P * E(CH_4)_b * A_r$$

Where:

$CH_{4\ emissions}$ = total CH_4 emisisons from flooded lands, kg CH_4/yr;

P = period of emissions, usually 365 days for annual inventory estimates, d/yr;

$E(CH_4)_d$ = averaged daily diffusive emissions, with a default value of 0.11 kg CH_4 / ha /day;

$E(CH_4)_b$ = averaged bubbles emissions, with a default value of 0.29 kg CH_4 / ha /day;

A_r = total flooded surface area, ha.

Based on Equation 2, the Tier 1 CH_4 emissions for 354.2 ha of flooded area are 51,450.4 kg CH_4/yr or 0.1466 kg CH_4/MWh.

Equation 3: Tier 1 N_2O Emissions from Flooded Lands

$$N_2O_{emissions} = P * E(N_2O)_d * A_r$$

Where:

$N_2O_{emissions}$ = total N_2O emisisons from flooded lands, kg N_2O/yr;

P = period of emissions, usually 365 days for annual inventory estimates, d/yr;

$E(N_2O)_d$ = averaged daily diffusive emissions, with a default value of 0.008 kg N_2O / ha /day;

A_r = total flooded surface area, ha.

Based on Equation 3, the Tier 1 N_2O emissions for 354.2 ha of flooded area are 1,029 kg N_2O/yr or 0.0029 kg N_2O/MWh.

A.8 Scenario 8: Small Hydro Power Plant

Table 8.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, cast iron)	Athena, 2005 GaBi Professional database (region: Canada)
Transport of construction materials	2,400 km by truck, 22 t payload	Estimated
Plant construction	<u>Greenfield site with inundation area of 190 ha</u> GHG emissions from inundation are estimated using IPPC, 2003 Tier 1 methodology: 5.2168 kg CO_2/MWh 0.1346 kg CH_4/MWh 0.0027 kg N_2O/MWh <u>Plant Construction</u> Concrete 17.9 g/kWh Gravel 14.3 g/kWh Steel 0.6689 g/kWh Aluminum 0.000345 g/kWh PE 0.117 g/kWh PVC 0.0251 g/kWh Cast iron 0.350 g/kWh Copper 0.00268 g/kWh Diesel 0.000687 MJ/kWh Transmission line construction (0.5 km of 138kV line)	IPCC, 2003 Flury and Frischknecht, 2012
Electricity Generation	Net electricity production: 31.7 GWh_e/yr	IEA, 2002

A.9 Scenario 9: Battery Storage

A lithium ion battery with an 8MW capacity and 5 hours discharge time was studied. The battery is a lithium iron phosphate cathode (hydrothermal) battery.

Lithium iron phosphate (LiFePO4) is a cathode material for lithium-iron batteries. It can be prepared hydrothermally or through a solid state technique. The hydrothermal pathway is selected (Dunn et al, 2014)[75].

Specific power density of different batteries varies significantly from one manufacturer to another. Two batteries from different manufacturers – UltraLife Corporation and SAFT Batteries were evaluated. The UltraLife Corporation's battery has a specific power density of 149 W/kg and the SAFT Batteries' specific power density is 60 W/kg.

Table 9.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, lithium iron phosphate, etc.) Battery lithium iron phosphate cathode (hydrothermal) battery <u>Battery manufacturing and assembly</u> Lithium iron phosphate ($LiFePO_4$) production CO_2 3.56 kg/kg $LiFePO_4$ CH_4 8.52 g/kg $LiFePO_4$ N_2O 76.06 mg/kg $LiFePO_4$ Battery production and assembly CO_2 4.36 kg/kg battery CH_4 9.21 g/ kg battery N_2O 81.25 mg/ kg battery CF_4 14.89 mg/ kg battery C_2F_6 2.05 mg/ kg battery 1 MW battery weight: 6,700kg (Ultalife)[76] 1 MW battery weight: 16,500kg (SAFT Batteries)[77]	GREET, 2015[78] Dunn et al., 2014
Transport of construction materials	<u>Battery transport</u> California to Alaska by sea – 3,226 km Alaska to Whitehorse -1,133 km by truck, 22t payload	Estimated

[75] Dunn et al. (2014). Material and Energy Flows in the Production of Cathode and Anode Materials for Lithium Ion Batteries. ANL/ESD/14/10.
[76] UltraLife Corporation https://www.ultralifecorporation.com/
[77] SAFT Batteries www.saftbatteries.com/
[78] GREET. (2015). GREET Model. The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model. Argonne National Laboratory https://greet.es.anl.gov/

Process	Assumptions	Source
Plant construction	Site preparation The site preparation includes clearing of 0.42 ha (4,200 m^2) area • Diesel: 800 L/km	Yukon Energy, 2016
Electricity Generation	Battery lifetime is 10-15 years. It's assumed that 1.5 batteries are required. Net electricity production: 2,780 MWh_e	

Lead Acid and Lithium-Ion Batteries Comparison

Lead acid and lithium ion batteries are two of the most popular energy storage technologies available, but have a significant impact on the environment. The environmental performance is primarily dependent on its lifetime durability and efficiency[79].

Lead acid batteries have been widely used for approximately 150 years and have proven to be a robust technology. However, extraction and processing of lead require significant amounts of energy and produce large amounts of pollution. Lead is a toxic substance, but the manufacturing and packaging technologies make the risk to humans insignificant. Fortunately, close to 98% of lead acid batteries are recycled in the United States[80]. Nevertheless, lead acid batteries include hazardous, flammable and explosive materials that present serious environmental risks[81,82]. In one study, analysis of a lead acid battery grid-connected to a photovoltaic system revealed that the overall climate change impact of the battery had a comparable CO_2e/year effect as driving over 4,000 km per year in a typical gasoline car. The overall conclusion was that there was a significant environmental impact[83]. Moreover, lead acid batteries are known for limitations in their useable capacity and number of charging cycles causing the need for early replacement. Their charging time can take longer compared to other battery types, and they have limited charging efficiency in that they may not store the full amount of power, which is problematic when charging using certain energy resources such as solar, where storing as much energy as possible is desirable before nightfall or cloud coverage. Another inefficiency of lead acid batteries is voltage sag, where lead acid batteries slowly lose their charge over time regardless of power use[84].

In the last few decades, lithium ion batteries have increased in use worldwide. They are known to perform better in colder climates, charge more quickly, can be charged more often before they reach

[79] Messagie, M., Oliveira, L., Rangaraju, S., Fomer, J.S., and Rivas, M.H. (2015). Rechargeable Lithium Batteries. From Fundamentals to Applications. Woodhead Publishing Series in Energy. pp. 303-318. doi:10.1016/B978-1-78242-090-3.00011-0

[80] http://www.batterycouncil.org/

[81] Zhanga, J., Chena, C., Zhangb, X., and Liua, S. (2016). Study on the environmental risk assessment of lead-acid batteries. Procedia Environmental Sciences 31: 873 – 879.

[82] Zhu, X., Li, L., Sun, X., Yang, D., Gao, L., Liu, J., Vasant Kumar, R., and Yang, J. (2001). Preparation of basic lead oxide from spent lead acid battery paste via chemical conversion. Hydrometallurgy.117:24-31.

[83] McKenna, E., McManus, M., Cooper, S., and Thomson, M. (2013). Economic and environmental impact of lead-acid batteries in grid-connected domestic PV systems. Applied Energy. 104: 239-249.

[84] Albright, G., Edie, J., and Al-Hallaj, S. (2012). A comparison of lead acid to lithium ion in stationary storage applications. AllCell Technologies. http://www.altenergymag.com/content.php?post_type=1884

their end of life, and have a longer lifespan compared to lead acid batteries[85,86]. Additionally, they can more easily deliver their full rated capacity of power and weigh about one-third to one-half of a standard lead acid battery, thus making them easier to transport. However, lithium ion technology does have its own environmental challenges[87]. Lithium ion batteries are comprised primarily of mined lithium carbonate, iron ore, aluminum and copper. Lithium mining is resource intensive, but lithium itself is only a small fraction of the battery. Therefore, the production and processing of the aluminum, copper and iron ore contribute more significantly to the overall environmental impacts. Additionally, compared to lead acid batteries, lithium ion batteries have a low recycling rate. However, it is expected that as the recovery and recycling technology matures, the battery materials will be recovered at rates comparable to lead acid batteries.

A.10 Scenario 10: Thermal Diesel Power Plant

Table 10.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum)	Athena, 2005 GaBi Professional database (region: Canada)
Crude oil extraction	Crude oil is extracted from Alaska's North Slope and Alberta (includes drilling and crude extraction)	Pembina, 2013 S&T^2, 2014
Crude oil processing	Crude oil is processed at Puget Sound refinery in the U.S.	GHGenius v4.03
Transport of construction materials, crude oil and diesel	<u>Construction materials transport</u> 2,400 km by truck, 22 t payload <u>Crude oil transport</u> Crude oil is transported to Puget Sound refinery via ocean vessel <u>Diesel transport</u> Ocean transport to Skagway - 1734 km (one way) Truck transport to Whitehorse - 354 km (round-trip)	 Estimated GHGenius v4.03 NREL LCI Database
Plant construction	<u>Site preparation</u> The site preparation includes clearing of 5 ha area • Diesel: 800 L/km <u>Plant construction</u>	 Yukon Energy, 2016 Stantec, 2016a

[85] Zubi, G., Dufo-López, R., Pardo, N, and Pasaoglu, G. (2016). Concept development and techno-economic assessment for a solar home system using lithium-ion battery for developing regions to provide electricity for lighting and electronic devices. Energy Conversion and Management. 122:439-448.
[86] Krieger, E.M., Cannarella, J., and Arnold, C.B. (2013). A comparison of lead-acid and lithium-based battery behavior and capacity fade in off-grid renewable charging applications. Energy. 60:492-500.
[87] Notter, D.A., Gauch, M., Widmer, R., Wäger, P., Stamp, A., Zah, R., and Althaus, HJ. (2010). Contribution of Li-Ion Batteries to the Environmental Impact of Electric Vehicles. *Environ. Sci. Technol.* 44: 6550–6556.

Process	Assumptions	Source
	• Concrete: 0.8423 kg/MWh electricity produced • Steel: 0.2825 kg/MWh electricity produced	Yukon Energy, 2016a
Electricity Generation	Net electricity production: 39.42 MWh_e/yr	S&T^2, 2014

A.11 Scenario 11: Thermal LNG Power Plant

Table 11.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum)	Athena, 2005 GaBi Professional database (region: Canada)
Natural gas extraction	Natural gas is extracted from conventional gas fields predominantly in Northeast BC and some from NW Alberta	Pembina, 2013 S&T^2, 2014
Natural gas processing	LNG is treated to remove impurities and liquefied at the Fortis BC Tillbury facility	GHGenius v4.03 S&T^2, 2014
Transport of construction materials, natural gas and LNG	Construction materials transport 2,400 km by truck, 22 t payload Natural gas transport Natural gas is delivered to the Fortis BC Tillbury facility from Spectra at Huntington Gate by pipeline LNG transport LNG is transported 5,440 km round trip by truck	Estimated GHGenius v4.03 Pembina, 2013 (LNG truck transport)
Plant construction	Site preparation The site preparation includes clearing of 6.5 ha area • Diesel: 800 L/km Plant construction • Concrete: 1.3932 kg/MWh electricity produced • Steel: 0.3208 kg/MWh electricity produced	Yukon Energy, 2016 Stantec, 2016a Yukon Energy, 2016a
Electricity Generation	LNG is vapourized and combusted to produce power in a Jenbacher generator operating at 46.3% efficiency (47% @ 90% load). Net electricity production: 39.42 MWh_e/yr	S&T^2, 2014 GHGenius v4.03

Methane Emissions from Natural Gas Life Cycle

Natural gas has been touted as a more environmentally friendly fuel. However, the extraction, processing and transportation of natural gas are not without concern. Fugitive, vented and flared methane emissions are present throughout the process, and the uncertainty surrounding the amount of emissions is disconcerting[88]. In order to fully understand the advantages of using natural gas, all emissions, from extraction to delivery and use, must be considered.

Fugitive emissions related to natural gas production and processing consist of (in this study, these emissions are included in the extraction of resources and fuel production life cycle stages):

- Emissions from venting and flaring of natural gas, waste gas, and vapour streams during production or processing;
- Emissions unrelated to venting and flaring, which are comprised of gas wellheads, well servicing, gas transportation, disposal activities, gas processing, storage, and combustion of fossil fuels that do not generate usable heat or electricity.

The key emission assessment issues are: (a) use of simple production-based emission factors is susceptible to excessive errors; (b) use of rigorous bottom-up approaches requires expert knowledge to apply and relies on detailed data which may be difficult and costly to obtain; and (c) measurement programmes are time consuming and very costly to perform.

The reported data for fugitive methane emissions vary widely[89]. This is due to the following key factors: 1) where the measurements are taken, 2) the method by which the measurement is taken, and 3) the implementation of measurement programmes is both costly and time consuming, and requires expert knowledge[90]. If there is an emission "hot spot" which has a higher-than-normal methane release, such as due to pipe or equipment failure, the reported data will not be representative of the entire gas stream. Conversely, if data are collected in an area that always has little to no leakage, fugitive emissions will be under-reported. As a result, there is a high degree of uncertainty in the available data on fugitive emissions[91].

Two different methods to collect fugitive emissions data are used. However, both of these also produce varying results. The first is a "bottom-up" approach. In this case, emissions are measured at a particular source, such as along a pipeline or the home that the fuel is being supplied to. While this provides a very accurate picture of a particular location, this method may miss critical components of the system that may lead to an inaccurate estimate. The second approach is "top-down" which measures methane concentrations at a pre-determined height (such as from an airplane or tall building) above a particular area. This method ensures that both high-emitting and low-emitting areas

[88]Greenhouse Gas Institute. (2016). Methane emissions from the oil and gas industry: is the world getting it right? http://ghginstitute.org/2016/07/18/methane-emissions-from-the-oil-and-gas-industry-is-the-world-getting-it-right/?utm_source=July+Newsletter+2016&utm_campaign=July+Newsletter+2016&utm_medium=email

[89] Zavala-Araiza et al. (2015). "Reconciling divergent estimates of oil and gas methane" *Proc Natl Acad Sci*. http://www.pnas.org/content/early/2015/12/03/1522126112.abstract

[90]IPCC. "Fugitive emissions from oil and natural gas activities." http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/2_6_Fugitive_Emissions_from_Oil_and_Natural_Gas.pdf

[91] NREL. (2015). Estimating U.S. Methane Emissions from the Natural Gas Supply Chain: Approaches, Uncertainties, Current Estimates, and Future Studies. http://www.nrel.gov/docs/fy16osti/62820.pdf

are accounted for. However, methane emissions unrelated to natural gas extraction are also included, thus giving higher concentrations. Additionally, this method does not identify specific troublesome areas since the measurements do not pinpoint which particular area contributed most to the measured methane levels[92]. To address this, some researchers have developed predictive models to determine which wells, or other emissions sources, may be at the greatest risk for releasing higher methane levels.

The difference in reported CH_4 emissions estimates can be seen when considering the available data in the 2015 and 2016 U.S. GHG inventories by the EPA[93,94]. The 2015 inventory reports data from 2012 that includes 23.3 MMT CO_2e from petroleum systems, and 154.4 MMT CO_2e from natural gas systems. However, the 2016 submission estimates emissions from 2012 to be 58.4 MMT CO_2e from petroleum systems, and 172.6 MMG CO_2e from natural gas. These comparisons are shown in Figure A.2 below.

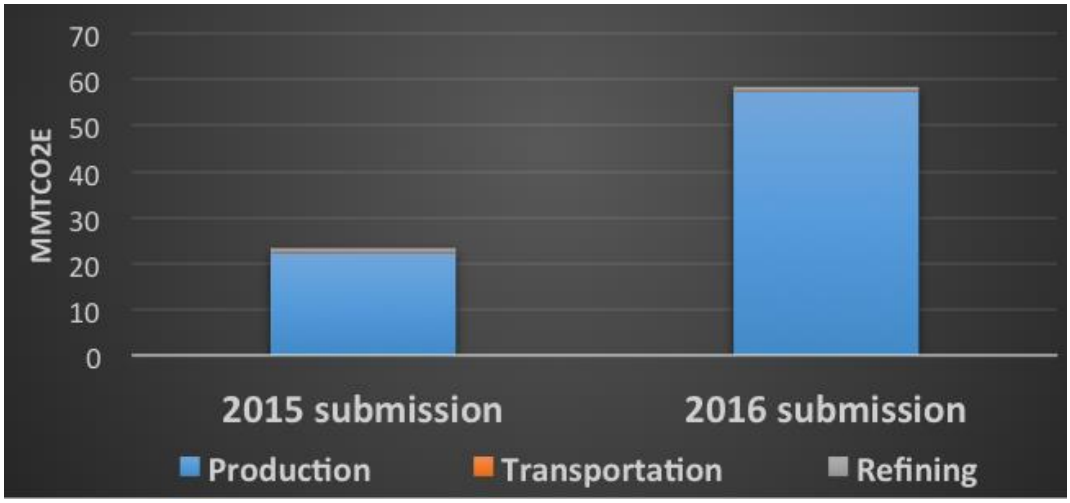

Figure A.2. Methane emissions from petroleum systems for the year 2012 in the 2015 and 2016 inventory submissions (Adapted from GHG Institute, 2016)

[92] EPA. Comparing top-down & bottom up estimates of oil & gas CH4 emissions: A spatially-resolved emission inventory for the Barnett Shale Region. (2015). https://www.epa.gov/sites/production/files/2015-09/documents/lyon_pres.pdf
[93] EPA. (2015). https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf
[94] EPA. (2016). https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html

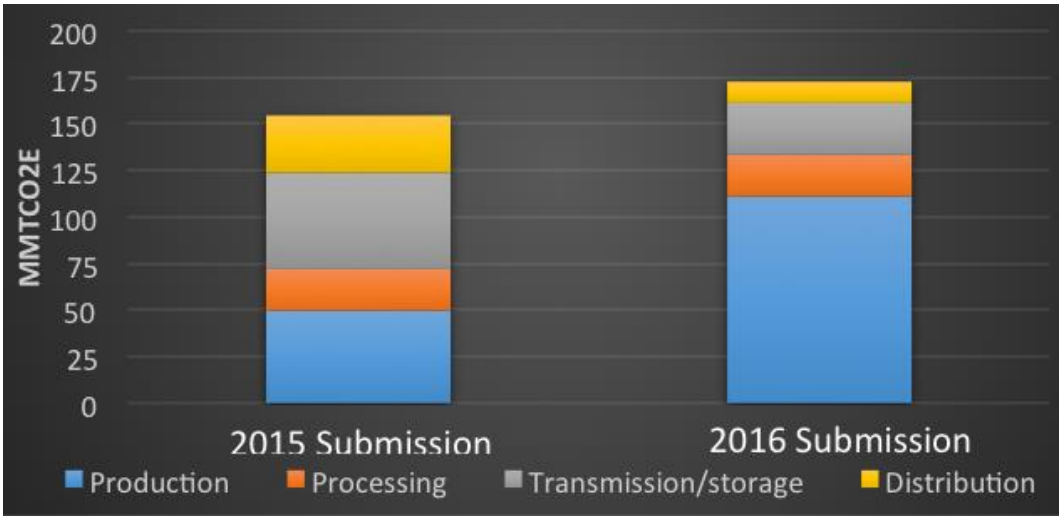

Figure A.3. Comparison of 2015 and 2016 inventory submissions for 2012 estimates of GHG emissions from natural gas (Adapted from GHG Institute, 2016)[95]

Improvements in reported estimates of GHG emissions are expected as new data and modelling techniques become available. In some estimates, only partial data sets are available when the inventory is performed, with the foreknowledge that they will be updated in the next inventory. In other instances, data may be extrapolated or recalculated based on more recent emission factors. Therefore, changes in the reported data are not surprising and are evidence of an industry and regulatory bodies working hard to determine emission impacts. This is a positive sign that suggests an evolving area of science attempting to keep abreast of the demands of climate change initiatives. However, this also signals that the accuracy of estimated emissions and the ability to carefully track the data is of concern. As a result, the 2006 IPCC Guidelines suggests a range of +/-100% uncertainty when applying their values to estimate natural gas methane emissions.

The application of correct emissions factors in order to estimate emissions is challenging. Many emissions in the oil and gas industry are unintentional and do not necessarily correlate with default emission factors; rather, they are dependent on the operation and condition of the specific equipment itself. When emission factors are unavailable, studies and assessments are forced to use generic emissions factors, regardless of the range of uncertainty. Therefore, understanding the inherent uncertainty is key to applying emissions factors in life cycle assessments.

Fugitive Emissions and Choice of Emission Factors

Significant differences can exist among data reported for fugitive emissions. The method in which data are collected, various modelling techniques, and the location where the data are collected contribute to the variability. Data on GHG emissions from natural gas extraction, transport and processing used in the LCA study of LNG pathway by Pembina Institute (Pembina, 2013) was extracted from CAPP, 2004[96]. While somewhat dated, the advantage is that the data are from Canadian sources.

[95] Production means natural gas extraction.
[96] CAPP. (2004). A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H_2S) Emissions by the Upstream Oil and Gas Industry.

The current standard in GHG accounting and reporting is to apply methodologies and emissions factors from the 2009 Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry developed by the American Petroleum Institute (API). This report included very specific data on fugitive emissions for equipment, components used in the natural gas field, facility use, onshore and offshore production, processing, transmission and storage equipment, stations and pipe material. However, close examination revealed that their source data was from the 1990s. Specifically, three reports from the EPA[97,98,99] are frequently referenced. The flare data for developed countries in the API 2009 Compendium came from a 2006 IPCC report.

The province of British Columbia published a Ministry of Environment Information Note (File: 280-30, CLIFF/tracking #: 197083) to address the amount of methane deliberately and/or accidentally vented into the atmosphere[100]. The emission intensity of CH_4 for the actual vented amount, according to the table below, is 0.00226 kg CH_4/m^3 of natural gas.

Table 11.2. Methane emissions into the atmosphere in BC in 2010 and 2011

Year	NG Production	Methane mass density	Methane amount	CO_2e amount if all released into Atm.	Actual Venting	% Vented out of Total Production	GWP
	m^3	kg/m^3	t CH_4	Mt CO_2e	Mt CO_2e		100 yr
2010	34,991,762,000	0.678	23724415	498.21	1.97	0.40%	21
2011	41,441,414,000	0.678	28097279	590.04	1.97	0.30%	21

The most updated fugitive emissions information come from a publication by Argonne National Laboratories dated 2015 that uses the GREET model[101]. The data used in the report originates from several sources, including data from the 1990s up to at least 2011. The model also included site-specific data and measurements from processing plants, urban distribution systems and natural gas gathering facilities. The reported data is shown in the Table 11.3 below.

[97] Harrison, M.R., L.M. Campbell, T.M. Shires, and R.M. Cowgill. (1996). Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report, Final Report, GRI-94/0257.1 and EPA-600/R-96-080b. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.
[98] Campbell, L.M., M.V. Campbell, and D.L. Epperson. (1996). Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.
[99] Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. (1999). Methane Emissions from the U.S. Petroleum Industry, Final Report, EPA-600/R-99-010. U.S. Environmental Protection Agency, February 1999.
[100] B.C. Ministry of Environment. (2013). Ministry of Environment Information Note. p. 8. http://docs.openinfo.gov.bc.ca/D331214A_Response_Package_MOE-2013-00244.PDF
[101] Argonne National Laboratory. (2015). Updated Fugitive Greenhouse Gas Emissions for Natural Gas Pathways in the GREET1_2015 Model. https://greet.es.anl.gov/files/fugitive-ch4-2015

Table 11.3. Summary of Methane Emissions in GREET1_2014 and GREET1_2015

Sector	Process	Unit	Conventional GREET1_2014	Shale GREET1_2014	Conventional GREET1_2015	Shale GREET1_2015	Conventional % Change	Shale % Change
Production	Completion	g CH_4/million Btu NG	0.5	12.4	0.5	7.2	0%	-42%
	Workover		0.0	2.5	0.0	1.4	0%	-42%
	Liquid Unloading		10.4	10.4	9.6	9.6	-7%	-7%
	Well Equipment		51.3	51.3	52.2	52.2	2%	2%
Processing	Processing	g CH_4/million Btu NG	26.7	26.7	26.7	26.7	0%	0%
Transmission	Transmission and Storage	g CH_4/million Btu NG	81.2	81.2	84.5	84.5	4%	4%
Distribution	Distribution	g CH_4/million Btu NG	83.1	83.1	88.9	88.9	7%	7%
Distribution	Distribution (station pathway)	g CH4/million Btu NG	63.6	63.6	69.1	69.1	9%	9%
Total		**g CH_4/million Btu NG**	**253.2**	**267.5**	**262.4**	**270.5**	**4%**	**1%**
Total (station pathway)		**g CH_4/million Btu NG**	**233.8**	**248.1**	**242.5**	**250.6**	**4%**	**1%**

According to the API 2009 report, uncertainties in methane emissions can be as high as +/- 200%, therefore, it becomes challenging to compare numbers from one set of calculations to another.

In this study, the Canadian data from CAPP, 2004 and GHGenius v4.03 was used. Emissions due to gas leaks and flares are captured under a separate category ("gas leaks and flares") in GHGenius. This helps to separate these emissions from other GHG emissions resulting from, for example, well exploration, well drilling, well completion, and acid gas removal.

A.12 Scenario 12: Transmission Line

Table 12.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials extraction and processing (steel, concrete, aluminum, cast iron, etc.)	Athena, 2005 GaBi Professional database (region: Canada)
Transport of construction materials	Transmission line components are transported 2,400 km by truck, 22t payload.	Estimated
Transmissions Line construction	<u>Line Construction</u> Steel 1.54E-04 kg/km Concrete 6.01E-04 kg/km Aluminum 5.37E-05 kg/km Cement 2.84E-07 m^3/km Lead 7.80E-06 kg/km Glass 4.58E-06 kg/km Bronze 1.79E-06 kg/km Copper 4.80E-06 kg/km Mineral oil 5.35E-06 kg/km Pp 1.06E-06 kg/km Paper 2.12E-06 kg/km Sand 8.93E-04 kg/km Zinc 3.46E-06 kg/km Cement 8.98E-16 kg/km <u>Land clearing</u> 170 km line, 30m right of way clearing and 68 km x 15m of an existing 34.5kv line (306 ha plus 102 ha of cleared area footprint) Initial vegetation clearing – 800 L of diesel/km Yearly vegetation clearing – 210 L of diesel/km <u>Diesel emission factors</u> Emissions factors, kg/L CO_2 CH_4 N_2O Diesel fuel 2.663 0.133 0.4	Itten et al., 2014[102] Yukon Energy Correspondence, 2016 WRI, 2010
Electricity Transmissions	Transfer Capacity: 443 MW, 230 kV transmission line	

[102] Itten, R., Frischknecht, R., and Stucki, M. (2014). Life Cycle Inventories of Electricity Mixes and Grid. Version 1.3. treeze Ltd., Switzerland, June, 2014.

A.13 Scenario 13: Water Diversion Project

Table 13.1 Data sources and assumptions for processes in the system boundaries

Process	Assumptions	Source
Construction materials extraction and processing	Raw materials (gravel, sand) are sourced locally.	
Transport of construction materials	Locally sourced materials are used Transport distance: 15 km by truck, 22 t payload	Estimated
Diversion channels and dam construction	Partial greenfield site with inundation area of 220 ha GHG emissions from inundation are estimated using IPPC, 2003 Tier 1 methodology: 17.4614 kg CO_2/MWh 0.4506 kg CH_4/MWh 0.0090 kg N_2O/MWh Channel excavation and dam construction Excavation by a single-bucket excavator Excavation rate: 130 m^3/hr Diesel consumption: 23 L/hr or 0.1769 L/ m^3 Channel excavation quantities 514,000 m^3 Quantities for Dam D (gravel till, impervious till, sand) 234,100 m^3	IPCC, 2003 Estimated AECOM, 2011[103]
Electricity Generation	Net electricity production: 29.7 GWh_e/yr – the project would utilize existing Hydro units.	

[103] AECOM. (2011). Gladstone Diversion Concept Conceptual Design. AECOM, May, 2011.

Appendix 5.2 Environmental, Social and Economic Attribute Evaluation of Resource Options (Intergroup, EDI, Ecofor and CNC 2016)

RESOURCE OPTIONS EVALUATION

FINAL REPORT

PREPARED FOR

YUKON ENERGY CORPORATION

BY

INTERGROUP CONSULTANTS LTD.

IN ASSOCIATION WITH EDI, ECOFOR AND CNC

DECEMBER 2016

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December 16, 2016

Marc-André Lavigne
Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, Yukon Y1A 6S7

Dear Mr. Lavigne:

Re: Resource Options Evaluation – Revised Final Report

Please find enclosed a PDF version of the revised final report for the Yukon Energy Corporation Resource Options Evaluation prepared by InterGroup Consultants Ltd. in association with EDI Environmental Dynamics Inc., Ecofor Consulting Ltd. and Campbell's North Consulting. The revised report contains updated economic information as provided by Yukon Energy on specific resource options, including an evaluation of one new option (i.e., the Anvil Creek small hydro site option).

This study supports Yukon Energy's current 2016 Resource Plan update by providing a comparative evaluation of more than 45 power generation and transmission resource options in Yukon and northern British Columbia against more than 40 environmental, social and economic indicators. No attempt is made to evaluate resource options in the context of forecast grid loads. The ratings for each indicator show on a common scale (low, medium and high) which indicators are particularly relevant to each resource option, without attempting to provide an overall ranking of these options.

This final revised report addresses comments received from Yukon Energy on the earlier report. We thank you for the opportunity to work on this project.

Yours truly,

INTERGROUP CONSULTANTS LTD.

Mona Pollitt-Smith
Principal and Consultant

Cam Osler
Chair/Principal

Attachment

TABLE OF CONTENTS

1.0 INTRODUCTION AND OVERVIEW 1
1.1 OVERVIEW OF RESOURCE OPTIONS 1
1.2 OVERVIEW OF EVALUATION APPROACH 6
2.0 EVALUATION OF RESOURCE OPTIONS 11
2.1 OVERVIEW 11
2.2 ENVIRONMENTAL EVALUATION OF RESOURCE OPTIONS 11
2.3 SOCIAL EVALUATION OF RESOURCE OPTIONS 20
2.4 ECONOMIC EVALUATION OF RESOURCE OPTIONS 32
3.0 SUMMARY AND CONCLUSIONS 39

APPENDICES

APPENDIX A: Project Summaries
APPENDIX B: Evaluation Approach – Criteria and Indicators
APPENDIX C: Environmental Evaluation Technical Report
APPENDIX D: Social Evaluation Technical Report
APPENDIX E: Economic Evaluation Technical Report

LIST OF TABLES

Table 1: Overview of Resource Options Evaluated 3
Table 2: Overview of Environmental, Social and Economic Evaluation Criteria, Indicators and Metrics 7
Table 3: Summary of Thermal Generation Option High & Medium Evaluations 42
Table 4: Summary of Other Non-Hydro Renewable Option High & Medium Evaluations 43
Table 5: Summary of Hydro Generation Option High & Medium Evaluations 44
Table 6: Summary of Transmission Corridor Option High & Medium Evaluations 45

LIST OF FIGURES

Figure 1: Rating Criteria for Indicator Evaluations 10
Figure 2: Evaluation of RP Resource Options - Environmental Criteria & Indicators 19
Figure 3: Evaluation of RP Resource Options - Social Criteria & Indicators 31
Figure 4: Evaluation of RP Resource Options - Economic Criteria & Indicators 38

1.0 INTRODUCTION AND OVERVIEW

This report supports Yukon Energy Corporation's (Yukon Energy's) current 2016 Resource Plan (RP) update by providing an evaluation against environmental, social and economic attributes of potential power generation and transmission resource options as inventoried by Yukon Energy to meet long-term load forecasts (2016-2035).

InterGroup Consultants Ltd. (InterGroup) has prepared this report in association with EDI Environmental Dynamics Inc. (EDI), Ecofor Consulting Ltd. (Ecofor) and Campbell's North Consulting (CNC). The evaluation is based on publicly available information and information from inventoried resource option project reports and other reports provided by Yukon Energy. No attempt is made in this report to evaluate resource options in the context of forecast Yukon Energy loads. Resource portfolio option definition and assessment in the context of long-term load forecasts will be done subsequently by Yukon Energy as part of the current RP update.

Section 1 of this report provides an overview of the resource options examined and the evaluation approach adopted. Section 2 provides the summary evaluation of the resource options against the environmental, social and economic criteria and indicators. Section 3 provides an overall summary and conclusions.

This report summarizes more detailed analysis provided in the following appendices:

- **Appendix A: Project Summaries**, which summarizes key information from Yukon Energy's resource option reports.
- **Appendix B: Evaluation Approach - Criteria & Indicators**, which reviews overall criteria, indicators, metrics and methods used to compare and rank resource options.
- **Appendix C: Environmental Evaluation - Technical Report**, which provides details on methodology, ranking approach and evaluation of resource options against environmental criteria.
- **Appendix D: Social Evaluation - Technical Report**, which provides details on methodology, ranking approach and evaluation of resource options against social criteria.
- **Appendix E: Economic Evaluation - Technical Report**, which provides details on methodology, ranking approach and evaluation of resource options against economic criteria.

1.1 OVERVIEW OF RESOURCE OPTIONS

The more than 45 resource options evaluated in this report are summarized below by technology groups. (See Table 1 for a list of the options and a summary of locations and key attributes. See Appendix A for added details.)

- **Fossil Thermal:** Diesel and Liquefied Natural Gas (LNG) 20 MW options - each in Whitehorse with two site options.

- **Non-Fossil Thermal:** Waste-to-energy and Biogas in Whitehorse, Biomass in Haines Junction (each small scale, i.e., less than 2 MW).
- **Other Non-Hydro Renewable:** Storage Battery option at Whitehorse (2 technologies); Solar PV in Whitehorse and Haines Junction (different scale options up to 10 MW); Wind farms (seven 20 MW site options examined); and Geothermal options (2 sites, average 1.6 to 3.8 MW).
- **Hydro Generation:** 8 pumped storage site options (2 scales of development at 2 sites - overall range 15 to 40 MW), 6 small hydro site options (5.7 to 20 MW range), 4 other hydro options to enhance existing generation (diversion or storage), and 2 refurbishment options (1 to 2.3 MW).
- **Transmission Corridors:** 6 options (the Stewart-Keno City transmission option, which was recently recommended in a Yukon Environment and Socio-economic Assessment Board [YESAB] report, is the only option that addresses an existing corridor).

Photo courtesy of: InterGroup Consultants Ltd.

Table 1: Overview of Resource Options Evaluated

Resource Options	Installed Capacity (MW)	Annual Average Energy (GWh)	Assumed Economic Life (years)	Comments
Fossil Thermal				
Diesel: 20 MW - Whitehorse	20.0	up to >166	20-40	Largest scale options at 2 locations (Whitehorse landfill & Takhini substation). Economic life reflects expected backup use.
Diesel: 20 MW - Takhini	20.0	up to >166	20-40	
LNG: 20 MW - Whitehorse	20.0	up to >166	20-40	
LNG: 20 MW - Takhini	20.0	up to >166	20-40	
Non-Fossil Thermal				
Waste to Energy	1.6	10.0	25	Unspecified Whitehorse location - need sale of waste heat.
Biogas (CHP)	0.2	0.4	20	Whitehorse landfill
Biomass 0.5 MW Boiler / Steam Turbine	0.5	3.2	20	Haines Junction-sale of waste heat-beetle-kill biomass.
Other Non-Hydro Renewable				
Storage Battery: 4 MW, 40 MW.h (lead acid, 10hrs)	4.0	0.04	30	Whitehorse-Takhini substation & some use of adjacent land. (Two technology options noted).
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	8.0	0.04	30	
Solar PV: Whitehorse Fixed Tilt: 1 MW	1.0	1	30	Range of development scales at two potential locations with lowest LCOE of technologies examined (Whitehorse Copper Mine Quarry location, and Haines Junction location at about 1 km from dump). Evaluations focus on largest scale option at each location.
Solar PV: Whitehorse Fixed Tilt: 5 MW	5.0	5	30	
Solar PV: Whitehorse Fixed Tilt: 10 MW	10.0	10	30	
Solar PV: Haines Junction Fixed Tilt: 1 MW	1.0	1	30	
Solar PV: Haines Junction Fixed Tilt: 5 MW	5.0	5	30	
Wind: Cyprus Mine Hill, 20 MW	20.0	50	25	Seven preferred site options, each evaluated at largest scale examined (20 MW). Kluane site requires added transmission to grid (unless Aishihik-Destruction Bay Transmission Corridor is developed).
Wind: Kluane Lake, 20 MW	20.0	48	25	
Wind: Miller's Ridge, 20 MW	20.0	57	25	
Wind: Mt. Sumanik , 20 MW	20.0	42	25	
Wind: Sugarloaf Mountain, 20 MW	20.0	32	25	
Wind: Tehcho (Ferry Hill), 20 MW	20.0	33	25	
Wind: Thulsoo Mountain, 20 MW	20.0	54	25	
Geothermal: McArthur Springs (3.8 MW Av.)	3.8	25	30	Two site options. Scale of development shown in each case is average of potential range identified (need drilling to define).
Geothermal: Vista Mountain (1.6 MW Av.)	1.6	11	30	
Hydro Generation				
Pumped Storage: Moon Lake (Tutshi-Moon)	20.2	54	65	Eight preferred site options evaluated (two sites also have 2 scale options for development). Evaluations focus normally on site and largest option for that site (current initial estimates for land areas affected not typically sensitive to scale options at a site). Moon Lake option based on Midgard report, and Vangorda Pit option based on EP report (all other sites based on KP report). All sites other than Canyon-Ittlemit and Vangorda Pit require added transmission to connect to grid (unless relevant Transmission Corridor developed). Most sites are in B.C. (i.e., all except the last three listed).
Pumped Storage: Racine - Moon	15.0	50	65	
Pumped Storage: Lindeman-Fraser	15.0	50	65	
Pumped Storage: Racine - Mt. Brown	15.0	50	65	
Pumped Storage: Racine - Mt. Brown	25.0	100	65	
Pumped Storage: Atlin - Black Mountain	15.0	50	65	
Pumped Storage: Atlin - Black Mountain	25.0	100	65	
Pumped Storage: Squanga - Dalayee	25.0	100	65	
Pumped Storage: Canyon - Ittlemit	25.0	100	65	
Pumped Storage: Vangorda Pit	40.0	134	50-65	
Small Hydro: Drury Lake	8.1	32	65	Six preferred site options evaluated - each site has storage, except for Wolf River (run of river). Atlin/Pine Creek option is expansion of existing hydro site (Morrison Hershfield report) in B.C., with transmission connection needed to Yukon grid. Drury Lake and Anvil Creek are only site options not requiring added transmission to connect to grid (absent Transmission Corridor development).
Small Hydro: Tutshi - Windy Arm	7.2	57	65	
Small Hydro: Wolf River	20.0	96	65	
Small Hydro: Finlayson River	17.6	139	65	
Small Hydro: Anvil Creek	9.8	41	65	
Small Hydro: Atlin/Pine Creek	5.7	36.3 avail to Yukon	65	
Other Hydro: Gladstone Diversion	NA	37	65	Diverts waters into Aishihik existing hydro reservoir.
Other Hydro: Southern Lakes Storage	1.0	6	NA	Extends storage into fall for existing Whitehorse hydro.
Other Hydro: Mayo Lake Storage	NA	2 to 4	NA	Adds bottom storage for existing Mayo hydro.
Other Hydro: Mayo Dredging	NA	1 to 2	NA	Removes sediment built up in Mayo Lake Outlet Channel.
Aishihik Re-runnering	1.0	3	NA	Refurbishing existing hydro generation units at Aishihik and at Mayo.
Mayo A Refurbishment	2.3	10	65	
Transmission Corridors	Transfer Capacity			
Transmission: Whitehorse - Atlin (138 kV)	97	NA	45	Six options examined for transmission corridors (options are not tied to any specific loads or generation projects, but many would provide transmission connection for other generation resource options [wind or hydro generation]). The Stewart-Keno City option was recently recommended in YESAB Screening Report (replace end-of-life line and enhance overall voltage).
Transmission: Whitehorse - Skagway (230 kV)	443	NA	45	
Transmission: Whitehorse - Teslin (138 kV)	95	NA	45	
Transmission: Faro - Watson Lake (230 kV)	190	NA	45	
Transmission: Aishihik - Destruction Bay (230 kV)	484	NA	45	
Transmission: Stewart-Keno City (138 kV & substations)	NA	NA	45	

In order to simplify the evaluations, variations in technologies for a specific resource option and/or smaller scale development alternatives for a specific resource option are generally ignored in this report. Where new transmission is required to connect an option to the grid, this requirement is reflected in the assessment where feasible. In order to avoid variances related to different possible utilization levels and/or ownership options, all options are assumed to be fully utilized (with the potential exception of fossil fuel thermal generation) and to be developed by Yukon Energy. A weighted average cost of capital of 3.38% (net of inflation) reflective of Yukon Energy costs is assumed when reviewing Levelized Cost of Energy (LCOE) for different resource options over an option's economic life.

GIS mapping of resource options to assist in the evaluations was developed to the extent feasible and based on available Yukon Energy reports, which in most cases were preliminary initial assessments. Buffer areas were assumed in the land area assessments where appropriate. Best management practices (BMPs) were assumed for each resource option's construction and operation, and each option was examined assuming that feasibility planning and environmental/socio-economic impact assessment was not yet feasible (although hydro storage enhancement options, Mayo Lake Outlet Channel Dredging, Stewart-Keno City transmission, and Gladstone Diversion have each already been subject to extensive examinations as compared to most other options).

The resource options in Table 1 cover a wide range of energy and/or capacity scales, as well as varying energy attributes:

- Fossil fuel thermal generation options (Diesel and LNG) each provide firm capacity of 20 MW and a wide range of dispatchable energy generation options up to 166 GWh/yr.; economic life varies from 20 to 40 years depending on whether these options are used for backup generation (e.g., for peak, winter, emergency or drought periods), which tends to extend unit life versus regular annual full use of capacity which would imply a 20 year life. Current resource studies have not examined waste heat use options for fossil fuel thermal generation options.
- Non-fossil thermal generation options, as well as geothermal options are each relatively small:
    - Capacity ranges from 0.2 to 3.8 MW (Geothermal estimates are an average of potentials for each site).
    - Annual energy initial year generation ranges from 0.4 GWh/year (biogas) to 33.4 GWh/year (geothermal option at McArthur Springs), with economic lives from 20 to 30 years (biogas and biomass at 20 years, waste-to-energy at 25 years, geothermal at 30 years).
    - These options are assumed to run year round with high utilization; waste-to-energy and biomass option waste heat is assumed to be fully utilized to displace other heating fuels.
    - Geothermal net capability is enhanced in winter, and declines at about 2% per year over the economic life without drilling of additional maintenance wells. e.g., lifetime average annual generation approximates 75.6% of the initial year generation.

- Other renewable energy generation-related options show a wide range of installed capacity and annual energy generation:
    - Solar PV is relatively small (1.1 to 10.2 GWh/year with 1 to 10 MW), with energy focused from March to August and limited from November through February. Options have an assumed 30 year life.
    - Wind at 20 MW per site ranges from 32.3 to 57.3 GWh/year, depending on site attributes and an assumed 25 year life. One of the seven wind site options (i.e., Kluane) requires added transmission corridor development to connect with the grid.
    - Small hydro sites range from 31.7 to 138.9 GWh/year, reflecting installed capacity ranging from 5.7 to 20 MW per site; except for Wolf River (which is run-of-river), each site has storage (requires a dam), which allows energy to be focused in winter months. Options were constrained to 20 MW, and some sites, such as Wolf River and Finlayson River, could likely accommodate higher capacities and energy generation than assumed in this evaluation. All small hydro options have an assumed 65 year life. All but two of the six small hydro site options (i.e., all but Drury Lake and Anvil Creek) require added transmission corridor development to connect with the grid. The Atlin-Pine Creek small hydro site is in B.C.
    - Pumped storage hydro sites range from 50 to 134 GWh/year, reflecting installed capacity ranging from 15 to 40 MW; generation is focused in winter months. All pumped storage options have an assumed 65 year life. These options also each need adequate non-winter surplus energy for the required pumping during summer months. All but two of the eight pumped storage hydro site options (i.e., all but Vangorda Pit and Canyon-Ittlemit) require added transmission corridor development to connect with the grid. Five of the eight pumped storage hydro sites are in B.C.
    - Gladstone Diversion provides up to 36.6 GWh of winter energy and has an assumed 65 year life.
    - Other hydro projects, which range from 2 to 10 GWh/year, affect existing hydro operations, e.g., storage enhancements, channel dredging, refurbishments.
- Other resource options are not directly related to generation of energy:
    - The energy storage battery option would facilitate energy storage to support variable renewable generation, e.g., wind or solar generation. This option has an assumed 30 year economic life.
    - Transmission corridor development options would facilitate access to some of the hydro and wind generation sites, as well as potential new markets for renewable generation (e.g., Skagway cruise ships, new mine developments that otherwise would be supplied by fossil fuel generation, diesel generation communities that are not currently connected to the hydro grid). Transmission corridor options have an assumed 45 year economic life.

1.2 OVERVIEW OF EVALUATION APPROACH

The evaluation approach displays key differences among the resource options, rather than attempting an overall ranking of these options. Accordingly, separate summary evaluation matrix tables are provided for each of the three main sets of attributes (i.e., environmental, social, and economic), and each evaluation matrix table has a range of separate criteria and indicators to be addressed:

- Each evaluation matrix includes multiple criteria (five environmental criteria, five social criteria, and two economic criteria) to address different aspects of each attribute that are important.
- Multiple indicators are also included for each criteria (with only one exception), resulting in 16 environmental indicators, 17 social indicators (including one that is also a criteria) and 8 economic indicators.
- Each resource option is evaluated separately for each indicator adopted for each of the criteria.

Table 2 provides an overview of the criteria, indicators and metrics adopted for each of the three main evaluations (see Appendix B for added details).

Photos courtesy of InterGroup Consultants Ltd.

Table 2: Overview of Environmental, Social and Economic Evaluation Criteria, Indicators and Metrics

Evaluation of Resource Options - Environmental Criteria & Indicators

Aquatic Environment

Criteria	Fish & Fish Habitat (En1)			Water Quantity & Quality (En2)		
Indicators	Salmon & Habitat (En1-1)	Species at Risk & Habitat (En1-2)	Commercial, Recreational & Aboriginal Fisheries Species & Habitat (En1-3)	Consumptive Water Use (En2-1)	Relative Scale of New Impoundment / Flooding (En2-2)	Flow Changes (En2-3)
Metric	Presence or absence (Y/N) & Relative Impact (+/-)	Presence or absence (Y/N) & Relative Impact (+/-)	Presence or absence (Y/N) & Relative Impact (+/-)	Water Use Intensity (m^3/day)	Presence or absence (Y/N) & Relative Scale (L/MH)	Presence or absence (Y/N) & Relative Scale (L/MH)

Terrestrial Environment

Criteria	Terrestrial Species & Habitat (En3)				Terrestrial Footprint & Land Use (En4)			
Indicators	Species at Risk & Habitat (En3-1)	Protected & Conservation Areas (En3-2)	Wildlife Key Areas (En3-3)	Caribou Ranges (En3-4)	Footprint Terrestrial Area (En4-1)	Linear Dev for Roads / Transmission (En4-2)	Permafrost (En4-3)	Wetlands (En4-4)
Metric	Presence or absence (Y/N) & Relative Impact (+/-)	Proximity to Protected & Conservation Area (L/M/H)	Proximity to WKAs (L/M/H)	Proximity to Caribou Ranges (L/M/H)	Area of Terrestrial Footprint (km^2)	Total Length of Linear Features (km)	Presence or absence (Y/N) & Relative Scale (L/MH)	Presence or absence (Y/N) & Relative Scale (L/MH)

Air

Criteria	Air Quality (En5)		
Indicators	GHG Emissions (En5-1)		Other Air Pollutants (En5-2)
Metric	with Biogenic CO2 --intensity per kWh	without Biogenic CO2 - intensity per kW.h	intensity per kWh

Evaluation of Resource Options - Social Criteria & Indicators

Criteria	First Nation Lands (S1)	Traditional Lifestyle (S2)				Heritage Resources (S3)		Tourism, Recreation & Other Resources and Land Use (S4)					Cultural & Community Well-being (S5)		
Indicators	First Nation Settlement Lands / Interim Protected Lands (S1-1)	Footprint Land Area Impact (S2-1)	Land Area Loss Re: Traditional Lifestyle (S2-2)	Land Quality Effects on Traditional Lifestyle (S2-3)	Cabins, Camps & Structures (S2-4)	Country Foods (S2-4)	Density of Heritage Resources (S3-1)	Importance / Cultural Value of Heritage Resources (S3-2)	Recreational Values (S4-1)	Tourism Values (S4-2)	Aesthetics (S4-3)	Non-renewable Resources (S4-4)	Other Renewable Resources (S4-5)	Land Use & Renewable Resources Plans (S4-6)	Infrastructure & Services (S5-1)	Public Safety, Worker Interaction, Human & Community Health (S5-2)	Community, First Nation & Personal Development (S5-3)
Metric	Overlap and/or access with these lands (Y/Potential/N)	Total area (ha) of direct land use	Total area (ha) of Traditional Use land area loss	Indirect effects on land or access for such pursuits (+/-; L/M/H)	Number in footprint that may be affected	Effects to opportunity to harvest (+/-, L/M/H)	Density of known or potential heritage resources	Importance/ Cultural Value of resources & land area (L/M/H)	Effect on nature & scale of rec. values (+/-; L/M/H)	Effect on nature & scale of tourism values (+/-; L/M/H)	Effect on auditory or visual aesthetics (+/-; L/M/H)	Effect on non-renewable resources (+/-; L/M/H)	Effect on other renewable resources (+/-; L/M/H)	Consistent with Land Use & Renewable Resources Plans (Y/N/NA)	Effect on Infrastructure & Services (+/-; L/M/H)	Risks to Community Health & Safety const. & operation (L/M/H)	Effect on local jobs, business, training & development (L/M/H)

Evaluation of Resource Options - Economic Criteria & Indicators

Criteria	Local Economic Impacts (Ec1)			Climate Change Risk affecting Resource Financial Attributes (Ec2)				
Indicators	Yukon Opportunities During Construction (Ec1-1)	Yukon Opportunities during Operation (Ec1-2)	Community & Other Development Opportunity (Ec1-3)	Susceptible to Extreme Heat / Drought (Ec2-1)	Susceptible to Extreme Precipitation - flood/snow (Ec2-2)	Susceptible to Extreme Wind Events (Ec2-3)	Susceptible to Ice Related Processes / Events (Ec2-4)	Conditions Susceptible to Climate Change (Ec2-5)
Metric	Capital cost -civil & other local share (L/M/H)	Operating costs - Yukon labour & business opp. (L/M/H)	Community, industry development opp. (L/M/H)	Susceptibility (L/M/H)	Susceptibility (L/M/H)	Susceptibility (L/M/H)	Susceptibility (L/M/H)	Extent of permafrost in project footprint (L/M/H)

The overall objective of the evaluation approach is to identify on a common scale (low, medium, and high) which indicators are particularly relevant to each resource option. A high rating indicates that potential effects on an indicator are high for a specific resource option compared with the other resource options under review. A low rating indicates that potential effects on an indicator are low for a specific resource option compared with the other resource options under review. A medium rating indicates an evaluation that falls between the high and low ratings.

The evaluation approach involves criteria that address a diverse range of risks, benefits, and potential linkages with the resource options. The following examples demonstrate this range, and highlight the need to consider in each instance the nature of the indicator when interpreting the ratings of high, medium or low for different resource options:

- **Adverse Effects Indicators:** Many of the environmental and social criteria and indicators focus on potential risks of adverse effects on specific criteria and indicators, where a high or red rating means a high relative risk of an adverse effect, e.g., effects on fish and fish habitat, effects on terrestrial species and habitat, effects on air quality, effects on First Nation lands, effects on traditional lifestyle, effects on heritage resources, and some indicators related to cultural and community well-being. When rating adverse effects for a resource option on an indicator, red means a high rating, yellow means a medium rating, and green means a low rating.
- **Positive Effects Indicators:** Some social and economic indicators focus on potential beneficial effects on specific criteria and indicators, where a high rating means a high relative level of potential benefits, e.g., effects on criteria such as Local Economic Impacts and Community, First Nation and Personal Development. In this instance, a red colour rating as adopted for adverse effects indicators might suggest (incorrectly) that a high rating has adverse rather than positive effects, while a green colour rating to suggest "positive" outcomes could also be confusing given that green means low level effects when assessing adverse effects indicators. Accordingly, no colour rating is used for the few indicators that focus on positive effects and tables simply show the rating as high positive, medium positive or low positive.
- **Linkage/Overlap Effects Indicators:** Some environmental, social and economic criteria and indicators address overall magnitudes related to linkages or overlaps, where a high or red rating means a high level of linkage or overlap without directly addressing specific adverse or positive effects that may occur, e.g., footprint territorial area, footprints land area effect, linear development distances, flow changes, relative scale of impoundment/flooding.
- **No Linkage included as Low Rating:** For many resource options there is no linkage with various environmental indicators (or the indicator is not applicable to the resource option). A low or green rating includes these situations (thereby highlighting no basis for special attention in the future with regard to this indicator when pursuing the resource option).

At this initial stage of the resource option review, effects on any indicator are often best characterized as "potential" given the need to rely on existing information without project specific baseline or assessment studies to verify existing conditions as well as expected effects. For most resource options evaluated here, current information is at a preliminary level of assessment.

In assessing potential adverse or positive effects, the evaluation assumes adoption of well understood mitigation measures or best management practices to manage potential effects. However, to provide a common evaluation approach for all options, customized mitigation developed for a specific resource option is not considered even for the few options where more detailed studies and assessments have been carried out, e.g., Stewart-Keno City Transmission, Mayo Lake and Southern Lakes hydro storage enhancement projects. This is particularly relevant to understanding the evaluations of environmental criteria for the enhanced storage projects. Detailed explanations behind the ratings are provided in Appendix C (Table C 2-5, Table C 3-5 and Table C 4-8).[1]

Accordingly, a high or red rating related to potential adverse effects on an environmental or social indicator does not in any way signify that the resource option is infeasible. Such a rating only shows that these effects will need to be addressed and managed/mitigated in order for the project to proceed.

In summary, the ratings for the evaluation of each indicator are classified in terms of high, medium and low as follows (see also Figure 1):

- **High (red when non-positive and no colour when positive effect)** means the resource option has a high expected effects linkage to the indicator (depending on the indicator, the likely effects may be adverse, positive or simply signify linkage and/or overlap without much additional guidance);
- **Medium (yellow when non-positive and no colour when positive effect)** means the resource option has potential expected linkage to the indicator that falls between high and low ratings; and
- **Low (green when non-positive and no colour when positive effect)** means the resource option likely has minimal, if any, expected effects linkage to the indicator (again, depending on the indicator, any potential minimal effects may be adverse, positive or simply signify no linkage/overlap with the indicator, i.e., no effects pathway).

[1] See Appendix C, Page C-14 which notes that the evaluations in Table C 2-5 do not take into account the specific mitigation and adaptive management measures developed to date as a result of detailed environmental assessment studies. Notably, for Mayo Lake Enhanced Storage Yukon Energy's Yukon Environmental and Socio-economic Assessment Board submission set out measures to address potential adverse effects based on studies and ongoing work with the local First Nation.

Figure 1: Rating Criteria for Indicator Evaluations

High	Classification of high means the resource option has a high expected effects linkage to the indicator (depending on the indicator, the likely effects may be adverse, positive or simply signify linkage/overlap without much additional guidance). Red signifies a high rating for all non-positive effect indicators. • A red (high) rating related to potential adverse effects does not signify that the resource option is infeasible - such a rating only shows that these effects are high and will need to be addressed and managed/mitigated in order for the project to proceed. • No colour is used to signify a high rating related to potential positive effects. A high positive rating indicates that such effects for the resource option are high relative to the effects on the indicator from other options; associated with such a rating is a likely requirement to address specific benefit management or enhancement measures.
Medium	Classification of medium means the resource option has potential expected linkage to the indicator that falls between green (low) and red (high) ratings. Yellow signifies a medium rating for all non-positive effect indicators. • A yellow (medium) rating related to potential adverse effects indicates a likely need to proceed with caution and/or special attention to the management of certain potential adverse effects (without any determination today that a high expected effects linkage exists). • No colour is used to signify a medium rating related to potential positive effects. • In many evaluations of adverse effects, a yellow (medium) rating indicates a lack of information needed for a red (high) or green (low) rating.
Low	Classification of low means the resource option has minimal, if any, expected effects linkage to the indicator (again, depending on the indicator, any potential minimal effects may be adverse, positive, or simply signify no linkage/overlap with the indicator, i.e., no effects pathway). Green signifies a low rating for all non-positive effect indicators. • A green (low) rating related to potential adverse effects indicates that such effects are well understood and likely can be managed through best management practices or standard mitigation measures. • No colour rating is used to signify a low rating related to potential positive effects. A low positive rating indicates that such effects for the resource option are low relative to the effects on the indicator from other options, and unlikely to require special benefit management or enhancement measures. • A green (low) rating may also signify no linkage between the resource option and the indicator.

2.0 EVALUATION OF RESOURCE OPTIONS

2.1 OVERVIEW

Evaluations for each inventoried resource option are summarized separately below for the following three sets of criteria (see Table 2):

- **Environmental** criteria and indicators;
- **Social** criteria and indicators; and
- **Economic** criteria and indicators.

Evaluations are provided for each resource option and indicator, using the rating scheme outlined in Figure 1. The detailed evaluations are provided in Appendix C (Environmental), Appendix D (Social) and Appendix E (Economic).

2.2 ENVIRONMENTAL EVALUATION OF RESOURCE OPTIONS

Figure 2 provides the summary evaluation of the RP resource options for the environmental criteria and indicators, grouped by Aquatic Environment, Terrestrial Environment and Air. Within each of these three broad groupings, separate criteria are addressed:

- **Aquatic Environment:** Fish and Fish Habitat, and Water Quantity and Quality (the first criteria focuses on effects to selected indicators, the second criteria focuses on specific pathways for resource project effects to affect the aquatic environment).
- **Terrestrial Environment:** Terrestrial Species and Habitat, and Terrestrial Footprint and Land Use (the first criteria focuses on effects to selected indicators, the second criteria focuses on specific pathways for resource project effects to affect the terrestrial environment).
- **Air:** Greenhouse Gas (GHG) Emissions, and Other Air Pollutants.

All effects are rated adverse for the environmental criteria and indicators.

Summary by Criteria and Indicators

Red or yellow ratings in Figure 2 highlight resource options that have high or medium levels of adverse effects on an indicator. These ratings are summarized as follows:

- **Aquatic Environment**:
    - **Fish and Fish Habitat:** Red (high) and yellow (medium) adverse effect ratings occur only with hydro resource options that require modification to water regimes.
        - **Salmon and Habitat:** Red (high) rating for only one pumped storage option, yellow (medium) rating for only three small hydro options and one storage enhancement option.

- **Species at Risk and Habitat:** Red (high) rating for only one pumped storage option, yellow (medium) rating for only one small hydro option.
- **Commercial, Recreational and Aboriginal Fisheries Species and Habitat:** Red (high) rating for six of the eight pumped storage options, four of the six small hydro options, Gladstone Diversion and both of the storage enhancement options[2]; yellow (medium) rating for the two remaining pumped storage and two remaining small hydro options.

o **Water Quantity and Quality:** Red and yellow adverse effect ratings occur only with hydro resource options that require modification to water regimes.

- **New Impoundment/Flooding:** Red (high) rating for all eight pumped storage options and two small hydro options; yellow (medium) rating for two of the remaining five small hydro options.
- **Flow Changes:** Red (high) rating for Gladstone Diversion and both storage enhancement options[3]; yellow (medium) rating for all pumped storage and small hydro options.

- **Terrestrial Environment:**

o **Terrestrial Species and Habitat:** Red (high) and yellow (medium) ratings occur for many wind, hydro and transmission options and one geothermal option; a yellow (medium) rating also occurs with the biomass option.

- **Species at Risk and Habitat:** Red (high) rating for Gladstone Diversion and one hydro storage enhancement option; yellow (medium) rating for six of the seven wind options, seven of the eight pumped storage options, all small hydro options and one hydro storage enhancement option[4].
- **Protected and Conservation Areas:** Red (high) rating for one geothermal option, one pumped storage option, one hydro storage enhancement option[4] and one transmission option; yellow (medium) rating for one wind option, one pumped storage option, one small hydro option and one transmission option.
- **Wildlife Key Areas:** Red (high) rating for three wind options, one pumped storage option, Gladstone Diversion and one hydro storage enhancement option[4]; yellow (medium) rating for three of the four remaining wind options, all seven of the remaining pumped storage options, three small hydro options, all transmission options, one geothermal option and the biomass option.
- **Caribou Ranges:** Red (high) rating for only one transmission option; yellow (medium) rating for three wind options, one geothermal option, seven of the eight pumped storage options, three small hydro options and Gladstone Diversion.

[2] See Appendix C, Table C 2-5 which provides rationale for ratings for Southern Lakes and Mayo Lake.
[3] See Appendix C, Table C 3-5 which provides rationale for ratings for Southern Lakes and Mayo Lake.
[4] See Appendix C, Table C 4-8 which provides rationale for ratings for Southern Lakes.

- **Terrestrial Footprint and Land Use:** Red (high) and yellow (medium) ratings occur for many wind, hydro and transmission options and one geothermal option; a yellow (medium) rating also occurs for the largest solar PV option.
  - **Footprint Terrestrial Area:** Red (high) rating for all wind, pumped storage, small hydro and transmission options and for one geothermal option and Gladstone Diversion option; yellow (medium) rating for largest solar PV option.
  - **Linear Development for Roads/Transmission:** Red (high) rating for all transmission options; yellow (medium) rating for all wind options, one geothermal option, six pumped storage options, all small hydro options, and Gladstone Diversion option.
  - **Permafrost:** No red (high) rating; yellow (medium) rating for three pumped storage options, three transmission options, one small hydro option, and Gladstone Diversion option.
  - **Wetlands:** Red (high) rating for one hydro storage enhancement option; yellow (medium) rating for four pumped storage options and one small hydro option.

- **Air – Air Quality**:
  - **GHG Emissions:** Red (high) and yellow (medium) ratings limited to thermal generation options.
    - **With biogenic CO_2 emissions**: red (high) rating for all fossil and non-fossil thermal generation options.
    - **Excluding biogenic CO_2 emissions**: red (high) rating for all fossil generation options, yellow (medium) rating for waste-to-energy and biogas options.
  - **Other Air Pollutants**: No red (high) ratings; yellow (medium) ratings limited to thermal generation options and include all fossil and non-fossil thermal generation options.

Summary by Resource Options

Overall assessments are summarized below by indicator for each of the major sets of resource options:

1. **Fossil Thermal (Diesel and LNG in Whitehorse area):** Each of these resource options is rated as follows:
   a. Aquatic and Terrestrial criteria and indicators: green (low or no linkage);
   b. GHG Emissions Air Quality indicator: red (high); and
   c. Other Air Pollutants Air Quality indicator: yellow (medium).
2. **Non-Fossil Thermal (Waste-to-energy and Biogas in the Whitehorse area, and Biomass in the Haines Junction area):** Ratings for these resource options vary as follows:
   a. Aquatic and Terrestrial criteria and indicators:

- With the exception of wood biomass effects on Wildlife Key Areas, each of these resource options is rated green (low or no linkage) for all of the Aquatic and Terrestrial indicators.
- Wood biomass is rated yellow (medium) with respect to Wildlife Key Area effects to reflect potential effects of harvesting beetle-kill timber on key wildlife and related habitat, including moose winter range.

b. Air Quality criteria and indicators: These non-fossil thermal generation options are each rated as follows:

- GHG Emissions with biogenic CO_2 emissions: red (high);
- GHG Emissions without biogenic CO_2 emissions: yellow (medium) (waste-to-energy and biogas) or green (low) (biomass); and
- Other Air Pollutants: yellow (medium).

3. **Other Non-Hydro Renewable (Storage Battery in Whitehorse, Solar PV in Whitehorse and Haines Junction, Wind at seven different sites, and Geothermal at two sites):** Ratings for these resource options vary as follows:

a. Aquatic and Air Quality criteria and indicators:

- All of these resource options: green (low or no linkage).

b. Terrestrial criteria and indicators:

i. Terrestrial Species at Risk and Habitat

- Each wind site other than Tehcho: yellow (medium).
- Tehcho wind site, storage battery, solar PV (both sites), geothermal (both sites): green (low or no linkage).

ii. Protected and Conservation Areas

- McArthur Springs geothermal (reflects location within Ddhaw Ghro Habitat Protection Area): red (high).
- Kluane Lake (reflects proximity to Kluane National Park and Kluane Wildlife Sanctuary): yellow (medium).
- Each wind site other than Kluane Lake, storage battery, solar PV (both sites), geothermal at Vista Mountain: green (low or no linkage).

iii. Wildlife Key Areas

- Three wind sites (Kluane Lake, Mt. Sumanik, and Sugarloaf Mountain; see Appendix C, Table C 4-3 for specifics): red (high).
- Three wind sites (Miller's Ridge, Tehcho, and Thulsoo Mountain), McArthur Springs geothermal: yellow (medium).
- Cyprus Mine Hill wind site, storage battery, solar PV (both sites), Vista Mountain geothermal: green (low or no linkage).

iv. Caribou Range

- Three wind sites (Cyprus Mine Hill, Miller's Ridge, and Sugarloaf Mountain), McArthur Springs geothermal: yellow (medium).
- The remaining four wind sites, storage battery, solar PV (both sites), Vista Mountain geothermal: green (low or no linkage).

v. Total Terrestrial Footprint Areas

- Each wind site: red (high).
- Solar PV (10 MW at Whitehorse site): yellow (medium).
- Storage battery, solar PV (Haines Junction, 5 MW at Whitehorse), geothermal (both sites): green (low or no linkage).

vi. Linear Development Footprint

- Each wind site, McArthur Springs geothermal: yellow (medium).
- Storage battery, solar PV (both sites), Vista Mountain geothermal: green (low or no linkage).

vii. Permafrost and Wetlands indicators

- All wind sites, storage battery, solar PV (both sites), geothermal (both sites): green (low or no linkage).

4. **Hydro Generation (Pumped Storage at eight different sites, Small Hydro at six different sites, Other Hydro [Gladstone Diversion, two Storage Enhancement options, Mayo Lake Outlet Channel Dredging], and hydro refurbishment/re-runnering at Mayo A and Aishihik)** - All hydro options are rated green (low) for all Air Quality criteria and indictors. Hydro resource options rankings for Aquatic and Terrestrial indicators are summarized below (Hydro refurbishment/re-runnering and Mayo Lake Outlet Channel Dredging are each rated green [low or no linkage] for all of these indicators):

a. **Fish and Fish Habitat Indicators**

i. **Salmon and Habitat**

- Vangorda Pit pumped storage: red (high).
- Drury Lake, Wolf River and Anvil Creek small hydro, Southern Lakes Enhanced Storage: yellow (medium).
- All other hydro generation options: green (low or no linkage).

ii. **Species at Risk and Habitat**

- Squanga-Dalayee pumped storage: red (high) (due to presence of Squanga Whitefish).
- Finlayson River small hydro: yellow (medium).
- All other hydro generation options: green (low).

iii. **Commercial, Recreational and Aboriginal Fisheries Species and Habitat**

- All pumped storage options other than Moon Lake and Atlin-Black Mountain, all of the small hydro options other than Wolf River and Atlin/Pine Creek, and all of the Other Hydro options[5] other than Mayo Lake Outlet Channel Dredging: red (high).
- Moon Lake and Atlin-Black Mountain pumped storage, Wolf River and Atlin/Pine Creek small hydro: yellow (medium).
- Mayo Lake Outlet Channel Dredging: green (low or no linkage).

b. **Water Quantity and Quality indicators**

i. **Consumptive Water** - All hydro resource options have no linkage (green rating).

ii. **Relative Scale of New Impoundment/Flooding**

- All pumped storage options, Finlayson River and Anvil Creek small hydro and Gladstone Diversion: red (high).
- Drury Lake and Tutshi-Windy Arm small hydro: yellow (medium).
- All other hydro options are rated green (low or no linkage).

iii. **Flow Changes**

- Gladstone Diversion and the Storage Enhancement options (Mayo Lake and Southern Lakes): red (high).[5]
- All other pumped storage and small hydro options: yellow (medium).

c. **Terrestrial Species and Habitat indicators**

i. **Species at Risk and Habitat**

- Gladstone Diversion and Southern Lakes Enhanced Storage: red (high).[6]
- All pumped storage and small hydro site options other than Vangorda Pit, Mayo Lake Enhanced Storage: yellow (medium).
- Vangorda Pit pumped storage: green (low or no linkage).

ii. **Protected and Conservation Areas**

- Lindeman-Fraser pumped storage (Chilkoot Trail National Historic Site), Southern Lakes Enhanced Storage[6] (overlaps Lewes Marsh and Tagish Narrow Habitat Protection Areas: red (high).

[5] See Appendix C, Table C 2-5 and Table C 3-5. For Southern Lakes, changes to downstream flows are predicted to be over 20% higher in the late winter than historical flows. For Mayo Lake, changes to downstream flows are predicted on average to be over 20% higher in late winter/spring than flows without the enhancement (effects will vary for different years). Reductions of flows that occur during the summer are expected to be over 10% and perhaps slightly over 20% (depending on load conditions).
[6] See Appendix C, Table C 4-8. Project effects are primarily related to changes in water levels during different seasons or years.

- Squanga-Dalayee pumped storage and Wolf River small hydro: yellow (medium).
- All other hydro resource options: green (no linkage).

iii. **Wildlife Key Areas**

- Squanga-Dalayee pumped storage, Gladstone Diversion and Southern Lakes enhanced storage[6]: red (high).
- All other pumped storage options, all small hydro options other than Atlin/Pine Creek, and Mayo Lake enhanced storage: yellow (medium).
- Atlin/Pine Creek small hydro, Southern Lakes enhanced storage, Mayo Lake Outlet Channel Dredging, re-runnering/refurbishment options: green (low or no linkage).

iv. **Caribou Ranges**

- All pumped storage options other than Canyon-Ittlemit, three small hydro options (Tutshi-Windy Arm, Finlayson River and Anvil Creek) and Gladstone Diversion: yellow (medium).
- All other hydro options: green (low or no linkage).

d. **Terrestrial Footprint and Land Use Indicators**

i. **Footprint Terrestrial Area**

- All pumped storage and small hydro options, Gladstone Diversion: red (high).
- Other Hydro storage enhancements (Mayo and Marsh), Mayo Outlet Channel Dredging and the re-runnering/refurbishment options: green (low or no linkage).

ii. **Linear Development for Roads/Transmission**

- All small hydro options, all pumped storage options other than Moon Lake and Atlin-Black Mountain, Gladstone Diversion: yellow (medium).
- Moon Lake (Tutshi-Moon) and Atlin-Black Mountain pumped storage, the Other Hydro storage enhancements (Mayo and Marsh), Mayo Outlet Channel Dredging and the re-runnering/refurbishment options: green (low or no linkage).

iii. **Permafrost**

- Gladstone Diversion, Finlayson River small hydro, and three pumped storage options (Racine-Mt. Brown, Canyon-Ittlemit, and Vangorda Pit): yellow (medium).
- All other hydro options: green (low or no linkage).

iv. **Wetlands**

- Southern Lakes Enhanced Storage: red (high) (reflecting quality wetlands at the edges of this storage).
- Wolf River small hydro, and four pumped storage options (Moon Lake, Racine-Moon, Squanga-Dalayee, and Vangorda Pit): yellow (medium).
- All other hydro options: green (low or no linkage).

5. **Transmission Corridors (Six Transmission Corridor Options)** - These resource options are each rated green (low or no linkage) for all of the Aquatic and Air Quality criteria and indicators. The following are noted for Terrestrial ratings:

   a. **Species at Risk and Habitat**: all transmission options rated green (low or no linkage).

   b. **Protected and Conservation Areas**

   - Aishihik-Destruction Bay (assumed use of Kluane National Park): red (high).
   - Whitehorse-Atlin: yellow (medium).
   - All other transmission options: green (low or no linkage).

   c. **Wildlife Key Areas:** all transmission options rated yellow (medium).

   d. **Caribou Ranges**

   - Faro-Watson Lake: red (high).
   - All other transmission options: green (low or no linkage).

   e. **Footprint Terrestrial Area and Linear Development**: all transmission options rated red (high).

   f. **Permafrost**

   - Faro-Watson Lake, Aishihik-Destruction Bay, and Stewart-Keno City: yellow (medium).
   - All other transmission options: green (low or no linkage).

   g. **Wetlands**: all transmission options rated green (low or no linkage).

Photo courtesy of InterGroup Consultants Ltd.

Figure 2: Evaluation of RP Resource Options - Environmental Criteria & Indicators

High
Medium
Low

Resource Options	Aquatic Environment						Terrestrial Environment								Air		
	Fish & Fish Habitat (En1)			Water Quantity & Quality (En2)			Terrestrial Species & Habitat (En3)				Terrestrial Footprint & Land Use (En4)				Air Quality (En5)		
	Salmon & Habitat (En1-1)	Species at Risk & Habitat (En1-2)	Commercial, Recreational & Aboriginal Fisheries Species & Habitat (En1-3)	Consumptive Water Use (En2-1)	Relative Scale of New Impoundment / Flooding (En2-2)	Flow Changes (En2-3)	Species at Risk & Habitat (En3-1)	Protected & Consevation Areas (En3-2)	Wildlife Key Areas (En3-3)	Caribou Ranges (En3-4)	Footprint Terrestrial Area (En4-1)	Linear Dev for Roads / Transmission (En4-2)	Permafrost En4-3)	Wetlands (En4-4)	GHG Emissions (En5-1)[1]		Other Air Pollutants (En5-2)
															with Biogenic CO2	without Biogenic CO2	
Fossil Thermal																	
Diesel: 20 MW - Whitehorse					No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage					
Diesel: 20 MW - Takhini					No Linkage	No Linkage		No Linkage	No Linkage	No Linkage							
LNG: 20 MW - Whitehorse					No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage					
LNG: 20 MW - Takhini					No Linkage	No Linkage		No Linkage	No Linkage	No Linkage							
Non-Fossil Thermal																	
Waste to Energy					No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage					
Biogas (CHP)					No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage					
Biomass 0.5 MW Boiler / Steam Turbine	No Linkage	No Linkage	No Linkage		No Linkage	No Linkage						No Linkage					
Other Non-Hydro Renewable																	
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage		No Linkage		No Linkage		No Linkage		No Linkage			
Solar PV: Whitehorse Fixed Tilt: 10 MW	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage					
Solar PV: Haines Junction Fixed Tilt: 5 MW	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage				No Linkage		No Linkage					
Wind: Cyprus Mine Hill, 20 MW	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage		No Linkage									
Wind: Kluane Lake, 20 MW	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage				No Linkage							
Wind: Millers Ridge, 20 MW		No Linkage		No Linkage	No Linkage	No Linkage		No Linkage									
Wind: Mt. Sumanik , 20 MW	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage		No Linkage		No Linkage							
Wind: Sugarloaf Mountain, 20 MW	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage									
Wind: Tehcho (Ferry Hill), 20 MW		No Linkage		No Linkage	No Linkage	No Linkage				No Linkage							
Wind: Thulsoo Mountain, 20 MW	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage		No Linkage							
Geothermal: McArthur Springs (3.8 MW Av.)	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage											
Geothermal: Vista Mountain (1.6 MW Av.)				No Linkage	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage							
Hydro Generation																	
Pumped Storage: Moon Lake (Tutshi-Moon)	No Linkage	No Linkage		No Linkage				No Linkage									
Pumped Storage: Racine - Moon	No Linkage	No Linkage		No Linkage				No Linkage									
Pumped Storage: Lindeman-Fraser	No Linkage	No Linkage		No Linkage													
Pumped Storage: Racine - Mt. Brown	No Linkage	No Linkage		No Linkage				No Linkage									
Pumped Storage: Atlin - Black Mountain	No Linkage	No Linkage		No Linkage				No Linkage									
Pumped Storage: Squanga - Dalayee	No Linkage			No Linkage													
Pumped Storage: Canyon - Ittlemit	No Linkage	No Linkage		No Linkage				No Linkage		No Linkage							
Pumped Storage: Vangorda Pit		No Linkage		No Linkage				No Linkage									
Small Hydro: Drury Lake		No Linkage		No Linkage				No Linkage	No Linkage								
Small Hydro: Tutshi - Windy Arm	No Linkage	No Linkage		No Linkage				No Linkage									
Small Hydro: Wolf River		No Linkage		No Linkage	No Linkage												
Small Hydro: Finlayson River	No Linkage			No Linkage				No Linkage									
Smally Hydro: Anvil Creek		No Linkage		No Linkage				No Linkage									
Small Hydro: Atlin/Pine Creek	No Linkage	No Linkage		No Linkage				No Linkage	No Linkage								
Other Hydro: Gladstone Diversion	No Linkage	No Linkage		No Linkage				No Linkage									
Other Hydro: Southern Lakes Storage		No Linkage		No Linkage							No Linkage		No Linkage				
Other Hydro: Mayo Lake Storage		No Linkage		No Linkage				No Linkage		No Linkage	No Linkage		No Linkage	No Linkage			
Other Hydro: Mayo Dredging	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage			No Linkage	No Linkage			
Aishihik Re-runnering	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage						
Mayo A Refurbishment	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage	No Linkage						
Transmission Corridors																	
Transmission: Whitehorse - Atlin (138 kV)		No Linkage		No Linkage	No Linkage	No Linkage											
Transmission: Whitehorse - Skagway (230 kV)		No Linkage		No Linkage	No Linkage	No Linkage		No Linkage									
Transmission: Whitehorse - Teslin (138 kV)				No Linkage	No Linkage	No Linkage											
Transmission: Faro - Watson Lake (230 kV)				No Linkage	No Linkage	No Linkage		No Linkage									
Transmission: Aishihik - Destruction Bay (230 kV)	No Linkage	No Linkage		No Linkage	No Linkage	No Linkage											
Transmission: Stewart-Keno City (138 kV & substations)				No Linkage	No Linkage	No Linkage				No Linkage							

1. GHG Emissions considers Global Warming Potential (GWP) for each option for both 20-year and 100-year time horizons

2.3 SOCIAL EVALUATION OF RESOURCE OPTIONS

Figure 3 provides the summary evaluation of the RP resource options for the social criteria and indicators, building on the outcomes of the environmental evaluations.

- The first three groupings of criteria and indicators focus on First Nations, traditional lifestyle and heritage resources potential effects from the resource options.
- The last two groupings of criteria and indicators focus on a broader range of potential social effects.

Except for Community, First Nation and Personal Development (for which effects are rated positive), all effects are rated adverse for the social criteria and indicators.

Summary by Criteria and Indicators

Red or yellow ratings in Figure 3 highlight resource options that have high or medium levels of adverse effects on an indicator. High and medium adverse and positive ratings are summarized as follows:

- **First Nation Lands:** Red (high) and/or yellow (medium) ratings occur for all transmission options, many of the hydro options that modify water regimes, and some of the wind options; yellow ratings occur for both geothermal options and one of the fossil thermal site options.
    - **First Nation Settlement Lands/Interim Protected Lands:** Red (high) rating for three transmission options, three pumped storage options, three small hydro options, two wind options, one of the hydro storage enhancement options, and the Gladstone Diversion option; yellow (medium) rating for remaining transmission options, two of three remaining small hydro options, two of the remaining five pumped storage options, both geothermal options, one wind option, and the Takhini fossil thermal site option.
- **Traditional Lifestyle:** Red (high) and yellow (medium) ratings occur for most of the non-thermal options for total footprint areas impacted, but are limited to only a few hydro options and one transmission option for all other indicators.
    - **Footprint Land Area Impact:**[7] Red (high) rating for all transmission options, all pumped storage options, five of six small hydro options, six of seven wind options, one geothermal option, Gladstone Diversion and both hydro storage enhancement options; yellow (medium) rating for the remaining small hydro, geothermal and wind options and both solar PV options.
    - **Land Area Loss regarding Traditional Lifestyle:** No red (high) ratings; yellow (medium) rating for only one pumped storage option and one small hydro option.

[7] See Page D-8. Footprint Land Area Impact is a quantitative metric that considers only direct land loss. The total footprint or land area affected may not be permanently lost for the purposes of traditional lifestyle activities. This indicator is used only as background information and is not directly adopted for the assessment of effects on the Land Quality Effects on Traditional Lifestyle. The rating criteria were selected simply to help assign resource project options to clearly separate groups based on the indicator.

- **Land Quality Effects on Traditional Lifestyle:** No red (high) ratings; yellow (medium) rating for only one pumped storage option, one small hydro option, Gladstone Diversion and one hydro storage enhancement option.
- **Cabins, Camps and Structures:** A red (high) rating for one hydro storage enhancement option and a yellow (medium) rating for only one transmission option.
- **Country Foods:** A red (high) rating for Gladstone Diversion; yellow (medium) rating for only one pumped storage option and one small hydro option.

- **Heritage Resources:** Red (high) ratings are limited to only two hydro options; yellow (medium) ratings occur for many of the non-thermal options.
  - **Density of Heritage Resources:** Red (high) rating for one pumped storage option and one hydro storage enhancement option; yellow (medium) rating for three pumped storage options, four small hydro options, five transmission options, and Gladstone Diversion.
  - **Importance/Cultural Value of Heritage Resources:** No red (high) ratings; yellow (medium) rating for five wind options, three pumped storage options, two small hydro option, one geothermal option, one transmission option, Gladstone Diversion, and one hydro storage enhancement option.
- **Tourism, Recreation and Other Resources and Land Use:** Red (high) and yellow (medium) ratings occur for many hydro options with water regime changes, many of the wind options, one geothermal option, and the biomass option.
  - **Recreational Values:** Red (high) rating for four pumped storage options, and five small hydro options; yellow (medium) rating for three wind options, one geothermal option, one of the four remaining pumped storage options, the one remaining small hydro option, and Gladstone Diversion.
  - **Tourism Values:** Red (high) rating for three small hydro options; yellow (medium) rating for two wind options, one geothermal option, five pumped storage options, and two of the three remaining small hydro options.
  - **Aesthetics:** Red (high) rating for one geothermal option and one small hydro option; yellow (medium) rating for biomass option, four wind options, four pumped storage options, two small hydro options, and Gladstone Diversion.
  - **Non-renewable Resources:** Red (high) rating for one small hydro option; yellow (medium) rating for one wind option, one geothermal option, five pumped storage options, two small hydro option and Gladstone Diversion.
  - **Other Renewable Resources:** No red (high) ratings; one yellow (medium) rating (for one geothermal option).
  - **Land Use and Renewable Resource Plans:** Red (high) rating for three pumped storage options and one geothermal option; yellow (medium) rating for biomass option, three wind options, four of the five remaining pumped storage options, five of the six small hydro options, and Gladstone Diversion.

- **Culture and Community Well-being:** Red (high) adverse effects ratings occur for all pumped storage and small hydro options; yellow (medium) adverse effects ratings occur for most wind options, one geothermal option, and Gladstone Diversion; high and medium positive effects ratings occur for all transmission options, all pumped storage and small hydro options, most wind options, and Gladstone Diversion; medium positive effects ratings occur for one geothermal option and thermal options other than diesel.
    - **Infrastructure and Services:** Red (high) rating for all pumped storage and small hydro options; yellow (medium) rating for six of the seven wind options, one geothermal option, and Gladstone Diversion.
    - **Public Safety, Worker Interaction, Human and Community Health:** Red (high) rating for all pumped storage and small hydro options; yellow (medium) rating for six of the seven wind options, one geothermal option, and Gladstone Diversion.
    - **Community, First Nation and Personal Development:** High positive effects rating for three transmission options, five pumped storage options, four small hydro options, two wind options, and Gladstone Diversion; medium positive effects rating for the three remaining transmission options, the three remaining pumped storage option, the two remaining small hydro options, four of the five remaining wind options, one geothermal option, all non-fossil thermal options, and the LNG fossil thermal options.

Summary by Resource Options

Overall assessments are summarized below by indicator for each of the major sets of resource options:

1. **Fossil Thermal (Diesel and LNG in Whitehorse area):** Each of these resource options is rated green (low) or low positive for all of the social criteria and indicators, except for the following yellow or medium positive ratings:
    a. **First Nation Settlement Lands:** The Takhini substation site is rated yellow (medium), reflecting proximity of such lands to the site and possible transmission access routing.
    b. **Community, First Nation and Personal Development:** The LNG options are rated medium positive, reflecting medium benefit opportunity to facilitate LNG use to displace other fossil fuel use in Whitehorse/Yukon.[8]
2. **Non-Fossil Thermal (Waste-to-energy and Biogas in the Whitehorse area and Biomass in the Haines Junction area):** Each of these resource options is rated green (low) for all of the social criteria and indicators, except for the following yellow or medium positive ratings:
    a. **Aesthetics:** A yellow (medium) rating for the biomass option at Haines Junction, reflecting siting near school as well as commercial and residential areas.
    b. **Land Use and Renewable Resource Plans:** A yellow (medium) rating for the biomass option at Haines Junction, reflecting anticipated need for some zoning variance.

[8] See Appendix D, Page D 6-4 which notes that by comparison diesel has no specific local development opportunities.

c. **Community, First Nation and Personal Development:** A medium positive rating for each of these options, reflecting medium local benefit opportunity to use renewable energy and (except for biogas) and to supply waste heat to displace fossil fuel use.

3. **Other Non-hydro Renewable (Storage Battery in Whitehorse, Solar PV in Whitehorse and Haines Junction, Wind at seven different sites, and Geothermal at two sites):** The storage battery option is rated green (low) or low positive for all social criteria and indicators, and the solar PV option at both sites is also rated green (low) or low positive for all social criteria and indicators other than Footprint Land Area Impact, where it is rated yellow (medium).[9]

   Other non-hydro renewable resource options (wind and geothermal) display common rankings for some of the social indicators, but also display variances. Detailed review of the evaluations for these options is provided below:

   a. **First Nation Settlement Lands/ Interim Protected Lands**

      - Kluane Lake and Sugarloaf Mountain wind options: red (high).
      - Wind option at Miller's Ridge and both geothermal options: yellow (medium).
      - All remaining wind sites: green (low).

   b. **Traditional Lifestyle**

      i. **Footprint Land Area Impact**

         - All wind options other than Kluane Lake, and Vista Mountain geothermal: red (high).[10]
         - Kluane Lake wind option and Vista Mountain geothermal: yellow (medium).

      ii. **Other Traditional Lifestyle Indicators:** All other traditional lifestyle indicators are rated green for all wind and geothermal options.

   c. **Heritage Resources**

      i. **Density of Heritage Resources**

         - All wind and geothermal options are rated green (low).

      ii. **Importance/Cultural Value of Heritage Resources**

         - All wind options other than Cyprus Mine Hill and Kluane Lake and the geothermal option at McArthur Springs: yellow (medium).
         - Cyprus Mine Hill and Kluane Lake wind options and the geothermal option at Vista Mountain: green (low).

   d. **Tourism, Recreation and Other Resources and Land Use:** Variances among these indicators are summarized as follows for wind and geothermal resource options:

[9] See Appendix D, Table D 3-2 for explanation of rating for Solar PV in Whitehorse compared to Haines Junction.
[10] See Appendix D, Table D 3-2 for explanation of rating for Kluane Wind Project compared to other wind projects.

i. **Recreational Values**

- Thulsoo Mountain, Miller's Ridge, and Kluane Lake wind farms, McArthur Springs geothermal: yellow (medium).
- Cyprus Mine Hill, Sugarloaf Mountain, Tehcho, and Mt. Sumanik wind farms; Vista Mountain geothermal: green (low).

ii. **Tourism Values**

- Miller's Ridge and Kluane Lake wind farms, McArthur Springs geothermal: yellow (medium).
- Cyprus Mine Hill, Sugarloaf Mountain, Tehcho, Mt. Sumanik, and Thulsoo wind farms, Vista Mountain geothermal: green (low).

iii. **Aesthetics**

- McArthur Springs geothermal: red (high).
- Thulsoo Mountain, Miller's Ridge, Kluane Lake, Sugarloaf Mountain wind farms: yellow (medium).
- Cyprus Mine Hill, Mt. Sumanik, Tehcho wind farms; Vista Mountain geothermal: green (low).

iv. **Non-Renewable Resources**

- Thulsoo Mountain, McArthur Springs geothermal: yellow (medium).
- Cyprus Mine Hill, Mt. Sumanik, Tehcho, Kluane Lake, and Miller's Ridge wind farms, Vista Mountain geothermal: green (low).

v. **Other Renewable Resources**

- McArthur Springs: yellow (medium).
- All wind options and Vista Mountain geothermal: green (low).

vi. **Land Use and Renewable Resources Plans**

- McArthur Springs geothermal: red (high) (located in protected area).
- Thulsoo Mountain, Miller's Ridge, Sugarloaf Mountain wind farms: yellow (medium).
- Cyprus Mine Hill, Tehcho, and Mt. Sumanik wind farms, Vista Mountain geothermal: green (low).

e. **Cultural and Community Well-being**

i. **Infrastructure and Services**

- All wind options other than Mt. Sumanik, McArthur Springs geothermal: yellow (medium).
- Mt. Sumanik wind option, Vista Mountain geothermal: green (low).

ii. **Public Safety, Worker Interaction, Human and Community Health**

- All wind options other than Mt. Sumanik, McArthur Springs geothermal: yellow (medium).
- Mt. Sumanik wind option, Vista Mountain geothermal: green (low).

iii. **Community, First Nation and Personal Development**

- Kluane Lake and Sugarloaf Mountain wind options: high positive (high benefit potential reflects the need to secure agreements with First Nations for use of settlement lands for each wind farm site).
- All wind options other than Mt. Sumanik, Kluane Lake and Sugarloaf Mountain; McArthur Springs geothermal: medium positive.
- Mt. Sumanik wind option and Vista Mountain geothermal: low positive.

4. **Hydro Generation (Pumped Storage at eight different sites, Small Hydro at six different sites, Other Hydro [Gladstone Diversion, two Storage Enhancement options, Mayo Outlet Channel Dredging], and hydro refurbishment/re-runnering at Mayo A and Aishihik):** Hydro refurbishment/re-runnering and Mayo Lake Outlet Channel Dredging are each rated green (low) or low positive for each of the social criteria and indicators, and Mayo Lake Storage Enhancement is rated green (low) or low positive for all of these same indicators other than Footprint Land Area Impact (where the rating is not relevant as it reflects lake water area, i.e., the resource option at most lowers average lake levels and does not impact new land areas).

   Other hydro generation resource options display common rankings for some of the social indicators, but also display variances as noted below:

   a. **First Nation Settlement Lands/Interim Protected Lands:** These evaluations include consideration of new road and transmission access requirements for these hydro resource options.

      - Three pumped storage options (Squanga-Dalayee, Canyon-Ittlemit, Vangorda Pit), three small hydro options (Wolf River, Finlayson River, and Anvil Creek), Gladstone Diversion, and Southern Lakes Enhanced Storage: red (high).
      - Two pumped storage options (Racine-Mt. Brown and Atlin-Black Mountain) and two small hydro options (Drury Lake and Atlin/Pine Creek): yellow (medium).
      - Remaining hydro generation options: green (low).

   b. **Traditional Lifestyle**

      i. **Footprint Land Area Impact**

      - All pumped storage options, all small hydro other than Tutshi-Windy Arm, Gladstone Diversion, both enhanced storage options (Southern Lakes, Mayo Lake): red (high).
      - Tutshi-Windy Arm small hydro: yellow (medium).

- Aishihik re-runnering, Mayo A refurbishment: green (low).

ii. **Land Area Loss regarding Traditional Lifestyle**

- Vangorda Pit pumped storage, Finlayson River small hydro: yellow (medium).
- All other hydro options: green (low).

iii. **Land Quality Effects on Traditional Lifestyle**

- Canyon-Ittlemit pumped storage, Finlayson River small hydro, Gladstone Diversion, Southern Lakes enhanced storage: yellow (medium).
- All other hydro options: green (low).

iv. **Cabins, Camps and Structures**

- Southern Lakes enhanced storage: red (high).
- All other hydro options: green (low).

v. **Country Foods**

- Gladstone Diversion: red (high).
- Squanga-Dalayee pumped storage, Finlayson River small hydro: yellow (medium).
- All other hydro options: green (low).

c. Heritage Resources

i. **Density of Heritage Resources**

- Atlin-Black Mountain pumped storage and Southern Lakes Enhanced Storage: red (high).
- Three pumped storage options (Lindeman-Fraser, Squanga-Dalayee, Canyon-Ittlemit), four small hydro options (Tutshi-Windy Arm, Finlayson River, Anvil Creek and Atlin/Pine Creek), and Gladstone Diversion: yellow (medium).
- All other hydro options: green (low).

ii. **Importance/Cultural Value of Heritage Resources**

- Three pumped storage options (Lindeman-Fraser, Squanga-Dalayee, and Canyon-Ittlemit), Finlayson River and Anvil Creek small hydro, Gladstone Diversion, and Southern Lakes Enhanced Storage: yellow (medium).
- All other hydro options: green (low).

d. **Tourism, Recreation and Other Resources and Land Use**

i. **Recreational Values**

- Four pumped storage options (Racine-Moon, Racine-Mt. Brown, Squanga-Dalayee, Canyon-Ittlemit) and five small hydro (Drury Lake,

Tutshi-Windy Arm, Finlayson River, Anvil Creek, and Atlin-Pine Creek): red (high).

- Lindeman-Fraser pumped storage, Wolf River small hydro, Gladstone Diversion: yellow (medium).
- Three pumped storage options (Vangorda Pit, Moon Lake [Tutshi-Moon], Atlin-Black Mountain), storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: green (low).

ii. **Tourism Values**

- Three small hydro options (Drury Lake, Finlayson River, and Atlin/Pine Creek): red (high).
- Five pumped storage options (Racine-Moon, Lindeman-Fraser, Racine-Mt. Brown, Squanga-Dalayee, Canyon-Ittlemit), Wolf River and Anvil Creek small hydro: yellow (medium).
- Vangorda Pit, Moon Lake (Tutshi-Moon), Atlin-Black Mountain, storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: green (low).

iii. **Aesthetics**

- Atlin/Pine Creek small hydro: red (high).
- Four pumped storage options (Moon Lake [Tutshi-Moon], Lindeman-Fraser, Squanga-Dalayee, Canyon-Ittlemit), Wolf River and Anvil Creek small hydro, Gladstone Diversion: yellow (medium).
- Vangorda Pit, Racine-Mt Brown, Racine-Moon, Atlin Black Mountain, storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: green (low).

iv. **Non-renewable Resources**

- Atlin/Pine Creek small hydro: red (high).
- Three pumped storage options (Moon Lake [Tutshi-Moon], Racine-Moon, Racine-Mt. Brown), Finlayson River and Anvil Creek small hydro, Gladstone Diversion: yellow (medium).
- Vangorda Pit, Lindeman Fraser, Atlin-Black Mountain, Squang-Dalayee, Canyon-Ittlemit, storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: green (low).

v. **Other Renewable Resources**

- All hydro options: green (low).

vi. **Land Use and Renewable Resources Plans**

- Three pumped storage options (Racine-Moon, Racine-Mt. Brown, Atlin-Black Mountain): red (high).
- Four pumped storage options (Moon Lake [Tutshi-Moon], Lindeman-Fraser, Squanga-Dalayee, Canyon-Ittlemit), all small hydro options other than Atlin/Pine Creek, Gladstone Diversion: yellow (medium).
- Vangorda Pit pumped storage, Atlin/Pine Creek small hydro, storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: green (low).

e. **Cultural and Community Well-being**:

i. **Infrastructure and Services**

- All pumped storage and small hydro options: red (high).
- Gladstone Diversion: yellow (medium).
- Storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: green (low).

ii. **Public Safety, Worker Interaction, Human and Community Health**

- All pumped storage and small hydro options: red (high).
- Gladstone Diversion: yellow (medium).
- Storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: green (low).

iii. **Community, First Nation and Personal Development**

- Five pumped storage options (Lindeman-Fraser, Atlin-Black Mountain, Moon Lake [Tutshi-Moon], Racine-Moon, Racine-Mt. Brown), all small hydro options other than Drury Lake and Anvil Creek, Gladstone Diversion (potential benefit arrangements with First Nations): high positive (indicating high potential benefits).
- Three pumped storage options (Squanga-Dalayee, Canyon-Ittlemit, and Vangorda Pit) and two small hydro options (Drury Lake and Anvil Creek): medium positive.
- Storage enhancements (Southern Lakes, Mayo Lake), Mayo Lake Outlet dredging, Aishihik re-runnering, Mayo A refurbishing: low positive.

5. **Transmission Corridors (Six Transmission Corridor Options)**

a. **First Nation Lands**

- Whitehorse-Atlin, Whitehorse-Skagway, Whitehorse-Teslin options: red (high).
- Remaining three options: yellow (medium).

b. **Traditional Lifestyle**

   i. **Footprint Land Area Impact:** all options rated red (high) (this indicator simply reflects total areas and does not address Traditional Lifestyle effects directly).

   ii. **All Other Traditional Lifestyle Indicators**

   - Whitehorse-Skagway: yellow (medium) for Cabins, Camps and Structures.
   - All other transmission options and indicators: green (low).

c. **Heritage Resources**

   i. **Density of Heritage Resources**

   - Faro-Watson Lake transmission option: green (low).
   - All transmission options other than Faro-Watson Lake: yellow (medium).

   ii. **Importance/Cultural Value of Heritage Resources**

   - Whitehorse-Skagway transmission option: yellow (medium).
   - All transmission options other than Whitehorse-Skagway: green (low).

d. **Tourism, Recreation and Other Resources and Land Use** - all transmission options are rated green (low) for all indicators.

e. **Cultural and Community Well-being**

   i. **Infrastructure and Services** – green (low) of all transmission options.

   ii. **Public Safety, Worker Interaction, Human and Community Health**: green (low) of all transmission options.

   iii. **Community, First Nation and Personal Development**

   - Faro-Watson Lake, Aishihik-Destruction Bay, and Stewart-Keno City transmission options: high positive (indicating high potential benefits).
   - Whitehorse-Atlin, Whitehorse-Skagway, Whitehorse-Teslin transmission options: medium positive.

Photo courtesy of: InterGroup Consultants Ltd.

Figure 3: Evaluation of RP Resource Options - Social Criteria & Indicators

High
Medium
Low

Resource Options	First Nation Lands (S1)	Traditional Lifestyle (S2)					Heritage Resources (S3)		Tourism, Recreation & Other Resources and Land Use (S4)						Cultural & Community Well-being (S5)			
	First Nation Settlement Lands/ Interim Protected Lands (S1-1)	Footprint Land Area Impact (S2-1)	Land Area Loss Re: Traditional Lifestyle (S2-2)	Land Quality Effects on Traditional Lifestyle (S2-3)	Cabins, Camps & Structures (S2-4)	Country Foods (S2-4)	Density of Heritage Resources (S3-1)	Importance/ Cultural Value of Heritage Resources (S3-2)	Recreational Values (S4-1)	Tourism Values (S4-2)	Aesthetics (S4-3)	Non-renewable Resources (S4-4)	Other Renewable Resources (S4-5)	Land Use & Renewable Resources Plans (S4-6)	Infrastructure & Services (S5-1)	Public Safety, Worker Interaction, Human & Community Health (S5-2)	Community, First Nation & Personal Development (S5-3) Positive Effects
Fossil Thermal																	
Diesel: 20 MW - Whitehorse																	Low Positive
Diesel: 20 MW - Takhini																	Low Positive
LNG: 20 MW - Whitehorse																	Medium Positive
LNG: 20 MW - Takhini																	Medium Positive
Non-Fossil Thermal																	
Waste to Energy																	Medium Positive
Biogas (CHP)																	Medium Positive
Biomass 0.5 MW Boiler / Steam Turbine																	Medium Positive
Other Non-Hydro Renewable																	
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)																	Low Positive
Solar PV: Whitehorse Fixed Tilt: 10 MW																	Low Positive
Solar PV: Haines Junction Fixed Tilt: 5 MW																	Low Positive
Wind: Cyprus Mine Hill, 20 MW																	Medium Positive
Wind: Kluane Lake, 20 MW																	High Positive
Wind: Millers Ridge, 20 MW																	Medium Positive
Wind: Mt. Sumanik , 20 MW																	Low Positive
Wind: Sugarloaf Mountain, 20 MW																	High Positive
Wind: Tehcho (Ferry Hill), 20 MW																	Medium Positive
Wind: Thulsoo Mountain, 20 MW																	Medium Positive
Geothermal: McArthur Springs (3.8 MW Av.)																	Medium Positive
Geothermal: Vista Mountain (1.6 MW Av.)																	Low Positive
Hydro Generation																	
Pumped Storage: Moon Lake (Tutshi-Moon)																	High Positive
Pumped Storage: Racine - Moon																	High Positive
Pumped Storage: Lindeman-Fraser																	High Positive
Pumped Storage: Racine - Mt. Brown																	High Positive
Pumped Storage: Atlin - Black Mountain																	High Positive
Pumped Storage: Squanga - Dalayee																	Medium Positive
Pumped Storage: Canyon - Ittlemit																	Medium Positive
Pumped Storage: Vangorda Pit																	Medium Positive
Small Hydro: Drury Lake																	Medium Positive
Small Hydro: Tutshi - Windy Arm																	High Positive
Small Hydro: Wolf River																	High Positive
Small Hydro: Finlayson River																	High Positive
Small Hydro: Anvil Creek																	Medium Positive
Small Hydro: Atlin/Pine Creek																	High Positive
Other Hydro: Gladstone Diversion																	High Positive
Other Hydro: Southern Lakes Storage																	Low Positive
Other Hydro: Mayo Lake Storage																	Low Positive
Other Hydro: Mayo Dredging																	Low Positive
Aishihik Re-runnering																	Low Positive
Mayo A Refurbishment																	Low Positive
Transmission Corridors																	
Transmission: Whitehorse - Atlin (138 kV)																	Medium Positive
Transmission: Whitehorse - Skagway (230 kV)																	Medium Positive
Transmission: Whitehorse - Teslin (138 kV)																	Medium Positive
Transmission: Faro - Watson Lake (230 kV)																	High Positive
Transmission: Aishihik - Destruction Bay (230 kV)																	High Positive
Transmission: Stewart-Keno City (138 kV & substations)																	High Positive

2.4 ECONOMIC EVALUATION OF RESOURCE OPTIONS

Figure 4 provides the summary evaluation of the RP resource options for the Economic criteria and indicators, building on the outcomes of the environmental and social evaluations.

- The first criteria (Local Economic Impacts) focuses on potential economic benefit effects during construction and operation of the resource options, as well as overall community and other development opportunities related to these options.
- The second criteria (Climate Change Risk) focuses on the potential effects of various climate change risks on resource option construction or operation, i.e., an overview of resource option financial attributes' relative vulnerability to these risks.

Economic indicators for the Local Economic Impacts criteria (Ec1) address potential positive effects from resource options. The ratings in such instances are highlighting where the magnitude or nature of potential positive effects is material. All effects for other economic criteria are rated adverse.

Summary by Criteria and Indicators

Red or yellow ratings in Figure 4 highlight resource options that have high or medium levels of adverse effects on an indicator. High and medium adverse and positive ratings are summarized as follows:

- **Local Economic Impacts:** High and/or medium positive ratings for all pumped storage options, most small hydro and wind options, most transmission options, waste-to-energy option, other thermal options other than diesel, one geothermal option and Gladstone Diversion.
    - **Yukon Opportunities during Construction:** High positive rating for all pumped storage options, two small hydro options, and two transmission options; medium positive rating for three of the four remaining transmission options, two of the four remaining small hydro options, one geothermal option and one wind option.
    - **Yukon Opportunities during Operation:** High positive rating for seven pumped storage options, all small hydro options, two wind options, and waste-to-energy option; medium positive rating for the one remaining pumped storage option, the five remaining wind options, and one geothermal option.
    - **Community and Other Development Opportunity**: High positive rating for three transmission options, five pumped storage options, four small hydro options, two wind options, and Gladstone Diversion; medium positive rating for the three remaining transmission options, the two remaining small hydro options, the three remaining pumped storage options, four of the five remaining wind options, one geothermal option, all of the non-fossil thermal options, and the LNG fossil thermal option.
- **Climate Change Risk Affecting Resource Financial Attributes:** Red (high) and/or yellow (medium) adverse effects ratings are noted for transmission options, hydro options, wind options, one geothermal option and the biomass option.

- **Susceptible to Extreme Heat/Drought:** Red (high) rating for all pumped storage and small hydro options, and Gladstone Diversion; yellow (medium) rating for three transmission options, both hydro storage enhancement options, and the biomass option.
- **Susceptible to Extreme Precipitation - Flood/Snow:** No red (high) ratings; yellow (medium) rating only for all transmission options.
- **Susceptible to Extreme Wind Events:** No red (high) ratings; yellow (medium) rating for all transmission options and all wind options.
- **Susceptible to Ice Related Processes/Events:** Red (high) rating for six of the seven wind options; yellow (yellow) rating for all transmission options.
- **Conditions Susceptible to Climate Change (Permafrost Conditions):** Red (high) rating for one wind option, one small hydro option, and one transmission option; yellow (medium) rating for all remaining transmission options, all remaining small hydro options, six of the eight pumped storage options, and one geothermal option.

Summary by Resource Options

Overall assessments are summarized below by indicator for each of the major sets of resource options:

1. **Fossil Thermal (Diesel and LNG in Whitehorse area)**: Each of these resource options is rated green (low) or low positive for all of the economic criteria and indicators, except for the following ratings:
    a. **Local Economic Impacts - Community and Other Development Opportunity**
        - LNG resource option: medium positive (reflects medium local benefit opportunities facilitated by the option [through its development of an LNG supply chain] to use LNG to displace other fossil fuel use in Whitehorse/Yukon).
        - Diesel resource option: low positive (reflects low local economic benefit impacts from this option).
2. **Non-Fossil Thermal (Waste-to-energy and Biogas in the Whitehorse area, and Biomass in the Haines Junction area)** - Each of these resource options is rated green (low) or low positive for all of the economic criteria and indicators, except for the following ratings:
    a. **Local Economic Impacts**
        i. **Yukon Opportunities during Operation**
            - Waste-to-energy: high positive (reflecting relatively high level of operating jobs and Opex cost level).
            - Biogas and biomass: low positive (relatively low local economic benefits).
        ii. **Community and Other Development Opportunity**
            - All non-fossil thermal options: medium positive (reflecting local opportunity to use renewable energy and [except for biogas] and to supply waste heat to displace fossil fuel use).

b. **Climate Change Risk**

i. **Susceptible to Extreme Heat/Drought**

- Biomass: yellow (forest fire risks).

3. **Other Non-Hydro Renewable (Storage Battery in Whitehorse, Solar in Whitehorse and Haines Junction, Wind at seven different sites, and Geothermal at two sites)**, **Storage Battery and Solar PV.**

a. **Local Economic Impacts:** Ratings tend to be similar across the site options for a resource technology option:

i. **Yukon Opportunities during Construction**

- Kluane Lake wind option, McArthur Springs geothermal: medium positive (Kluane Lake wind rating reflects added requirement for new transmission line to connect to grid at Haines Junction or Aishihik).
- All other non-hydro renewable options – low positive.

ii. **Yukon Opportunities during Operation, and Community and Other Development Opportunity**

- Kluane Lake and Sugarloaf Mountain wind options: high positive for both indicators (reflects added opportunities for First Nation lease revenues and [for Kluane Lake] the benefits of the added transmission connection which will allow Destruction Bay and likely Burwash Landing to stop relying on diesel generation).
- All other wind farm site options, except for Mt. Sumanik (for Community and Other Development Opportunity), and McArthur Springs geothermal option: medium positive for both indicators.
- Mt. Sumanik wind option (for Community and Other Development Opportunity) and Vista Mountain geothermal, Solar PV, storage battery for both indicators: low positive (reflecting relatively low local economic impacts).

b. **Climate Change Risk**

i. **Susceptible to Ice-related Processes/Events**

- All wind farm options other than Kluane Lake: red (high susceptibility risk).
- Kluane Lake wind option (reflects lower elevation and better weather conditions), storage battery, solar options, and both geothermal options: green (low susceptibility risk).

ii. **Susceptible to Extreme Heat/Drought** and **Susceptible to Extreme Precipitation (flood/snow):** all of the other non-hydro renewable options are rated green (low) for these indicators.

iii. Susceptible to Extreme Wind Events

- All wind options: yellow (medium).
- Storage battery, solar PV options, and both geothermal options: green (low).

iv. **Conditions Susceptible to Climate Change**: This indicator is focused entirely on relative risks related to permafrost.[11]

- Kluane Lake wind option: red (high) (reflects permafrost risks in this region).
- McArthur Springs geothermal option: yellow (medium).
- All wind options other than Kluane Lake, storage battery, solar PV options, and Vista Mountain geothermal option: green (low).

4. **Hydro Generation (Pumped Storage at eight different sites, Small Hydro at six different sites, Other Hydro [Gladstone Diversion, two Storage Enhancement options, Mayo Lake Outlet Channel Dredging], and hydro refurbishment/re-runnering at Mayo A and Aishihik):** The economic criteria and indicator ratings tend to be very similar for various site options within each hydro generation resource option:

a. **Local Economic Impacts**

i. Yukon Opportunities during Construction

- All pumped storage options, two small hydro options (Wolf River, Finlayson River): high positive.
- Three small hydro options (Tutshi-Windy Arm, Anvil Creek, Atlin/Pine Creek): medium positive.
- Drury Lake small hydro option, all other hydro options, Aishihik re-runnering, Mayo A refurbishment: low positive.

ii. Yukon Opportunities during Operation

- All pumped storage options other than Moon Lake, all small hydro options: high positive.
- Moon Lake (Tutshi-Moon) pumped storage: medium positive.
- All other hydro options, Aishihik re-runnering, Mayo A refurbishment: low positive.

iii. Community and Other Development Opportunity

- Five pumped storage options that each provide high development opportunity benefits related to major new transmission (Moon Lake, Racine-Moon, Lindeman-Fraser, Racine-Mt. Brown, Atlin- Black Mountain), all small hydro options except Drury Lake and Anvil Creek

[11] For discussion of ratings see Table E3-1.

(each of these four options require major new transmission), Gladstone Diversion (reflects opportunity for local First Nation income benefits if this option developed): high positive.

- Three pumped storage options (Squanga-Dalayee, Canyon-Ittlemit, and Vangorda Pit), Drury Lake and Anvil Creek small hydro: medium positive.
- Storage enhancement options (Southern Lakes, Mayo Lake), Mayo Lake Outlet Channel Dredging, Aishihik re-runnering, Mayo A refurbishment: low positive.

b. **Climate Change Risk**

i. Susceptible to Extreme Heat / Drought

- All pumped storage options, all small hydro options, Gladstone Diversion: red (high susceptibility).
- Storage enhancement option (Southern Lakes, Mayo Lake): yellow (medium).
- Mayo Lake Outlet Channel Dredging, Aishihik re-runnering, Mayo A refurbishment: green (low susceptibility).

ii. Conditions Susceptible to Climate Change (permafrost risks)[12]

- Drury Lake small hydro: red (high).
- All pumped storage options other than Canyon-Ittlemit and Vangorda Pit, all small hydro options other than Drury Lake: yellow (medium).
- Two pumped storage options (Canyon-Ittlemit and Vangorda Pit), all Other Hydro options, Aishihik re-runnering, Mayo A refurbishment: green (low).

iii. **All other Climate Change Risk indicators** - All hydro options are rated green for all other Climate Change Risk indicators (low susceptibility to Extreme Precipitation, to Extreme Wind Events, and to Ice Related Processes/Events).

5. **Transmission Corridors (Six Transmission Corridor Options):** Transmission corridor options tend to have similar economic criteria and indicator ratings, with a few exceptions as noted below:

a. **Local Economic Impacts**: variable ratings among these options reflect varying scales of development (capital costs), as well as related impacts known today from each development:

[12] For discussion of ratings see Table E 3-1. Each option other than Drury Lake has a medium rating reflecting potential permafrost conditions affecting material new transmission access development requirements. Drury Lake has a red rating based on geotechnical risks and presence of permafrost noted in previous KGS reports.

i. **Yukon Opportunities during Construction**

- Whitehorse-Skagway and Faro-Watson Lake Transmission Corridor options: high positive (high opportunities).
- Whitehorse-Atlin and Whitehorse-Teslin Transmission Corridor options: medium positive.
- Stewart-Keno City options: low positive.

ii. **Yukon Opportunities during Operation** - all of the Transmission Corridor options are rated low positive, indicating relatively low local economic impact opportunities.

iii. **Community and Other Development Opportunity**

- Three Transmission Corridor options (Faro-Watson Lake, Aishihik-Destruction Bay, and Stewart-Keno City): high positive (reflecting opportunities to displace local diesel generation (or sustain existing transmission capacity to do this), as well as to facilitate new mining and renewable generation (hydro or wind) development.
- Three remaining Transmission Corridor options (Whitehorse-Skagway, Whitehorse-Atlin, Whitehorse-Teslin): medium positive (reflecting potential local development impacts if the option facilitates renewable generation [pumped storage and small hydro] and, in the case of the Skagway connection, potential sale of summer renewable generation [hydro or wind] to cruise ships).

b. **Climate Change Risk**

i. **Susceptible to Extreme Heat/Drought** - this risk includes increased risk of forest fires:

- Three Transmission Corridor options (Faro-Watson Lake, Aishihik-Destruction Bay, and Stewart-Keno City): yellow (medium).
- Three Transmission Corridor options (Whitehorse-Atlin, Whitehorse-Skagway, Whitehorse-Teslin): green (low) (reflecting the extent that each route covers well developed areas and/or mountain areas).

ii. **Conditions Susceptible to Climate Change**[13]

- Aishihik-Destruction Bay Transmission Corridor: red (high) (risks regarding permafrost).
- All other Transmission Corridor options: yellow (medium).

iii. **All Other Climate Change Risk Indicators** - All Transmission Corridor options are rated yellow for all other Climate Change Risk indicators (medium susceptibility to Extreme Precipitation, to Extreme Wind Events, and to Ice Related Processes/Events).

[13] For discussion of ratings see Table E 3-1.

Figure 4: Evaluation of RP Resource Options - Economic Criteria & Indicators

High
Medium
Low

Resource Options	Installed Capacity MW	Annual Average Energy GWh	Assumed Economic Life (years)	Local Economic Impacts (Ec1) (Positive Effects)			Climate Change Risk affecting Resource Financial Attributes (Ec2)				
				Yukon Opportunities During Construction (Ec1-1) Positive Effects	Yukon Opportunities during Operation (Ec1-2) Positive Effects	Community & Other Development Opportunity (Ec1-3) Positive Effects	Susceptible to Extreme Heat/Drought (Ec2-1)	Susceptible to Extreme Precipitation - flood/snow (Ec2-2)	Susceptible to Extreme Wind Events (Ec2-3)	Susceptible to Ice Related Processes/ Events (Ec2-4)	Conditions Susceptible to Climate Change (Ec2-5)
Fossil Thermal											
Diesel: 20 MW - Whitehorse	20.0	up to >150	25-40	Low Positive	Low Positive	Low Positive					
Diesel: 20 MW - Takhini	20.0	up to >150	25-40	Low Positive	Low Positive	Low Positive					
LNG: 20 MW - Whitehorse	20.0	up to >150	25-40	Low Positive	Low Positive	Medium Positive					
LNG: 20 MW - Takhini	20.0	up to >150	25-40	Low Positive	Low Positive	Medium Positive					
Non-Fossil Thermal											
Waste to Energy	1.6	10	25	Low Positive	High Positive	Medium Positive					
Biogas (CHP)	0.2	0.4	20	Low Positive	Low Positive	Medium Positive					
Biomass 0.5 MW Boiler / Steam Turbine	0.5	3	20	Low Positive	Low Positive	Medium Positive					
Other Non-Hydro Renewable											
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	8.0	0.04	30	Low Positive	Low Positive	Low Positive					
Solar PV: Whitehorse Fixed Tilt: 10 MW	10.0	10	30	Low Positive	Low Positive	Low Positive					
Solar PV: Haines Junction Fixed Tilt: 5 MW	5.0	5	30	Low Positive	Low Positive	Low Positive					
Wind: Cyprus Mine Hill, 20 MW	20.0	51	20	Low Positive	Medium Positive	Medium Positive					
Wind: Kluane Lake, 20 MW	20.0	49	20	Medium Positive	High Positive	High Positive					
Wind: Millers Ridge, 20 MW	20.0	59	20	Low Positive	Medium Positive	Medium Positive					
Wind: Mt. Sumanik , 20 MW	20.0	43	20	Low Positive	Medium Positive	Low Positive					
Wind: Sugarloaf Mountain, 20 MW	20.0	33	20	Low Positive	High Positive	High Positive					
Wind: Tehcho (Ferry Hill), 20 MW	20.0	35	20	Low Positive	Medium Positive	Medium Positive					
Wind: Thulsoo Mountain, 20 MW	20.0	56	20	Low Positive	Medium Positive	Medium Positive					
Geothermal: McArthur Springs (3.8 MW Av.)	4.0	25	30	Medium Positive	Medium Positive	Medium Positive					
Geothermal: Vista Mountain (1.6 MW Av.)	1.8	11	30	Low Positive	Low Positive	Low Positive					
Hydro Generation											
Pumped Storage: Moon Lake (Tutshi-Moon)	20.2	54	65	High Positive	Medium Positive	High Positive					
Pumped Storage: Racine - Moon	15.0	50	65	High Positive	High Positive	High Positive					
Pumped Storage: Lindeman-Fraser	15.0	50	65	High Positive	High Positive	High Positive					
Pumped Storage: Racine - Mt. Brown	15.0	50	65	High Positive	High Positive	High Positive					
Pumped Storage: Atlin - Black Mountain	15.0	50	65	High Positive	High Positive	High Positive					
Pumped Storage: Squanga - Dalayee	25.0	100	65	High Positive	High Positive	Medium Positive					
Pumped Storage: Canyon - Ittlemit	25.0	100	65	High Positive	High Positive	Medium Positive					
Pumped Storage: Vangorda Pit	40.0	134	50-65	High Positive	High Positive	Medium Positive					
Small Hydro: Drury Lake	8.1	32	65	Low Positive	High Positive	Medium Positive					
Small Hydro: Tutshi - Windy Arm	7.2	57	65	Medium Positive	High Positive	High Positive					
Small Hydro: Wolf River	20.0	96	65	High Positive	High Positive	High Positive					
Small Hydro: Finlayson River	17.6	139	65	High Positive	High Positive	High Positive					
Small Hydro: Anvil Creek	9.8	41	65	Medium Positive	High Positive	Medium Positive					
Small Hydro: Atlin/Pine Creek	5.7	36.3 avail to Yukon	65	Medium Positive	High Positive	High Positive					
Other Hydro: Gladstone Diversion	NA	37	65	Low Positive	Low Positive	High Positive					
Other Hydro: Southern Lakes Storage	1.0	6	NA	Low Positive	Low Positive	Low Positive					
Other Hydro: Mayo Lake Storage	NA	2 to 4	NA	Low Positive	Low Positive	Low Positive					
Other Hydro: Mayo Dredging	NA	1 to 2	NA	Low Positive	Low Positive	Low Positive					
Aishihik Re-runnering	1.0	3	na	Low Positive	Low Positive	Low Positive					
Mayo A Refurbishment	2.3	10	65	Low Positive	Low Positive	Low Positive					
Transmission Corridors	Transfer Capacity										
Transmission: Whitehorse - Atlin (138 kV)	97	NA	45	Medium Positive	Low Positive	Medium Positive					
Transmission: Whitehorse - Skagway (230 kV)	443	NA	45	High Positive	Low Positive	Medium Positive					
Transmission: Whitehorse - Teslin (138 kV)	95	NA	45	Medium Positive	Low Positive	Medium Positive					
Transmission: Faro - Watson Lake (230 kV)	190	NA	45	High Positive	Low Positive	High Positive					
Transmission: Aishihik - Destruction Bay (230 kV)	484	NA	45	Medium Positive	Low Positive	High Positive					
Transmission: Stewart-KenoCity (138 kV & substations)	NA	NA	45	Low Positive	Low Positive	High Positive					

3.0 SUMMARY AND CONCLUSIONS

This study supports Yukon Energy's current 2016 Resource Plan update by providing a comparative evaluation of more than 45 power generation and transmission resource options in Yukon and northern British Columbia against more than 40 environmental, social and economic indicators.

The evaluation approach displays key differences among the resource options, rather than attempting an overall ranking of these options. The ratings for each criteria and indicator show on a common scale (low, medium, and high) which indicators are particularly relevant to each resource option. A high rating identifies when potential effects on an indicator are high for a specific resource option compared with the other resource options under review at this time. Medium ratings indicate when potential effects on an indicator are medium for a specific resource option, and therefore meriting attention as compared to options with a low rating. The indicators vary in focus; some highlight the need to manage potential adverse effects (where red indicates a high effect and yellow indicates a medium effect), while others highlight the need and opportunity to manage potential positive effects (no colours are used for these positive effect ratings in order to avoid possible confusion with the adverse effect ratings).

No attempt is made in this study to evaluate resource options in the context of forecast grid loads. Resource portfolio option definition and assessment in the context of long-term load forecasts will be done subsequently by Yukon Energy as part of the current Resource Plan update.

The more than 45 electricity resource options reviewed reflect a diverse range of technologies, scales of development, and locations within Yukon and northern British Columbia. Each option's assessment includes consideration of new transmission and/or road access requirements.

Ratings vary for different sets of resource options (e.g., thermal versus non-thermal, wind versus hydro or solar renewables), and for different renewable sites within each set of resource options. Tables 3, 4, 5 and 6 provide a summary of high and medium ratings for each of the major sets of resource options:

- **Thermal Generation Options (Table 3):** Fossil (diesel and LNG) and non-fossil (waste-to-energy, biogas and biomass) thermal generation options have high or medium ratings for only a few indicators:
    - **Environmental Indicators:** Red or yellow (high or medium adverse) ratings for Air Quality indicators for all of these options, and yellow rating for biomass option effects on Wildlife Key Areas. Air emission effects are sensitive to actual operation of the resource options.
    - **Social Indicators:** Yellow (medium adverse) ratings for the Takhini site (fossil thermal options) proximity to First Nation Lands and for biomass option effects on Aesthetics and Land Use and Renewable Resources; medium positive ratings for Community, First Nation and Personal Development indicator for the LNG, waste-to-energy, biogas and biomass options.
    - **Economic Indicators:** High or medium positive ratings for Local Economic Impacts for waste-to-energy, LNG, biogas and biomass options; yellow (medium adverse) rating for biomass option susceptibility to Extreme Heat/Drought.

- **Other Non-hydro Renewable Options (Table 4):** Storage battery, solar PV, wind and geothermal options have high or medium ratings that in many instances may be affected by specific site options:
    - **Environmental Indicators:** Red or yellow (high or medium adverse) ratings for various Terrestrial Species and Habitat indicators and Terrestrial Footprint and Land Area indicators occur for all wind options, one geothermal option, and (for only one indicator) the largest solar PV option.
    - **Social Indicators:** Red or yellow (high or medium adverse) ratings for various Social indicators occur for each of these resource options other than the storage battery option, but ratings for specific indicators typically vary among the different site options for a resource option; high or medium positive ratings for the Community, First Nation and Personal Development indicators occur for seven of eight wind options and for one geothermal option.
    - **Economic Indicators:** High or medium positive ratings for Local Economic Impact indicators occur for all wind options and one geothermal option and red or yellow (high or medium adverse) ratings occur for all wind options and one geothermal option with regard to at least one Climate Change Risk indicator.
- **Hydro Generation Options (Table 5):** Pumped storage, small hydro, Gladstone Diversion, and hydro storage enhancement options have high or medium ratings that in many instances may be affected by specific site options:
    - **Environmental Indicators:** Red or yellow (high or medium adverse) ratings for a range of Aquatic environment and Terrestrial environment indicators occur for all hydro resource options that require modified water regimes, with variations as to ratings among different site options.
    - **Social Indicators:** Red or yellow (high or medium adverse) ratings for various Social indicators occur for all hydro resource options that require modified water regimes, with variations as to ratings among different site options; high or medium positive ratings for the Community, First Nation and Personal Development indicators occur for all pumped storage and small hydro options and the Gladstone diversion option.
    - **Economic Indicators:** High or medium positive ratings for Local Economic Impact indicators occur for all pumped storage and small hydro options and the Gladstone diversion option and red or yellow (high or medium adverse) ratings for all pumped storage, small hydro, Gladstone Diversion and storage enhancement options occur with regard to at least one Climate Change Risk indicator.
- **Transmission Corridor Options (Table 6):** The six transmission corridor options have high or medium ratings that in many instances may be affected by the specific site option:
    - **Environmental Indicators:** Red or yellow (high or medium adverse) ratings for some of the terrestrial environment indicators occur for all transmission options (red ratings apply with regard to all of these options for Footprint Terrestrial Area and Linear Development, and yellow ratings apply for all of these options with regard to Wildlife Key

Areas; red or yellow ratings apply to only some transmission options for some of the other Terrestrial indicators).

- **Social Indicators:** Red or yellow (high or medium adverse) ratings for First Nation Lands and Footprint Land Area Impact occur for all transmission options, and yellow ratings also occur for some of these options with regard to a few other Traditional Lifestyle and Heritage Resources indicators; high or medium positive ratings for the Community, First Nation and Personal Development indicator occurs for all transmission options.
- **Economic Indicators:** High or medium positive ratings for at least one of the Local Economic Impact indicators occur for all transmission options and red or yellow (high or medium adverse) ratings for all transmission options occur with regard to several of the Climate Change Risk indicators.

Table 3: Summary of Thermal Generation Option High & Medium Evaluations

Criteria and Indicators	High	Medium
Fossil Fuel Thermal (Diesel & LNH in Whitehorse Area)		
Environmental		
Air Quality - GHG Emissions (with & without biogenic CO_2)	Diesel, LNG	
Air Quality - Other Emissions		Diesel, LNG
Social		
First Nation Lands		Takhini Site (Diesel & LNG)
Community, First Nation & Personal Development (positive effect)		LNG
Economic		
Community & Other Development Opportunity (positive effect)		LNG
Non Fossil Fuel Thermal (Waste-to-energy and Biogas in Whitehorse and Biomass in Haines Junction)		
Environmental		
Wildlife Key Areas		Biomass
Air Quality - GHG Emissions (with biogenic CO_2)	WTE, Biogas, Biomass	
Air Quality - GHG Emissions (without biogenic CO_2)		WTE, Biogas
Air Quality - Other Emissions		WTE, Biogas, Biomass
Social		
Aesthetics, Land Use & Renewable Resource Plans		Biomass
Community, First Nation & Personal Development (positive effect)		WTE, Biogas, Biomass
Economic		
Yukon Opportunities - Operation (positive effects)	WTE	
Community and Other Development Opportunity (positive effect)		WTE, Biogas, Biomass
Susceptible to Extreme Heat/Drought		Biomass

Table 4: Summary of Other Non-Hydro Renewable Option High & Medium Evaluations

Criteria and Indicators	High	Medium
Environmental		
Terrestrial Species at Risk & Habitat		All W sites ex Tehcho
Protected & Conservation Areas	G (McA S site)	W (Kluane L)
Wildlife Key Areas	W (Kluane L, Mt.Sumanik, Sugarloaf M)	W (Miller's R, Tehcho, Thulsoo M), G (McA S site)
Caribou Ranges		W (Cyprus Mine H, Miller's R, Sugarloaf M), G (McA S)
Footprint Land Area	All W, G (McA S site)	
Linear Development for Roads/Transmission		W (all sites), G (McA S site)
Social		
First Nation Lands	W (Kluane L, Sugarloaf M)	W (Miller's R), G
Footprint Land Area Impact	All W sites ex Kluane L, G at (McA S)	S sites, W (Kluane L), G (Vista M)
Importance/Cultural Importance of Heritage Resources		All W (ex Cyprus M, Kluane L), G (McA S)
Recreational Values, Tourism Values		W (Kluane L, Miller's R, Thulsoo M for rec.), G (McA S)
Aesthetics, Land Use & Renewable Resource Plans	G(McA S site)	W (Kluane L for aes., Miller's R, Thulsoo M)
Non-Renewable Resources, Other Renewable Resources		W (Thulsoo M for non-renewable), G (McA S)
Infrastructure & Services		All W (ex M Sumanik), G (McA S)
Public Safety, Worker Interaction & Community Health		All W (ex M Sumanik), G (McA S)
Community, First Nation & Personal Development (positive effect)	W (Kluane L, Sugarloaf M)	All W (ex M Sumanik, Kluane L, Sugarloaf M), G (McA S)
Economic		
Yukon Opportunities - Construction (positive effect)		W (Kluane L), G (McA S)
Yukon Opportunities - Operation (positive effect)	W (Kluane L, Sugarloaf M)	All W (ex Kluane L, Sugarloaf M), G (McA S)
Community and Other Development Opportunity (positive effect)	W (Kluane L, Sugarloaf M)	All W (ex M Sumanik, Kluane L, Sugarloaf M), G (McA S)
Susceptible to Ice-Related Processes/Events	W (all sites ex Kluane L)	
Susceptible to Extreme Wind Events		All W
Conditions Susceptible to Climate Change (permafrost risk)	W (Kluane L)	G (McA S)

Key: **Storage Battery (SB) in Whitehorse,**
Solar PV (S) in Whitehorse and Haines Junction,
Wind (W) at seven different sites, and Geothermal (G) at two sites.

Table 5: Summary of Hydro Generation Option High & Medium Evaluations

Criteria and Indicators	High	Medium
Environmental		
Salmon & Salmon Habitat	PS (Vangorda P)	SH (Drury L, Wolf R, Anvil Ck), Southern L Storage
Aquatic Species at Risk & Habitat	PS (Squanga-Dalayee)	SH (Finlayson R)
Commercial, Recreational, & Aboriginal Fisheries Species & Hab	All PS (ex Tutshi-Moon, Atlin-BM), all SH (ex Wolf R, Atlin/PC), GD, Southern Lakes & Mayo L St.	PS (Tutshi-Moon, Atlin-BM), SH (Wolf R, Atlin/PC)
Relative Scale of Impoundment/Flooding	All PS, SH (Finlayson R, Anvil Ck)	SH (Drury L, Tutshi WA)
Flow Changes	GD, Southern Lakes & Mayo L Storage	All PS, all SH
Terrestrial Species at Risk & Habitat	GD and Southern Lakes	All PS (ex. Vangorda P), all SH, Mayo L St.
Terrestrial Protected & Conservation Areas	PS (Lindeman-Fraser) and Southern Lakes	PS (Squanga-D), SH (Wolf R)
Wildlife Key Areas	PS (Squanga-D), GD, Southern Lakes	All PS (ex. Squanga-D), SH (Tutshi-WA, Finlayson R, Wolf R)
Caribou Ranges		All PS (ex. Canyon-I), SH (Tutshi-WA, Finlayson R, Anvil Ck), GD
Footprint Land Area	All PS, all SH, GD	
Linear Development for Roads/Transmission		All PS (ex.Tutshi-Moon, Atlin-BM), all SH, GD
Permafrost		PS (Racine-MB, Canyon-I, Vangorda-P), SH (Finlayson R), GD
Wetlands	Southern Lakes Storage	PS (Tutshi-Moon, Racine-M, Squanga-D, Vangorda P), SH (Wolf F)
Social		
First Nation Lands	PS (Squanga-D, Canyon-I, Vangorda P), SH (Wolf R, Finlayson R, Anvil Ck), GD, Southern Lakes Storage	PS (Racine-MB, Atlin-BM), SH (Drury L, Atlin/PC)
Footprint Land Area Impact	All PS, all SH (ex.Tutshi-WA), GD, Southern L & Mayo L St.	SH (Tutshi-WA)
Land Area Loss for Traditional Lifestyle		PS (Vangorda P), SH (Finlayson R)
Land Quality Effects on Traditional Lifestyle		SH (Finlayson R), GD, Southern L Storage
Cabins, Camps, & Structures	Southern Lakes Storage	
Country Foods	Gladstone Diversion	PS (Squanga-D), SH (Finlayson R)
Density of Heritage Resources	PS (Atlin-Black M), Southern Lakes Storage	PS (Lindeman-F, Squanga D, Canyon-I), SH (Tutshi-WA, Finlayson R, Anvil Ck, Atlin/PC), GD
Importance/Cultural Importance of Heritage Resources		PS (Lindeman-F, Squanga D, Canyon-I), SH (Finlayson R, Anvil Ck), GD, Southern Lakes
Recreational Values	PS (Racine-M, Racine-MB, Squanga-D, Canyon-I), SH (Drury L, Tutshi-WA, Finlayson R, Anvil Ck, Atlin/PC)	PS (Lindeman-F), SH (Wolf R), GD
Tourism Values	SH (Drury L, Finlayson R, Atlin/PC)	PS (Racine-M, Lindeman-F, Racine-MB, Squanga-D, Canyon-I), SH (Wolf R, Anvil Ck)
Aesthetics	SH (Atlin/PC)	PS (Tutshi-Moon, Lindeman-F, Squanga-D, Canyon-I), SH (Tutshi-WA, Anvil Ck), GD
Non-Renewable Resources	SH (Atlin/PC)	PS (Tutshi-Moon, Racine-Moon, Racine-MB, Atlin-BM, Squanga-D), SH (Finlayson R, Anvil Ck), GD
Land Use & Renewable Resource Plans	PS (Racine-M, Racine-MB, Atlin-BM)	PS (Tutshi-Moon, Lindeman-F, Squanga-D, Canyon-I), all SH (ex. Atlin/PC), GD
Infrastructure & Services	All PS, all SH	Gladstone Diversion
Public Safety, Worker Interaction & Community Health	All PS, all SH	Gladstone Diversion
Community, First Nation & Personal Development (positive effect)	All PS (ex.Squanga-D, Canyon-I, Vangorda P), all SH (ex.Drury L), GD	PS (Squanga-D, Canyon-I, Vangorda P), SH (Drury L, Anvil Ck)
Economic		
Yukon Opportunities - Construction (positive effect)	All PS, SH (Wolf R, Finlayson R)	SH (Tutshi-WA, Anvil Creek, Atlin/PC)
Yukon Opportunities - Operation (positive effect)	All PS (ex. Tutshi-Moon), all SH	PS (Tutshi-Moon)
Community and Other Development Opportunity (positive effect)	All PS (ex.Squanga-D, Canyon-I, Vangorda P), all SH (ex.Drury L, Anvil Ck), GD	PS (Squanga-D, Canyon-I, Vangorda P), SH (Drury L, Anvil Ck)
Susceptible to Extreme Heat/Drought	All PS, all SH, GD	Southern Lakes and Mayo L Storage
Conditions Susceptible to Climate Change (permafrost risk)	SH (Drury L)	All PS (ex. Canyon-I, Vangorda P), all SH (ex. Drury L)

Key: Pumped Storage (PS) at 8 sites,
Small Hydro (SH) at 6 sites,
Other Hydro (Gladsone Diversion [GD], Southern Lakes & Mayo L Storage, Mayo Dredging),
Hydro refurbishment/re-runnering (HRR) at Mayo A and Aishihik.

Table 6: Summary of Transmission Corridor Option High & Medium Evaluations

Criteria and Indicators	High	Medium
Environmental		
Terrestrial Protected & Conservation Areas	Aishihik-Destruction Bay	Whitehorse-Atlin
Wildlife Key Areas		All Transmission Corridor options
Caribou Ranges	Faro-Watson L	
Footprint Land Area	All Transmission Corridor options	
Linear Development for Roads/Transmission	All Transmission Corridor options	
Permafrost		Faro-Watson L, Aishihik-Destruction Bay, Stewart-Keno City
Social		
First Nation Lands	Whitehorse-Atlin, Whitehorse-Teslin, Whitehorse-Skagway	Faro-Watson L, Aishihik-Destruction Bay, Stewart-Keno City
Footprint Land Area Impact	All Transmission Corridor options	
Cabins, Camps, & Structures		Whitehores-Skagway
Density of Heritage Resources		All Transmission Corridor options (ex. Faro-Watson Lake)
Importance/Cultural Importance of Heritage Resources		Whitehorse-Skagway
Community, First Nation & Personal Development (positive effect)	Faro-Watson L, Aishihik-Destruction Bay, Stewart-Keno City	Whitehorse-Atlin, Whitehorse-Teslin, Whitehorse-Skagway
Economic		
Yukon Opportunities during Construction (positive effect)	Whitehorse-Skagway, Faro-Watson L	Whitehorse-Atlin, Whitehorse-Teslin, Aishihik-Destruction Bay
Community and Other Development Opportunity (positive effect)	Faro-Watson L, Aishihik-Destruction Bay, Stewart-Keno City	Whitehorse-Atlin, Whitehorse-Teslin, Whitehorse-Skagway
Susceptible to Extreme Heat/Drought		Faro-Watson L, Aishihik-Destruction Bay, Stewart-Keno City
Susceptible to Extreme Precipitation - Flood/Snow		All Transmission Corridor options
Susceptible to Ice-Related Processes/Events		All Transmission Corridor options
Susceptible to Extreme Wind Events		All Transmission Corridor options
Conditions Susceptible to Climate Change (permafrost risk)	Aishihik-Destruction Bay	All Transmission Corridor options (ex. Aishihik-Destruction Bay)

APPENDICES

APPENDIX A:
PROJECT SUMMARIES

TABLE OF CONTENTS

1.0 INTRODUCTION A-1
2.0 FOSSIL THERMAL GENERATION A-4
3.0 NON-HYDRO RENEWABLE GENERATION A-5
3.1 NON-FOSSIL FUEL THERMAL GENERATION A-5
3.2 ENERGY STORAGE FACILITY (BATTERIES) A-7
3.3 SOLAR PV A-8
3.4 WIND FARMS A-9
3.5 GEOTHERMAL A-11
4.0 HYDRO RENEWABLE GENERATION A-14
4.1 PUMPED STORAGE PROJECTS A-14
4.2 SMALL HYDRO PROJECTS A-20
4.3 GLADSTONE DIVERSION A-25
4.4 HYDRO STORAGE ENHANCEMENTS A-27
4.5 MAYO LAKE OUTLET CHANNEL DREDGING A-28
4.6 REFURBISH EXISTING HYDRO GENERATION A-29
5.0 TRANSMISSION CORRIDOR OPTIONS A-30
5.1 NEW TRANSMISSION CORRIDORS A-30
5.2 STEWART KENO CITY TRANSMISSION PROJECT A-31
6.0 SUMMARY OF PROJECTS TO BE EVALUATED A-33
7.0 RESOURCE OPTION REPORTS CITED A-38

LIST OF TABLES

Table A 3-1: Solar PV Energy Production & Economics (2015$) (Assumes First Solar Cells, ABB Central Inverter - 30 year life) A-9
Table A 3-2: Wind Farm Sites Energy Production & Economics (2015$) (25-year life) A-11
Table A 3-3: Geothermal Site Production & Economics (2015$) (30-year life) A-13
Table A 4-1: Pumped Storage Sites Energy Production & Economics (2015$) (65-year life) A-19
Table A 4-2: Small Hydro Site Options - Physical Requirements A-24
Table A 4-3: Small Hydro Sites Energy Production & Economics (2015$) (65-year life) A-25

1.0 INTRODUCTION

This appendix provides a summary of key information for resource options that is relevant to the evaluations, including identification of the specific sites and cases to be evaluated and the relevant report information to be utilized.

The project summaries are based on publicly available information and information from inventoried resource option project reports supplied by Yukon Energy Corporation (Yukon Energy). Geographic information system (GIS) and mapping information on each site option and its footprint (including road access and transmission interconnection) that is currently available for each resource option has been provided by Yukon Energy separately as required for each member of the Study Team to proceed with the resource options evaluation.

The current Resource Plan focuses in most instances on generation options that do not exceed 20 MW in scale. Referenced resource option project reports often examine a range of sites, scales of development, and different financial attributes, including interest cost assumptions. In order to simplify the resource options evaluation, key information for each resource option has been limited or assumed as noted below:

- **Sites** - Sites used for the evaluation of each resource option, when identified, are limited to those specifically noted below. In cases where referenced resource option project reports screened a wide range of site options, the following resource options evaluation typically focuses on the short list of top-ranked sites identified in the reports.
- **Linkage with Required Transmission Corridor Developments** - Referenced generation resource option reports include transmission interconnection to the grid as required for development of each site option; however, in several instances, the scope for the referenced report assumes separate development of a new transmission corridor that has been examined separately. For the purpose of the current resource options evaluation, it is necessary to highlight where a generation site development option presumes development of a new transmission corridor and/or an added transmission connection to the current grid (and to identify the linked transmission connection so that it is evaluated concurrently with the generation site option).
- **Development Scale** - Where a range of scales for development (e.g., MW or GWh/year) was examined in a referenced resource option project report, the following resource options evaluation focuses on one scale (usually the largest scale examined). In some cases (e.g., geothermal resource options), where uncertainty exists regarding the potential scale for development (due to the need for further site investigation), the resource options evaluation for convenience adopts where relevant the average of the potential scales that have been identified. For some pumped storage site options, two scales of development are included in the evaluation. For solar PV options, various scales of development for each site are included in the evaluation.
- **Utilization of Resource Options** - The resource options evaluation is being done without reference to any forecast grid load or economic opportunities for new generation or transmission, i.e., each renewable resource option (regardless of scale) is assumed to be fully utilized, unless it is designed to be dispatchable in response to load requirements (e.g., fossil or biomass thermal

generation). In practice, final selection of any resource option for development would require evaluation of its ability to supply forecast grid capacity and energy loads (including provision to meet capacity reliability requirements) on a least cost basis relative to all other available resource options.

- **Weighted Average Cost of Capital for Resource Development** - All resource options are assumed for this evaluation to be developed by Yukon Energy (rather than another party) at the Yukon Energy weighted average cost of capital (WACC) specified for the resource option reports, i.e., 3.38%/year real cost of capital (net of inflation). This WACC is used in the referenced resource reports to define one case for Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC) for each resource option over its assumed economic life (assuming full utilization of the resource over this period).

Summaries are grouped by four general sets of resource options as follows (as noted, there are multiple resource options within each set, and several of these resource options include multiple sites, i.e., approximately 51 different options overall are identified for discussion in this appendix):

1. **Fossil Fuel Thermal Generation:** (two resource options [diesel and LNG], each in Whitehorse - two sites are examined for each).
2. **Non-hydro Renewable Generation:**
    a. **Non-fossil Thermal Generation** (three resource options: biomass in Haines Junction, biogas in Whitehorse, and waste-to-energy [WTE] in Whitehorse);
    b. **Energy Storage Facility** (batteries) in Whitehorse;
    c. **Solar PV** (two site options are examined: Haines Junction and Whitehorse, each with various scales of development [total of five options]);
    d. **Wind Farms** (seven site options are examined); and
    e. **Geothermal** (two site options are examined).
3. **Hydro Renewable Generation:**
    a. **Pumped Storage** (nine site options are examined; two site options include two scales of development);
    b. **Small Hydro Projects** (five site options are examined, one of which is run-of-river and four of which include storage);
    c. **Gladstone Diversion** (feasibility work was done separately from the current Resource Plan, the project would enhance hydro generation at Aishihik);
    d. **Hydro Storage Enhancements** (two options: Mayo Lake Storage Enhancement to improve winter generation at Whitehorse Hydro [YESAB submission already been prepared], and Southern Lakes Storage Enhancement to improve winter generation at Mayo Hydro [considerable assessment and feasibility work has been done separately from the current Resource Plan]);
    e. **Mayo Lake Outlet Channel Dredging** (ongoing investigation of issues and options related to sediment build up in Mayo Lake Outlet Channel); and

f. **Refurbish Existing Hydro Generation** (two options: Mayo A Refurbishment, and Aishihik Re-runnering).

4. **Transmission Corridor Options:**

   a. **New Transmission Corridors** (five options are examined - several of these would facilitate specific pumped storage and small hydro project sites, as well as one wind site. In several instances, segments of a project would enhance an existing transmission corridor); and

   b. **Stewart-Keno Transmission Project** - (this project, which enhances an existing transmission corridor wherein a major segment is at end-of-life, has recently completed YESAB review and recommendation).

Each resource option project summary only includes information relevant to the current assessment and aims for simplicity across all projects. The information also reflects the specific stage of each Yukon Energy resource option report, i.e., many reports provided to the study team were still at draft stage and may have been materially changed thereafter in the process of being finalized.[1]

For convenience, a final section provides a summary of the specific options to be included in the current resource options evaluation.

[1] Cost estimates and LCOE estimates in particular may change materially between draft and final reports, and therefore specific numbers provided in this report may not reflect final numbers that are provided to Yukon Energy in other referenced reports. Given the broad rating approach used for this evaluation study, it is not expected that updated costs for specific projects would materially change ratings and conclusions in this evaluation study.

2.0 FOSSIL THERMAL GENERATION

A Stantec report is available for fossil fuel thermal generation ("2016-007 - Thermal Energy Plant Development Study", November 21, 2016).

Stantec examined stand-alone, greenfield installation on a four hectare parcel of new diesel or natural gas (LNG) thermal generation adjacent to brownfield sites in Whitehorse that are not near the existing Whitehorse Generating Station. The two sites examined were the Whitehorse Landfill (assumes use of brownfield land, owned by the City of Whitehorse near the McIntyre substation) and the Mayo Road Substation (a vacant greenfield site on Commissioner's Land adjacent to Takhini S164). Based on the potential site locations selected for the study, there are no existing potential heat customers nearby.

Plant capacities were examined at each site at 5 MW, 10 MW and 20 MW. These resource options provide dispatchable generation with no requirement for high utilization, waste heat sales or subsidy support in order to be economic (waste heat use and boil off gas use [for LNG storage] may be considered when such options are relevant).

The current resource option evaluation focuses only on the 20 MW options at each site:

- Diesel thermal generation has similar capital cost estimate ($62.2 to $62.5 million) at each site for 20 MW. Site layouts were provided for each site.
- Natural gas thermal generation has similar capital cost estimate ($100.0 to $100.1 million) at each site for 20 MW. Site layouts were provided for each site.

Assumed economic life for fossil thermal generation units is very dependent on assumed annual use levels, reflecting the adaptability and reliability of this option. Full use averaging 95% of capacity at 20 MW would provide 166.4 GWh/year for an assumed 20 year economic life (per the Stantec report). Fossil thermal generation on Yukon Energy's hydro grid, however, tends to provide backup generation for peak, winter, emergency or drought period use, resulting in low average annual generation and an economic life of 40 years.

The Stantec report estimated annual O&M costs (excluding fuel) for a 20 MW reciprocating engine facility at $1.19 million, excluding insurance, property taxes or asset management. This estimate assumed high annual usage of the facility (e.g., average 95% capacity factor for each year). Retaining the same use levels and a 20 year life for 20 MW options (WACC at 3.38% real), the Stantec report estimated LCOO at $349-$350/kW for natural gas generation and $217-$218/kW for diesel generation (lower cost for Takhini site). LCOE excluding fuel was estimated based on these same assumptions at $0.049/kW.h for natural gas generation and $0.033/kW.h for diesel generation.

Fossil fuel thermal generation includes material waste heat that is potentially available for heating uses that could displace other fossil fuels. However, such waste heat use tends to be uneconomic unless the thermal generation is expected to be operated throughout periods when the waste heat is required and the thermal generation is also located relatively close to a site able to use the waste heat. In light of these considerations, Yukon Energy's current resource studies have not examined waste heat use options for fossil fuel thermal generation.

3.0 NON-HYDRO RENEWABLE GENERATION

3.1 NON-FOSSIL FUEL THERMAL GENERATION

Three resource options are included in this resource option grouping for non-fossil thermal generation: waste-to-energy at Whitehorse (1.6 MW, no specific site), biomass at Haines Junction (0.5 MW if rely only on beetle-kill biomass, a site identified near school), and biogas at Whitehorse (0.2 MW, located at municipal landfill). Although these options are each technically dispatchable, economic assessments assume full utilization, i.e., these options are not suited to peaking or backup generation use. With the exception of biogas, Yukon Energy assessments of these options have assumed high levels of waste heat use in order to enhance project economics.

Overall, each of these options involves a small scale facility in either Whitehorse or Haines Junction that would be economically feasible only with material waste heat sales for biomass and WTE, tipping fees for WTE and biogas, and material capital cost subsidy for biomass and biogas.

There is limited basis for providing detailed environmental or social evaluations of these resource options, and GIS-related site details are not relevant to the current resource options evaluation.

For reference, the following summary information is noted for each of these resource options:

- **Waste-to-Energy Generation (WTE)** plant in Whitehorse (Morrison Hershfield [MH] report, "Waste to Energy Updated Design Basis and Business Case Analysis", April 24, 2012 for 1.6 MW plant option generating 9,975 MWh/year with controlled-air two-stage technology; Nov. 13, 2015 MH letter reviewing business case). The following are summarized from these MH reports:
    - The option assumes use of municipal solid waste (MSW) as fuel, augmented with higher cost wood biomass during winter when MSW volume is reduced, and potential to use waste heat from the electricity generation in a future District Energy System (DES).
    - Available MSW volumes was assumed to be reduced significantly coinciding with Zero Waste program in the City's Solid Waste Action Plan (City of Whitehorse 2013). Wood biomass was assumed to be obtained from a variety of sources (including spruce beetle-killed wood, local brushing and clearing, construction and demolition waste).
    - It was considered premature to select a 2 ha site for this option within Whitehorse (the 2012 report assumed site in the Marwell Industrial area because of proximity to potential heat customers, access to municipal services and compatibility with adjacent land uses).
    - Revenues from this option in the 2012 business case analysis were highly dependent on revenues from both MSW tipping fees (assumed $108 per tonne of MSW received) and sale of heat to a future DES in Whitehorse ($81/MWh derived from a DES study completed for Yukon Energy in 2013, "Whitehorse Community Energy Project: Community Energy System Feasibility Study Report", FVB Energy Inc).

- Base case cost of power was estimated at $0.31/kWh, assuming a 25 year economic life.[2] This cost would be lower if able to secure federal grants for about 39% of the capital cost ($0.21/kWh was estimated).
- WTE facilities have emissions to air, land and water (in the form of stack emissions, ash and waste water). Air emissions controls can account for up to one-third of facility capital costs. The most probable carbon credit opportunities are for emissions avoided from the displacement of fossil fuel electricity generation and oil and propane for heating.
- The facility has an annual water demand of 14,500,000 litres.

- **Wood Biomass Generation** plant near Haines Junction (Stantec report, "Final FEED Report, Front End Engineering Design [FEED] Study, Yukon Bioenergy Demonstration Project in Haines Junction. Yukon", Oct. 18, 2013; Jan. 15, 2016 "Biomass Technology Update" Stantec letter).

  The following are summarized from the 2016 and 2013 Stantec reports (for the current resource option evaluation, only the smaller 0.5 MW option [using 3,000 oven dry tonnes/year] is considered as it is likely able to proceed solely using beetle-kill biomass, plus forest harvest and sawmill residues):

  - A screening assessment was provided for options in the range of 0.5 to 2.0 MW, using gasification technology to combust biomass (wood chips) to heat a fluid for use in a turbine-generator. Beetle-kill biomass would offer a much lower moisture content (15%) than green (live) biomass (50%). The smaller plant option could likely be supplied with minimal impact to existing operators/policies (sawmill residues and forest harvesting residues, mostly dead trees from the spruce beetle infestation until that supply runs out); in contrast, the larger plant operation would require additional biomass supplied by new harvesting operations/policies and would extend into harvesting green trees sooner.
  - The 2013 Stantec report considered plant siting, noting the likely need to consider waste heat use options and a 400 m buffer zone around buildings that could use the waste heat. A location near the school was recommended to capture the school waste heating load.
  - A conventional boiler/steam turbine option was estimated (2016 Stantec) to have the following characteristics for the 0.5 and 2.0 MW scales (two other technology options were also examined):
    - Annual net generation 3,224 MWh to 14,708 MWh;
    - Capital cost of $11.3 to $14.9 million;
    - Annual operations and maintenance (O&M) cost of $615,000 to $750,000, excluding any biomass feedstock cost; and
    - A 20-year economic life is assumed.

[2] Assumed capital cost of $34.6 million (annual capital cost of $2.6 million assuming 25-year life and 5.5% interest), non-fuel operating cost of $3.3 million/year (including 18 staff), wood biomass cost of $0.8 million/year (7,652 wet tonnes/year), heat sales revenue of $1.9 million/year ($81/MWh), and tipping fees revenue of $1.7 million/year (16,098 tonnes MSW/year). Absent sale of waste heat the cost of power would be higher at $0.34/kW.h (with 625/kWh per tonne of biomass or 14,844 MWh/year and 2.0 MW capacity).

- Assuming full utilization of the energy provided, financial viability depends on subsidization of a large portion of the initial capital cost (2013 Stantec).
- The 2013 Stantec report included a draft Environmental and Socio-economic Impact Assessment.

- **Biogas Generation** plant in Whitehorse (WSP Canada Inc. [WSP], "Biogas Plant in Whitehorse, Feasibility Study", January 2016). The following are summarized from the 2016 WSP report:
  - The plant of about 200 kW capacity, with annual energy initially at about 0.4 GWh (increasing over 20 year life) would treat residential and commercial source separated organic (SSO) waste and utilize the biogas to produce power and/or heat. About 65% of generation would be in the warmer months from May to October.
  - The plant would be located at the Whitehorse municipal landfill next to the existing composting site (footprint of about 1800 m^2). Waste heat sale is not recommended given the location and seasonality issues.
  - Estimated capital cost is $7.1 million, with annual operating cost of $255,000.
  - Revenues would come from gate fees (assumed $38/tonne), electricity sales (assumed $0.21/kWh) and heat savings (assumed $12/GJ). Based on current market price assumptions, the project is not viable and would require significant capital subsidy support (e.g., 70%).

3.2 ENERGY STORAGE FACILITY (BATTERIES)

Energy storage facilities can enhance opportunities for renewable generation options that may be affected by interruptions to the resource, e.g., solar and wind. Non-hydro energy storage options were examined as part of the current Resource Plan. Pumped storage hydro options have been examined separately (see Section 4.1 below).

Trans Grid Solutions Inc. (TGS) provided Yukon Energy with a report "Energy Storage Technologies," April 18, 2016 that examined a wide range of energy storage options, including mechanical, chemical, electrochemical, high temperature batteries, electrical field, magnetic field and thermal. The report identified the following electrochemical battery technology options as the optimum options using lead acid batteries or lithium ion batteries to supply power and energy demands during peak load conditions, as well as mitigating power quality concerns on the grid:

- 3 lead acid based systems rated at 4 MW/40 MWh, 6 MW/60 MWh, and 8 MW/80 MWh; and
- 1 lithium ion based system rated at 8 MW/40 MWh.

Over an assumed 30 year life all of these Battery Energy Storage System (BESS) options had significantly higher costs compared to their respective benefits.[3] The smallest lead acid based system and the lithium

[3] Capital cost (including replacements and balance of plant) estimated at $39.1 million for lead acid based system (4000 kW, 10h) and $49.5 million for lithium ion system (replacements needed in 15 and 20 years respectively at $17.4 million and $22.1 million). Annual O&M at $210k and 260k per year respectively. Annual energy use estimated at 2.4 GW.h for lead acid based system and 2.8 GW.h for lithium ion system (about 60 and 70 days of operation respectively). LCOE in nominal values (5.45% WACC) estimated at

ion system had the best net present values. Footprints for these two facility options approximate 6,400 m^2 and 4,200 m^2, respectively. No specific site option was specifically examined, but Yukon Energy advises that this resource option is assumed to be located at the Takhini Substation (the facility footprint would be about 15% larger than can be accommodated on the existing substation site and some adjacent land already zoned for utility use would be required).

It is not expected that this option will require material evaluation under environmental, social or economic criteria in the existing study.

3.3 SOLAR PV

The Solvest final report is available for the utility scale photovoltaic (PV) solar energy resource option ("Solar Site Inventory," May 2016). Review of solar resource irradiance data for various communities in Yukon showed a variance of only 9% across all communities connected to the grid and only 6% variance from Whitehorse. Based on this information, two communities were selected (Whitehorse and Haines Junction) in order to control construction costs and keep the facility close to existing electrical infrastructure and points of use.

The Solvest report examines a range of PV technologies for modules, inverters and racking. Solar efficiency declines with lower temperatures. Overall, for both sites and the range of solar plant scales, the report indicates the lowest LCOE generally occurs with First Solar cells, the central inverter from ABB, and fixed tilt racking.[4] Plant scales were examined at 1 MW, 5 MW and (for Whitehorse site only due to site limits) 10 MW, assuming the above technology combination as a reflection of lowest LCOE cost. The 10 MW option displayed higher LCOE due to added complexities and the need to incorporate batteries.

Table A 3-1 summarizes the available information on energy production and economics for the options at each site with the lowest LCOE. Annual energy production for these options tends to range between 10% and 15% of installed capacity. The report provides a breakdown of this energy production by month, highlighting that low production can be expected during November through February (due to both sun availability and cold temperatures).[5]

The following summary information is provided on the two selected sites (global positioning system [GPS] coordinates are provided in the Solvest report for each site):

- **Whitehorse Quarry Site (120 acres, with about 110 acres useable for solar farm configuration)** - Located on the old tailings pile for the Whitehorse Copper Mine within Whitehorse city limits, with established road access and 120 acres of open land with minimal fluctuations in elevation across the pile. The site is 2.8 km from Mount Sima substation (connection will be at 34.5 kV). Estimated site area required for the option with the lowest LCOE i.e., First Solar with ABB central inverter at 1 MW is about 11 acres, at 5 MW is about 51.2 acres with fixed tilt tracking (71.2 acres with single axis tracking), and at 10 MW is about 102.4 acres

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$1.01/kW.h and $1.06/kW.h respectively. [LCOE in real terms (3.38% WACC) would approximate $0.79/kW.h and $0.83/kW.h respectively.]

[4] The report suggests that this technology option with single axis tracking for 5 MW at the Haines Junction site may yield a very slightly lower LCOE ($0.141/kW.h) than with fixed tilt tracking ($0.142/kW.h).

[5] Information in the report suggests that irradiation is relatively strong in March through August.

with fixed tilt tracking (142.4 acres if using single axis tracking, i.e., single axis tracking with 10 MW First Solar does not fit on this site - only Sunpower, Panasonic HIT, or Prism Bi-facial would fit with single axis tracking).

- **Haines Junction Site North of Dump (65 acres, with about 55 acres useable for solar farm configuration)** - Located 1 km from the Haines Junction dump, in a largely open area with thin tree cover, minimal fluctuation in elevation across the site, and close proximity to the highway (500 m) and substation (3.4 km). Estimated site area required for the option with the lowest LCOE at 1 MW is about 11 acres, and at 5 MW is about 51.2 acres (71.2 acres if use single axis tracking, i.e., single axis tracking with 5 MW First Solar does not fit on this site - only Sunpower, Panasonic HIT, or Prism Bi-facial would fit with single axis tracking).

Table A 3-1: Solar PV Energy Production & Economics (2015$)
(Assumes First Solar Cells, ABB Central Inverter - 30 year life)

Solar Site Option	Net MW	Annual Energy GWh/year[1]	Average Capital Costs ($million)	Average O&M Costs ($million year 1)	LCOC ($million/MW-year)	LCOE ($/kWh)
Whitehorse (with fixed tilt tracking) Heliene Poly[2]	1 MW 5 MW 10 MW	1.076 5.239 11.471	$3.3 $12.7 35.6	0.0315 0.1426 0.3732	$0.658 $0.491 $0.804	$0.174 $0.141 $0.200
Haines Junction (with fixed tilt racking)	1 MW 5 MW	1.111 5.232	$2.9 $12.8	$0.0315 $0.1426	$0.553 $0.493	$0.147 $0.142

Notes:
1. Energy production is reduced materially from September through February, i.e., estimates indicate only 21% to 26% of annual energy for these options occurs in six months from September to February inclusive, and about 50% to 52% of annual energy in 5 months from June to October inclusive. Peak energy generation is in March-May period (37% to 41% of total annual generation is in these three months).
2. Heliene Poly is lowest LCOE of 10 MW options at Whitehorse with an estimated LCOE. Report does not provide cost or energy estimates for First Solar option at 10 MW at Whitehorse.

3.4 WIND FARMS

The Canadian Biomass Energy Research Ltd. (CBER), with ENVINT Consulting and V3 Energy, LLC, provided Yukon Energy with a final report on wind farm options ("Yukon Wind Site Inventory", August 24, 2016), identifying five potential new wind project sites near existing and planned power infrastructure plus the Tehcho and Mt. Sumanik sites, which Yukon Energy had previously examined in some detail.

Wind farms include the following infrastructure: towers with turbines, access road, turbine road, and transmission line to connect to the grid. The CBER study developed estimates of annual net generation, capital costs and annual operating costs for each of the seven identified sites at 6 MW, 10 MW and 20 MW scales of development. The CBER study provided estimates of monthly distribution of annual generation at each of the seven sites, indicating a clear pattern for each site of lower monthly mean power production during the summer months compared to winter (on average, three-fourths of wind energy generated for the seven sites would be during the seven months from October to April). The

study commented on reliable capacity contributions from wind farms[6], but did not address the potential requirements for other new facilities on the grid for reliability requirements.[7]

The current evaluation assumes the 20 MW capacity case from the CBER study for each site option, with 10 turbines each of 2 MW capacity with a 90-metre rotor diameter, and 80-metre hub height. For the representative wind turbine layouts provided in the CBER study, an approximate turbine separation of five rotor diameters, or 450m, was consistently assumed and was reported to be the conservative end of the three to five rotor diameter separation ranges generally recommended within the wind power industry for turbines oriented perpendicular to the prevailing wind.

The following seven short-listed 20 MW wind farm sites from the CBER report are to be evaluated (GIS information has been provided on these sites). See Table A 3-2 for summary of generation, capital cost, O&M annual cost, and LCOE for each site over an assumed 25 year life. Information on long-term average power generation by month will be provided in future.

- **Cyprus Mine Hill** - Located north of Faro mine on a brownfield site previously developed for this mine with 7.6 km transmission line to existing transmission and 12.5 km access road and turbine road.
- **Kluane Lake (west shore)** - Located on west side of Kluane Lake, northwest of Haines Junction and south of Destruction Bay, with transmission at 58.6 km to Haines Junction and 21.4 km underwater. Costing in Table A 3-2 assumes that the required transmission from the wind farm to the grid is developed independently of this wind farm project, e.g., the Aishihik-Destruction Bay transmission corridor would address this requirement. The CBER report indicates that this is the only relatively low elevation location in Yukon with projected high wind speeds, and it is at much lower elevation than the six other shortlisted sites. CBER notes that the lower elevation would mean that the wintertime rime icing that would be an operational challenge at the higher elevation sites would likely not exist at Kluane Lake or be significantly less problematic.
- **Miller's Ridge** - Located west of (and close to) Carmacks, with 13.6 km transmission to grid and 8.19 km access road and turbine road.
- **Sugarloaf Mountain** - Located south east of Carcross, with 3.77 km transmission to grid and 5.57 km access road and turbine road.
- **Mount Sumanik** - Located northwest of (and close to) Whitehorse, with 3.13 km transmission to grid and 10.64 km access road and turbine road. Yukon Energy has prior studies on this site.
- **Tehcho (Ferry Hill)** - Located north of (and close to) Stewart Crossing, with 3.30 km transmission to grid (upgrade) and 3.79 km access road and turbine road. Yukon Energy has prior studies on this site option.

[6] The study estimated reliable winter capacity as being equal to the mean annual power output, and estimates (based on all seven wind farms examined) that this would equal 5.2 MW (26% capacity factor) for a 20 MW wind farm. The study noted that additional wind farms would lower the capacity credit per farm but could also increase the ability of wind to provide base load power (firm capacity) when they are geographically distant.

[7] The 2011 Yukon Energy Resource Plan assumed that a 5 MW diesel rotary uninterruptible power (DRUPS) unit would be required for a 20 MW wind farm connection to provide for grid reliability requirements.

- **Thulsoo Mountain** - Located close to the Aishihik hydro generation station, with 10.6 km transmission to grid and 12.75 km access road and turbine road.

It has been noted by Yukon Energy that Kluane Lake and Tehcho are sites that obviously require clearing. To the extent other sites are located on mountain ridges, less clearing may be required for the turbines. The Cyprus Mine site is a brownfield site.

Table A 3-2: Wind Farm Sites Energy Production & Economics (2015$) (25-year life)[8]

Wind Site Option	MW	Annual Net Capacity Factor[1] (%)	Annual Net Energy GWh/year	Capital Costs ($million)	O&M Costs ($million/year)[3]	LCOC ($million/MW-year)	LCOE ($/kWh)[3]
Cyprus Mine	20 MW	28.3%	49.6	69	1.360	N/A	0.117
Kluane (ex. trans. to grid)[2]	20 MW	27.3%	47.8	62	1.307	N/A	0.110
Miller's Ridge	20 MW	32.7%	57.3	73	1.442	N/A	0.107
Sugarloaf	20 MW	18.4%	32.3	62	0.984	N/A	0.153
Sumanik	20 MW	23.7%	41.5	64	1.119	N/A	0.124
Tehcho	20 MW	19.1%	33.4	64	0.972	N/A	0.151
Thulsoo	20 MW	31.0%	54.4	72	1.390	N/A	0.109

Notes:
1. CBER estimates of annual average wind generation per site, less wake loss, and losses for de-icing electricity and turbine stalling, low-temperature downtime, transformer losses, sub-optimal performance, and maintenance.
2. Costs exclude capital and O&M adjustments for transmission connection from the local area to the grid (see Section 5.1 of this Appendix for current cost estimates).
3. O&M costs based on variable O&M costs for first five years at $15/MW.h gross generation (2015$) without provision for expected increases of variable O&M costs thereafter (the study estimates that variable O&M costs [2015$] will increase to $25/MW.h from years 6 to 10 and then to $30 after that).

3.5 GEOTHERMAL

The KGS Group provided YEC with a final report for the geothermal resource option ("Geothermal Review and Site Inventory", September 2016). After review of available information, this study concluded that two sites (Vista Mountain and McArthur Springs) have the largest production capacity for sites located close (i.e., within about 25 km) to Yukon Energy's existing and future planned grid infrastructure. As the exact amount of production capacity is unknown (i.e., no exploration wells have been drilled yet at either site), a best and worst case scenario (in terms of water production) was considered for each location.

A geothermal facility at either site includes the plant site (building and related fenced area), two production wells and one induction well (the wells are about 1 km apart), plus the access road and transmission connection to the grid. Geothermal production capability is higher in winter (lower temperatures) than in summer (the report provides generation by month). Energy generation and

[8] Estimates are per Tables 8 and 18 and Appendix D of CBER study.

capacity degenerate over time unless added maintenance wells are drilled - the study assumes 2% per year degeneration over an assumed 30 year project life. Operating employment is estimated at a half-time FTE for each plant option.

The following summary information is noted for the two site options identified (see Table A 3-3):

- **Vista Mountain** - This site requires about 5 km of new transmission (34.5 kV) for connection to the existing grid. It is close to the Whitehorse load centre, the existing Klondike Highway and the Takhini substation. It is located on Crown land and has the highest inferred temperature of options examined within 25 km of existing infrastructure. The plant site footprint is estimated to range from 1,840 to 2,900 m^2 (depending on the ultimate capacity that is confirmed).

  Expected plant annual average net capacity in first year of operation ranges from 0.9 MW to 2.3 MW (low and high estimates), with initial annual energy generation ranging from 8.15 GWh/year to 20.95 GWh/year (after 30 years this degenerates to the range of 4.54 GWh/year to 11.66 GWh/year). Average annual energy over the 30 year life is 11.03 GWh/year. Project capital cost for this range of capacity is $37.8 million to $45.2 million, and annual fixed operating costs range from $0.35 million to $0.8 million (2015$).

  LCOE estimates (2015$) over the 30 year life at 3.38% WACC range from $0.194 to $0.368 per kWh, depending on plant capacity, with the highest LCOE cost being associated with the low capacity.

- **McArthur Springs** - This site was the most promising of the options reviewed (highest inferred temperature), but it is located more than 25 km from the existing grid (estimated transmission and road development connection distance of 43 km with transmission at 138 kV). The site is located east of Highway no. 2, southeast of Stewart Crossing. It is located within the Ddhaw Ghro Habitat Protection Area, in an area designated for mine development by Selkirk First Nation. The plant site footprint is estimated to range from 2,900 to 5,000 m^2 (depending on the ultimate capacity that is confirmed).

  Expected plant annual average net capacity in first year of operation ranges from 2.1 MW to 5.5 MW (low and high estimate), with initial annual energy generation ranging from 18.62 GWh/year to 48.24 GWh/year (after 30 years this degenerates to the range of 10.37 GWh/year to 26.85 GWh/year). Average annual energy over the 30 year life is 25.33 GWh/year. Project capital cost for this range of capacity is $114 million to $127 million, and annual fixed operating costs range from $0.8 million to $1.8 million (2015$).

  LCOE estimates (2015$) over the 30 year life at 3.38% WACC range from $0.225 to $0.469 per kWh, depending on plant capacity, with the highest LCOE cost being associated with the low capacity estimate.

Table A 3-3: Geothermal Site Production & Economics (2015$) (30-year life)

Geothermal Site Option	Net MW (Average annual, initial year)[1]	Annual Energy GWh/yr. (initial year)[1]	Capital Costs ($million)	O&M Costs ($million/ year)	LCOC ($million/ MW-yr.)	LCOE ($/kWh)
Vista Mountain	0.9 to 2.3 MW Average 1.6 MW	8.15 to 20.95 GWh 1st yr. Average 14.55 GWh Lifetime average 11.03 GWh	$37.8 to $45.2 Average $41.5	$0.350 to $0.8 Average $0.575	$1.1 to $2.3 Average $1.71	$0.19 to $0.37 Average $0.281
McArthur Springs	2.1 to 5.5 MW Average 3.8 MW	18.62 to 48.24 GWh 1st year Average 33.43 GWh Lifetime average 25.33 GWh	$114 to $127 Average $120.5	$0.8 to $1.8 Average $1.3	$1.4 to $3.2 $2.30	$0.22 to $0.47 Average $0.347

Note:
1. Net capacity and annual energy degenerate at 2%/year over 30 year life; net capacity is higher in winter than in summer.

4.0 HYDRO RENEWABLE GENERATION

4.1 PUMPED STORAGE PROJECTS

Pumped storage resource options are identified below from three separate sets of reports.

Knight Piesold Report

Knight Piesold Consulting (KP) provided Yukon Energy with a report on pumped storage options ("Pumped-Storage Assessment, Preliminary Assessment", September 30, 2016), identifying viable pumped storage sites (outside parks and protected areas) within a 25 km radius of existing and proposed transmission infrastructure.

The pumped storage sites were assumed in the KP assessment to provide seasonal pumping from May through to September and seasonal generation from October through to April. Aside from an assumed variable O&M cost of $0.005/kWh, energy required for pumping is assumed in the KP report to have no cost, implicitly assuming adequate surplus renewable energy on the grid from May through September. Surplus renewable energy on the Yukon grid is affected by assumed grid loads, long-term average hydro generation by season, and renewable wind or solar generation. With current renewable generation, seasonal surplus generation is typically focused in the period from late May to early November.

Out of 473 potential reservoir basins and approximately 200 technically viable sites, the following 7 sites were selected by KP for further evaluation (see Table A 4-1 below for summary of capacity and energy options assessed by KP for each site that is retained for the current evaluation, including pumping annual energy requirements, resulting capital and O&M cost estimates, and resulting LCOE and LCOC estimates):[9]

- **Tutshi-Moon** - located near Tutshi Lake, BC (study assumed existence of Whitehorse-Skagway transmission corridor only 2.6 km from site. Without this line, the distance to the nearest point of intersection increases by approximately 35 km and that would only connect to the 34.5 kV network).
- **Racine-Moon** - located near Racine Lake, BC (study assumed existence of Whitehorse-Skagway transmission corridor 20.6 km from site. Without this line, the distance to the nearest point of intersection increases by approximately 35 km and that would only connect to the 34.5 kV network). KP only examined the 50 GWh/year option for this site.
- **Racine-Mt. Brown** - located near Racine Lake, BC (study assumed existence of Whitehorse-Skagway transmission corridor 24 km from site. Without this line, the distance to the nearest point of intersection increases by approximately 35 km and that would only connect to the 34.5 kV network).

[9] KP did not show comparative areas for natural versus flooded for these options. Reservoir areas with each project site show increase for the upper reservoir area in some cases if examine 100 GWh versus 50 GWh options, e.g., Tutshi-Moon goes from 500 to 61 ha, Racine-Mt. Brown goes from 210 to 290 ha, and Atlin-Black mountain goes from 230 to 313 ha; however, the lower reservoir changes are generally much more muted for these three sites when the larger option is examined.

- **Lindeman-Fraser** - located near Fraser, BC (study assumed existence of Whitehorse-Skagway transmission corridor only 5 km from site. Without this line, the distance to the nearest point of intersection increases by approximately 45 km and that would only connect to the 34.5 kV network). KP only examined the 50 GWh/year option for this site.
- **Atlin-Black Mountain** - located near Atlin, BC (study assumed existence of Whitehorse-Atlin transmission corridor within less than 1 km from site. Without this line, the distance to the nearest point of intersection increases by over 40 km and that would only connect to the 34.5 kV network).
- **Squanga-Dalayee** - located between Johnson's Crossing and Jake's Corner, Yukon (study assumed existence of Whitehorse-Teslin transmission corridor less than 2 km from site (the existing transmission is 34.5 kV). KP only examined a 100 GWh storage option for this site.
- **Canyon-Ittlemit** - located near Canyon Lake and the Aishihik Hydro Facility, Yukon (transmission connection 13.9 km to existing 138 kV grid). KP only examined a 100 GWh storage option for this site.

The KP report concluded as follows with regard to pumped storage site options and configurations:

- Tutshi-Moon site option was the most cost-effective option for all cases examined. The Atlin-Black Mt. and Racine-Mt. Brown options also have similarly competitive costs, particularly for the 50 GW.h configurations.
- Racine-Moon and Lindeman-Fraser site options have technical constraints that make them less promising.
- Squanga-Dalayee and Canyon-Ittlemit site options are less cost-effective than Tutshi-Moon, but have the advantage of being relatively closer to existing Yukon Energy infrastructure. It was noted that it is not known at this stage whether a viable project configuration can be found for the Canyon-Ittlemit facility that does not negatively impact the existing Aishihik Hydro Facility.
- Preliminary site visits were recommended as a next step to five of the short-listed sites, which excluded Racine-Moon and Lindeman-Fraser sites.
- The lowest LCOE ($0.19/kWh) is achieved with the 15 MW/100 GWh configuration; however, the lowest LCOC ($650/KW/year) is achieved with the 25 MW/50 GWh configuration. These costs exclude new transmission required from the site area to the Whitehorse grid.
- KP noted that reducing energy storage further may provide a lower cost of capacity and would be more in line with the development trend in pumped storage facilities worldwide (short duration storage of hours to days rather than seasonal storage, focusing on rapid response with variable-speed units, which make a facility able to provide grid stability, frequency control, voltage regulation, spinning reserve and other grid support ancillary services).

Sites were identified in the KP report with 15 to 25 MW and (for each capacity) 50 and 100 GWh/year energy storage. Annual pumping energy required can vary materially among site options depending on site features. For the purpose of the current resource options evaluation, Yukon Energy has requested

that the 15 MW capacity with 50 GWh/year option and the 25 MW with 100 GWh/year option be included.

Based on the above request, the 15 MW option with 100 GWh/year and the 25 MW option with 50 GWh/year are not included at any site in the current resource options evaluation (see Table A 4-1).

The current resource options evaluation also excludes the KP version of the Tutshi-Moon site option and instead looks at the Moon Lake resource option as examined in the Midgard report (see below).

Midgard Report

The Tutshi-Moon site in the KP desktop study is the same site assessed by Midgard Consulting Inc. (Midgard) in an earlier, more detailed conceptual study for Yukon Energy ("Moon Lake - Pumped Storage Conceptual Study Report", December 14, 2015). Yukon Energy has requested that the Midgard study be used for the Moon Lake pumped storage site option in the current evaluation study.

The following are noted from the Midgard study (see Table A 4-1 below for a summary of capacity and energy options assessed by Midgard for the Moon Lake site option assuming 54 GWh/year of annual energy generation for use on the grid, 48 GWh/year pumping annual energy requirements, resulting capital and O&M cost estimates, and resulting LCOE and LCOC estimates):

- Assumed 48 GWh/year of available pumping energy from weeks 20 to 44 (late May to early November, based on Yukon Energy 2022 forecast for surplus hydro and assumed wind generation - this forecast also indicated diesel generation to be displaced at 23.75 GWh). Surplus energy available for pumping with current renewable capacity declines as grid load increases (2030 forecast showed reduction to 31 GWh/year), and the report assumes adequate new renewable generation is provided to retain the surplus energy needed for this pumped storage site option.
- Assumed facility has 31m high, 700m long earth dam at outflow of Moon Lake, a 5.5 km long, 0.5m diameter buried steel penstock, and a concrete and structural steel powerhouse 400m below on the shore of Tutshi Lake. The project will create a 690 ha reservoir over the existing Moon Lake, and this reservoir level will vary from minimum operating level (MOL) of 1,114m [3.44 km^2 area] and a full supply level (FSL) of 1,125m [6.9 km^2 area]. Over 45 years of water records, water in the reservoir is estimated to spill 18 years and draw down to MOL 2 years.
- Capital cost and O&M cost estimates for this site option are lower than for the KP report, and the LCOE is also notably lower (assumed 65-year life with constant energy levels and WACC at 3.38%/year net of inflation).
    - Capital cost is $217.6 million in the Midgard report, compared with $237.6 million in the KP report for 15 MW and 50 GWh of pumped storage.
    - O&M cost is $1.896 million/year in the Midgard report, compared with $4.784 million/year in the KP report for 15 MW and 50 GWh of pumped storage. [KP O&M cost assumes 2.0% of capital cost before IDC plus $0.005/kWh variable cost for generation and pumped energy, without specific consideration of BC resource fees. Midgard's O&M cost estimate includes BC resource fees and explicit provision for general O&M, major

maintenance allowance, management/ administration/ overhead, insurance and property tax].

- LCOE is $0.189/kWh in the Midgard report, compared with $0.28/kWh in the KP report for 15 MW and 50 GWh of pumped storage.

EP Report

In addition to the above, EMC^2-Picacho (EP) provided Yukon Energy with a conceptual assessment of seasonal pumped storage options at the Faro Mine Complex (EP Technical Memo, May 16, 2016).

The overall approach in the EP report assumes the use of the existing infrastructure of the Faro Mine Complex (e.g., pits, roads, transmission) to develop seasonal pumped storage to provide four to five months of winter generation. The upper reservoir would be created in or close to existing or future (i.e., if future development occurred of the unexploited Grizzly Deposit) waste rock dumps and would involve appropriate measures to provide the necessary environmental protection and a watertight reservoir. The EP study concluded that the following two options potentially could be economically viable only when the upper reservoir costs are shared by a mining operation (all costs in US$2015):

- **Scheme A: Faro Pit** - A 4 MW option with 9.6 GWh pumped storage (winter generation supply) with the upper reservoir located on top of the existing waste rock dump south of the Faro Pit and with the Faro Pit serving as the lower reservoir. The scheme will have a pump/turbine in the pit area that will pump stored water to the waste dump reservoir; in return, the water will drop via a penstock pipe to the pump/turbine installed on a floating barge on the pit lake (total available head of at least 300 m). The summer energy required for pumping is 11.7 GWh.

  Estimated cost of the Faro Pit scheme is US$89 million as a stand-alone project, with 50 year assumed life and annual O&M cost of approximately US$0.233 million plus an assumed summer pumping cost of US$0.351 million (assumes summer power cost of US$0.03/kWh). The study noted that if the mine picked up 50% of the reclamation costs (i.e., regarding the upper reservoir side slopes and lining the upper reservoir with an 80 mil HDPE geomembrane), then the capital cost reduces to US$48 million. Similarly, the study noted that if the mine picked up all of the upper reservoir costs, which is work that the study stated they would do anyway to close the dump, then the scheme would cost US$4.5 million.

  The EP study did an economic assessment using a different approach than that adopted for the KP and Midgard assessments of pumped storage options. Using the KP approach with the EP cost estimates and energy generation, a 50 year life, no cost for summer energy, and a WACC of 3.38% yields an LCOE of US$0.413/kWh for the stand-alone project and US$0.232/kWh if the mine picked up 50% of the reclamation costs.

- **Scheme C: Vangorda Pit** - A 40 MW option with 134 GWh of pumped storage (annual winter generation) with two reservoirs: the upper reservoir with a storage volume capacity 123 million m^3 (built on the generally flat plateau east of the Vangorda Pit, abutting the waste dump on the south side of the Vangorda Pit), and a lower reservoir with a storage capacity of 70 million m^3 (located in a very narrow region of the stream below the upper reservoir). The total available head is 390 m with a 1,780m long penstock leading to the powerhouse located next to the lower embankment. The summer energy required for pumping is 163.4 GWh.

Water from Vangorda Pit operations could be blended into the 106 million m^3 per year of natural inflow volume from the upper and lower catchments, which blending would be beneficial to the mine treatment operations currently ongoing at the pit. Just west of the upper reservoir is the Grizzly Deposit, an unexploited zinc/lead/nickel deposit previously identified as a potentially viable deposit, which if and when developed would enable the upper reservoir embankment to be created from mine waste at almost no extra cost to the mining operations.

The estimated cost of the Vangorda Pit scheme in the EP study is US$392.8 million as a stand-alone project, with a 50 year assumed life and annual O&M cost of approximately US$1.160 million plus an assumed summer pumping cost of US$4.902 million (assumes summer power cost of US$0.03/kWh). The study noted that if the Mine operation related to Grizzly Pit development picked up 50% of the cost for the dam, then the capital cost reduces to US$230.4 million (at Mine support for 75% of this cost, the capital cost overall reduces to US$176 million).

The EP study did an economic assessment using a different approach than that adopted for the KP and Midgard assessments of pumped storage options. Using the KP approach with the EP cost estimates and energy generation, a 50 year life, and a WACC of 3.38% with a cost for summer power of US$.03/kWh yields an LCOE of US$0.168/kWh (US$0.131/kWh if no cost summer power) for the stand-alone project and US$0.117/kWh (US$0.080/kWh if no cost summer power) if the Mine picked up 50% of the reclamation costs.

Both of the above options are assumed to require considerable funding of capital costs by the mine site. The Faro Pit option is also relatively small, while the Vangorda Pit option, at 40 MW, is well beyond the 20 MW cap for resource options being examined for the current Resource Plan.

Yukon Energy has requested that only the Vangorda Pit option be included in the current evaluation without assuming any related mine development. To be consistent with the other projects reviewed, cost related assumptions for the Vangorda Pit are included in Table A 4-1 based on the above EP cost estimates assuming 1$CAN equals $0.75US, as well as assuming a 50 year life with O&M cost for pumped storage energy at only $0.005/kWh.

Table A 4-1: Pumped Storage Sites Energy Production & Economics (2015$) (65-year life)

Pumped Storage Site Option	Net MW	Annual Energy Supply GWh/year	Annual Pump Energy Required GWh/year	Capital Costs ($million)	O&M Costs ($million/ year)	LCOC ($million/ MW-year)	LCOE ($/kWh)
Moon (Midgard report) (ex. trans. to grid)[1]	20.2 MW	54	48	217.6	1.893 with 0.168 BC resource fees	N/A	0.189
Racine-Moon (KP report) (ex. trans. to grid)[1]	15 MW	50	31.8	473.0	9.2	1.80	0.54
Racine-Mt. Brown (KP report) (ex. trans. to grid)[1]	15 MW 25 MW	50 100	51.8 113.6	284.0 486.0	5.8 10.1	1.1 1.1	0.33 0.29
Lindeman-Fraser (KP report) (ex. trans. to grid)[1]	15 MW	50	55.8	483.8	9.5	1.9	0.56
Squanga-Dalayee (KP report) (ex. trans. to grid)[1]	25 MW	100	119.7	613.4	12.5	1.4	0.36
Atlin-Black Mountain (KP report) (ex. trans. to grid)[1]	15 MW 25 MW	50 100	59.5 121.3	253.8 464.4	5.2 9.7	1.0 1.1	0.30 0.27
Canyon-Ittlemit (KP report)	25 MW	100	119.9	691.2	13.9	1.60	0.40
Vangorda Pit (EP Report-50 year life)[2]	40 MW	134	163.4	523.8	2.4	N/A	0.18

Notes

1. Costs exclude capital and O&M adjustments for transmission connection from the local area to the grid (see Section 5.1 of this Appendix for current cost estimates). Capital costs include interest during construction.
2. Cost, life and LCOE assumptions are not necessarily compatible for this site and other sites.

4.2 SMALL HYDRO PROJECTS

Small hydro resource options are identified from three separate sets of reports below.

Knight Piesold Report

KP provided Yukon Energy with a report on small hydro resource options ("Small Hydroelectric Projects Screening Assessment", October 7, 2016), which screened a wide range of site options and identified five preferred projects and related conclusions based on a desktop level assessment of location, project layout, site characteristics, capacity, energy and cost. The initial study as drafted in April 2016 included Surprise Lake as one of five top projects screened for more intensive assessment. The final report removed Surprise Lake from the top five and included Anvil Creek (Surprise Lake is addressed separately in the MH report summarized below).

Key conclusions from the final KP report include:

- The five most attractive or preferred projects as examined by KP are Drury Lake, Finlayson River, Anvil Creek, Tutshi-Windy Arm, and Wolf River. All of these are storage projects, except for Wolf River (which is a run-of-river project). See Tables A 4-2 and A 4-3 for summary information from the KP report on these preferred projects. Cost estimates for transmission assume that proposed new transmission corridors are in place as noted in Table A 4-2.
- Based on a stand-alone assessment of hydropower development and interconnection to the closest existing or proposed transmission line, the most attractive small hydro sites as assessed in the KP report are the Finlayson River, Wolf River, and Tutshi-Windy Arm. Drury Lake and Anvil Creek appear to be more expensive on a cost of energy basis.
- The initial installed capacities for the Finlayson River, Tutshi-Windy Arm and Wolf River projects are likely in the order of double those used in the present study (where 20 MW was the upper limit):
    - Finlayson River optimum cost to benefit scale could perhaps be in the order of 40 to 45 MW (versus 17.8 MW assumed in this study, which operates at 100% capacity factor).
    - Tutshi-Wind Arm optimum cost to benefit scale could perhaps be in the order of 15 MW (versus 7.2 MW assumed in this study, which operates at 100% capacity factor).
    - Wolf River optimum cost to benefit scale could perhaps be in the order of 40 to 45 MW (versus 20 MW cap assumed in this study). An earlier 1991 study also noted the potential opportunity for storage at Wolf Lake, which could improve winter generation and the plant capacity factor.
- The Tutshi-Windy Arm project has the additional benefit (as a result of storing water for increased winter use) of increasing the winter generation at the Yukon Whitehorse Generating Station on the Yukon River downstream of these small hydro projects:
    - An earlier KGS study estimated an increase of 6 GWh/year in Whitehorse winter generation from control of Tutshi Lake outflows.

- The initial draft KP study estimated that similar downstream benefits from the Surprise Lake project would be slightly less than 3 GWh/year.

- If the Moon Lake-Tutshi Lake pumped storage project is developed, it may have material synergies with development of the Tutshi-Windy Arm small hydro project, including provision of added downstream winter generation benefits at the Whitehorse Generating Station.

The five small hydro preferred sites in the final KP report are included in the summary information shown in Tables A 4-2 and A 4-3.

Morrison Hershfield Report

The Surprise Lake project assessed in the initial draft KP report is similar to a small hydro project (Atlin project) at this site that Morrison Hershfield (MH) recently examined in more detail ("Atlin Hydro Expansion Pre-Feasibility Study" for Atlin Tlingit Economic Limited Partnership, Revised June 23, 2016). Yukon Energy has directed that the MH study rather than the KP study be used for the current evaluation of this small hydro project.

Comparison of the MH assessment with the initial KP assessment for this site indicates the following:

- Similar design flow, but MH assumes lower gross head than KP (163.3m versus 238.0m).
- MH has lower assumed capacity (7.8 MW versus 14.2 MW with KP), as well as lower annual generation (44.6 GWh versus 58.8 GWh with KP).
- MH capital cost of $120.7 million includes $40.9 million for 100 km of 69 kV transmission; the KP capital cost of $165.7 million excludes any similar transmission connection to the Yukon grid.
- LCOE with MH is $0.144/kWh excluding transmission connection, compared with 0.18/KWh LCOE with KP.

The following MH report information is summarized for the Atlin project (see also Tables A 4-2 and A 4-3):

- The 2.1 MW Atlin Hydro Project on Pine Creek (about 4 km east of the community of Atlin) began commercial power production on April 1, 2009. It is owned by a partnership which is 100% owned by Taku River Tlingit First Nation. The community of Atlin is not connected to any external electrical power grid. Power created by this current project is sold to BC Hydro on a 25-year energy purchase agreement (which includes an obligation to provide 8.3 GWh/year by 2032). The existing project, which currently meets all of the community's electrical power needs and has additional underutilized generating capacity, only develops a portion of the hydropower potential of this site.
- The MH study provided a preliminary assessment of increasing hydropower production for export to the Yukon electrical grid. It looked at expanding the current powerhouse with two additional turbines of 1.45 MW each with related added penstock and intake structure (bringing the total powerhouse capacity to 5 MW) and developing a second lower powerhouse on Atlin Lake (with related new penstock, head pond and intake structure, to provide an additional 2.5 MW to 3 MW [2.8 MW assumed] of capacity). A new 69 kV transmission line of approximately 100 km is

assumed to connect the project with the Yukon electrical grid at Jake's Corner. Modifications were also assumed to the existing Surprise Lake control structure and weir to increase water storage range. A small diversion ditch will divert Spruce Creek into the new lower head pond just upstream up the mouth of creek into Pine Creek.

- Long-term average annual power generation from the project (including existing capacity) was estimated (assuming 2.5m storage at Surprise Lake) at 44.6 GWh/year, with 30.8 GWh (69%) of this generation in the six months from November 1 to April 30; the upper plant contributed 28.2 GWh of the estimated annual generation, and the lower plant contributed 16.3 GWh. Net of an 8.3 GWh/year obligation to BC Hydro, the project can provide long-term average generation of 36.3 GWh/year for export to Yukon. Line losses from transmission would reduce the useable electricity in Yukon: losses of 2.2% are estimated for delivery to Jake's Corner (existing 34.5 kV system in Yukon), and about 5.7% for delivery to Whitehorse (assuming current Yukon grid).[10]
- A capital cost estimate for the project of +/-30% (pre-feasibility) in 2016$ was provided of $79.7 million for the hydroelectric generation component, and $120.7 million including 69 kV transmission required to connect with the Yukon system at Jakes Corner with ability to supply power to Yukon Energy at Whitehorse (when it is not used on the ATCO portion of the southern grid).
- The MH study did not provide any estimate of annual O&M costs for the project. [An O&M cost estimate developed on a basis comparable to the KP study is included in Table A 4-3, assuming a fixed annual cost at 2.0% of capital cost excluding interest during construction (assume this approximates $1.59 million per year based on $79.7 million cost estimate for the project excluding the 100 km transmission line) plus $0.005/kWh variable cost ($0.181 million/year based on 36.3 GW.h new energy for Yukon), or a total O&M cost of $1.771 million/year].
- Assuming 65 year life, 3.38% WCC, the above capital and O&M cost estimates, and 36.3 GWh/year generation for export to Yukon, the estimated LCOE is $0.133/kWh excluding 100km transmission connection cost and $0.176/kWh including the transmission connection cost (2016$). A lower O&M cost than adopted using the KP approach would reduce the LCOE (see separate comments earlier re Moon pumped storage costs based on the Midgard study).

The current resource evaluation study will include the Atlin resource option as described in the MH report. It is noted that costs for transmission connection to the grid as developed in the MH report are not necessarily compatible with cost estimates for this portion as developed for the transmission corridor assessment of the Whitehorse-Atlin Transmission Corridor option (see Section 5.1 below of Appendix A). YEC advises that it expects to use the transmission assessment cost estimates for transmission-related cost elements related to the Atlin project.

[10] The MH study examined transmission connection options linking to a 138 kV new line from Whitehorse to Carcross, which would reduce line loss for transmission to Whitehorse. The study concluded that the option to connect at Jake's Corner, with interconnection on the existing 34.5 kV ATCO line to Yukon Energy's 138 kV grid at Whitehorse, is the most viable option available today for this project.

Earlier Studies regarding Moon Lake Small Hydro Site Option

The KP study of small hydro options excluded the Moon Lake site, which was addressed under pumped storage hydro resource options. The following information is noted from other earlier studies regarding a small hydro option at Moon Lake (this option is not examined further in the current evaluation):

- A conventional Moon Lake site option was included in the study that Midgard (Midgard recently provided for Yukon Energy on the Moon Lake project ("Moon Lake - Pumped Storage Conceptual Study Report", December 14, 2015). Based on Midgard's estimated generation (20 GWh/year), capital cost ($155 million) and related O&M costs (likely about $1.5 million/year based on Midgard's approach), the LCOE for this Moon Lake small hydro option would be very high compared to other options examined in the KP study (i.e., about $0.371/kWh) even before considering transmission connection costs for supply to the current grid.
- An earlier AECOM study[11] for Yukon Energy, using information from the 2007 KGS study, estimated annual generation of 32.9 GWh/year and a LCOE (2009$) of $0.146/kWh excluding transmission connection costs and $0.199/kWh including transmission connection costs (55 km connection).

[11] AECOM, "2009 Large Hydro Stage 1: Initial Investigation", November 2010 (Table 4.4).

Table A 4-2: Small Hydro Site Options - Physical Requirements

Project	Type	Flood Areas (km^2 of New Impoundment)	Design Flow (m^3/s)	Gross Head (m)	Location	Distance (km) to Transmission Lines	Access Road (km)
Drury (KP report)	With Storage	27.9 (new area flooded 1.9)	9.3	99.0	On Drury Creek between Drury Lk and Little Salmon Lk	0.5 to existing	5.3
Finlayson (KP report)	With Storage	10.6 (Wolverine Lk); 23.0 (Finlayson Lk) (new area flooded 5.4)	13.3	150.0	On Finlayson River upstream of Frances Lk. 300 km NE of Whitehorse (relocate 3 km of Highway due to flooding)	155.3 to existing; 5.1 to proposed (Faro-Watson L TL)	17
Atlin (Pine Creek) (MH report)	With Storage	Not applicable (no increase to FSL at Surprise Lake, increase to LSL)	6 to 7	163.1	On Pine Creek between Surprise Lk and Atlin Lk near Atlin, BC. (Upper 5.0 MW [2.9 MW new], lower 2.8 MW)	100 to existing Yukon 34.5 kV transmission	N/A
Tutshi-Windy Arm (KP report)	With Storage	55.0 (Tutshi Lk) (new area flooded 3.1)	15.0	51.0	Between Tutshi Lk and Windy Arm of Tagish Lk in northern BC. 45 km south of Carcross	24.8 to existing; 0.5 to proposed (Whitehorse-Skagway TL)	23.5
Wolf River (KP report)	Run of the River	Not applicable	37.7	60.0	On Wolf River near river mouth and 22 km NE of Teslin and Alaska Hwy	55.1 to existing; 23 to proposed (Whitehorse-Teslin TL)	23
Anvil Creek (KP report)	With Storage	5.9 (new area flooded 0.6)	8.2	13.5	On Anvil Creek approx. 4.7 km downstream of Anvil Lake outlet and upstream of Anvil Creek-Blind Creek confluence (control dam at Anvil Lake outlet)	11 to existing	3.5 new access road

Table A 4-3: Small Hydro Sites Energy Production & Economics (2015$) (65-year life)

Small Hydro Site Options	Installed Capacity (MW)	Net Annual Generation (GWh)	Capital Costs ($million)	O&M Costs ($million/ year)	LCOC ($million/MW-year)	LCOE ($/kWh)
Drury (KP report)	8.1 (8.1 firm winter)	31.7 (100% Nov.-April) (100% firm)	103.3	2.103	0.7	0.19
Finlayson (KP report) (ex. trans. to grid)[1]	17.6 (17.6 firm winter)	138.9 (about 50% Nov.-April) (100% firm)	282.5	6.015	1.0	0.12
Atlin (Pine Creek) (MH report)[1]	7.8 (5.7 new)	44.6 (36.3 available for Yukon - about 70% Nov.-April)	79.7 (excludes cost for 100 km connection)	1.771 (estimated based on KP methods)	N/A	0.133 ex. TL (estimated per KP approach)
Tutshi-Windy Arm (KP report) (ex. trans. to grid)[1]	7.2 (7.2 firm winter)	56.6 (about 50% Nov.-April) (100% firm)	133.2	2.791	1.1	0.14
Wolf River (KP report) (ex. trans. to grid)[1]	20.0 (2.2 firm winter)	95.6 (about 20% Nov.-April) (91% firm)	233.8	4.881	0.7	0.14
Anvil Creek (KP report)	9.8 (2.5 firm winter)	41.3 (about 32% Nov.-April) (75% firm)	116.0	2.391	0.7	0.17

Note:
1. Costs exclude capital and O&M adjustments for transmission connection from the local area to the grid (see Section 5.1 of this Appendix for current cost estimates). Atlin capital cost estimate is in 2016$.

4.3 GLADSTONE DIVERSION

Considerable assessment and feasibility work was done for the Gladstone Diversion project prior to the last Yukon Energy General Rate Application (GRA), including a report by AECOM ("Gladstone Diversion Concept Conceptual Design", May 2011). Based on this earlier work and Yukon Energy filings during its 2012/13 GRA before the Yukon Utilities Board, the following are noted for this project:

- The project proposes to divert water from the headwaters of Gladstone Creek into the Aishihik Lake system and would increase the amount of water available for hydroelectric generation at

the Aishihik Hydro Facility. The project is within the traditional territory of the Champagne and Aishihik First Nations. Kluane First Nation and White River First Nation also have interests in the vicinity of the project on or near Gladstone Creek near Kluane Lake.

- The project concept includes two diversion structures to divert the headwaters of Gladstone Creek into Isaac Creek, which flows into Sekulmun Lake (the primary storage reservoir of Yukon Energy's 37 MW Aishihik Hydro Facility).
- The project is forecast to provide sufficient water for up to an additional 36.6 GWh (on average) of production from the Aishihik facility, focused in the winter months. The project would not add to firm winter capacity on the grid.
- Based on feasibility studies prior to Yukon Energy's last GRA, project cost was estimated at $40 million (2010$) and LCOE over the 65 year project life estimated at 5.7 ¢/kWh (assuming full utilization of added energy generation of up to 36.6 GWh/year during the winter months at the current Aishihik plant and an assumed Yukon Energy blended capital cost averaging 6.56%/year).
- Prior work indicated concerns from the Department of Fisheries and Oceans (DFO) as well as from local First Nations.
- DFO indicated that it had a concern that the proposed Gladstone concept will result in significant effects to fish and fish habitat in the Yukon and Alsek river systems, both of which support high value fisheries. According to DFO, effects would be due particularly to transfer of pathogens and parasites from one watershed to the other. DFO suggested that Yukon Energy revise its concept to eliminate the interbasin water transfer and reduce negative effects to fish habitat. Yukon Energy advised DFO that the concept is still in the very early stages of study/planning, specifically the collection of baseline information and preliminary engineering development to gain an understanding of the feasibility of the concept. Specifically, Yukon Energy noted its intention as part of the baseline studies to gather sufficient information regarding the presence of pathogens and parasites and the risk associated with potential transfer of any pathogens and parasites after all mitigation measures are considered. Once this information is available and the preliminary assessment of risk can be completed, Yukon Energy intends to share this with DFO staff for further discussion and analysis. Yukon Energy reported that the results of a full year of baseline studies provide no evidence to date to support a concern regarding interbasin pathogen transfer.
- Yukon Energy committed as a first priority in 2012 to work with the local First Nations until they make a decision as to whether or not they will support the project.
- The Overview of the 20-year Resource Plan: 2011-2030 from July 2012 recommended that Yukon Energy plan within the next 6 to 12 months to reach a final determination regarding whether the project is feasible to pursue at this time, based on discussions with local First Nations and regulators. Yukon Energy has continued to work with the local First Nations to seek support for this project, given its potential long-term benefits for the system.

4.4 HYDRO STORAGE ENHANCEMENTS

Considerable assessment and feasibility work has been done or is ongoing separate from the current Resource Plan process to examine potential hydro storage enhancement options at Mayo Lake and the Southern Lakes. In the case of the Mayo Lake Enhanced Storage Project, a YESAB submission was filed in 2015 (information from that submission is used for the summary below of this project).

- **Mayo Lake Enhanced Storage Project** – This project would revise the existing Mayo Lake Water Licence to allow up to 1 metre lower supply level (LSL), thereby enabling added long-term average hydro generation at the Mayo hydro generating station (particularly related to enhanced retention of water that would otherwise be spilled during high run off years).

  The specific project proposed serves to increase the long-term average hydro generation potential to displace fossil fuel generation on the Yukon system by approximately 2 to 4 GWh/year[12] (the specific yearly benefit will depend on the overall load level on the Yukon grid, flow conditions throughout Yukon, the Mayo Lake LSL then allowed under the AMP, and the extent of future new renewable generation on the grid).

  The proposed Project requires no new physical works. It will utilize the Mayo Lake Control Structure facilities already in-service for the existing Mayo hydro generation, and ongoing maintenance activities of the structure and associated infrastructure from Mayo Lake to the Mayo Lake Control Dam.[13] Hydro power generation will occur at the existing Yukon Energy facilities at Mayo A and B.

  Mitigation measures proposed for the project are focused on addressing potential adverse effects on fish and fish habitat in the Mayo Lake area (whitefish and lake trout in particular). Changes to water releases would likely enhance downstream salmon spring habitat below the Mayo hydro generating facilities.

  For the first three years of project operation, the lake will be operated with an additional 0.5 m storage range (i.e., between the existing FSL of 665.84 m to a revised LSL of 662.75 m which is 0.5 m below the current LSL of 663.25 m).[14] After the first three years, the results of monitoring and the proposed Adaptive Management Plan will be used to determine if and how to proceed with up to a full metre extra storage (lowering the LSL to 3.59 m below the FSL of 665.84 m) or if the storage range should be reduced to less than 3.09 m.

[12] By way of example, at loads ranging from of 437 to 454 GWh/year, additional long-term average fossil fuel displacement due to the Project's enhancement of long-term average hydro generation ranges from 1.9 to 2.8 GWh/year with 0.5 m enhanced Mayo Lake storage and from 3.4 to 4.2 GWh/year with 1.0 m enhanced Mayo Lake storage. Within the load range of about 460 to 480 GWh/year, fossil fuel generation displacement benefits with 0.5 m enhanced Mayo Lake storage range between 2.9 and 3.2 GWh/year.

[13] Maintenance activities noted here refer to any ongoing works required to keep the control structure operational. See Mayo Outlet Channel Dredging Project.

[14] The current controlled range reflects that under certain water conditions, it is possible for the water level of Mayo Lake to be outside of the stated range due to drought or flood conditions. Under those circumstances, Yukon Energy would be required to operate its facilities at the lake so as to not further exacerbate the elevation conditions. In particular, Clause 25 of the Mayo Water Licence requires that when the lake elevation exceeds the licensed maximum range, Yukon Energy is required to have all of the gates open; a similar practice would be exercised in the event the licensed minimum range was exceeded, consistent with minimum downstream flow requirements.

The project YESAB filing has been delayed pending Yukon Energy addressing the separate maintenance requirement for dredging of sediment built up in the Mayo Outlet Channel. This sediment reduces long-term average hydro generation of the existing facility, and needs to be removed in order for the Mayo Lake project to operate (see Section 4.5 below). The Mayo Lake project in contrast enhances the economic benefit of actions to remove channel sediment and reduce the risk of added future sediment additions to this area.

- **Southern Lakes Enhanced Storage Project** – This project would revise the existing Marsh Lake Water Licence to allow 30 cm higher FSL (656.53 m asl) and 10 cm lower LSL (653.70 m asl) in order to enhance storage in the fall for increased winter use at the Whitehorse hydro generating station. No new dam or generating facilities are required – any works would be related to mitigation measures for shoreline erosion protection or other mitigation.

  The Overview of the 20-year Resource Plan: 2011-2030 in July 2012 estimated that this project would increase long-term average winter hydro generation by up to 6.4 GWh/year, and enhance reliable winter capacity by about 1 MW, at an estimated capital cost of $10.5 million (2010$).

  Marsh Lake water levels can have influence upstream on both Tagish and Bennett Lakes when its lake levels are above about 654.2 m when flows are receding in winter, and above 655.5 m when inflows are increasing in summer. Atlin Lake, along with other higher elevations lakes in the Southern Lakes region are not, and will not be affected by higher levels on Marsh Lake.

4.5 MAYO LAKE OUTLET CHANNEL DREDGING

The Mayo Lake Outlet Channel Dredging Project would remove an old cofferdam as well as sedimentation that has infilled in the Mayo Lake Outlet Channel over the past 63 years since the original Mayo hydro generation was developed and address measures to mitigate potential future sediment infill in this outlet channel.

Current sediment infill is restricting the full hydro capability of the downstream Mayo A and B hydro generation. In addition, this infill plus the cofferdam remnants are preventing any benefit from the Mayo Lake Enhanced Storage project from being realized. There is a risk that additional material sediment infill can occur in response to a major wind event, which would further reduce Mayo hydro long-term average generation capability through further erosion of the cliffs along the north shore of the lake within about 700 m of the mouth of the outlet channel.

Ongoing investigations are required to assess issues and cost effective options to remove existing sedimentation and to minimize the risks of near-term new sedimentation build up in this channel. Maintenance measures to remove sediment infill could involve dredging to move approximately 40,000 to 80,000 m^3 of sediment from the channel to an acceptable nearby land location and/or using releases from the lake at low lake levels that create velocities of flow in the channel, facilitating the occurrence of a natural process of sediment erosion. Mitigation to control future sediment infill could involve shoreline stabilization (in the nearby lake cliff areas and/or in the channel), jetties to control ingestion of sediment-laden plums into the channel or combinations of these measures. Work on this maintenance project would be required to protect fish and fish habitat and water quality. Terrestrial effects would be limited to local areas on the north side of the channel used for access and/or the deposit of sediment removed from the channel.

4.6 REFURBISH EXISTING HYDRO GENERATION

- **Mayo A Refurbishment Project** – A KGS Group draft report is available for Mayo A refurbishment ("Mayo Hydro [MHO] Future Facility Option – Concept Design Report", May 2016). This report covers a conceptual scope of work economic assessment and cost estimate for the following four options for the aged 5 MW Mayo A hydro facility. In all options, the existing dam would remain. The assessments address asset conditions that require action.
  - Option 1: Replace Mayo A hydro station, retaining the foundations and other embedded parts and providing one new turbine and generator, powerhouse, and other facilities.
  - Option 2: Refurbish Mayo A hydro station, retaining the foundations and other embedded parts of the Unit 2 turbine and providing one new generator (2.3 MW, annual energy of 10.2 GWh), turbine support systems, new turbine inlet valves (TIV), balance of plant systems, support systems, control room and surge tank. Repairs/upgrades to the existing powerhouse superstructure and cranes are required. Geotechnical work would be included to stabilize slopes, repair roads and trailrace.
  - Option 3: Remove the powerhouse (excluding the foundation) and the surge tanks, including permanently plugging the penstock upstream of the surge tank take-off and backfilling the powerhouse foundation and tailrace to return the site to near greenfield conditions.
  - Option 4: Abandon the powerhouse in place. The facility would be made safe for abandonment, the penstock would be permanently plugged upstream of the surge tank, and the tailrace would be backfilled.

  Option 2 (the refurbishment option) was found to be the most economical and is the preferred option to be included in the current resource options evaluation. Total project capital cost was estimated at $27.4 million, with an assumed 65-year life span and present value costs during operation of $2.5 million. The report estimated LCOE at $0.147/kWh.

- **Aishihik Rerunnering Project** - The KGS Group final report is available for Aishihik turbine rerunnering ("Aishihik Turbines Uprate Study," February 2016). The study examined two options, both of which would keep plant discharge within existing maximum flows and would not affect hydraulic stability during start-up and shut-down. The options are:
  - Option 1: Uprate only turbine AH2 (estimated capital cost of $3.0 million; 0.7 MW increase in capacity; 2.15 to 2.26 GWh/year benefit of increased energy, varying depending on load; payback estimated in 6 years); and
  - Option 2: Uprate both turbines AH1 and AH2 (estimated capital cost of $4.7 million; 1.3 MW increase in capacity; 2.74 to 3.04 GWh/year benefit of increased energy, varying depending on load; payback estimated in 6 to 7 years).

  Option 2 is assumed for the purpose of the current study, i.e., assumed re-runnering of units AH1 and AH2, providing increased capacity of about 1 MW and increased annual energy of about 3 GWh.

5.0 TRANSMISSION CORRIDOR OPTIONS

5.1 NEW TRANSMISSION CORRIDORS

Midgard has examined for Yukon Energy[15] the following five transmission corridor transmission options (related substation requirements are not addressed in this existing information):[16]

- **Whitehorse-Atlin Corridor** (172 km [reliable transfer capacity 97 MW], 138 kV): Route is assumed to go via Jake's Corner area existing distribution line routing). This option would provide transmission connection into northern BC for the pumped storage option at Atlin-Black Mt. and the small hydro option at Atlin (Pine Creek). Estimated capital expenditure (Capex) at $158 million, estimated operating expense (Opex) at $236k/year; includes 34.5 kV underbuild for 79 km.
- **Whitehorse-Skagway Corridor** (170 km [reliable transfer capacity 443 MW with 230 kV, 114 MW reliable transfer capacity with 138 kV): This corridor would be routed via that Carcross area. This option would provide transmission connection for pumped storage and hydro-related options in northern BC (Moon, Racine-Moon, Racine-Mt. Brown, Lindeman-Fraser, Tutshi-Windy Arm), as well as potential new summer loads (cruise ships) and other new hydro generation options at Skagway. Estimated Capex at $251 million for 230 kV and $166 million for 138 kV, estimated Opex at $285k/year; includes 34.5 kV underbuild for 68 km.
- **Whitehorse-Teslin Corridor** (174 km [reliable transfer capacity 95 MW], 138 kV): This option would provide transmission connection for the Wolf River small hydro option and the Squanga-Dalayee pumped storage option. Estimated Capex at $165 million, estimated Opex at $239k/year; includes 34.5 kV underbuild for 174 km.
- **Faro-Watson Lake Corridor** (414 km [reliable transfer capacity 190 MW], 230 kV); if developed, this option would allow Watson Lake to no longer be a diesel community, and would provide transmission connection for the Finlayson small hydro option as well as larger next generation hydro options in this region. Estimated Capex at $597 million, estimated Opex at $613k/year.
- **Aishihik-Destruction Bay Corridor** (157 km [reliable transfer capacity 484 MW with 230 kV. 122 MW reliable transfer capacity with 138 kV) – a distribution line assumed then from Burwash Landing to Destruction Bay): If developed, this option would allow Burwash Landing and Destruction Bay to no longer be diesel zone communities and would provide transmission connection for the Kluane Lake wind farm option as well as for potential future mine developments in this region. Estimated Capex at $241 million for 230 kV and $167 million for 138 kV, estimated Opex at $217k/year; includes 34.5 kV underbuild for 49 km.

Economic life for new transmission is assumed at 45 years.

[15] Midgard Consulting Inc. (Midgard), "Transmission Options Evaluation", November 8, 2016. All cost estimates in 2016$.
[16] Currently there is no grid in Yukon above 138 kV. The corridor options going south from Whitehorse include adding 138 kV to the existing distribution line voltages (25/34 kV) to Carcross and Teslin.

The Midgard study also provided the following additional assessments of transmission options to connect various project options to the Yukon grid:

- **Faro-Finlayson connection** (233 km with reliable transfer capacity 84 MW at 138 kV; estimated Capex at $221 million, estimated Opex at $351k/year.
- **Whitehorse-Squanga-Dalayee connection** (105 km with reliable transfer capacity 134 MW at 138 Kv; estimated Capex at $100 million, estimated Opex at $143k/year); includes 34.5 kV underbuild for 105 km.
- **Whitehorse-Atlin-Black Mt connection** (127 km with reliable transfer capacity 131 MW at 138 kV; estimated Capex at $119 million, estimated Opex at $174k/year); includes 34.5 kV underbuild for 79 km.
- **Whitehorse-Tutshi Windy Arm connection** (96 km with reliable transfer capacity 135 MW at 138 kV; estimated Capex at $94 million, estimated Opex at $143k/year); includes 34.5 kV underbuild for 68 km.
- **Whitehorse-Racine Mt. Brown; Moon Lake; and Tutshi-Moon Lake connections** (112 km with reliable transfer capacity 132 MW at 138 kV; estimated Capex at $108 million, estimated Opex at $168k/year); includes 34.5 kV underbuild for 68 km.
- **Whitehorse-Lindeman-Fraser connection** (129 km with reliable transfer capacity 129 MW at 138 kV; estimated Capex at $125 million, estimated Opex at $200k/year); includes 34.5 kV underbuild for 68 km.

Centreline GIS information has been provided for each transmission corridor, confirming that each would generally follow existing highway corridors. Each corridor (regardless of voltage variances) is assumed to require a 60 m right-of-way (ROW), with the cleared area constituting only about half of this ROW. The corridor for possible routing options is assumed for current study purposes at 500 m. In general, transmission routing will typically offer ample opportunity to mitigate environmental and socio-economic adverse effects specific to the terrain.

5.2 STEWART KENO CITY TRANSMISSION PROJECT

The Stewart-Keno City Transmission Project is well advanced in terms of permitting assessments. A project proposal was submitted to YESAB in the past year, and a YESAB Screening Report and Recommendation was issued on May 31, 2016.

The project involves the installation of a new 138 kV transmission line from Stewart Crossing to Keno City (about 112 km, located mainly within the existing ROW with the exception of five substantive deviations along the way), along with decommissioning of the existing 69 kV transmission line between Mayo and Keno City and accessory activities, such as the construction of new and modified sub-stations.

The project would replace end-of-life existing 69 kV transmission between Mayo and Keno City with voltage capability able to serve potential future new mine and/or renewable hydro generation connections and extend the 138 kV Yukon grid north beyond Stewart Crossing. Possible options include initial development of only the Mayo to Keno City segment at 138 kV with operation initially at 69 kV.

Yukon Energy's estimated capital cost for the full project (2015$) is approximately $86 million, with $59 million for line construction; $21 million for substation construction; and $5 million for planning, permitting and engineering. About 22% of the estimated transmission line costs is for equipment and about 50% for its installation, while about 25% of the substation costs is for materials and installation.

6.0 SUMMARY OF PROJECTS TO BE EVALUATED

The following summarizes the resource project options to be included in the current evaluation:

1. **Fossil Fuel Thermal Generation:**
    a. Diesel option at 20 MW new facility in Whitehorse, with energy generation dispatchable as required up to 166 GWh/year. Two sites are specified (Whitehorse landfill and Takhini substation). Economic life varies from 20 to 40 years, depending on average annual use of capacity.
    b. LNG option at 20 MW new facility in Whitehorse, with energy generation dispatchable as required up to 166 GWh/year. Specifies same two sites as diesel option. Economic life varies from 20 to 40 years, depending on average annual use of capacity.
2. **Non-Hydro Renewable Generation:**
    a. **Non-fossil Thermal Generation:**
        i. Waste-to-energy (WTE) at Whitehorse. 1.6 MW facility with 10 GWh annual generation, using solid MSW augmented with wood biomass during winter. It is currently premature to select site as viability is greatly enhanced by the sale of waste heat in district waste heating systems. Economic life is 25 years).
        ii. Wood Biomass at Haines Junction. 0.5 MW facility with 3.2 GWh annual net generation, located near school for waste heat use. Uses beetle-kill biomass feedstock. Economic life is 20 years).
        iii. Biogas at Whitehorse. 0.2 MW new facility, with 0.4 GWh initial annual energy. Plant located at municipal landfill next to existing composting site. Footprint is about 1800 m^2. Economic life is 20 years.
    b. **Energy Storage Facility:** (batteries) in Whitehorse (4 MW/40 MWh lead acid-based system or 8 MW/40 MWh lithium ion system). Assumed to be located at Takhini substation with some use of adjacent land. Economic life is 30 years.
    c. **Solar PV:**
        i. Whitehorse: 1 MW, 5 MW and 10 MW options (3 separate options, each at Whitehorse Copper Mine Quarry Site). Annual energy at 1.1 GWh, 5.2 GWh and 10.3 GWh, respectively. 30 year economic life.
        ii. Haines Junction; 1MW, 5 MW options (2 separate options, each located about 1 km from Haines Junction dump on site from the report). Annual energy at 1.1 GWh and 5.2 GWh, respectively. 30 year economic life.

d. **Wind Farms:**

i. Seven site options are examined, each with 25 year economic life:

- Sugarloaf: 20 MW with 32.3 GWh annual energy;
- Tehcho: 20 MW with 33.4 GWh annual energy;
- Mt. Sumanik: 20 MW with 41.5 GWh annual energy;
- Kluane: 20 MW with 47.8 GWh annual energy;
- Cyprus Mine: 20 MW with 49.6 GWh annual energy;
- Thulsoo: 20 MW with 54.4 GWh annual energy; and
- Miller's Ridge: 20 MW with 57.3 GWh annual energy.

ii. Transmission for each site to connect to grid is addressed on stand-alone basis (Kluane Lake option requires consideration of added transmission from what is in Wind report), assuming current centrelines and 60 m ROW, with 30 m cleared and corridor for selecting ROW at 500m width.

e. **Geothermal:** 2 site options, energy capacity at each is the average of potential range in first year of operation. At each site, 2% per year decline in net capacity and energy over 30 year economic life is assumed.

i. Vista Mountain near Takhini substation: Installed capacity average of 1.6 MW with average annual energy of 11.0 GWh over 30 year life.

ii. McArthur Springs south east of Stewart Crossing: Installed capacity of average 3.80 MW with average annual energy of 25.0 GWh over 30 year life.

3. **Hydro Renewable Generation:**

a. **Pumped Storage:** eight site options are examined, and two site options include two scales of development. Transmission for each site to connect to grid is addressed for the evaluation on stand-alone basis without estimating added transmission corridor costs (Canyon-Ittlemit and Vangorda sites are the only options that do not require consideration of added transmission costs according to the Midgard or KP reports), assuming current centrelines and 60 m ROW, with 30 m cleared and corridor for selecting ROW at 500m width. Specific site options are as follows (65 year economic life for each option except Vangorda Pit, where 50 to 65 years is assumed):

i. Midgard report: 1 option: Moon Lake at 20.2 MW and 54 GWh/year;

ii. KP report: 6 sites, 8 options:

- Racine-Moon (1 option): 15 MW with 50 GWh annual energy;
- Lindeman-Fraser (1 option): 15 MW with 50 GWh annual energy;
- Racine-Mt Brown (2 options): 15 MW with 50 GWh annual energy and 25 MW with 100 GWh annual energy;

- Atlin-Black Mountain (2 options): 15 MW with 50 GWh annual energy and 25 MW with 100 GWh annual energy;
- Squanga-Dalayee (1 option): 25 MW with 100 GWh annual energy; and
- Canyon-Ittlemit (1 option): 25 MW with 100 GWh annual energy.

iii. EP report: 1 option: Vangorda Pit: 40 MW with 134 GWh/year of annual energy, without any concurrent mine development.

b. **Small Hydro Projects:** five site options are examined, one of which is run of river and four of which include storage. Transmission for each site to connect to grid addressed for the evaluation on a stand-alone basis without estimating added transmission corridor costs (Drury and Anvil Creek are the only options that do not require consideration of added transmission costs according to the KP or MH reports), assuming current centrelines and 60 m ROW, with 30 m cleared and corridor for selecting ROW at 500m width. Specific site options are as follows (65 year economic life assumed for each option):

i. KP report: 5 sites (includes site added after initial report):

- Drury: 8.1 MW with 31.7 GWh annual energy;
- Tutshi-Windy Arm: 7.2 MW with 56.8 GWh annual energy;
- Wolf River: 20 MW with 95.8 GWh annual energy;
- Finlayson: 17.5 MW with 138.9 GWh annual energy and
- Anvil Creek: 9.8 MW with 41.3 GW.h annual energy (this site added after initial report).

ii. MH report: 1 site: Atlin/Pine Creek: 5.7 MW new capacity with 36.3 GWh/year annual energy for Yukon.

c. **Gladstone Diversion:** One option to enhance hydro generation at Aishihik by up to 36.6 GWh per year. Assumes 65 year economic life (generation at Aishihik generating station).

d. **Hydro Storage Enhancements:** Two options:

i. Mayo Lake Storage Enhancement through a water licence change (without new facilities) to improve winter generation at Mayo hydro on average by 2 to 4 GWh per year, depending on grid load and the outcomes of adaptive management plan activities (YESAB submission has already been prepared).

ii. Southern Lakes Storage Enhancement through a water licence change to improve winter generation at Whitehorse hydro by up to 6.4 GWh/year.

e. **Mayo Lake Outlet Channel Dredging:** one option: maintenance work to remove sediment build up and an old cofferdam in the Mayo Lake Outlet Channel and mitigation measures to inhibit future sediment infill in the channel. This option will restore Mayo B long-term average generation that is currently being restricted and enable the Mayo Lake Storage Enhancement to provide added long-term average hydro generation benefits.

f. **Refurbish Existing Hydro Generation:** Two options:

i. Mayo A Refurbishment: Refurbish Mayo A hydro station, retaining the foundations and other embedded parts of the Unit 2 turbine and providing one new generator (2.3 MW, annual energy of 10.2 GWh); and

ii. Aishihik Re-runnering: Re-runner units AH1 and AH2, providing increased capacity of about 1 MW and increased annual energy of about 3 GWh.

4. **Transmission Corridor Options:**

a. **New Transmission Corridors:** Five options are examined, including segments of a project that would enhance an existing transmission corridor. Each option assumes 60m ROW, with 30 m cleared and corridor for selecting ROW at 500m width (250 m on each side of centreline). Specific site options are as follows (assume 45 year economic life):

i. Whitehorse- Atlin at 138 kV;

ii. Whitehorse Skagway at 230 Kv;

iii. Whitehorse- Teslin at 138 kV;

iv. Faro- Watson Lake at 230 kV; and

v. Aishihik-Destruction Bay at 230 Kv.

b. **Stewart-Keno City Transmission Project:** As recommended in the YESAB Executive Committee Screening Report of May 31, 2016, a new 138 kV transmission line from Stewart Crossing to Keno City (about 112 km, located mainly within the existing ROW with the exception of five substantive deviations along the way), along with decommissioning of the existing 69 kV transmission line between Mayo and Keno City and accessory activities such as the construction of new and modified sub-stations.

When evaluating various renewable generation options, it is relevant to also note comparative scales of energy and/or capacity impacts for the grid.

- Fossil fuel thermal generation provides firm capacity and a wide range of dispatchable energy generation, i.e., up to 166 GW.h per year for 20 MW facility.
- Non-fossil thermal generation options, as well as geothermal options, are each relatively small in terms of capacity (0.2 to 4.0 MW); annual energy generation ranges from 0.4 GWh/year (biogas) to 33.4 GWh/year (geothermal option at McArthur Springs).
- Other renewable energy options show a wide range of annual energy generation:
    - Solar PV is relatively small (1.1 to 10.2 GWh/year), with energy focused from March to August;
    - Wind at 20 MW ranges from 32.8 to 59.0 GWh/year;
    - Small storage hydro ranges from 31.7 to 138.9 GWh/year;
    - Pumped storage hydro ranges from 50 to 134 GWh/year, focused in winter months (these options each need adequate non-winter surplus energy for the required pumping);

- Gladstone Diversion provides up to 36.6 GWh of winter energy; and
- Other hydro projects range from 2 to 10 GWh/year.

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APPENDIX B: EVALUATION APPROACH – CRITERIA AND INDICATORS

TABLE OF CONTENTS

1.0 INTRODUCTION B-1
2.0 RFP DRAFT RESOURCE OPTIONS EVALUATION MATRIX..... B-2
3.0 CONSIDERATIONS FOR REVIEW OF EVALUATION APPROACH B-3
4.0 ENVIRONMENTAL CRITERIA AND INDICATORS..... B-6
5.0 SOCIAL CRITERIA AND INDICATORS..... B-9
6.0 ECONOMIC CRITERIA AND INDICATORS.....B-12
7.0 RESOURCE OPTIONS RATINGS FOR EACH INDICATOR.....B-14

LIST OF TABLES

Table B 4-1: Resource Options Evaluation Matrix - Environmental Criteria & Indicators B-8
Table B 5-1: Resource Option Evaluation Matrix - Social Criteria & Indicators B-11
Table B 6-1: Resource Options Evaluation Matrix - Economic Criteria & Indicators B-13

LIST OF FIGURES

Figure B 7-1: Rating Criteria Considerations B-16

1.0 INTRODUCTION

An initial task in this study was to review the environmental, social and economic criteria, indicators and metrics in a Draft IRP Resource Option Evaluation Matrix and provide recommendations on removing and/or adding evaluation criteria, potentially changing criteria definitions, and on changing, adding or removing indicators and/or their associated metrics. A rating scheme was also to be developed in collaboration with Yukon Energy Corporation (Yukon Energy) for each of the three attributes in the Evaluation Matrix, and data sources identified for the evaluation.

The Resource Option Evaluation approach is reviewed below as follows:

1. RFP Draft Resource Option Evaluation Matrix;
2. Considerations for Review of Evaluation Approach;
3. Environmental Criteria and Indicators;
4. Social Criteria and Indicators;
5. Economic Criteria and Indicators; and
6. Resource Options Ratings for Each Indicator.

2.0 RFP DRAFT RESOURCE OPTIONS EVALUATION MATRIX

Yukon Energy's Request for Proposal (RFP) 2016-010 for the Resource Options Evaluation (the RFP) provided a Draft IRP Resource Option Evaluation Matrix (the Draft Evaluation Matrix) for review of the various 2016 Resource Plan resource options (see Attachment 1). The Draft Evaluation Matrix includes three separate sets of evaluation criteria:

- **Environmental Criteria:** 4 Environmental criteria, each with 1 to 4 indicators (each indicator needs 1 or more metric for a total of 21 metrics).
- **Social Criteria:** 4 Social criteria, each with 2 to 5 indicators (each indicator needs 1 or more metrics for a total of 13 metrics).
- **Economic Criteria:** 1 Economic criteria with 3 indicators and 5 metrics.

The RFP anticipated that the Draft Evaluation Matrix would be used to evaluate 40 different resource options, including thermal generation options (fossil and non-fossil fuel), solar PV options, geothermal options, wind farm options, pumped storage options, small hydro options, other hydro options, and transmission corridor options.

An initial task for the current resource options evaluation study was to review the Draft Evaluation Matrix and provide recommendations on removing and/or adding evaluation criteria, potentially changing criteria definitions, and on changing, adding or removing indicators and/or their associated metrics.

3.0 CONSIDERATIONS FOR REVIEW OF EVALUATION APPROACH

The resource options evaluation approach has been reviewed in the context of the specific requirements for the current evaluation of the broad range of 2016 Resource Plan resource options.[1]

Basic issues to address for the required study approach include the following:

- The environmental effects must often be characterized as "potential" given that the evaluation is based on secondary sources and additional baseline studies would be required to verify presence or absence of a species or habitat feature.
- The socio-economic evaluation of the priority sites can potentially focus on various forms of land tenure and dispositions, historic and archaeological resources, jobs and gross domestic product (GDP), and qualitative assessments of potential effects on local labour supply, traditional Aboriginal activities and community well-being. The evaluation can also potentially include broad indicators of potential effects, given the many opportunities that exist to mitigate adverse effects and enhance positive ones.
- The comparative ranking of different resource options will need to highlight the key advantages or disadvantages between the options, representing the positive effects that could occur and might need to be enhanced and the negative effects that will likely require attention through design and further mitigation. Initial consideration might be given to using a "Higher," "Moderate" and "Lower" rating scheme to provide a preliminary indication of the level of constraint relative to other priority sites that is likely to be associated with the proposed development:
    - **Higher** ratings in this context would mean that an option may result in negative effects and/or offers the least potential for positive effects. In some cases, this rating could also mean that the effects are of greater magnitude relative to other sites. This rating would imply requirements for a greater level of future investigation, the potential requirement for site-specific design features, and a likely need for greater effort in the design of mitigation, compensation and enhancement measures.
    - **Moderate** ratings would mean that the option has a mix of positive and negative effects.
    - **Lower** ratings in this context would mean that an option has less potential for negative effects and/or offers greater potential for positive socio-economic effects than other sites; however, this rating would not necessarily mean that a site is constraint free or will require less attention through further assessment, design and mitigation.

[1] The study team also reviewed the approach adopted in a similar prior assessment for the Yukon Development Corporation by SLR Consulting Global Environmental Solutions (SLR) of six large hydro priority site options ("Yukon Next Generation Hydro and Transmission Viability Study - Positive and Negative Environmental and Socio-economic Effects - Technical Paper", November 2015).

The resource options evaluation approach has also been reviewed in the context of the following four specific considerations, keeping in mind the requirement to review here a very broad range of resource options with varying capacity scales and characteristics:

- **Risk and Opportunity Comparative Focus** – Meaningful evaluation of diverse options at a preliminary state of assessment needs to compare distinct risks and opportunities to facilitate the selection of options meriting further work, recognizing that future work will be needed to reach more definitive assessments as to feasibility and potential effects. The highlighting of adverse effect risks for a resource option also provides a focus on the varying regulatory review challenges for the different options, recognizing that mitigation measures will be required to address these risks before a resource option can be implemented and noting that some resource options or project elements (e.g., transmission corridors or interconnections, access roads) may offer greater opportunities to mitigate (by varying site location) than other resource options or project elements dependent on the use of a specific site (e.g., pumped hydro storage reservoir options).
- **Comparative Assessments by Separate Criteria –** Comparative assessment needs to be retained for each of the separate criteria defined for each of the three attributes (i.e., environmental, social and economic attributes), recognizing the importance at this stage of displaying key differences among the resource options rather than attempting an overall ranking of these options across very different criteria. Separate evaluation matrix tables are accordingly developed for the environmental, social and economic evaluations. In each table, the key criteria are separately retained in any final assessment (showing comparative ranking of each resource option for each of these criteria).
- **Comparative Assessment of Resource Options versus Project Options –** Meaningful and easily understood comparison of very different resource options (e.g., widely varying generation options, storage options, and transmission corridor options) is required, as well as comparative assessment of project options specific to each type of resource option (e.g., different hydro sites or different wind sites, as well as different potential scales or cases for development of a specific option). In the current study, an important related consideration is clarity in showing when a generation resource project option is dependent on a specific transmission corridor project option.
- **Comparative Assessment of Resource Options with Different Technical and Financial Attributes –** Where feasible, meaningful comparison of resource options needs to consider material differences in technical attributes (e.g., capacity and energy scales, dependability, seasonal variability, timing for development) and financial attributes (e.g., capital costs and related risks, operating and maintenance costs, levelized costs of energy and capacity). Useful comparative evaluation is enhanced when resource options are sorted by similar technical and financial attributes.

The criteria were also reviewed and compared to address the following concerns:

- Avoid double counting of criteria (i.e., not use two or more criteria to measure the same thing). This is particularly important within each of the three main assessments (e.g., separate

environmental, social and economic evaluations). In some cases, information from the environmental evaluation may also be useful for the social and economic evaluations.

- Add, delete or shift criteria and/or indicators to improve or optimize assessment. Suggested additions or deletions are reviewed in greater detail for environmental, social and economic categories.
- A survey document has already been issued using the criteria developed and included in the Draft Evaluation Matrix included as Attachment 1, and it is therefore necessary that the final criteria adopted at least reflect or include the thrust points of the criteria used in the Draft Evaluation Matrix (i.e., additional criteria may be added, but the initial criteria must also be represented).

It was considered desirable to adopt a simple standard scale for the evaluation of each criteria to optimize the comparative evaluation of the various resource options separately for environmental, social and economic criteria. Initial planning looked in most cases at a Low/Medium/High or three-part numerical scale, with provision for showing whether effects are beneficial (+) or adverse (-), and with Low representing low adverse effects overall and High representing high adverse effects or concerns overall.

Based on the above considerations, the following 2016 Resource Plan Resource Option Evaluation Matrix tables have been prepared:

- Table B 4-1 - Resource Option Evaluation Matrix - Environmental Criteria & Indicators;
- Table B 5-1 - Resource Option Evaluation Matrix - Social Criteria & Indicators; and
- Table B 6-1 - Resource Option Evaluation Matrix - Economic Criteria & Indicators.

Key factors affecting each of the three attributes are reviewed below. To simplify each matrix, complex descriptions and objectives sections of the Attachment 1 Draft table are excluded and attention is directed solely at the criteria and indicators used to evaluate resource options for each attribute and the metrics used to evaluate each indicator.

4.0 ENVIRONMENTAL CRITERIA AND INDICATORS

Table B 4-1 includes the following key changes to Yukon Energy's initial list of environmental criteria and indicators (summarized in the Draft Evaluation Matrix included as Attachment 1 to this appendix):

- For **En1 (Species and Habitat)** and **En2 (Land/Resource Use Intensity and Naturalness)** as set out in Attachment 1, it is noted that many elements considered under each criteria are difficult to define as separate (e.g., footprint effects under En2 affect species and habitat under En1).

  The changes to the environmental criteria and indicators consider many of the same issues, but the presentation is simplified for the following reasons: to be consistent with the basic requirements for this evaluation as reviewed in Section 3 above and to be consistent with how these matters would be considered, addressed and understood as part of an environmental assessment (i.e., focus on effects to the aquatic environment, terrestrial environment and air quality).

  Species and Habitat and **Land Use/Resource Use Intensity and Naturalness** are still explicitly considered, but now as part of the separate consideration of the aquatic environment and the terrestrial environment.

  The criteria and indicators for the draft versions of En1 and En2 are now as follows (see Table B 4-1 for the metrics related to each indicator):

  - **En1 – Fish and Fish Habitat**: This will include consideration of the following indicators:
    - Salmon and Habitat;
    - Species at Risk and Habitat; and
    - Commercial, Recreational or Aboriginal Fishery Species and Habitat.

    For each of the above, the assessment will include consideration of the presence or absence of the species (Yes/No), as well as the relative effect (positive or negative effects and L/M/H assessments).
  - **En2 – Water Quality and Quantity**: This will include consideration of the following indicators:
    - Consumptive Water Use;
    - Relative Scale of New Impoundment/Flooding; and
    - Flow Changes.
  - **En3 – Terrestrial Species and Habitat**: This will include consideration of the following indicators:
    - Species at Risk and Habitat;
    - Protected and Conservation Areas;
    - Wildlife Key Areas; and

- Caribou Ranges.

For each of the above, where relevant the assessment will include consideration of the presence or absence of the species (Yes/No), as well as the relative effect (positive or negative effects and L/M/H assessments).

- **En4 – Terrestrial Footprint and Land Use**: This will include consideration of the following indicators:
  - Footprint Terrestrial Areas, including access and new flooding;
  - Linear Development for roads, transmission;
  - Permafrost; and
  - Wetlands.

It is also noted that **Visual Aesthetics** (considered under Land and Resource Use Intensity and Naturalness in Attachment 1) is shifted from the environmental assessment to the social assessment (aesthetics in environmental assessments typically relates to people's relationship to the environment, and is therefore included under the social matrix). This also reduces duplication between the environmental assessment and the social assessment.

- **En3 (Pollution and Contamination)** as set out in Attachment 1 is not considered as a separate criteria in the environmental assessment, but instead will be considered as follows:
  - Effects related to greenhouse gas (GHG) and other emissions will be considered as part of **En5 (Air Quality)**.
  - Other effects related to the risk of unintended release of pollutants are typically considered and addressed as part of planning for each project as part of the assessment of accidents and malfunctions (and are not intended outcomes of the proposed project). As such, there is less importance to considering these risks when evaluating different resource options at this initial planning stage. However, in the event that a specific option involves enhanced risks that merit attention, these can be addressed in the evaluation either with regard to risks to specific species and/or habitats or specific social effect concerns.
  - Other contamination risks that may arise from implementation of a project, such as mercury contamination due to impoundment, will be considered as part of the effects due to the relative scale of new impoundment/flooding (as well as social evaluations related to human and community health and traditional lifestyle activities).
- **En4 (Climate Change Adaptation/Resiliency)** as set out in Attachment 1 addresses the effects of the environment on the project (as opposed to effects of the project on the environment, which is the focus of all other environmental criteria). As such, this has been included as an economic criteria for this assessment (as opposed to being an environmental criteria) to address potential risks related to project design and operation. Overall, a project will need to be planned to address risks imposed by environmental factors such as flood, drought, wind and climate change. This requirement will affect construction and operating costs for the project.

Table B 4-1: Resource Options Evaluation Matrix - Environmental Criteria & Indicators

	ID	Criteria	Indicator	Metric ID	Metric
	Environmental Criteria				
Aquatic Environment	**En1**	**Fish and Fish Habitat**	Salmon & Habitat	En1-1	Presence or absence (Y/N) & Relative Impact (+/-)
			Species at Risk & Habitat	En1-2	Presence or absence (Y/N) & Relative Impact (+/-)
			Commercial, Recreational or Aboriginal Fishery Species & Habitat	En1-3	Presence or absence (Y/N) & Relative Impact (+/-)
	En2	**Water Quantity & Quality**	Consumptive Water Use	En2-1	Water Use Intensity (m3/day)
			Relative Scale of New Impoundment/ Flooding	En2-2	Presence or absence (Y/N) & Relative Scale (L/M/H)
			Flow changes	En2-3	Presence or absence (Y/N) & Relative Scale (Run of River; Storage; Pumped Storage)
Terrestrial Environment	**En3**	**Terrestrial Species & Habitat**	Species at Risk & Habitat	En3-1	Presence or absence (Y/N) & Relative Impact (+/-)
			Protected & Conservation Area	En3-2	Proximity to Protected & Conservation Areas (L/M/H)
			Wildlife Key Areas	En3-3	Proximity to WKAs (L/M/H)
			Caribou Ranges	En3-4	Proximity to Caribou Ranges (L/M/H)
	En4	**Terrestrial Footprint & Land Use**	Footprint Terrestrial Area including access & new flooding (Total km2)	En4-1	Area of Project Terrestrial Footprint (km2)
			Linear Development for roads, transmission (km)	En4-2	Total length of linear features (km)
			Permafrost	En4-3	Presence or absence (Y/N) & Relative Scale (L/M/H)
			Wetlands	En4-4	Presence or absence (Y/N) & Relative Scale (L/M/H)
Air	**En5**	**Air Quality**	GHG Emissions (in Yukon)	En5-1	Intensity (per kWh)
			Other Air Pollutants	En5-2	Intensity (per kWh)

5.0 SOCIAL CRITERIA AND INDICATORS

The criteria and indicators presented in Table B 5-1 maintain in most respects the original criteria provided by Yukon Energy (as summarized in Attachment 1 to this appendix) with the following key changes:

- Addition of a new criteria to address **First Nations Settlement Lands** (S1 First Nations Lands). This will consider whether there is an overlap with or effect on access to Settlement Lands or Interim Protected Lands.
- The criteria **Traditional Lifestyle** and **Heritage Resources** are maintained but are numbered separately (now S2 and S3, respectively). The indicators are refined as follows:
    - **Footprint Land Area Impact** will consider, as a point of reference, the total hectares (ha) of direct land loss (provided as part of the environment assessment Footprint Terrestrial Area [En4-1]).
    - **Land Area Loss regarding Traditional Lifestyle and Land Quality Effects on Traditional Lifestyle -** will provide a more qualitative assessment related to effects on access or direct loss of traditional areas due to impoundments or other issues related to project footprint effects. This corresponds to the **Land Quality Effects** indicator in Attachment 1.
    - **Cabins, Camps and Structures** – This addresses the **Land Tenure** indicator included in Attachment 1. It is considered that the revised title better indicates what is being examined.
    - **Country Foods** – This addresses the **Diet** indicator included in Attachment 1, but clearly shows that country foods, meat and fish are being combined into one assessment. The assessment will rely in part on information collected for the environmental assessment under Commercial, Recreational or Aboriginal Fishery Species and Habitat (En1-3).
- **Heritage Resources Potential**: The proposed criteria and indicators follow the criteria and indicators included in Attachment 1.
- **Tourism and Recreation** (S2 in Attachment 1) is maintained as a criteria but expanded in scope to include **Other Resources and Land Use**. The indicators are refined as follows:
    - **Recreational Values:** Existing and new recreational values/opportunities were considered as separate indicators in the Attachment 1 matrix. These are combined into one indicator in order to simplify the evaluation.
    - **Tourism Values:** This follows the original indicator as presented in Attachment 1.
    - **Aesthetics:** Attachment 1 considered effects on visual and auditory aesthetics as part of the environmental assessment (En2-2 in Attachment 1) or as part of Heritage Resource Potential (S3-1 in Attachment 1). This has been shifted to be considered as part of the assessment of tourism, recreation and other resources and land use.

- **Other Renewable Resources and Non-renewable Resources**: This was not included in Attachment 1, but consideration of effect on all other resources and resource use due to new access being created (or other effects of the resource option) is warranted.
- **Land Use and Renewable Resources Plans**: This was not included in Attachment 1, but consideration of land use and consistency with renewable resources plans is considered warranted.

- **Cultural and Community Well-being** is maintained with the following refinement to indicators (undertaken to be consistent with matters typically considered as part of socio-economic assessments):
  - **Infrastructure and Services**: Potential effects to infrastructure and services were considered in part under **Community value** (under the **Other Value Generation and Distribution Criteria**, Ec1-5) in Attachment 1; this is now broken into its own indicator under Cultural and Community Well-being. Effects can be positive or negative.
  - **Public Safety, Worker Interaction, Human and Community Health:** Considers issues over construction and operation (as opposed to only construction effects) and clarifies that worker interaction, as well as human and community health, are also included.
  - **Community, First Nation and Personal Development:** The key change in indicators compared to Attachment 1 is to shift consideration of employment and education opportunities from being separate indicators to being considered as part of Community and Personal Development indicator. Overall, there is concern that at this stage in project development, there will be limited information available related to employment, training and other educational opportunities. Further, such effects are typically included under economic criteria. As revised, the indicator allows for broad consideration of overall effects on local community and personal development. Effects can be positive or negative.

Table B 5-1: Resource Option Evaluation Matrix - Social Criteria & Indicators

ID	Criteria	Indicator	Metric ID	Metric	Rating Scheme
Social Criteria					
S1	**First Nation Lands**	Settlement Lands, Interim Protected Lands	S1-1	Overlap and/or access with these lands (Y/ Potential/N)	
S2	**Traditional Lifestyle**	Footprint land area impact	S2-1	Total area (ha) of direct land loss	
		Land area loss re Traditional Lifestyle	S2-2	Total area (ha) of Traditional Use land area loss	
		Land Quality Effects on Traditional Lifestyle	S2-3	Indirect effects on land or access for such pursuits (+/- and L/M/H)	
		Cabins, Camps & Structures	S2-4	Number of cabins, camps, homesteads, etc. in footprint (corridor for linear access) that may be affected (n)	
		Country Foods	S2-5	Effects to the opportunity to harvest country foods (+/- and L/M/H)	
S3	**Heritage Resources**	Heritage Resource Potential	S3-1	Density (number of discrete) known or potential archeological, palaeontological, ethnological, prehistoric, or historic resources (L/M/H)	
			S3-2	Importance/Cultural Value of heritage resources, including areas of land containing heritage resources. (L/M/H)	
S4	**Tourism, Recreation & Other Resources and Land Use**	Recreational Values	S4-1	Effect on nature and scale of existing and new Recreational Values. (+/- and L/M/H)	
		Tourism Values	S4-2	Effect on nature and Scale of Tourism Values. (+/- and L/M/H)	
		Aesthetics	S4-3	Effect on auditory or visual aesthetics. (+/- and L/M/H)	
		Non-renewable Resources	S4-4	Effect on Non-Renewable Resources. (+/- and L/M/H)	
		Other Renewable Resources	S4-5	Effect on other Renewable Resources. (+/- and L/M/H)	
		Land Use & Renewable Resources Plans	S4-6	Consistent with Land Use& Renewable Resources Plans (Y/N, NA)	
S5	**Cultural and Community Well Being**	Infrastructure & Services	S5-1	Effect on Infrastructure & Services (+/- and L/M/H)	
		Public Safety, Worker Interaction, Human and Community Health	S5-2	Risks to Community Health & Safety - construction & operation (L/M/H)	
		Community, First Nation & Personal Development	S5-3	Effects on local jobs, business, training & development (+/- and L/M/H)	

6.0 ECONOMIC CRITERIA AND INDICATORS

Economic criteria were reviewed to consider added criteria to address separate key risks and concerns related to economic effects throughout the economic life of each resource option.

The following concerns and interests are addressed in the Table B-6-1 economic criteria and indicators:

- Reliance on economic indicators such as GDP and Gross Progress Indicator (GPI) have limited use at this time based on available information and use in Yukon, duplication with other indicators/criteria and overall usefulness within the economic criteria evaluation of the different resource options to be examined at this time. Local Economic Effects can be addressed through other indicators based on information developed to date or otherwise available for the resource options.
- Effects of the environment on the resource option are relevant to economic evaluations of resource options (as such effects could affect costs and risks for specific options). In the context of the 2016 Resource Plan, this climate change risk assessment involves assessing climate change risk effects on financial attributes of resource options.

Economic evaluation for any socio-economic assessment of a resource option in Yukon would normally also include effects on ratepayers, i.e., costs of power, and any related risks and other development effects, e.g., risks of fixed costs adversely affecting ratepayers and other ratepayer risks related to potential resource underutilization. These considerations are addressed elsewhere in Yukon Energy's 2016 Resource Plan process are therefore are not included in Table B 6-1.[2]

In summary, Table B-6-1 includes the following economic criteria:

- **Ec1 – Local Economic Impacts:** Considers opportunities during construction and operation as well as community and other development opportunities (similar to **Economic Opportunity** and **Community Value** indicators included in Attachment 1).
- **Ec2 – Climate Change Risk Affecting Resource Financial Attributes:** As discussed in Section 4, each resource option will need to be planned to address risks imposed by environmental factors such as flood, drought, wind and climate change. These factors may affect construction and operating costs and economic risks for the project resource option.

[2] These considerations were not included in the Attachment 1 matrix, reflecting the fact that the 2016 Resource Plan process is currently addressing these matters separately as "Technical Attributes" and "Financial Attributes."

Table B 6-1: Resource Options Evaluation Matrix - Economic Criteria & Indicators

ID	Criteria	Indicator	Metric ID	Metric
Economic Criteria				
Ec1	**Local Economic Impacts**	Yukon Opportunities during Construction	Ec1-1	Capital Cost - Civil and Other Local Share (L/M/H)
		Yukon Opportunities during Operation	Ec1-2	Operation Costs - Yukon Labour & Business Opportunity (L/M/H)
		Community & Other Development Opportunity	Ec1-3	Community, Industry Development Opportunity (L/M/H)
Ec2	**Climate Change Risk Affecting Resource Financial Attributes**	Susceptibility to Extreme Weather Events/Conditions	Ec2-1	Susceptible to Extreme Heat/Drought (L/M/H)
			Ec2-2	Susceptible to Extreme Precipitation - flood/snow
			Ec2-3	Susceptible to Extreme Wind Events (L/M/H)
			Ec2-4	Susceptible to Ice Related Processes/Events (L/M/H)
		Conditions Susceptible to Climate Change	Ec2-5	Extent of Permafrost in project footprint (L/M/H)

7.0 RESOURCE OPTIONS RATINGS FOR EACH INDICATOR

The range of resource options to be evaluated and the groupings adopted for these options are summarized in Section 6 of Appendix A. For certain resource options, a range of sites and/or scales of potential development are also included in the evaluation.

The evaluation of each resource option is reported separately for each indicator adopted to assess environmental, social and economic criteria. This approach recognizes the importance at this stage of displaying key differences among the resource options rather than attempting any overall ranking of these options across very different key indicators.

Separate evaluation matrix tables are provided for the three main attributes (i.e., environmental, social and economic attributes) using the criteria and indicators as set out in Tables B 4-1, B 5-1 and B 6-1 of this appendix. In each evaluation matrix table, each resource option is ranked for each indicator adopted to evaluate the separate criteria.

Rating approaches for each indicator were developed separately, as appropriate, for the criteria adopted to evaluate resource options for each main attribute (see Appendix C for Environmental, Appendix D for Social and Appendix E for Economic for the technical analysis supporting each evaluation).

The overall framework for reporting on the ranking evaluation for each indicator follows the colour-coded rating system described below.

The overall objective of the evaluation approach is to identify on a common scale (low, medium, and high) which indicators are particularly relevant to each resource option. A high rating indicates that potential effects on an indicator are high for a specific resource option compared with the other resource options under review. A low rating indicates that potential effects on an indicator are low for a specific resource option compared with the other resource options under review A medium rating indicates an evaluation that falls between the high and low ratings.

The evaluation approach involves criteria that address a diverse range of risks, benefits, and potential linkages with the resource options. The following examples demonstrate this range, and highlight the need to consider in each instance the nature of the indicator when interpreting the ratings of high, medium or low for different resource options:

- **Adverse Effects Indicators -** Many of the environmental and social criteria and indicators focus on potential risks of adverse effects on specific criteria and indicators, where a high or red rating means a high relative risk of an adverse effect, e.g., effects on fish and fish habitat, effects on terrestrial species and habitat, effects on air quality, effects on First Nation lands, effects on traditional lifestyle, effects on heritage resources, and some indicators related to cultural and community well-being. When rating adverse effects for a resource option on an indicator, red means a high rating, yellow means a medium rating, and green means a low rating.
- **Positive Effects Indicators -** Some social and economic indicators focus on potential beneficial effects on specific criteria and indicators, where a high rating means a high relative level of potential benefits, e.g., effects on criteria such as Local Economic Impacts and Community, First

Nation and Personal Development. In this instance, a red colour rating as adopted for adverse effects indicators might suggest (incorrectly) that a high rating has adverse rather than positive effects - while a green colour rating to suggest "positive" outcomes could also be confusing given that green means low level effects when assessing adverse effects indicators. Accordingly, no colour rating is used for the few indicators that focus on positive effects and tables simply show the rating as high positive, medium positive or low positive.

- **Linkage/Overlap Effect Indicators -** Some environmental, social and economic criteria and indicators address overall magnitudes related to linkages or overlaps, where a high or red rating means a high level of linkage or overlap without directly addressing specific adverse or positive effects that may occur, e.g., footprint territorial area, footprints land area effect, linear development distances, flow changes, relative scale of impoundment/flooding, climate change risk affecting resource financial attributes.
- **No Linkage included as Low Rating** - For many resource options, there is no linkage with various environmental indicators (or the indicator is not applicable to the resource option). A low or green rating includes these situations (thereby highlighting no basis for special attention in the future with regard to this indicator when pursuing the resource option).

At this initial stage of the resource option review, effects on any indicator are often best characterized as "potential" given the need to rely on existing information without project specific baseline or assessment studies to verify existing conditions, as well as expected effects. For most resource options evaluated here, current information is at a preliminary level of assessment.

In assessing potential adverse or positive effects, the evaluation assumes adoption of well understood mitigation measures or best management practices to manage potential effects; however, to provide a common evaluation approach for all options, customized mitigation developed for a specific resource option is not considered (even for the few options where more detailed studies and assessments have been carried out, e.g., Stewart-Keno City Transmission, Mayo Lake and Southern Lakes hydro storage enhancement projects).

Accordingly, a high or red rating related to potential adverse effects on an environmental or social indicator does not in any way signify that the resource option is infeasible. Such a rating only shows that these effects will need to be addressed and managed/mitigated in order for the project to proceed.

In summary, the ratings for the evaluation of each indicator were classified in terms of high, medium, and low as follows (see also Figure B 7-1):

- **High (Red when non-positive - no colour when positive effect)** means the resource option has a high expected effects linkage to the indicator (depending on the indicator, the likely effects may be adverse, positive or simply signify linkage and/or overlap without much additional guidance);
- **Medium (Yellow when non-positive - no colour when positive effect)** means the resource option has potential expected linkage to the indicator that falls between high and low ratings; and

- **Low (Green when non-positive - no colour when positive effect)** means the resource option likely has minimal, if any, expected effects linkage to the indicator (again, depending on the indicator, any potential minimal effects may be adverse, positive or simply signify no linkage/overlap with the indicator, i.e., no effects pathway).

Figure B 7-1: Rating Criteria Considerations

High	Classification of high means the resource option has a high expected effects linkage to the indicator (depending on the indicator, the likely effects may be adverse, positive or simply signify linkage/overlap without much additional guidance). Red signifies a high rating for all non-positive effect indicators. A red (high) rating related to potential adverse effects does not signify that the resource option is infeasible - such a rating only shows that these effects are high and will need to be addressed and managed/mitigated in order for the project to proceed. No colour is used to signify a high rating related to potential positive effects. A high positive rating indicates that such effects for the resource option are high relative to the effects on the indicator from other options; associated with such a rating is a likely requirement to address specific benefit management or enhancement measures.
Medium	Classification of medium means the resource option has potential expected linkage to the indicator that falls between low and high ratings. Yellow signifies a medium rating for all non-positive effect indicators. A yellow (medium) rating related to potential adverse effects indicates a likely need to proceed with caution and/or special attention to the management of certain potential adverse effects (without any determination today that a high expected effects linkage exists). No colour is used to signify a medium rating related to potential positive effects. In many evaluations of adverse effects a medium rating indicates a lack of information needed for a red (high) or green (low) rating.
Low	Classification of low means the resource option has minimal, if any, expected effects linkage to the indicator (again, depending on the indicator, any potential minimal effects may be adverse, positive or simply signify no linkage/overlap with the indicator, i.e., no effects pathway). A green (low) rating related to potential adverse effects indicates that such effects are well understood and likely can be managed through best management practices or standard mitigation measures. No colour rating is used to signify a low rating related to potential positive effects. A low positive rating indicates that such effects for the resource option are low relative to the effects on other options and unlikely to require special benefit management or enhancement measures. A green (low) rating may also signify no linkage between the resource option and the indicator.

ATTACHMENT 1:
RFP 2016-010 Draft IRP
Resource Options Evaluation Matrix

Attachment 1: RFP 2016-010 Draft IRP Resource Options Evaluation Matrix

ID	Criteria1	Description	Objective	Indicator	Metric ID	Metric	Rating Scheme	Data Sources
Environmental Criteria								
En1	**Species and Habitats**	The greater the number of valued species that inhabit a given area the greater the species richness implying greater heterogeneity of habitat - i.e., faunal species biodiversity. Species protection and recovery/restoration. Habitats of acknowledged high ecological value (e.g., calving grounds, winter range, wetlands, spawning grounds, protected areas). Habitat conservation considerations. Influence on water quality and quantity.	Options that have the lowest negative effect on biodiversity are preferred. Options that have minimal or no effects to such areas are preferred. No significant change beyond range of natural variability and ability of ecosystem to be sustainable.	Effects Radius/Influence Relative to Fish and Wildlife Key Areas	En1-1	Key habitat areal extent affected by option (km^2)		
				Effects Radius/Influence Relative to SARA Listed Species	En1-2	Type and number of SARA-relevant species in project area (type and n)		
				Effects Radius/Influence Relative to Protected Areas	En1-3	Proximity of Project to Protected Areas (km)		
				Effects to Water Quality	En1-4	Physical or chemical changes to water quality relative to baseline (various dependent on key analyses, e.g., temp, dissolved metals, pH, total gas pressure, total suspended solids)		
				Effects to Water Quantity	En1-5	Changes to water quantity relative to baseline (m^3, m^3/s) during all times of the year		
En2	**Land/Resource Use Intensity and Naturalness**	Landscape patterns are linked to biodiversity and other ecological values of the landscapes. Measures of anthropogenic footprint and intensity as well as biodiversity and other measures of naturalness and ecosystem robustness to be used here. Stream crossings captured may include those with known fish resources or anadromous fish resources (i.e., salmon), or all substantive watercourses regardless of fish (TBD).	Projects that have smaller project footprints or otherwise minimize negative effects to biodiversity and naturalness are preferable.	Project Footprint	En2-1	Areal Extent of Project Footprint (km^2)		
					En2-2	Visual Aesthetic Effects (Naturalness) Profiles (L/M/H)		
					En2-3	Length of Project, if linear development (km)		
				Access Requirements	En2-4	Length of Access Roads (km)		
					En2-5	No. of Stream Crossings (n)		
				Consumptive Water Use	En2-6	Water Use Intensity (m^3/day)		

ID	Criteria1	Description	Objective	Indicator	Metric ID	Metric	Rating Scheme	Data Sources
En3	**Pollution and Contamination**	Waste products and pollution created by resource option. Relative risk profile of resource for environmental releases and contamination.	Lower results are favoured.	Air Pollution	En3-1	Comparative Criteria Air Contaminant Production per unit energy produced (e.g., tonnes SOx, NOx, PM per kWh)		
				GHG Profile	En3-2	Life Cycle GHG Production in Yukon (tonnes/kWh)		
					En3-3	GHG ratio with fossil fuel alternative/default (tonnes renewable GHG/tonnes default Fossil GHG per kWh or vice versa)		
				Risk of Unintended Release of Pollutants	En3-4	Relative Likelihood/Probability of spill/release (L/M/H)		
					En3-5	Consequences of Spill/Release (L/M/H)		
En4	**Climate Change Adaptation / Resiliency**	Character of the option in the context of resiliency or adaptability to predicted long-term climate change and immediate severe weather effects. (Move permafrost indicator and metrics here; develop additional indicators and metrics).	Sites with higher resiliency to forecast CC effects preferred.	Susceptibility to Extreme Weather Events/Conditions	En4-1	Resilience to Extreme Heat/Drought (L/M/H)		
					En4-2	Resilience to Extreme Precipitation - flood/snow (L/M/H)		
					En4-3	Resilience to Extreme Wind Events (L/M/H)		
					En4-4	Resilience to Ice Related Processes/Events (L/M/H)		
				Conditions Susceptible to CC	En4-5	Extent of Permafrost in project footprint (L/M/H)		
Social Criteria								
S1	**Traditional Lifestyle**	Access to country foods, medicinal plants, other subsistence pursuits.	Projects that have lower magnitude effects preferred.	Land Availability/Access Effects	S1-1	Direct Loss of Land or Land Access for such pursuits (km2)		
				Land Quality Effects	S1-2	Indirect effects on land for such pursuits (+/- and L/M/H)		
				Land Tenure	S1-3	Number of cabins, camps, homesteads, etc. in study area that may be affected (n)		
				Diet	S1-4	Predicted effects to the ability/availability of country foods (+/- and L/M/H)		
					S1-5	Effects to the opportunity to harvest fish and meat (+/- and L/M/H)		

ID	Criteria1	Description	Objective	Indicator	Metric ID	Metric	Rating Scheme	Data Sources
S2	**Tourism & Recreation**	Qualitative assessment of effect on valued tourism, leisure, and/or recreational opportunities/resources (e.g., swimming, boating, sport fishing, playgrounds, youth/community centres, campgrounds, significant water recreation, trails, etc.) Professional judgment required to assess this criteria based on local knowledge. Includes big game outfitters.	Sites with less effect to tourism and recreational resources are preferred.	Existing Recreational Values	S2-1	Effect on nature and Scale of Recreational Values. (+/- and L/M/H)		
				New Recreational Opportunities	S2-2	Number/value of new opportunities that project-related access may provide for recreation (+/- and L/M/H)		
				Tourism Value	S2-3	Potential for improved Annual Value of tourism in Regional Study Area (+/- and L/M/H)		
S3	**Heritage Resources**	Project specific effects that can damage sacred or historic areas, artifacts, and loss of use of traditional place names.	Sites that do not effect known high value or significant heritage sites are preferred.	Heritage Resource Potential	S3-1	Density (number of discrete) known or potential archeological, palaeontological, ethnological, prehistoric, historic, or aesthetic resources (L/M/H)		
					S3-2	Importance/Cultural Value of heritage resources, including areas of land containing heritage resources. (L/M/H)		
S4	**Cultural and Community Well Being**	Effects of development/operation on public and worker safety, employment and educational (skills and training) opportunities, Shifts in patterns of work availability and employment can have effects on family/community contributions and/or support of community infrastructure/culture.	Projects that have positive effects on cultural and community wellbeing are preferred.	Employment	S4-1	No. of Direct/Indirect Jobs Created during construction and operations (n)		
				Public Safety	S4-2	Public safety risks posed by project - construction period (L/M/H)		
				Educational Opportunities	S4-3	Provides opportunities for advanced education of local people (L/M/H)		

ID	Criteria1	Description	Objective	Indicator	Metric ID	Metric	Rating Scheme	Data Sources
Economic Criteria								
Ec1	**Other Value Generation and Distribution**	Value of wages, taxes, and consumer spending locally and regionally. Economic leakage. Options that provide, or leverage, the greatest long-term or durable social benefits that contribute to the community sustainability vision. Payments to capital providers and governments.	Maximize circulation of wealth locally and regionally.	Economic Growth / Financial Value	Ec1-1	Gross Domestic Product (GDP)		
					Ec1-2	Genuine Progress Indicator (GPI)		
					Ec1-3	Change in total local/regional employment (no. of FT/PT jobs for construction and operation phases)		
				Economic Opportunity	Ec1-4	% of project employment opportunities that match the skills of the locally/regionally available workforce		
				Community Value	Ec1-5	Value of infrastructure contributions/improvements in communities required for, or inevitable with, project (L/M/H)		

APPENDIX C:
ENVIRONMENTAL EVALUATION TECHNICAL REPORT

TABLE OF CONTENTS

1.0 INTRODUCTION C-1

2.0 FISH AND FISH HABITAT C-3

2.1 RATING CRITERIA AND DATA SOURCES FOR EN-1: FISH & FISH HABITAT C-3

2.2 EVALUATIONS C-4

2.2.1 Resource Options with No Material Concerns regarding Fish and Fish Habitat C-4

2.2.2 Hydro Renewable Generation C-7

3.0 WATER QUANTITY & QUALITY C-17

3.1 RATING CRITERIA AND DATA SOURCES FOR EN-2: WATER QUANTITY & QUALITY C-17

3.2 EVALUATIONS C-19

3.2.1 Resource Options with No Material Concerns re: Water Quantity and Quality C-19

3.2.2 Hydro Renewable Generation C-19

4.0 TERRESTRIAL SPECIES & HABITAT C-28

4.1 RATING CRITERIA AND DATA SOURCES FOR EN-3: TERRESTRIAL SPECIES AND HABITAT C-28

4.2 EVALUATIONS C-31

4.2.1 Resource Options with No Material Concerns re: Terrestrial Species & Habitat C-31

4.2.2 Non-Hydro Renewable Generation C-33

4.2.3 Hydro Renewable Generation C-39

4.2.4 Transmission Corridors C-49

5.0 TERRESTRIAL FOOTPRINT & LAND USE C-55

5.1 RATING CRITERIA AND DATA SOURCES FOR EN-4: TERRESTRIAL FOOTPRINT AND LAND USE C-55

5.2 EVALUATIONS C-60

5.2.1 Resource Options with No Material Concerns regarding Terrestrial Footprint and Land Use C-60

5.2.2 Hydro Renewable Generation C-61

5.2.3 Transmission Corridors C-61
6.0 AIR QUALITY C-63
6.1 RATING CRITERIA AND DATA SOURCES FOR EN-5: AIR QUALITY C-63
6.2 EVALUATIONS C-68
6.2.1 Resource Options with No Material Concerns re: Air Quality C-68
6.2.2 Thermal Generation Resource Options C-68
7.0 REFERENCES C-70

LIST OF TABLES

Table C 1-1: Resource Option Evaluation Matrix - Environmental Criteria & Indicators C-2
Table C 2-1: Resource Project Options with No Linkage (NL) or Low Ratings for All Fish & Fish Habitat Indicators C-6
Table C 2-2: Summary of Assessment for Pumped Storage C-7
Table C 2-3: Summary of Assessment for Small Hydro Projects C-11
Table C 2-4: Summary of Assessment for Gladstone Diversion C-14
Table C 2-5: Summary of Assessment for Hydro Storage Enhancements C-15
Table C 2-6: Summary of Assessment for Mayo Lake Outlet Channel Dredging C-16
Table C 3-1: Summary of Assessment for Pumped Storage C-20
Table C 3-2: Summary of Information Regarding Relative Scale of New Impoundment/Flooding C-23
Table C 3-3: Summary of Assessment for Small Hydro C-24
Table C 3-4: Summary of Assessment for Gladstone Diversion C-26
Table C 3-5: Summary of Assessments for Hydro Storage Enhancements C-27
Table C 4-1: Summary of Potential Effects on Terrestrial Species C-29
Table C 4-2: Summary of Assessment for Wood Biomass (Timber Harvesting) C-34
Table C 4-3: Summary of Assessment for Wind Farms C-35
Table C 4-4: Summary of Assessment for Geothermal C-38
Table C 4-5: Summary of Assessment for Pumped Storage C-39
Table C 4-6: Summary of Assessment for Small Hydro C-43
Table C 4-7: Summary of Assessment for Gladstone Diversion C-47
Table C 4-8: Summary of Assessment for Hydro Storage Enhancements C-48
Table C 4-9: Summary of Assessment for Transmission Corridors C-51
Table C 5-1: Terrestrial Footprint & Land Use: Footprint Terrestrial Area & Linear Development C-58
Table C 6-1: Summary of GHG Emissions from Resource Options (20 and 100 Year GWP) C-67

LIST OF FIGURES

Figure C 2-1: Summary of Rating Criteria for Fish & Fish Habitat C-3
Figure C 3-1: Summary of Rating Criteria for Water Quantity & Quality C-17
Figure C 4-1: Summary of Assessment Rating Criteria for Terrestrial Species & Habitat C-28
Figure C 5-1: Summary of Assessment Rating Criteria for Terrestrial Footprint & Land Use C-55
Figure C 6-1: Summary of Assessment Rating Criteria for Air Quality C-63

1.0 INTRODUCTION

Environmental criteria and indicators for evaluating the resource options, as finalized in Appendix B, are copied below in Table C 1-1.

The technical environmental evaluation of each resource option is addressed in Appendix C, with separate sections for each of the five main environmental criteria in Table C 1-1.

At the start of each section of Appendix C, the distinct issues, rating criteria and data sources for each criteria are summarized. In each case, environmental indicators address non-positive effects, e.g., adverse effects as well as non-linkage cases. Accordingly, as outlined in Section 7 of Appendix B, the ratings for the evaluation of each environmental indicator are classified in terms of high (red), medium (yellow), and low (green) as follows:

- **High (red)** means the resource option has a high expected non-positive effects linkage to the indicator (depending on the indicator, the likely effects may be adverse or simply signify linkage/overlap without much additional guidance);
- **Medium (yellow)** means the resource option has potential expected non-positive linkage to the indicator that falls between green and red ratings; and
- **Low (green)** means the resource option likely has minimal, if any, expected non-positive effects linkage to the indicator (again, depending on the indicator, any potential minimal effects may be adverse or simply signify no linkage / overlap with the indicator, i.e., no effects pathway).

“No linkage,” which is shown as green, is separated out in the environmental evaluations to identify circumstances where there is no apparent or likely link between a resource project option (including new road and/or transmission access related to the resource project) and a given environmental indicator.

As each resource project option was reviewed, it was assumed that standard best management practices (BMPs) would be applied during the construction and operation stages to mitigate adverse effects. Where standard BMPs are expected to prevent any likely effect of concern on an indicator, a green or low effect rating is adopted.

Table C 1-1: Resource Option Evaluation Matrix - Environmental Criteria & Indicators

	ID	Criteria	Indicator	Metric ID	Metric
	Environmental Criteria				
Aquatic Environment	**En1**	**Fish and Fish Habitat**	Salmon & Habitat	En1-1	Presence or absence (Y/N) & Relative Impact (+/-)
			Species at Risk & Habitat	En1-2	Presence or absence (Y/N) & Relative Impact (+/-)
			Commercial, Recreational or Aboriginal Fishery Species & Habitat	En1-3	Presence or absence (Y/N) & Relative Impact (+/-)
	En2	**Water Quantity & Quality**	Consumptive Water Use	En2-1	Water Use Intensity (m3/day)
			Relative Scale of New Impoundment/ Flooding	En2-2	Presence or absence (Y/N) & Relative Scale (L/M/H)
			Flow changes	En2-3	Presence or absence (Y/N) & Relative Scale (Run of River; Storage; Pumped Storage)
Terrestrial Environment	**En3**	**Terrestrial Species & Habitat**	Species at Risk & Habitat	En3-1	Presence or absence (Y/N) & Relative Impact (+/-)
			Protected & Conservation Area	En3-2	Proximity to Protected & Conservation Areas (L/M/H)
			Wildlife Key Areas	En3-3	Proximity to WKAs (L/M/H)
			Caribou Ranges	En3-4	Proximity to Caribou Ranges (L/M/H)
	En4	**Terrestrial Footprint & Land Use**	Footprint Terrestrial Area including access & new flooding (Total km2)	En4-1	Area of Project Terrestrial Footprint (km2)
			Linear Development for roads, transmission (km)	En4-2	Total length of linear features (km)
			Permafrost	En4-3	Presence or absence (Y/N) & Relative Scale (L/M/H)
			Wetlands	En4-4	Presence or absence (Y/N) & Relative Scale (L/M/H)
Air	**En5**	**Air Quality**	GHG Emissions (in Yukon)	En5-1	Intensity (per kWh)
			Other Air Pollutants	En5-2	Intensity (per kWh)

2.0 FISH AND FISH HABITAT

2.1 RATING CRITERIA AND DATA SOURCES FOR EN-1: FISH & FISH HABITAT

The rating system outlined in Figure C 2-1 was adopted to guide evaluations of each resource project option for each of the fish and fish habitat indicators.

Figure C 2-1: Summary of Rating Criteria for Fish & Fish Habitat

Indicator	Low	Medium	High
Salmon & Habitat (En1-1)	No salmon present, or no linkage	Potential to interact with salmon rearing habitat	Potential change to salmon migration and/or spawning areas
Species at Risk & Habitat (En1-2)	No fish Species at Risk present, or no linkage	Species of Concern present and no basis for potential major concern.	Endangered species or Species of Concern present[1] and basis for potential major concern
Commercial, Recreational or Aboriginal Fisheries Species & Habitat (En1-3)	No commercial, recreational or Aboriginal fishery present, or no linkage	Commercial, recreational or Aboriginal fishery and no basis for potential major concern	Commercial, recreational or Aboriginal fishery present and basis for potential major concern

Note:

1. Evaluation assumes if a species on Schedule 1 or 2 of *Species at Risk Act* (SARA) are present and there is a basis for potential major concern due to potential effects of the project, this would be high effect to reflect potential levels of concern.

The fish and fish habitat indicators as defined in Table C 1-1 focus on the presence or absence of each indicator (Yes/No rating) and whether the effect is positive or negative. Unless otherwise explicitly noted, the evaluations of each resource option for these indicators have identified only negative effects. Notwithstanding the presence of an indicator species, a green or low rating is applied for access roads and transmission access or corridors for a resource option based on the assumption that BMPs are applied as required for permitting. The Figure C 2-1 rating system also provides a rationale to separate medium (yellow) ratings for each indicator from high (red) ratings, rather than treating the potential for adverse effects as red (high) in each instance. A red (high) rating indicates the need for additional mitigation to be designed that adequately addresses specific concerns if the resource project was to proceed to further review.

Fish habitat indicators have been evaluated based on available fish distribution data from the BC Ministry of Environment and Fisheries and Oceans Canada (DFO). As project-specific habitat assessments have not been undertaken, potential interactions are based on known species life-history functions.

In developing and applying the rating system, the ratings are based on available information regarding resource project option descriptions, as well as known types of environmental effects that the various

types of projects can have on the aquatic environment. Ratings also reflect the preliminary status of the project information available today.

- For **En1-1 (Salmon and Salmon Habitat)**, a project in a watershed with salmon will automatically generate a yellow (medium) rating, highlighting the need to proceed with some caution; however, a red (high) rating will apply if the project includes potential change to salmon migration and/or spawning areas. For example, if the project includes a dam across the river, the rating is elevated to red (high) due to the known effects dams have on salmon migration and access to spawning areas, even if specific spawning locations have not been identified at this time.
- For **En1-2 (Species at Risk and Habitat)**, a red (high) rating applies if endangered species or species of concern are present and there is a basis for potential major concern related to potential effects of the project that are likely to require additional mitigation to be designed that adequately addresses specific concerns if the resource project was to proceed to further review.
- For **En1-3 (Commercial, Recreational or Aboriginal Fisheries Species and Habitat)**, a red (high) rating applies if any of these species/habitat are present and there is a basis for potential major concern related to potential effects of the project that are likely to require additional mitigation to be designed that adequately addresses specific concerns if the resource project was to proceed to further review. In the case of hydro storage projects, for example, habitat changes resulting from flooding can result in an increase in methylmercury production that may affect commercial, recreational or Aboriginal (CRA) fisheries.

2.2 EVALUATIONS

2.2.1 Resource Options with No Material Concerns regarding Fish and Fish Habitat

The fish and fish habitat indicators are not applicable to many resource project options due to the following factors:

- No linkage circumstances where there is no apparent or likely link between a resource project option and a given environmental indicator (e.g., waters with no salmon, no species at risk, no fisheries and settings where a resource option does not have an apparent link or effect pathway with regard to any fish or fish habitat).
- The nature of some of the project types (e.g., there would be no fish habitat in streams for wind projects situated on mountain tops), where use of BMPs would control erosion and prevent negative effects to fish habitat in down gradient areas outside of the immediate project footprint. This same situation applies for resource options where it is recognized that BMPs will address any concerns regarding effects of fish and fish habitat (e.g., transmission projects that involve river or stream crossings) and are recognized not to raise material concerns regarding fish and fish habitat so long as appropriate BMPs are implemented.
- Location of infrastructure on previously disturbed or brownfield sites that are not affecting river environments. For example, resource project options such as solar PV, energy storage, and

various thermal options addressed in this evaluation that are located within urban areas (e.g., Whitehorse or Haines Junction), require no new disturbance and are expected to use standard BMPs to control erosion would also prevent negative effects to fish habitat in down gradient areas that are outside the immediate project footprint.

Table C 2-1 provides a summary of the resource project options with either no linkage (NL) or other green (low) rating (due to assumed BMPs being applied) for any of the fish and fish habitat indicators. Brief supporting information and analysis is provided below on these resource options:

1. **Fossil Fuel Thermal (Diesel or LNG), Non-fossil Fuel Thermal (Biomass, Waste-to-Energy, Biogas), Energy Storage Facility and Solar PV:** Each of these resource options is located in either Whitehorse or Haines Junction, and in most cases, on brownfield sites (e.g., Whitehorse Landfill, Takhini Substation),[1] with no anticipated direct effect pathway on any stream, river or other water body. For projects located in Whitehorse, it is noted that the Yukon River and tributaries in this area provide habitat for salmon and other fish species. However, as noted, none of these resource options would be expected to have any direct effects on the Yukon River. The application of standard BMPs during construction and operation of these resource options are assumed to minimize the risk of sediment or other elements from the project area entering any stream down gradient from the proposed resource option site areas.
2. **Wind Farms and Geothermal:** Each of these resource options involves no anticipated direct effect pathway on any stream, river or other water body. Application of standard BMPs during construction and operation are assumed to minimize the risk of sediment or other elements from the project area entering any stream down gradient from the proposed resource option site areas. Table C 2-1 shows no linkage (NL) for specific options where there is no salmon species, species at risk, or fisheries in the vicinity; in contrast, low is shown where the species or fisheries are in the vicinity (in some cases along access routes and/or transmission routes) and BMPs are required to prevent any effects on fish and fish habitat indicators.
3. **Refurbish Existing Hydro Generation:** Each of these resource options occurs within an existing facility and does not involve any changes to water flows or levels. Application of standard BMPs during construction and operation of these resource options are assumed to minimize the risk of sediment or other elements from the project area entering any stream down gradient from the proposed resource option site areas.
4. **Transmission Corridors:** commercial, recreational or Aboriginal fisheries species and habitat are present in the areas crossed by each transmission corridor option. Salmon and salmon habitat are also likely present for some transmission corridors, e.g. Whitehorse-related corridors and Stewart-Keno City Transmission; however, transmission projects crossing of rivers or streams are recognized not to raise material concerns regarding fish and fish habitat so long as BMPs are implemented as required for any permitting of such projects.

[1] The Haines Junction sites for biomass or solar resource options are within the town in already cleared or largely open areas. The biomass resource option will use beetle-kill wood and not require harvesting green trees.

Table C 2-1: Resource Project Options with No Linkage (NL) or Low Ratings for All Fish & Fish Habitat Indicators

Project / Options	Salmon & Habitat	Species at Risk & Habitat	Commercial, Recreational or Aboriginal Fisheries Species & Habitat
Fossil Fuel Thermal (Diesel or LNG)			
Whitehorse Landfill	Low	Low	Low
Takhini Substation	Low	Low	Low
Non-Fossil Thermal			
Biomass (Haines Junction)	NL	NL	NL
Waste-to-Energy (Whitehorse)	Low	Low	Low
Biogas (Whitehorse)	Low	Low	Low
Energy Storage Facility			
Takhini Substation	NL	NL	NL
Solar PV			
Whitehorse	NL	NL	NL
Haines Junction	NL	NL	Low
Wind Farms			
Cyprus Mine Hill	NL	NL	NL
Kluane Lake	NL	NL	Low
Miller's Ridge	Low	NL	Low
Mt. Sumanik	NL	NL	NL
Sugarloaf Mountain	NL	NL	Low
Tehcho (Ferry Hill)	Low	NL	Low
Thulsoo Mountain	NL	NL	Low
Geothermal			
McArthur	NL	NL	Low
Vista Mountain	Low	Low	Low
Refurbish Existing Hydro Generation			
Mayo A	NL	NL	Low
Aishihik re-runnering	NL	NL	Low
Transmission Corridors			
Aishihik-Destruction Bay	NL	NL	Low
Faro–Watson Lake	Low	Low	Low
Whitehorse–Atlin	Low	NL	Low
Whitehorse–Skagway	Low	NL	Low
Whitehorse–Teslin	Low	Low	Low
Stewart-Keno City	Low	Low	Low

2.2.2 Hydro Renewable Generation

Each of the hydro resource options that affect aquatic resources is evaluated separately in the following sections.

2.2.2.1 Pumped Storage

Pumped storage hydro generation resource options each require two reservoirs with water pumped from the lower reservoir to the upper reservoir during the summer season, and the upper reservoir then used for generation during the winter. Effects on fish and fish habitat indicators are reviewed in Table C 2-2 for each of the site options, taking into consideration available information on fish and fish habitat, as well as the changes in the water regime currently assumed for each project option. This evaluation does not attempt to assess any differences in effects on fish and fish habitat due to different scales of development for some of these options, e.g., storage at 50 GWh versus 100 GWh.

Table C 2-2: Summary of Assessment for Pumped Storage

Project / Option	Indicator	Ranking	Assessment
Atlin – Black Mountain	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur within the project area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur or that are likely to occur in the project area are listed under *Species at Risk* Act (SARA).
	Commercial, Recreational or Aboriginal Species & Habitat	**Medium**	Fish species known to occur in Atlin Lake include: Arctic Grayling, Lake Trout Lake Whitefish, Northern Pike, Round Whitefish, Burbot, Least Cisco, Longnose Sucker, Lake Chub and Coarse (Large) Scale Sucker. Examining some of the adjacent lakes and streams, it is likely that species such as Slimy Sculpin and Burbot could also be present in the lake. There is no fisheries data available for the watershed 837-088400-28000-50000, in which the upper unnamed lake is located (Lake 00172ALL; BC MoE 2016 a, b). There is a commercial, recreational and Aboriginal fishery on Atlin Lake. There is a possibility of fish species being present in the upper reservoir lake that are of value to recreational and Aboriginal fisheries. ***The effect on these types of fisheries is considered to be Medium due to the remote location of the upper reservoir lake, uncertainty as to species in this upper reservoir lake and the minimal effects expected on Atlin Lake levels.***
Canyon – Ittlemit	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur within the project area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.

Project / Option	Indicator	Ranking	Assessment
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	Lake Trout are known to occur in Ittlemit Lake. Lake Whitefish, Lake Trout, Northern Pike, Longnose Sucker, and Slimy Sculpin have been documented in Canyon Lake. The presence of Lake Trout in Ittlemit Lake and the diverse fish community in Canyon Lake is an indication that recreational or Aboriginal fisheries could be present. The significant increase in Canyon Lake volume (based on the presence of a >30 m high dam), could result in adverse effects to fish populations (e.g. spawning/incubation success, habitat changes). ***Therefore, effects on this indicator were considered to be High.***
Lindeman – Fraser	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	Lake Trout, Arctic Grayling, and Lake Whitefish are known to occur in Lindeman Lake. There was no fish information available for Fraser Lake. Based on the known fish species present, there is likely a recreational and Aboriginal fishery in Lindeman Lake. The size of the enlargements of the upper and lower reservoir lakes is unknown at this time. The increase in impoundment size could result in adverse effects to fish populations (e.g. spawning/incubation success, habitat changes). In addition, the dam at the lake outlet could affect fish movements and access to spawning habitat. ***Therefore, effects on this indicator were considered to be High.***
Racine – Moon	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	Arctic Grayling, Burbot, Lake Trout and Round Whitefish are known to occur in Racine Lake. According to local guides, there are no fish present in Moon Lake. Based on the known fish species present, there is likely a recreational and Aboriginal fishery in Racine Lake. The construction of a dam on Racine Lake would control water levels and could obstruct movements between Racine and Tagish Lake. The preliminary dam location would also make the lake smaller resulting in a loss of habitat. Based on the available information it is not possible to assess the potential significance of the changes to Tagish Lake water levels and connection. Given the species diversity in Racine Lake, the loss of habitat and potential changes to water levels and migration, ***this has been assessed as High.***

Project / Option	Indicator	Ranking	Assessment
Racine – Mt. Brown	Salmon & Habitat	No Linkage	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	No Linkage	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	High	Arctic Grayling, Burbot, Lake Trout and Round Whitefish are known to occur in Racine Lake. According to local guides, there was no fish sampling information for the unnamed lake that will be used as the upper reservoir. Based on the known fish species present, there is likely a recreational and Aboriginal fishery in Racine Lake. The construction of a dam on Racine Lake would change water levels and could obstruct movements between Racine and Tagish Lake. The preliminary dam location would also make the lake smaller resulting in a loss of habitat. Based on the available information it is not possible to assess the potential significant of the changes to Tagish Lake water levels and connection. ***Given the species diversity in Racine Lake, the loss of habitat and potential changes to water levels and migration, this has been assessed as High.***
Squanga – Dalayee	Salmon & Habitat	No Linkage	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	High	The Squanga Whitefish are a genetically distinct form of Lake Whitefish. While the speciation of the Squanga Whitefish has not yet been clarified (i.e., are they a sub-species of Lake Whitefish or a separate species), they are currently listed as a Species of Concern under Schedule 3 of SARA. There is very little known about the life-history and habitat requirements of the Squanga Whitefish; however, it is a fall spawning species that can be affected by water level management. Impoundments and water level management on the two lakes have the potential to affect spawning/incubation success as well as habitat. ***As this project has the potential to change habitat in a substantial portion of the Squanga Whitefish known range, it has been ranked as High.***
	Commercial, Recreational or Aboriginal Species & Habitat	High	Arctic Grayling, Lake Trout and Burbot are known to occur in Dalayee Lake. Arctic Grayling, Lake Whitefish, Northern Pike and Slimy Sculpin occur in the stream between Dalayee and Squanga lakes. Northern Pike and Squanga Whitefish are known to occur in Squanga Lake and it is likely that the species found upstream of Squanga Lake would also be found in Squanga Lake. The impoundments on the two lakes could affect fish species important to recreational and Aboriginal fisheries, both in the lakes and the interconnecting stream reach. The increase in impoundment

Project / Option	Indicator	Ranking	Assessment
			size on Squanga Lake and water level management on both lakes could result in adverse effects to fish populations. The preliminary dam locations will also result in a loss of existing habitat (at and behind the dam) in both lakes. ***Therefore, this has been assessed as High.***
Moon Lake (Tutshi – Moon)	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**Medium**	Arctic Grayling, Burbot, Coarse Scale Sucker, Inconnu, Lake Trout, Longnose Sucker, Northern Pike, Round Whitefish and Slimy Sculpin are known to occur in Tutshi Lake. Arctic Grayling, Lake Trout, Round Whitefish and unidentified sucker species are known to occur downstream of the project area in Tagish Lake. The importance of the downstream flows between Tutshi and Tagish lakes to local fish populations is currently unknown; however, based on its size and geomorphological characteristics visible in the satellite images, it is likely an important migration corridor and would likely provide spawning habitat to stream spawning species such as Arctic Grayling and the various sucker species. Available analysis suggests that the project will have no material effect on water levels at Tutshi Lake, implying no material effect on downstream flows to Tagish Lake. ***Given the effects on fish appear to be restricted to the river where information on fish populations and flow changes is not available, this has been assessed as Medium.***
Faro – Vangorda Pit	Salmon & Habitat	**High**	There are no salmon species in the project area of the upper reservoir; however, the lower reservoir area will flood a large portion of Blind Creek, which is a known Chinook Salmon spawning stream. ***The flooding of Chinook spawning habitat results in this being ranked as High.***
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	A waterfall on Vangorda Creek approximately 4 km upstream of Pelly River prevents fish use of the upper section of this creek near the proposed project. However, the preliminary layout of the reservoir dimensions shows the lower reservoir affecting a portion of Blind Creek, which is a known Chinook Salmon spawning stream and likely has several other fish species. ***Therefore, this has been ranked as High.***

2.2.2.2 Small Hydro Projects

With the exception of the Wolf River option (which assumes a run-of-river development at 20 MW), the Small Hydro generation resource options in this evaluation each include a dam as required to provide storage for winter generation (with resultant effects on aquatic resources related to changed water flows, lake levels and impediments to fish movement). Effects on fish and fish habitat indicators are reviewed in Table C 2-3 for each of the site options, taking into consideration available information on fish and fish habitat, as well as the changes in the water regime currently assumed for each project option.

Table C 2-3: Summary of Assessment for Small Hydro Projects

Project / Option	Indicator	Ranking	Assessment
Drury Lake	Salmon & Habitat	**Medium**	Chinook Salmon are known to occur in Drury Creek downstream of Drury Lake and the dam. Therefore, dam operation could affect downstream flows; the extent of flow changes has not been modelled; ***therefore, this has been assessed as Medium.***
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	Arctic Grayling, Lake Trout and Northern Pike are known to occur in Drury Lake and Chinook Salmon have been documented in Drury Creek. Commercial, recreational and Aboriginal fisheries occur in the project area. In addition, increased lake levels and impoundment areas would flood terrestrial areas, which could have adverse effects on fish populations in the lake (e.g., spawning and incubation success and changes to habitat). Such changes could affect commercial, recreational and Aboriginal fisheries. ***Therefore, this has been assessed as High.***
Finlayson River	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	**Medium**	None of the fish species known to occur in the project area are listed under SARA. Bull Trout are known to occur in the project area. The Yukon population of this species are currently listed as "Data Deficient" (COSEWIC 2012). ***Due to uncertainties associated with this species, and the fact that it has been listed as a Species of Special Concern in other parts of its Canadian range, the Species at Risk & Habitat fish species indicator has been ranked as Medium.***

Project / Option	Indicator	Ranking	Assessment
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	Arctic Grayling, Bull Trout, Lake Trout, Northern Pike, and unidentified species of whitefish are known to occur in Finlayson Lake. Increases in impoundment size could result in adverse effects to fish populations. Water level management could have an effect on critical life-stages (e.g., egg incubation) and habitat quality. Specifically, changes in lake levels could affect spawning habitat for fall spawning fish species (Lake Trout and whitefish). There are potential changes in downstream flows that potentially could affect fish habitat in the lower 6 km of the Finlayson River (upstream of the Frances Lake) due to diversion of water into the penstock. The importance of this river to local fish populations is currently unknown; however, based on its size and geomorphological characteristics visible in the satellite images, it is likely an important migration corridor and would likely provide spawning habitat to stream spawning species such as Arctic Grayling and Bull Trout. ***Changes to the lake and river habitats, combined with numerous species present results in High ranking***.
Altin – Pine Creek	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**Medium**	Arctic Grayling and Slimy Sculpin are known to occur in Surprise Lake. A barrier prevents other species from accessing the middle/upper portion of the watershed. The lower watershed (~2 km) can be accessed by the several fish species found in Atlin Lake; however, in terms of commercial, recreational or Aboriginal fish species, this area appears most suitable for Arctic Grayling. The Surprise Lake Arctic Grayling population has limited spawning habitat available and a fish way was included in the current power generating facility to provide unrestricted movements between the lake and Pine Creek (outflow tributary stream). Surprise Lake is already affected by an existing hydro development with a current licence allowing water levels up to 913.85 m. The proposed project would retain the current upper level of licensed operation but utilize increased storage by drawing down the lake to 911.35 m. The project has the potential to change water levels in Pine Creek and Surprise Lake and will have to be planned to mitigate effects on fish; however, ***given there appears to be only one species of concern that is generally resilient to change, this indicator has been ranked as Medium.***

Project / Option	Indicator	Ranking	Assessment
Tutshi – Windy Arm	Salmon & Habitat	**No Linkage**	There are no salmon species known to occur in the project area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	Arctic Grayling, Burbot, Inconnu, Lake Trout, Least Cisco, Longnose Sucker, Northern Pike, Round Whitefish and Slimy Sculpin are known to occur in the project area. Based on the fish species known to occur in the project area there would likely be recreational and Aboriginal fisheries. This project involves raising Tutshi Lake by 5 m, which will likely affect fish populations and habitat. There are also potential changes in downstream flows to the reach of river between Tutshi and Tagish lakes and upstream movements into Tutshi Lake due to the new dam and operation of the powerhouse. The importance of this river between Tutshi and Tagish lakes to the local fish populations is currently unknown; however, based on its size and geomorphological characteristics visible in the satellite images, it is likely an important migration corridor and would likely provide spawning habitat to stream spawning species such as Arctic Grayling and the various sucker species. ***Changes to the lake and river habitats, combined with numerous species present results in a High ranking.***
Wolf River	Salmon & Habitat	**Medium**	There are Chinook Salmon present in Wolf River and spawning has been documented as far upstream as the outlet of Wolf Lake. This project is run-of-river, which is limited to a short section of the lower Wolf River (~8 km) and should not impede fish passage. ***This has been ranked as Medium as the area affected is small and the extent of flow modifications has not been modelled.***
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**Medium**	Fish species known to occur in the Wolf River include Arctic Grayling, Burbot, Chinook Salmon, Inconnu, Lake Trout, Least Cisco, Longnose sucker, Northern Pike, Round Whitefish, and Slimy Sculpin. The fish species present would contribute to commercial, recreational and Aboriginal fisheries. ***This has been ranked as Medium due as the area affected is small and the extent of flow modifications has not been modelled.***

Project / Option	Indicator	Ranking	Assessment
Anvil Creek	Salmon & Habitat	**Medium**	Blind Creek is a known Chinook salmon spawning stream. There is also likelihood that Anvil Creek is used by Chinook (especially juveniles). Flow reductions in Anvil Creek and modifications to flow rates in Blind Creek could affect Chinook salmon. The extent of flow changes has not been modelled; ***therefore, this has been assessed as Medium.***
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**High**	Lake trout, northern pike, Arctic grayling and whitefish (unspecified species) have been documented in Anvil Creek near the outlet of Anvil Lake. Some cabins are present on the lake and recreational fishing does occur. Impoundment of the lake will result in flooding of terrestrial vegetation and this combined with fluctuating water levels could affect fish populations in the lake, especially fall spawning species such as lake trout; as such, ***this indicator has been ranked as High.***

2.2.2.3 Gladstone Diversion

The Gladstone Diversion resource option would divert water from the headwaters of Gladstone Creek into Isaac Creek, which flows into Sekulmun Lake and then Aishihik Lake. Lake trout spawning occurs in all four Gladstone Lakes, and Arctic Grayling spawning and rearing occur between the lakes and in Gladstone Creek. Lake Whitefish and other fish species occur in the Aishihik Lake area and there is an Aboriginal fishery in this area.

As reviewed in Section 4.3 of Appendix A, past work by Yukon Energy has indicated concerns from the Department of Fisheries and Oceans (DFO) as well as from local First Nations regarding interbasin pathogen transfer. YEC reported that the results of a full year of baseline studies provided no evidence to support a concern regarding interbasin pathogen transfer. Yukon Energy has continued to work with local First Nations to seek support for this project. A summary assessment for this project is provided in Table C 2-4.

Table C 2-4: Summary of Assessment for Gladstone Diversion

Project / Option	Indicator	Ranking	Assessment
Gladstone Diversion	Salmon & Habitat	**No Linkage**	No salmon or salmon habitat has been identified in this area.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.

	Commercial, Recreational or Aboriginal Species & Habitat	High	Arctic Grayling is known to occur in the area and project development would result in loss of spawning and rearing habitat between the lakes and in Gladstone Creek. Lake Trout spawn in Gladstone Lakes and project development may affect spawning/incubation success.

2.2.2.4 Hydro Storage Enhancements

Two potential hydro storage enhancement options have been under detailed review and planning by Yukon Energy for several years. Each option would enhance existing storage for existing hydro generation without developing any new dams. The evaluations in Table C 2-5 do not take into account the specific mitigation and adaptive management measures developed to date as a result of detailed environmental assessment studies (for the Mayo Lake Enhanced Storage, Yukon Energy's Yukon Environmental and Socio-economic Assessment Board [YESAB] submission set out measures to address potential adverse effects based on studies and ongoing work with the local First Nation).

Table C 2-5: Summary of Assessment for Hydro Storage Enhancements

Project / Option	Indicator	Ranking	Assessment
Mayo Lake Enhanced Storage	Salmon & Habitat	Low	No salmon or salmon habitat has been identified in this area. Project may have positive downstream effects on salmon habitat.
	Species at Risk & Habitat	No Linkage	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	High	Lake Trout and Lake Whitefish are known to occur in the area. As a result of the proposed reduction in the Mayo Lake licence lower supply level, Lake Trout and Lake Whitefish production may be lower.
Southern Lakes Enhanced Storage	Salmon & Habitat	Medium	Chinook salmon are present in the project area; however, flow changes are unlikely to have adverse effects.
	Species at Risk & Habitat	No Linkage	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	High	Lake Trout are known to occur in the area. The project may have an adverse effect on incubation success and food sources.

2.2.2.5 Mayo Lake Outlet Channel Dredging

The Mayo Lake Outlet Channel Dredging Project would remove an old cofferdam, as well as sedimentation that has infilled in the Mayo Lake Outlet Channel over the past 63 years since the original Mayo hydro generation was developed and address measures to mitigate potential future sediment infill in this outlet channel. As such, this can be viewed as a system maintenance activity that would not be anticipated to have adverse effects on fish and fish habitat assuming that BMPs are adopted as required for all of the activities. As noted for the Mayo Lake Enhanced Storage Project, there are no salmon or endangered fish species in the Mayo Lake storage area or in the outlet channel area affected by the proposed dredging.

For the purpose of this evaluation, Table C 2-6 provides a summary assessment of the Mayo Lake Outlet Channel Dredging option. This assessment does not take into account any specific mitigation and adaptive management measures developed to date as a result of detailed environmental assessment studies.

Table C 2-6: Summary of Assessment for Mayo Lake Outlet Channel Dredging

Project / Option	Indicator	Ranking	Assessment
Mayo Lake Outlet Channel Dredging	Salmon & Habitat	**No Linkage**	No salmon or salmon habitat has been identified in this area. Project may have positive downstream effects on salmon habitat.
	Species at Risk & Habitat	**No Linkage**	None of the fish species known to occur in the project area are listed under SARA.
	Commercial, Recreational or Aboriginal Species & Habitat	**Low**	Assuming BMPs for this project are implemented, no effects of concern are expected on these fisheries.

3.0 WATER QUANTITY & QUALITY

3.1 RATING CRITERIA AND DATA SOURCES FOR EN-2: WATER QUANTITY & QUALITY

The rating system outlined in Figure C 3-1 was adopted to guide evaluation of each resource project option for each of the water quantity and quality indicators.

Figure C 3-1: Summary of Rating Criteria for Water Quantity & Quality

Indicator	Low	Medium	High
Consumptive Water Use (En2-1)	<10% of instantaneous flows is not returned to the natural environment, or no linkage	10% to 20% of instantaneous flows is not returned to the natural environment	>20% of instantaneous flows is not returned to the natural environment
Relative Scale of New Impoundment / Flooding (En2-2) [relevant to water quality]	No new impoundment; water levels will be held high for longer periods of time increasing potential for erosion/sediment mobilization, or no linkage	>0% and <10% of lake surface area will be affected due to new impoundment	>10% of lake surface area will be due to new impoundment, increasing potential for erosion/sediment mobilization and mercury issues
Flow Changes (En2-3)	<10% of instantaneous flows, or no linkage	10% to 20% of instantaneous flows	>20% of instantaneous flows

The water quantity and quality indicators as defined in Figure C 3-1 each require a relative scale for comparing the different resource options. Implicit with each indicator is also an initial assessment as to whether the project is likely to have any effect on the indicator. In assessing water quantity and quality indicators, overlaps may occur with fish and fish habitat indicators, e.g., criteria for assessing high effects from new flooding may take into consideration increased potential for erosion/sediment mobilization and mercury issues that affect fish and fish habitat. Water quantity and quality effects during construction that are assumed to be addressed by BMPs (e.g., sediment disturbance) are rated green (low).

The following are noted regarding the rating scheme used for the assessment:

- **Consumptive Water Use (En2-1):** Consumptive water use is considered to be relevant to projects that consume water directly from a river, stream or lake and do not return water to the source following use (e.g., a steam plant, if it took water directly from a river and then used the water, which was evaporated and released to the atmosphere). The temporary diversion of water (e.g., run-of-river, pump storage) are included in the changes in the Flow Changes indicator (En2-3). No attempt is made for this evaluation to assess loss of water use due to reservoir evaporation or potential changes to groundwater flow regimes related to any of the resource options.

The indicator adopted focuses on the approximate assessment of changes to instantaneous flows that is not returned to the natural environment. The 10% of instantaneous flows adopted in Figure C 3-1 as the upper range of effect for low or green rating has been used in BC in recent water licence applications to indicate a low rating; 20% of instantaneous flows has been uses as an unofficial BC Ministry of Forests, Lands and Natural Resource Operations (FLNRO) guideline for run-of-river projects to indicate a high level of regulatory concern that needs to be addressed.

- **Relative Scale of New Impoundment/Flooding (En2-2):** The rating for impoundment is based on changes to water levels and the increase in lake size to reflect potential increases in erosion/sediment mobilization and methylmercury production.
    - Low rating applies if no new impoundment or increase in lake size, and includes options where existing impoundments will be used to hold water levels high for longer periods of time than is currently allowed.
    - An increase in lake surface area of less than 10% due to impoundment is rated as yellow or medium.
    - An increase in lake surface area of more than 10% due to impoundment is rated as red or high to reflect increasing potential for adverse effects related to potential increases in erosion/sediment mobilization and methylmercury production.
- **Flow Changes (En2-3):** Guidelines for small hydro and water diversions used by regulators in BC have been referenced to provide a range of rating values to develop the evaluation criteria for water quantity and flows. Unlike the En2-1 indicator, En2-3 addresses simple changes in review flows without any consumptive use of the water that removes it from the natural environment. The guidelines provide the following thresholds which have been used to evaluate effects on flows:
    - Less than 10% change in instantaneous flows has been used as a regulatory threshold for recent water licences in BC (i.e., project likely not to have a significant effect on the aquatic environment);
    - More than 20% change in instantaneous flows has been used as an unofficial FLNRO guideline for run-of-river projects to indicate a high level of regulatory concern that needs to be addressed; and
    - Projects with over 10% and less than 20% change in instantaneous flows are rated yellow (medium) to indicate the need to address potential regulatory concerns.

Some of the pumped storage projects and small hydro projects could affect lake levels in downstream reservoir lakes, as well as in the outflow streams/rivers of the downstream reservoir lakes. Detailed modelling of downstream changes for most of the hydro projects has not yet been done. In these situations, where there could be a change in flows, but the scale is unknown, the ranking has defaulted to yellow (medium). That ranking would need to be reassessed in the future, when flow modelling information becomes available. In the case of small hydro projects, a red (high) indicator has been used where relevant based on anticipated flow change effects on fish and fish habitat.

3.2 EVALUATIONS

3.2.1 Resource Options with No Material Concerns re: Water Quantity and Quality

Indicators related to the scale of new impoundments and flow changes are most applicable to the pump-storage and small hydro options, as well as upgrades or changes to existing hydroelectric facilities (i.e., Southern Lakes, Mayo Lake, and Gladstone).

A number of projects included in the resource review do not require the impoundment or diversion of water and also do not require consumptive uses of water. For these projects there is clearly no linkage to the water quantity and quality criteria or indicators.

In summary, based on currently available information, all of the resource project options shown in Table C 2-1 (for fish and fish habitat indicators) are assessed in this study to not require the impoundment or diversion of water or any consumptive uses of water. For example, none of the thermal generation projects is indicated to assume consumptive use of water from local rivers or water bodies. The Mayo Outlet Channel Dredging Project is also included in this assessment as not likely to have any effect of concern on water quantity or quality, assuming implementation of BMPs. The BMPs are assumed to address water quality impacts from sediment disturbance during construction and are therefore not specifically addressed in the water quantity and quality indicators.

3.2.2 Hydro Renewable Generation

Each of the hydro resource options that affects aquatic resources related to water quantity and quality is evaluated separately in the following sections. In many cases, flow changes have not yet been modelled and therefore a yellow or medium rating is provided (this may well change to red for many hydro options when there is further information).

3.2.2.1 Pumped Storage

Consistent summary information on each of the Pumped Storage projects is not available to summarize existing lake areas, new lake areas, area flooded and other related information. Each project involves two lake areas (upper reservoir and lower reservoir), with impoundment and flooding effects primarily being on the upper reservoir

Table C 3-1 provides the assessment on water quantity and quality of each Pumped Storage hydro generation option examined in this review. This evaluation does not attempt to assess any differences in effects on water quantity and quality due to different scales of development for some of these options, e.g., storage at 50 GWh versus 100 GWh.

Table C 3-1: Summary of Assessment for Pumped Storage

Project / Option	Indicator	Ranking	Assessment
Atlin – Black Mountain	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	High	The project consists of an unnamed upper lake/reservoir (BC Waterbody Identifier 00172ALL) south of Black Mountain and a lower reservoir (Atlin Lake). The project will involve the construction of dams (26 to 42 m) at each end of the unnamed lake to enlarge storage capacity of the unnamed lake. Water will be directed via an intake structure on the west end of the lake to a powerhouse on the shore of Atlin Lake. This will change the flows from the unnamed lake, from heading east to west. There will be some flooding associated with the dam development on the upper reservoir lake; the amount could double the size of the reservoir. Available satellite imagery shows that the lake is surrounded by alpine meadow and wetland habitat. These areas are high in organic material. Microbial degradation of flood organic materials could increase the rate of mercury methylation in the upper reservoir lake meaning that the pump and storage could be a vector for transporting methylmercury to Atlin Lake. ***Therefore, this risk is considered to be High.***
	Flow changes	Medium	The project will see flows directed from Stream 837-088400-28000-50000 and direct them to the west into Atlin Lake. The potential effects of such a flow diversion on Stream 837-088400-28000-50000 could not be assessed with the available information; ***therefore flow changes have been ranked as Medium. However, this ranking could be changed with further hydrological studies.***
Canyon – Ittlemit	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	High	The project will use Ittlemit Lake as the upper reservoir and Canyon Lake as the lower reservoir. An expansion of the existing Canyon Lake dam and a saddle dam would cause a significant increase in the surface area of Canyon Lake. A 16 m high dam would be required on the outlet of Ittlemit Lake. The proposed project would increase Canyon Lake surface area by almost 50% and increase Ittlemit Lake by 12%. The significant increase in Canyon Lake volume (based on the presence of a >30 m high dam), could result in an increase in erosion/sediment mobilization and methylmercury production. ***Therefore, effects related to the relative scale of new impoundment/flooding were considered to be High.***
	Flow changes	Medium	Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***

Project / Option	Indicator	Ranking	Assessment
Lindeman – Fraser	Consumptive Water Use	**No Linkage**	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	**High**	This project will use Fraser Lake as the upper reservoir and Lindeman Lake as the lower reservoir. It will include a 16 km penstock to bring water from Fraser Lake to Lindeman Lake. The proposed project would increase Fraser Lake surface area by 80% and increase Lindeman Lake by 36%. ***Therefore, effects related to the relative scale of new impoundment/flooding are considered to be High.***
	Flow changes	**Medium**	Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Racine – Moon	Consumptive Water Use	**No Linkage**	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	**High**	The project would use Moon Lake as the upper reservoir and Racine Lake as the lower reservoir. A 16 m to 21 m high dam would be constructed on Moon Lake and a control structure on Racine Lake. The construction of a dam on Racine Lake would control water levels and could obstruct movements between Racine and Tagish Lake. The proposed project would increase Moon Lake surface area by 60%, but would not change the surface area of Racine Lake. Such changes on Moon Lake could increase in erosion/sediment mobilization and methylmercury production. ***Therefore, effects related to the relative scale of new impoundment/ flooding are considered to be High.***
	Flow changes	**Medium**	Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Racine – Mt. Brown	Consumptive Water Use	**No Linkage**	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	**High**	The project would involve the impoundment of an unnamed lake near Mt. Brown by the construction of a 29 to 43 m high dam. A dam would be constructed on the outlet of Racine Lake to control water levels. The project would increase the surface areas of the Mt. Brown lake by 500%; ***therefore, effects related to the relative scale of new impoundment/flooding are considered to be High.***
	Flow changes	**Medium**	Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***

Project / Option	Indicator	Ranking	Assessment
Squanga – Dalayee	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	High	The facility is located between Johnson's Crossing and Jake's Corner. Dalayee Lake would be the upper reservoir and Squanga Lake would serve as the lower reservoir. The proposed project would not increase the surface area of Dalayee Lake, but would increase the surface area of Squanga Lake by about 12%. ***Therefore, effects related to the relative scale of new impoundment/flooding are considered to be High.***
	Flow changes	Medium	Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Moon Lake (Tutshi – Moon)	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	High	This option would use Moon Lake as the Upper Reservoir. The penstock would divert water to Tutshi Lake. Project operations are not expected to have a material effect on water levels of Tutshi Lake, and inflows and outflows from Tutshi Lake will remain uncontrolled during project operations. The proposed project would increase the surface area of Moon Lake by 100%, but would not increase the surface area of Tutshi Lake. ***Therefore effects related to the relative scale of new impoundment / flooding are considered to be High.***
	Flow changes	Medium	Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Faro – Vangorda Pit	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment/ Flooding	High	The project will involve the creation of new water bodies for the upper and lower reservoirs. The lower reservoir would be in the Blind Creek Valley and be 439 ha in size. The upper reservoir will be a new waterbody 520 ha in size. ***Therefore, effects related to the relative scale of new impoundment / flooding are considered to be High.***
	Flow changes	Medium	Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***

3.2.2.2 Small Hydro Projects

Table C 3-2 below summarizes some of the information available for the four small hydro projects where new impoundments are required (see also the general comments provided at outset of Section 2.2.2.2 with regard to these resource projects - Wolf River is run of river project, and the Atlin-Pine Creek project enhances power generation from storage facilities already in place).

Table C 3-2: Summary of Information Regarding Relative Scale of New Impoundment/Flooding

	Natural Lake Area (km^2)	New Lake Area (km^2)	Area Flooded (km^2)	Lake Level Increase (m)	Percentage increase of Existing Lake Surface Area	Est. Storage ($000\ m^3$)
Drury Lake	26	27.9	1.9	5	7%	134,750
Finlayson (includes Finlayson and Wolverine lakes)	28.2	33.6	5.4	5	19%	154,500
Tutshi – Windy Arm (Tutshi Lake only)	51.9	55	3.1	5	6%	267,125
Anvil Creek	5.3	5.9	0.6	5	11%	27,875

Effects on water quantity and quality indicators are reviewed in Table C 3-3 for each of the site options, taking into consideration available information on the changes in the water regime currently assumed for each project option.

Table C 3-3: Summary of Assessment for Small Hydro

Project / Option	Indicator	Ranking	Assessment
Drury Lake	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment /Flooding	Medium	The project will include an impoundment on Drury Lake, which would increase lake levels by 5 m and the lake surface area by 1.9 km^2. An increase in lake levels and impoundment areas would flood terrestrial areas and could change rate of methylmercury production. ***There is a small increase in impoundment size (7%), therefore, this has been ranked as Medium.***
	Flow changes	Medium	There will be a diversion of flows from Drury Creek. The reduction in flows from Drury Lake outlet stream by diversion into the penstock could potentially affect fish movement between Drury Lake and Little Salmon Lake (downstream of Drury Lake) and access to habitat in the stream reach between the two lakes. Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Finlayson River	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment /Flooding	High	The project would store water in Finlayson and Wolverine lakes and include a 5 m dam on each lake, which would result in an increase in surface area of 3 km^2 for Finlayson Lake and 2.4 km^2 for Wolverine Lake. Increases in impoundment size could result in increased production of methylmercury. There will be a 22% increase in Wolverine Lake and a 13% increase in Finlayson Lake. ***Therefore, this has been ranked as High.***
	Flow changes	Medium	There are potential changes in downstream flows in the lower 6 km of the Finlayson River (upstream of Frances Lake) due to the diversion of water into the penstock. Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Atlin/Pine Creek	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment	Low	The project would include an increase to power generation facilities already in place. This will include increasing the water level range on Surprise Lake from 913.85 m to 911.35 m (vs the existing operating range from 913.1 to 912.1). The existing permits allow maximum

Project / Option	Indicator	Ranking	Assessment
	/ Flooding		water levels up to 913.85 m, so no change to the permit is required. As such the project would likely just result in a higher frequency of water levels at or near the permitted full supply level; ***therefore, this has been ranked as Low.***
	Flow changes	**Medium**	There are potential changes to downstream flows in Pine Creek and changes to access because of changes in operating levels. The existing facility already modifies flows; however, incremental changes to downstream flows have not been modelled; Therefore, ***flow changes has been ranked as Medium.***
Tutshi – Windy Arm	Consumptive Water Use	**No Linkage**	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment / Flooding	**Medium**	The project would increase the water level in Tutshi Lake by 5 m and increase the surface area by 3.1 km^2 by constructing a dam across the outlet of the lake. Increases in impoundment size could result in increased production of methylmercury. There is a small increase in lake surface area (6%). ***This has been ranked as Medium.***
	Flow changes	**Medium**	There are potential changes in downstream flows to the reach of river between Tutshi and Tagish lakes and upstream movements into Tutshi Lake, due to the new dam and operation of the powerhouse. Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Wolf River	Consumptive Water Use	**No Linkage**	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment / Flooding	**No Linkage**	The project is a run-of-river development and therefore there is not anticipated to be any new impoundment/flooding.
	Flow changes	**Medium**	Wolf River is a run-of-the-river facility and does not involve impounding of water. Water intake will be constructed and water diverted through the powerhouse located approximately 8 km downstream. Due to the diversion of water, an 8 km section of river will experience changes in flows. Changes to downstream flows have not been modelled; ***therefore, this was ranked as Medium.***
Anvil Creek	Consumptive Water Use	**No Linkage**	The Project is not anticipated to have consumptive water use.

Project / Option	Indicator	Ranking	Assessment
	Relative Scale of New Impoundment /Flooding	High	The project will include an impoundment on Anvil Lake, which would increase lake levels by 5 m and the lake surface area by 0.6 km^2. An increase in lake levels and impoundment areas would flood terrestrial areas and could change rate of methylmercury production. There is a moderate increase in impoundment size (11%), ***therefore, this has been ranked as High.***
	Flow changes	Medium	There will be diversion of flow from Anvil Lake to a powerhouse located near the mouth of the stream that will result in a reduction of flow in Anvil Creek and some changes in flow rates in Blind Creek. The extent of changes to downstream flows habitat not been modelled; ***therefore, this was ranked as Medium.***

3.2.2.3 Gladstone Diversion

The Gladstone Diversion project will require flooding of area adjacent to several small lakes, creating one larger lake. The project will also result in changes in flow in Gladstone Creek of >20% and increases in flows in Isaac Creek, leading to Sekulmun Lake. Table C 3-4 provides a summary assessment of this project effects on water quantity and quality.

Table C 3-4: Summary of Assessment for Gladstone Diversion

Project / Option	Indicator	Ranking	Assessment
Gladstone Diversion	Consumptive Water Use	No Linkage	The Project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment / Flooding	High	The project requires flooding the area adjacent to several small lakes to create one larger lake. ***Therefore, this was ranked as High.***
	Flow changes	High	The project will result in changes in flow in Gladstone Creek >20% and increases in flows in Isaac Creek, leading to Sekulmun Lake. ***Therefore, this was ranked as High.***

3.2.2.4 Hydro Storage Enhancements

The Hydro Storage Enhancements projects involve changes to the use of existing storage (impoundments) without creating any new impoundment or expansion of lake surface area. Table C 3-5 outlines the expected effects of these resource options on water quantity and quality.

Table C 3-5: Summary of Assessments for Hydro Storage Enhancements

Project / Option	Indicator	Ranking	Assessment
Southern Lakes Enhanced Storage	Consumptive Water use	No Linkage	The project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment /Flooding	Low	The project includes an increase to the high supply limit where lake levels can be controlled; however, this is designed to keep water levels high in late summer and fall rather than impound/flood any land. Higher water levels for a longer period of time will increase the potential for erosion/sediment mobilization. ***Therefore, this project has been ranked as Low.***
	Flow changes	High	Changes to downstream flows are predicted to be over 20% higher in the late winter than historical flows. Reductions of flows occur during the late summer but are expected to be < 10 % lower than historical. ***Given the higher changes in late winter, diversion of flows has been ranked as High.***
Mayo Lake Enhanced Storage	Consumptive Water use	No Linkage	The project is not anticipated to have consumptive water use.
	Relative Scale of New Impoundment / Flooding	Low	The project would actually decrease the average water level in Mayo Lake and, as such, erosion from high water events should be reduced. ***Therefore, this has been ranked as Low.***
	Flow changes	High	Changes to downstream flows are predicted on average to be over 20% higher in late winter/spring than flows without the enhancement (effects will vary for different years). Reductions of flows that occur during the summer are expected to be over 10% and perhaps slightly over 20% (depending on load conditions). ***Therefore, this has been assessed as High.***

4.0 TERRESTRIAL SPECIES & HABITAT

4.1 RATING CRITERIA AND DATA SOURCES FOR EN-3: TERRESTRIAL SPECIES AND HABITAT

The rating system outlined in Figure C 4-1 was adopted to guide evaluation for each resource project option for each of the terrestrial species and habitat indicators.

Figure C 4-1: Summary of Assessment Rating Criteria for Terrestrial Species & Habitat

Indicator	No Linkage-Low	Low	Medium	High
Species at Risk & Habitat (SAR) (En3-1)	No SAR within Zone of Influence (ZoI)	Potential indirect effects; SAR occurrences within sensory disturbance ZOI	Potential direct effects; magnitude estimated to affect < a quarter of local population/habitat, effects on regional populations very limited, if any	Potential direct effects; magnitude estimated to affect > a quarter of local population/habitat, effects on regional populations may be measurable
Protected & Conservation Areas (PCA) (En3-2)	No PCA within 2 km of project	New access within 2 km of PCA, but no potential effect expected on PCA	Potential indirect effect due to proximity	Potential direct material effect within PCA
Wildlife Key Areas (WKA) (En3-3)	No WKAs within species-specific sensory disturbance ZoI	Potential indirect effects; WKAs within sensory disturbance ZOI of relevant species	Potential direct effects; magnitude estimated to affect < a quarter of WKA	Potential direct effects; magnitude estimated to affect > a quarter of WKA
Caribou Ranges (En3-4)	No caribou range within ZoI	Potential indirect effects; caribou range within sensory disturbance ZOI	Potential direct effects; magnitude limited to small proportion (< approximately 5%) of range	Potential direct effects; magnitude > approximately 5% of range

The terrestrial species and habitat indicators as defined in Table C 1-1 focus on the presence or proximity of the indicator relative to the resource project option's terrestrial footprint. Unless otherwise explicitly noted, the evaluations of each resource option for these indicators address only adverse effects. Assessments for each indicator consider the terrestrial zone of influence (ZOI)[2] for a project's footprint (e.g., noise effects can extend beyond the physical footprint), as well as the extent to which project effects are likely to affect the indicator (e.g., how much of the species habitat or WKA area would be affected). Figure C 4-1 provides separate rating criteria for No Linkage to address the degree of proximity to the indicator beyond which no linkage is assumed. As reviewed below, ratings for specific resource

[2] Zone of influence is the extent surrounding the footprint of an anthropogenic activity within which wildlife and/or habitat are affected by the activity.

options modify the criteria in Figure C 4-1 to reflect relevant factors, e.g., flexibility with transmission elements to avoid material effects (reduces ratings), caribou ranges that are very small or that are declining (increases ratings).

This subset of potential indicators for Terrestrial Species and Habitat were selected based on:

- Conservation concern (species at risk);
- Potential land use constraints (protected and conservation areas);
- High value wildlife habitat areas (wildlife key areas); and
- Regional and territorial emphasis on caribou management.

This selection of indicators is meant to provide a strategic assessment of key values of terrestrial species to identify potential showstopper issues and to facilitate a high-level comparison of relative values among projects. Assessment of additional indicators will be required for projects that advance from this strategic assessment to feasibility studies and environmental assessment stages.

Assignments of green (no linkage or low), yellow (medium) and red (high) ratings were driven by the type of project effects (i.e., mechanism of effect on the indicator) and the potential degree of overlap between the project and indicator. A list of potential effects associated with each project type on Terrestrial Species and Habitat is listed in Table C 4-1.

Table C 4-1: Summary of Potential Effects on Terrestrial Species

Project Type	Potential Effects on Terrestrial Species
Facilities (Storage, generating stations)	• Direct and indirect habitat effects of facility (generally small footprints).
Wood Biomass	• Direct and indirect habitat effects of biomass collection activities (potentially large footprints). • See also Access Roads.
Small hydro, pumped storage, enhanced storage	• Direct and indirect habitat effects of dams and associated infrastructure. • Effects to shoreline-associated birds. • Effects to littoral, shoreline and riparian vegetation and habitat.
Solar PV	• Direct and indirect habitat effects of site clearing and solar panel arrays.
Wind Farms	• Direct and indirect habitat effects of site clearing and turbines. • Collision risk to birds and bats.
Transmission Lines	• Direct and indirect habitat effects of right-of-way clearing. • Collision risk to birds. • Increased human access (disturbance and mortality effects by humans). • Facilitated predation. • Invasive plants.
Access Roads	• Direct and indirect habitat effects of roads. • Increased human access (disturbance and mortality effects by humans). • Facilitated predation. • Invasive plants.

Medium (yellow) and/or red (high) ratings were applied to situations where the project has the potential to have a direct effect on the indicator, as well as situations where data limitations prevent a clear green (low) or red (high) rating.

The list of specific criteria used to guide ratings for each indicator are described in Figure C 4-1, and reviewed below.

- For **Species at Risk** and **Wildlife Key Areas,** the primary measure used to assess magnitude of effects was proportion of local habitat potentially affected.
    - For most species this was assessed qualitatively with respect to visual estimates of broad habitat types and conceptual stage project maps. For example, for Olive-sided Flycatcher potential habitat was considered as conifer leading forest visible in satellite imagery.
    - For most projects more detailed species-specific habitat data are not available.
    - For situations where direct effects could result from a project, an approximate level of a quarter of total potential habitat was used as a threshold to define yellow (Medium) (< a quarter of total habitat) and red (High) (> a quarter of total habitat) risk ratings. That threshold was assessed qualitatively based on conceptual project design maps and written project descriptions.
    - Caribou are noted where relevant within WKA', but (to avoid doubling counting with the separate "caribou ranges" indicator) are not a key factor in determining ratings for the overall Wildlife Key Areas ratings indicator.
- For **Protected and Conservation Areas,** any projects with potential direct material effects within Protected and Conservation Areas were rated red (High). Projects with potential measureable indirect effects on Protected and Conservation Areas due to proximity were rated yellow (Medium). Projects with new access within 2 km of Protected and Conservation Areas were rated green (Low) if no indirect effects are expected, based on the potential negative effects of new human access.
- For **caribou ranges,** ratings focussed on amount of range affected, however, location of the project within the range, habitat type (e.g. calving vs general range), and population status of the herd were also considered. This indicator focuses specifically on caribou WKAs.

Ratings were modified from the general criteria outlined in Figure C 4-1 by a one class upgrade or downgrade for specific situations.

- One situation was for assumed design flexibility and mitigations. For example, where a transmission line was proposed in proximity to a rare plant occurrence, the risk rating was downgraded from red (high) to yellow (medium) to account for flexibility in pole locations to avoid occurrences of the plant.
- Another situation was consideration of the population status (size and trend) of caribou ranges. Ratings were increased by one category for caribou ranges that are very small or that are declining.
- Another situation for caribou was where proposed roads or transmission lines followed existing rights-of-way. In those circumstances, incremental effects of the new linear features were assumed to be minimal and the potential effects were rated green (low).

Assessment of Species at Risk (SAR) considered all species listed under Schedule 1 of the federal Species at Risk Act and all species listed as vulnerable (S3), imperiled (S2), or critically imperiled (S1) within

Yukon by the Yukon Conservation Data Centre (CDC). This included birds, mammals, amphibians, insects, and plants. The primary sources of information used to evaluate potential SAR occurrences near projects in this assessment were CDC species occurrence data and Wildlife Key Areas mapping. This information was supplemented with range and habitat association information from guidebooks (e.g. Birds of the Yukon), regional studies, and knowledge of local biologists. However, information about the ranges, distribution, and habitat associations of many SAR species across the project area is incomplete. Due to the large number of SAR species, incomplete knowledge of distribution and habitat associations of many SAR species, limited base habitat information available, and limited time associated with the strategic nature of this assessment, results of the assessment of Species at Risk & Habitat indicator should not be considered comprehensive. More detailed desktop reviews and field studies could find SAR occurrences not located as part of this assessment.

In the following evaluations for the resource project options, a summary of the key factors guiding the rating assignment is provided, including note of any modifying criteria. Where relevant, site specific differences among projects and indicators are noted.

Maps and data of Wildlife Key Areas and Protected and Conservation Areas were obtained from Geomatics Yukon (ftp://ftp.geomaticsyukon.ca/GeoYukon/Biological/Wildlife_Key_Areas_250k/ and ftp://ftp.geomaticsyukon.ca/GeoYukon/Base/Wetlands_50k/).

Caribou range maps were obtained from Troy Hegel (Biologist, Yukon Environment) and population estimates and trend were obtained from the Yukon State of the Environment Report (2014) (http://www.env.gov.yk.ca/publications-maps/stateenvironment.php).

4.2 EVALUATIONS

4.2.1 Resource Options with No Material Concerns re: Terrestrial Species & Habitat

The following resource project options have green (low or no linkage) ratings for each of the terrestrial species and habitat indicators:

- **Fossil Fuel Thermal Generation: Diesel and LNG**, each in Whitehorse ([landfill or Takhini substation locations]):
    - No linkage for En3-2, Wildlife Key Areas (En3-3) and Caribou Ranges (En3-4);
    - Green (low) for En3-1 (Species at Risk and Habitat) - No occurrences of SAR are known in vicinity of these sites. Species that may occur based on habitat and range are Olive-sided Flycatcher (both sites) and Short-eared Owl (Takhini substation); and
    - It is noted that other terrestrial species are valued in the Whitehorse landfill site area. McIntyre Creek and adjacent marsh and upland habitat is a known wildlife corridor (EDI 2011) that is located 1 km south of the project. Ridges along McIntyre Creek are used by raptors for migration and staging. The area, including the landfill, is used by a wintering population of Bald Eagles.

- **Non-fossil fuel thermal generation: Biogas and Waste to Energy**, each at Whitehorse locations (Biogas at Whitehorse landfill; Waste-to-energy site not known but in Whitehorse in area where other commercial/government/institutional activity to utilize waste heat):
    - No linkage for Protected and Conservation Areas (En3-2), Wildlife Key Areas (En3-3) and Caribou Ranges (En3-4);
    - Green (low) for En3-1 (Species at Risk and Habitat): No occurrences of SAR are known in vicinity of Whitehorse landfill or are expected at any likely Waste-to-Energy site in Whitehorse. Species that may occur based on habitat and range at the biogas site (Whitehorse landfill) are Olive-sided Flycatcher. No likely issue of concern for any site likely to be selected for Waste-to-energy option; and
    - It is noted that other terrestrial species are valued in the Whitehorse landfill site area (biogas site). McIntyre Creek and adjacent marsh and upland habitat is a known wildlife corridor (EDI 2011) that is located 1 km south of the project. Ridges along McIntyre Creek are used by raptors for migration and staging. The area, including the landfill, is used by a wintering population of Bald Eagles.
- **Energy Storage Facility** at Whitehorse (Takhini substation):
    - No linkage for Protected and Conservation Areas (En3-2) and Caribou Ranges (En3-4); and
    - Green (low) for En3-1 (Species at Risk and Habitat) and En3-3 (Wildlife Key Areas) The project footprint is anticipated to be within late winter moose habitat, but there is low risk based on small project footprint.
- **Solar PV** at Whitehorse (old mine quarry) and Haines Junction:
    - No linkage for Caribou Ranges (En3-4) at both sites and for Protected and Conservation Areas (En3-2) and Wildlife Key Areas (En3-3) at Whitehorse site;
    - Green (low) for En3-1 (Species at Risk and Habitat) at both sites as no occurrences of species of concern are known in the vicinity of each site (at Whitehorse site, species that may occur based on habitat and range are Common Nighthawk, which nests on exposed soil and sparsely vegetated sites);
    - Green (low) for En3-2 (Protected and Conservation Area) at Haines Junction due to possible visual effect concerns with proximity (700 m) to Kluane National Park; and
    - Green (low) for En3-3 (Wildlife Key Areas) at Haines Junction site, which is within late winter moose range WKA. Potential effects assumed to be negligible due to small footprint and location.
- **Mayo Lake Outlet Channel Dredging:**
    - No linkage for Protected and Conservation Areas (En3-2), Wildlife Key Areas (En3-3) and Caribou Ranges (En3-4); and
    - Green (low) for En3-1 (Species at Risk and Habitat). No occurrences of species of concern have been recorded within 500 m of the proposed project. Wildlife species that may occur based on habitat and range are Olive-sided Flycatcher, Barn Swallow, Bank

Swallow, and Common Nighthawk. Overall, project effects on Species at Risk and Habitat are expected to be low and mostly mitigatable via site-level BMPs.

- **Refurbishment / Maintenance: Aishihik Rerunnering, and Mayo A Refurbishment**
    - No linkage to any of the indicators, assuming BMPs and that all material work is located within each facility.

4.2.2 Non-Hydro Renewable Generation

4.2.2.1 Non-Fossil Thermal Generation - Wood Biomass

The Wood Biomass resource option assumes a 0.5 MW generating facility located in Haines Junction (near school and other existing activities for use of waste heat) and 3,000 oven dry tonnes (ODT)/year of wood biomass from local beetle kill areas (unspecified location, but assuming no change in existing harvesting areas).

For the biomass generating facility in Haines Junction, the ratings for terrestrial species and habitat indicators are all green (low or no linkage):

- No linkage for Caribou Ranges (En3-4): and
- Green (low) for Species at Risk and Habitat (En3-1), Protected and Conservation Areas (En3-2) and Wildlife Key Areas (En3-3):
    - No occurrences of SAR are known in the vicinity. Species that may occur based on habitat and range are Olive-sided Flycatcher.
    - For En3-2 (Protected and Conservation Areas), there are possible visual and air quality concerns associated with proximity of the project (700 m) to Kluane National Park.
    - For En3-3 (Wildlife Key Areas), the site is within late winter moose range WKA. Potential effects are assumed to be negligible due to small footprint and location.

Under the current instance of a 0.5 MW facility, the biomass supply is assumed primarily to be residues from existing forest harvesting and sawmill activities. If biomass supply results in incremental timber harvesting operations, that could have effects on biodiversity and individual focal species. However, a variety of coarse- and fine-filter, ecosystem-based, management strategies are available to mitigate timber harvesting effects.

Table C 4-2 presents the assessment of the harvesting operations on terrestrial species and habitat indicators.

Table C 4-2: Summary of Assessment for Wood Biomass (Timber Harvesting)

Project / Option	Indicator	Ranking	Assessment
Wood Biomass (Timber Harvesting Operations)	Species at Risk & Habitat	Low	Although harvest areas have not been spatially identified, associations of SAR with target forests are generally low. Species that may occur based on habitat and range are: Olive-sided Flycatcher, which are known to use beetle damaged forests. Potential effects to Olive-sided Flycatcher may be mitigated via stand and landscape level forest harvesting strategies.
	Protected & Conservation Areas	Low	Timber harvesting can be spatially managed to avoid PCA.
	Wildlife Key Areas	Medium	Beetle damaged stands in southwest Yukon occur within numerous WKAs, notably moose winter range. Timber harvesting and road construction could have several types of effects including habitat effects, disturbance and mortality by humans, and facilitated predation.
	Caribou Ranges	Low	Beetle damaged stands in southwest Yukon are largely outside caribou ranges. However, if harvesting does occur in caribou range, habitat effects of logging and disturbance and mortality by humans, and facilitated predation by natural predators could be High.

4.2.2.2 Wind Farms

Wind farms typically have three types of infrastructure that can affect terrestrial species and habitat: wind turbines and associated facilities, access roads, and transmission lines. The following are potential project effects associated with wind farms that were frequently noted during project evaluations. A summary of potential project-specific effects of wind farms are listed in Table C 4-3.

- Direct habitat effects associated with vegetation clearing and construction of roads, turbines, facilities, and transmission lines.
- Indirect effects that result in species avoiding project infrastructure as a result of sensory disturbance.
- Increased disturbance and mortality by humans, and facilitated predation by natural predators, associated with new linear features (roads and transmission lines).

Potential focal species vary by location but often include resident and migrating raptors (Golden Eagle, Peregrine Falcon, Short-eared Owl), migrating waterfowl, rare plants in grassland steppe habitats, and ungulate winter ranges. Although not highlighted for specific sites, other valued terrestrial species may be affected by turbines, new access and new transmission lines at most sites, e.g., alpine raptors and migrating birds passing through the area.

Table C 4-3: Summary of Assessment for Wind Farms

Project / Option	Indicator	Ranking	Assessment
Cyprus Mine Hill (central site, 10 turbines, access road and transmission line; also dependent on Faro-Watson Lake Transmission Line)	Species at Risk & Habitat	**Medium**	No occurrences of species of concern are known in vicinity. Alpine areas offer potential habitat for Short-eared Owl; turbines and transmission lines could reduce habitat effectiveness and present collision risk. Talus slopes offer potential habitat for Collared Pika; project could affect habitat.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Low**	Project occurs within early winter moose range WKA. Project would create new linear feature access onto Mount Aho that could result in increased disturbance and mortality by humans and facilitated predation by natural predators along the road and transmission line.
	Caribou Ranges	**Medium**	Project is in southwestern edge of Tay Caribou herd range. Project would create new linear feature access onto Mount Aho that could result in increased disturbance and mortality by humans and facilitated predation by natural predators. Turbines would have a small direct habitat effect and larger indirect effect via sensory disturbance.
Kluane Lake (central site, 10 turbines, access road and transmission line; also dependent on associated Transmission Lines)	Species at Risk & Habitat	**Medium**	Grizzly Bear are assumed to occur based on WKA designation (see below). Other species that may occur based on habitat and range are Olive-sided Flycatcher, Bank Swallow.
	Protected & Conservation Areas	**Medium**	Associated transmission line runs close to Kluane National Park and Kluane Wildlife Sanctuary and, under some options, might run through these protected areas. Rating may be reduced to Low depending on how project integrates with existing infrastructure.
	Wildlife Key Areas	**High**	Grizzly bear – spring, summer, fall range; project could have direct and indirect habitat effects; linear feature development could elevate risk of disturbance and mortality by humans. Moose late winter range; project could have direct and indirect habitat effects; linear feature development could affect risk of disturbance and mortality by humans, and result in facilitated predation risk.
	Caribou Ranges	**No Linkage**	
Miller's Ridge (central site, 10 turbines, access road and transmission	Species at Risk & Habitat	**Medium**	No occurrences of species of concern are known in vicinity, but risks of potential direct effects are noted. Grassland steppe ecosystems offer potential habitat for rare plants; BMP siting location mitigations to minimize effects to local plant occurrences are assumed to reduce rating to Low for such effects. Alpine areas offer suitable habitat for Short-eared Owl; turbines and transmission lines could reduce habitat effectiveness and present collision risk. Talus slopes may offer habitat for Collared Pika.

Project / Option	Indicator	Ranking	Assessment
line; also dependent on associated Transmission Lines)	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	Medium	The eastern section of transmission line intersects WKAs for Golden and Bald Eagles. Transmission line could reduce habitat effectiveness and be a collision risk. Turbines on ridge could also reduce habitat effectiveness for foraging and be a collision risk. Effects on Bald Eagle expected to be low to none.
	Caribou Ranges	Medium	Project is in southeastern edge of Klaza Caribou herd range. Project would create new linear feature access onto Miller's Ridge that could result in increased disturbance and mortality by humans and facilitated predation by natural predators along the road and transmission line. Turbines would have a small direct habitat effect and larger indirect effect via sensory disturbance.
Mt. Sumanik (central site, 10 turbines, access road and transmission line)	Species at Risk & Habitat	Medium	Collared Pika are known to occur in vicinity; project could affect habitat. Alpine areas offer suitable habitat for Short-eared Owl; turbines and transmission lines could reduce habitat effectiveness and present collision risk.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	High	Alpine raptor – summer reproduction WKA; turbines and transmission lines could reduce habitat effectiveness and present collision risk.
	Caribou Ranges	No Linkage	
Sugarloaf Mountain (central site, 10 turbines, access road and transmission line; also dependent on associated Transmission Lines)	Species at Risk & Habitat	Medium	No occurrences of species of concern are known in vicinity. Alpine areas offer potential habitat for Short-eared Owl; turbines and transmission lines could reduce habitat effectiveness and present collision risk. Talus slopes offer potential habitat for Collared Pika; project could affect habitat.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	High	Alpine raptor – summer reproduction WKA; turbines and transmission lines could reduce habitat effectiveness and present collision risk. Woodland Caribou – fall rut and winter range WKAs; project could have direct and indirect habitat effects and linear feature development could elevate risk of disturbance and mortality by humans, and facilitated predation by natural predators (however, note that roads and trails already exist in area).

Project / Option	Indicator	Ranking	Assessment
			Mountain Goat – year-round WKA; project could displace goats from cliffs north of installations (however habitat is marginal).
	Caribou Ranges	**Medium**	Project is within Carcross Caribou herd range. Project would create new linear feature access onto Montana Mountain that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators (however, note that roads and trails already exist in area). Turbines could have a small direct habitat effect and larger indirect effect via sensory disturbance.
Tehcho (Ferry Hill) (central site, 10 turbines, access road and transmission line; also dependent on associated Transmission Lines)	Species at Risk & Habitat	**Low**	No occurrences of species of concern are known in vicinity. Species that may occur based on habitat and range are: Olive-sided Flycatcher.
	Protected & Conservation Areas	**Low**	Devil's Elbow Habitat Protection Area is located 1.5 km to SE.
	Wildlife Key Areas	**Medium**	Black Bear – spring range; project could have direct and indirect habitat effects (however infrastructure avoids most high value habitat)
	Caribou Ranges	**No Linkage**	
Thulsoo Mountain (central site, 10 turbines, access road and transmission line; also dependent on associated transmission lines)	Species at Risk & Habitat	**Medium**	No occurrences of species of concern are known in vicinity. Alpine areas offer suitable habitat for Short-eared Owl; turbines and transmission lines could reduce habitat effectiveness and present collision risk. Talus slopes may offer habitat for Collared Pika.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Medium**	Bison – year-round core range; linear feature development could elevate risk of disturbance and mortality by humans, and facilitated predation by natural predators. Thin horn Sheep – winter range; turbines could have indirect habitat effects; linear feature development could elevate risk of disturbance and mortality by humans.
	Caribou Ranges	**No Linkage**	

4.2.2.3 Geothermal

The two proposed geothermal projects have three types of infrastructure that can affect Terrestrial Species and Habitat: the geothermal facilities, access roads, and transmission lines. Most potential effects were associated with the access roads and transmission lines. The following are potential project effects

associated with the geothermal projects that were noted during project evaluations. A summary of potential project-specific effects are listed in the Table C 4-4.

- Direct habitat effects associated with vegetation clearing and construction of facilities, roads, and transmission lines.
- Indirect effects that result in species avoiding project infrastructure as a result of sensory disturbance.
- Increased risk of disturbance and mortality by humans, and facilitated predation by natural predators associated with new linear features (roads and transmission lines).

Table C 4-4: Summary of Assessment for Geothermal

Project / Option	Indicator	Ranking	Assessment
McArthur Springs (facility plus 43 km access road and transmission line)	Species at Risk & Habitat	Low	No occurrences of species of concern are known in vicinity. Species that may occur based on habitat and range are: Olive-sided Flycatcher.
	Protected & Conservation Areas	High	Facility and approximately 13 km of road and transmission line occur within Ddhaw Ghro Habitat Protection Area.
	Wildlife Key Areas	Medium	Woodland Caribou - winter range; project would create 43 km of new linear feature access that could result in increased disturbance and mortality by humans and facilitated predation by natural predators.
	Caribou Ranges	Medium	Project is within Ethel Lake Caribou herd range. Project would create 43 km of new linear feature access that could result in increased disturbance and mortality by humans and facilitated predation by natural predators.
Vista Mountain	Species at Risk & Habitat	Low	No occurrences of species of concern are known in vicinity. Species that may occur based on habitat and range are: Olive-sided Flycatcher.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	No Linkage	
	Caribou Ranges	No Linkage	

4.2.3 Hydro Renewable Generation

Hydro renewable projects, including pumped storage, small hydro, enhanced storage and the Gladstone Diversion, typically have four types of infrastructure that can affect terrestrial species and habitat: dams and associated facilities, reservoirs that flood terrestrial habitat and affect shoreline dynamics, access roads, and transmission lines. The following are potential project effects associated with hydro renewable projects that were frequently noted during project evaluations. A summary of potential project-specific effects are listed in the following tables.

- Direct habitat effects associated with reservoirs flooding terrestrial habitats and wetlands, and affecting shoreline dynamics.
- Increased risk of disturbance and mortality by humans, and facilitated predation by natural predators, associated with new linear features (roads and transmission lines).

Potential focal species vary by location but often include resident and migrating water birds, rare plants, and moose winter ranges.

4.2.3.1 Pumped Storage

The range of pumped storage site options are reviewed below in Table C 4-5.

Table C 4-5: Summary of Assessment for Pumped Storage

Project / Option	Indicator	Ranking	Assessment
Atlin – Black Mountain (reservoir, penstock, transmission line; also dependent on associated transmission line)	Species at Risk & Habitat	Medium	No Data (BC). Wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, and Western Toad. Reservoir development could directly affect habitat of latter four species.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	Medium	Thin horn Sheep – Ungulate Winter Range (BC); project construction could displace sheep and have indirect habitat effects. *
	Caribou Ranges	Medium	Project is within Atlin and Carcross Caribou herd ranges. Project would have relatively small direct and indirect habitat effects (further study could possibly downgrade rating to Low based on small extent of footprint).
	*New access roads are not specified; if required, new roads could result in increased disturbance and mortality by humans to thin horn Sheep and, depending on location, could increase rating to high.		
Canyon –	Species at	Medium	No occurrences of species of concern are known in vicinity. Wildlife

Project / Option	Indicator	Ranking	Assessment
Ittlemit (reservoir, penstock, transmission line; also dependent on associated transmission line)	Risk & Habitat		species that may occur based on habitat and range are: Olive-sided Flycatcher, Bank Swallow, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, and Short-eared Owl. Reservoir development could directly affect habitat of latter 5 species.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Medium**	Bison – year-round core range; elevated water levels could affect foraging habitat.* Thin horn Sheep – spring lambing; project not likely to have any significant effects. * Golden Eagle – summer breeding; elevated water levels could affect prey habitat. Bald Eagle – summer breeding; elevated water levels could affect riparian nesting habitat and prey (fish). Mule Deer – year-round range; project not likely to have any significant effects.
	Caribou Ranges	**No Linkage**	
	*New access roads are not specified; if required, new roads could result in increased disturbance and mortality by humans to Bison and thin horn Sheep and, depending on location, could increase rating to high.		
Lindeman – Fraser (reservoir, penstock, transmission line; also dependent on associated transmission line)	Species at Risk & Habitat	**Medium**	No occurrences of species of concern are known in vicinity. Wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Bank Swallow, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, Common Nighthawk, and Western Toad. Reservoir development could directly affect habitat of latter 6 species.
	Protected & Conservation Areas	**High**	Within Chilkoot Trail National Historic Site.
	Wildlife Key Areas	**Medium**	Carcross Caribou – fall rutting habitat. Project would create 5 km of new linear feature access that could result in increased disturbance and mortality by humans and facilitated predation by natural predators.
	Caribou Ranges	**Medium**	Project is within Carcross Caribou herd range. Project would create 5 km of new linear feature access that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.

Project / Option	Indicator	Ranking	Assessment
Racine – Moon (reservoir, penstock, transmission line; also dependent on associated transmission line)	Species at Risk & Habitat	**Medium**	No data (BC). Wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Bank Swallow, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, Common Nighthawk, and Western Toad. Reservoir development could directly affect habitat of latter six species.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Medium**	Carcross Caribou – fall rutting habitat and winter range. Project would create 21 km of new linear feature access that could result in increased disturbance and mortality by humans and facilitated predation by natural predators. Mountain Goat – year-round range; project construction could have disturbance effects. * Thin horn Sheep – Ungulate Winter Range (proposed, BC); project construction could have disturbance effects. *
	Caribou Ranges	**Medium**	Project is within Carcross Caribou herd range. Project would create 21 km of new linear feature access that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.
	*New access roads are not specified; if required, new roads could result in increased disturbance and mortality by humans to Mountain Goats and Thin horn Sheep and, depending on location, could increase rating to high.		
Racine – Mt. Brown (reservoir, penstock, transmission line; also dependent on associated transmission line)	Species at Risk & Habitat	**Medium**	No data (BC). Wildlife species that may occur based on habitat and range are: Banks Swallow, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, Common Nighthawk, and Western Toad. Reservoir development could directly affect habitat of all species.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Medium**	Carcross Caribou – fall rutting habitat and winter range. Project would create 24 km of new linear feature access that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators. Mountain Goat – year-round range; project construction could have disturbance effects. * Thin horn Sheep – Ungulate Winter Range (proposed, BC); project construction could have disturbance effects. *
	Caribou Ranges	**Medium**	Project is within Carcross Caribou herd range. Project would create 24 km of new linear feature access that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators

Project / Option	Indicator	Ranking	Assessment
	*New access roads are not specified; if required, new roads could result in increased disturbance and mortality by humans to Mountain Goats and thin horn Sheep and, depending on location, could increase rating to high.		
Squanga – Dalayee (reservoir, penstock, transmission line)	Species at Risk & Habitat	**Medium**	No occurrences of terrestrial species of concern are known in vicinity. Terrestrial wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Bank Swallow, Horned Grebe, Red-necked Phalarope, and Rusty Blackbird. Reservoir development could directly affect habitat of latter four species.
	Protected & Conservation Areas	**Medium**	Elevated water level in Dalayee Lake would affect Agay Mene Natural Environment Park. Rating downgraded from high due to limited effect on edge of Park.
	Wildlife Key Areas	**High**	Carcross Caribou - fall rutting habitat and winter range. Project would create 8 km of new linear features (penstock) that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators. Waterfowl – summer breeding and fall staging; changes in water levels could affect breeding and staging habitat. Bald Eagle – summer breeding; changes in water levels could affect riparian nesting habitat and prey (fish). High (red) rating reflects direct mechanism of potential effects and extent of effects on WKAs for three species.
	Caribou Ranges	**Medium**	Project is within Carcross Caribou herd fall rutting habitat and winter range. Project would create 8 km of new linear features (penstock) that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.
Tutshi – Moon	Species at Risk & Habitat	**Medium**	No data (BC). Species that may occur based on habitat and range are: Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, Common Nighthawk, and Western Toad. Reservoir development could directly affect habitat of latter six species.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Medium**	Carcross Caribou - fall rutting habitat and winter range. Project would create linear features that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators. Mountain Goat – year-round range; project construction could have disturbance effects; new roads could result in increased disturbance and mortality by humans. Thin horn Sheep – Ungulate Winter Range (proposed, BC); project construction could have disturbance effects; new roads could result in increased disturbance and mortality by humans.
	Caribou	**Medium**	Project is within Carcross Caribou herd fall rutting habitat and winter

Project / Option	Indicator	Ranking	Assessment
	Ranges		range. Project would create linear features that could result in increased disturbance and mortality by humans and facilitated predation by natural predators.
Faro – Vangorda Pit	Species at Risk & Habitat	Low	No occurrences of terrestrial species of concern are known within project ZOI. An occurrence of Mount Sheldon Ragwort is recorded 6 km north of the reservoir and Canada Darner has been recorded 2 km east. Other species that may occur based on habitat and range are: Olive-sided Flycatcher. Grass steppe areas in the vicinity are candidates for rare plant species.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	Medium	Thin horn Sheep – movement corridor; project could directly affect movement corridor.
	Caribou Ranges	Medium	Project is in southwestern edge of Tay Caribou herd range. Project would have limited direct habitat effects.

4.2.3.2 Small Hydro

The range of small hydro site options are reviewed below in Table C 4-6.

Table C 4-6: Summary of Assessment for Small Hydro

Project / Option	Indicator	Ranking	Assessment
Drury Lake	Species at Risk & Habitat	Medium	No occurrences of species of concern are known in vicinity. Wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Short-eared Owl, Horned Grebe, Red-necked Phalarope, and Rusty Blackbird. Reservoir development could directly affect habitat of latter three species.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	No Linkage	
	Caribou Ranges	Low	Southeast edge of Tatchun Caribou Herd range; project is expected to have minimal incremental effects to existing development.
Finlayson River	Species at Risk & Habitat	Medium	Rusty Blackbird and Barn Swallow have been documented in area. Other species that may occur based on habitat and range are: Olive-sided Flycatcher, Short-eared Owl, Horned Grebe, and Red-necked Phalarope. Changes in water levels in reservoir lakes and Finlayson River could directly affect habitat of latter two species and Rusty Blackbird.

Project / Option	Indicator	Ranking	Assessment
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	Medium	Finlayson Caribou – fall rutting habitat and winter range. Project would create new linear feature access that could result in increased disturbance and mortality by humans and facilitated predation by natural predators. Moose – late winter range; project could directly affect habitat by flooding habitat; new linear feature access could result in increased disturbance and mortality by humans and facilitated predation by natural predators. Thin horn Sheep – winter, rutting and lambing range; new roads could result in increased disturbance and mortality by humans.
	Caribou Ranges	Medium	Within Finlayson Caribou Herd range; project would create new linear feature access could result in increased disturbance and mortality by humans and facilitated predation by natural predators.
Atlin/Pine Creek	Species at Risk & Habitat	Medium	No occurrences of species of concern are known in vicinity. Wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Bank Swallow, Barn Swallow, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, and Short-eared Owl. Reservoir development could directly affect habitat of latter six species.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	No Linkage	
	Caribou Ranges	Low	Within Atlin Caribou Herd range; based on existing development in area, project would have minimal incremental effects to existing development.
Tutshi – Windy Arm	Species at Risk & Habitat	Medium	No data (BC). Species that may occur based on habitat and range are: Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, Common Nighthawk, and Western Toad. Reservoir development could directly affect habitat of all six species.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	Medium	Carcross Caribou - fall rutting habitat and winter range. Project would create new linear feature access that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators. Mountain Goat – year-round range; project construction could have disturbance effects; new roads could result in increased disturbance

Project / Option	Indicator	Ranking	Assessment
			and mortality by humans. Thin horn Sheep – Ungulate Winter Range (proposed, BC); project construction could have disturbance effects; new roads could result in increased disturbance and mortality by humans.
	Caribou Ranges	**Medium**	Project is within Carcross Caribou herd fall rutting habitat and winter range. Project would create linear features that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.
Wolf River	Species at Risk & Habitat	**Medium**	Northern Mudwort occurrence within Nisutlin National Wildlife Area (NWA). Other species that may occur based on habitat and range are: Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, Common Nighthawk, and Western Toad. Transmission line may present collision risk to birds in area.
	Protected & Conservation Areas	**Medium**	Access road and transmission line run along edge of Nisutlin River Delta NWA; road access may increase disturbance and mortality by humans to wildlife in NWA; transmission line may present collision risk to water birds in NWA.
	Wildlife Key Areas	**Medium**	Moose – late winter range; new linear features could result in increased disturbance and mortality by humans, and facilitated predation by natural predators. Muskrat – year-round all functions; changes to water flows could affect species (low risk). Bald Eagle – summer breeding; transmission lines could present collision risk. Waterfowl – summer breeding; transmission lines could present collision risk. Swan – summer breeding; transmission lines could present collision risk.
	Caribou Ranges	**Low**	On edge of Wold Lake Caribou Herd range; new linear features could result in increased disturbance and mortality by humans, and facilitated predation by natural predators; effects likely to be low due to limited overlap with range.
Anvil Creek	Species at Risk & Habitat	**Medium**	One species of conservation concern has been documented in the area, Canada Darner, a dragonfly. Other wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Short-eared Owl, Horned Grebe, Red-necked Phalarope, Rusty Blackbird. Changes in water levels in Anvil Lake and the outlet stream could directly affect habitat of latter 3 species and Canada Darner.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Low**	The transmission line intersects a Thin horn Sheep movement corridor across Blind Creek; project could result in incremental disturbance and mortality by humans along the transmission line.

Project / Option	Indicator	Ranking	Assessment
	Caribou Ranges	**Medium**	Project is in southwestern edge of Tay Caribou herd range. Project would have limited direct habitat effects and create 19 km of new linear features that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.

4.2.3.3 Gladstone Diversion

The Gladstone Diversion involves dams to raise water levels in or to divert flows into the Aishihik Lake existing hydro generation. Table C 4-7 summarizes the assessment of terrestrial species and habitat effects.

Table C 4-7: Summary of Assessment for Gladstone Diversion

Project / Option	Indicator	Ranking	Assessment
Gladstone Diversion	Species at Risk & Habitat	High	Three occurrences of species of concern have been recorded within 500 m of the proposed project: Dawson Wallflower, Rock Wormwood, and Pale Comandra. Other wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Peregrine Falcon, Short-eared Owl, Common Nighthawk, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Sharp-tailed Grouse, Grizzly Bear, and Collared Pika. Reservoir development could flood two occurrences of rare plants and affect habitat for Horned Grebe, Red-necked Phalarope, Rusty Blackbird, Short-eared Owl, and Common Nighthawk.
	Protected & Conservation Areas	No Linkage	
	Wildlife Key Areas	High	The project overlaps with 16 Wildlife Key Areas: • Woodland Caribou – fall rutting and winter range (6). • Moose – late winter range (1). • Thin horn Sheep – winter range (2). • Bison – annual core range (1). • Ungulate miner lick (2). • Golden Eagle, Gyrfalcon, Peregrine Falcon – summer breeding (5). Potential project effects include: • New linear features could result in increased disturbance and mortality by humans, and facilitated predation by natural predators, on ungulates. • Disturbance effects on nesting raptors. • Disturbance and indirect habitat effects on thin horn Sheep. o Effects may be partially mitigated by route selection. • Disturbance and habitat effects on ungulate mineral licks. o Effects may be partially mitigated by infrastructure siting locations.
	Caribou Ranges	Medium	The project occurs within the Aishihik Caribou Herd range. New linear features could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.

4.2.3.4 Hydro Storage Enhancements

Hydro storage enhancement projects will utilize existing road and transmission corridors and generally not involve new structures or any increase in flooded areas. Therefore, project effects are primarily related to changes in water levels during different seasons or years. Table C 4-8 provides a summary of the assessment of effects on terrestrial species and habitat for the two hydro storage enhancement projects.

Table C 4-8: Summary of Assessment for Hydro Storage Enhancements

Project / Option	Indicator	Ranking	Assessment
Mayo Lake Enhanced Storage	Species at Risk & Habitat	**Medium**	No occurrences of species of concern are known in vicinity. Wildlife species that may occur based on habitat and range with habitat that could be affected by changes in water levels include Common Nighthawk, Horned Grebe, Red-necked Phalarope, and Rusty Blackbird.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Low**	Bald Eagle – summer breeding; changes in water levels could affect riparian nesting habitat and foraging habitat in lake.
	Caribou Ranges	**No Linkage**	
Southern Lakes Enhanced Storage	Species at Risk & Habitat	**High**	Twelve occurrences of species of concern have been recorded within 500 m of the proposed project: Barn Swallow, Buff-breasted Sandpiper, Collared Pika, Columbia Spotted Frog, Dune Tachnid Fly, Muskeg Emerald, Baikal Sedge, Water Awlwort, Water Pygmyweed, and Slim-leaved Goosefoot. Other wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Peregrine Falcon, Bank Swallow, Short-eared Owl, Common Nighthawk, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, and Western Toad. Changes in water levels could affect habitat and/or forage for most of the known and potential species of concern.
	Protected & Conservation Areas	**High**	The project overlaps the Lewes Marsh and Tagish Narrows Habitat Protection Areas (HPAs). Changes in water levels associated with the project could affect wetland habitats within the HPAs.
	Wildlife Key Areas	**High**	The project overlaps with 72 Wildlife Key Areas: • Woodland Caribou: fall rutting and winter range (25). • Moose: late winter range (1). • Thin horn Sheep: winter range and spring lambing (3). • Mountain Goat: annual range (20). • Muskrat: annual habitat (2). • Bald Eagle: summer nesting (4). • Golden Eagle, Gyrfalcon, alpine Raptor: summer breeding (8). • Waterfowl, Swan, Duck – spring and fall staging, summer

Project / Option	Indicator	Ranking	Assessment
			breeding (12, 8 noted as national / international significance). Potential project effects include: • Changes in water level that could affect. o Staging and breeding habitat for water birds; o Habitat and overwintering conditions for muskrats; and o Riparian nesting habitat and prey (fish) for Bald Eagle and Osprey. • Effects to riparian and wetland vegetation in moose winter range. • Changes in distribution and abundance of water birds as prey for raptors. • Minimal project effects expected on caribou, sheep, goats.
	Caribou Ranges	Low	The project overlaps with the Carcross Caribou Herd range and, peripherally, with the Idex Caribou Herd range. The project would have minimal incremental effects to existing development.

4.2.4 Transmission Corridors

Due to the long, linear nature of transmission corridors these projects tend to have the highest degree of overlap with terrestrial species and habitat indicators. However, the mechanism and magnitude of effects on terrestrial species and habitats is relatively low in most circumstances, in part due to best management practices (including routing to avoid specific concerns) and in part due to the nature of the disturbance caused by a transmission line.

The primary factors associated with transmission line development on terrestrial species and habitat are removal of tree and shrub cover within the right-of-way and installation of power poles and transmission lines. A small area of site disturbance (clearing down to mineral soil) is also associated with power pole installation and construction access. The long (10s to 100s of km), narrow (<100 m) shape of transmission line corridors has specific effects associated with terrestrial species. For most mid- to large-wildlife species, at the individual territory or home range level, the right-of-way represents a narrow break in natural vegetation that most species will simply travel across. Prey species, especially smaller species, may be reluctant to cross the right-of-way, similar to how they avoid natural areas that lack cover. At larger scales, the transmission corridors may function as new access corridors. This includes human access, which could result in increased disturbance and direct mortality by humans on certain wildlife (notably ungulates). Transmission corridors may also be used by wolves for enhanced travel and hunting resulting in facilitated predation. Transmission corridors may also facilitate the spread of invasive species.

Often, potential site-specific effects of transmission line development on terrestrial species, such as effects on ungulates using a mineral lick or a rare plant occurrence, can be avoided by route selection, power pole location, and site-level BMPs. Where new transmission lines are located along existing highway or utility rights-of-way the incremental effects of the new lines are much reduced compared to completely new lines.

The following are potential project effects associated with transmission corridors that were frequently noted during project evaluations. A summary of potential project-specific effects are listed in the Table C 4-9.

- Transmission corridors may result in new human access that could result in disturbance and mortality (i.e., hunting) to certain wildlife species. This effect is most likely to occur where the transmission corridors occur in proximity to high use wildlife areas, such as ungulate winter ranges or escape terrain for mountain goats and tinhorn sheep. Information sources that identified potential areas where this effect is more likely to occur include WKAs and caribou ranges.
- Transmission corridors may provide travel corridors that elevate natural predation by wolves by allowing them to hunt more effectively under certain circumstances.[3] Information sources that identified potential areas where this effect is more likely to occur include WKAs and caribou ranges.
- Transmission corridors may directly affect high value terrestrial species habitat or provide new access that could result in disturbance effects to wildlife concentration areas. Information sources that identified where this effect is more likely to occur include Parks and Conservation Areas, species occurrence locations from the Conservation Data Centre, and wildlife key areas.
- Power lines can be a source of avian mortality as a result of collisions and electrocution. This effect is elevated where birds with large wing spans congregate. Information sources that identified where this effect is more likely to occur include Parks and Conservation Areas and WKAs.

[3] This situation is often referred to as facilitated predation.

Table C 4-9: Summary of Assessment for Transmission Corridors

Project / Option	Indicator	Ranking	Assessment
Aishihik – Destruction Bay	Species at Risk & Habitat	Low	Fourteen occurrences of species of concern have been recorded within 500 m of the proposed project. These include Rusty Blackbird, Yukon Grasshopper, Yukon Draba, Narrow-leaved Moonwort, Rock Wormwood, Yukon Aster, Pale Comandra, Many-headed Sedge, and Winterfat. Other wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Peregrine Falcon, Short-eared Owl, Common Nighthawk, and Sharp-tailed Grouse. Overall, project effects on Species at Risk are expected to be low and mostly mitigatable via route selection and site-level BMPs.
	Protected & Conservation Areas	High	A portion of the project is assumed to run through Kluane National Park and Kluane Wildlife Sanctuary. Options are noted for a route to avoid the park.
	Wildlife Key Areas	Medium	The project overlaps with 43 Wildlife Key Areas: • Grizzly Bear – spring, summer and fall range (7). • Moose – late winter range (7). • Mountain Goat – annual range (2); project is on edge of WKA, no escape terrain is affected. • Mule Deer – annual range (2). • Thin horn Sheep – winter range (3). • Swan – fall staging (2). • Bald Eagle, Osprey – summer breeding (1). • Peregrine Falcon – summer breeding (1). • Sharp tailed Grouse – year-round habitat (6). Potential project effects include: • Transmission line right-of-way (ROW) may provide suitable forage for grizzly bears that could result in elevated risk of human interactions and vehicle collisions. • New linear features could result in increased disturbance and mortality by humans, and facilitated predation by natural predators, on ungulates. o Effects can be partially mitigated by overlapping route with existing highway and utility ROW. • Collision risk for nesting and migrating raptors and swans. o Effects can be partially mitigated by route selection and visual deterrents • Indirect habitat effects on Sharp-tailed Grouse. o Effects may be partially mitigated by route selection.
	Caribou Ranges	Low	The project has very limited overlap with the Kluane Caribou Herd range. Potential project would have minimal incremental effects to existing development.

Project / Option	Indicator	Ranking	Assessment
Faro – Watson Lake	Species at Risk & Habitat	**Low**	Twenty one occurrences of species of concern have been recorded within 500 m of the proposed project. These include Rusty Blackbird, Barn Swallow, Woodchuck, Raups's Willow, Yukon Goldenweed, Shadow Darner, Siberian Polypod Additional species that may occur based on habitat and range are: Olive-sided Flycatcher, Peregrine Falcon, Short-eared Owl, Common Nighthawk, and Western Toad (southern extent only). Overall, project effects on SAR are expected to be low and mostly mitigatable via route selection and site-level BMPs.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Medium**	The project overlaps with 23 WKAs: • Moose – late winter range and mineral licks. • Thin horn Sheep – winter range, mineral licks, migration corridor. • Caribou – fall rutting, winter range, and mineral licks. • Bald Eagle, Osprey, Golden Eagle, Peregrine Falcon – summer breeding. Potential project effects include: • Linear features that could result in increased disturbance and mortality by humans and facilitated predation by natural predators on ungulates. o Effects can be partially mitigated by overlapping route with existing highway ROW. • Habitat and disturbance effects at mineral licks. o Effects can be largely mitigated by route selection. • Collision risk for nesting raptors. o Effects can be partially mitigated by route selection and visual deterrents.
	Caribou Ranges	**High**	The project overlaps with five Caribou Herd ranges: Tay, Pelly (limited overlap), Finlayson, Horseranch and Little Rancheria. Development of the transmission line would create a new linear feature that could result in increased disturbance and mortality by humans, and facilitated predation by natural predators. The High rating is based on the large linear extent of the project. Potential effects could potentially be reduced to Medium or Low if the project as finally planned followed the nearby highway ROW to a greater extent (the footprint as provided is offset from the highway ROW for most of its length).
Whitehorse – Atlin	Species at Risk & Habitat	**Low**	Four occurrences of species of concern have been recorded within 500 m of the proposed project. These include Common Nighthawk, Barn Swallow, Dune Tachnid Fly, and Dryland Sedge. Other wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Rusty Blackbird, Short-eared Owl, and Western Toad. Overall, project effects on Species at Risk are expected to be low and mostly mitigatable via route selection and site-level BMPs.

Project / Option	Indicator	Ranking	Assessment
	Protected & Conservation Areas	**Medium**	The project runs just inside Agay Mene Natural Environment Park and outside Lewes Marsh Habitat Protection Area, along existing highway ROW. New transmission lines may pose a collision risk to concentrations of birds at Lewes Marsh.
	Wildlife Key Areas	**Medium**	The project overlaps with 37 Wildlife Key Areas: • Moose – late winter range (3). • Woodland Caribou – fall rutting and winter range (16). • Mountain Goat – year-round (2); project is on edge of WKA, no escape terrain is affected. • Muskrat – year-round (2). • Bald Eagle, Osprey, Riparian Raptor– summer breeding (3). • Golden Eagle – summer breeding (2). • Waterfowl, Swan– spring and fall staging, summer breeding (9, 4 noted as national/international significance). Potential project effects include: • New linear features could result in increased disturbance and mortality by humans, and facilitated predation by natural predators, on ungulates. o Effects expected to be minimal because route follows existing highway and utility ROW. • Collision risk for nesting and migrating raptors and waterfowl. o Effects can be partially mitigated by route selection and visual deterrents. • No effects expected for Muskrat.
	Caribou Ranges	**Low**	The project overlaps with three Caribou Herd ranges: Carcross, Atlin, and Laberge (peripheral). Most of the project utilizes existing highway and utility ROW, and would have minimal incremental effects to existing development. Small sections of new linear feature development could result in increased disturbance and mortality by humans and facilitated predation by natural predators.
Whitehorse – Skagway	Species at Risk & Habitat	**Low**	Eight occurrences of species of concern have been recorded within 500 m of the proposed project. These include Common Nighthawk, Collared Pika, Dune Tachnid Fly, Muskeg Emerald, Baikal Sedge, and Water Pygmyweed. Species that may occur based on habitat and range are: Olive-sided Flycatcher, Rusty Blackbird, Short-eared Owl, Common Nighthawk, and Western Toad. Overall, project effects on Species at Risk are expected to be low and mostly mitigatable via route selection and site-level BMPs.
	Protected & Conservation Areas	**No Linkage**	
	Wildlife Key Areas	**Medium**	The project overlaps with 30 Wildlife Key Areas: • Moose – late winter range (1). • Mountain Goat – annual range (4); project is on edge of WKAs, no escape terrain is affected.

Project / Option	Indicator	Ranking	Assessment
			• Thin horn Sheep – spring lambing (1). • Woodland Caribou – fall rutting and winter range (19). • Swan and waterfowl– spring staging (2). • Bald Eagle and Osprey– summer breeding (2). • Alpine Raptor – summer breeding (1). Potential project effects include: • New linear features could result in increased disturbance and mortality by humans and facilitated predation by natural predators on ungulates. o Effects can be substantially mitigated by overlapping route with existing highway and utility ROW. • Collision risk for nesting and migrating raptors and waterfowl. o Effects can be partially mitigated by route selection and visual deterrents.
	Caribou Ranges	**Low**	The project overlaps with one Caribou Herd range, the Carcross Caribou Herd. Most of the project utilizes existing highway and utility ROW, and would have minimal incremental effects to existing development. Small sections of new linear feature development could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.
Whitehorse – Teslin	Species at Risk & Habitat	**Low**	Five occurrences of species of concern have been recorded within 500m of the proposed project. These include Common Nighthawk, Barn Swallow, and Elko Paintbrush. Additional wildlife species that may occur based on habitat and range are Olive-sided Flycatcher, Rusty Blackbird, and Short-eared Owl. Overall, project effects on SAR are expected to be low and mostly mitigatable via route selection and site-level BMPs.
	Protected & Conservation Areas	**Low**	The project runs just outside Agay Mene Natural Environment Park and Lewes Marsh Habitat Protection Area, along existing highway ROW. New transmission lines may pose a collision risk to concentrations of birds at Lewes Marsh.
	Wildlife Key Areas	**Medium**	The project overlaps with 42 Wildlife Key Areas: • Moose – late winter range (2). • Woodland Caribou – fall rutting and winter range (16). • Ungulate – mineral lick (1). • Muskrat – year-round (4). • Beaver – year-round (2). • Bald Eagle, Osprey, Riparian Raptor– summer breeding (5). • Golden Eagle – summer breeding (1). • Waterfowl, Swan– spring and fall staging, summer breeding (11, 4 noted as national/international significance). Potential project effects include: • New linear features could result in increased disturbance and mortality by humans and facilitated predation by natural predators on ungulates.

Project / Option	Indicator	Ranking	Assessment
			o Effects expected to be minimal because route follows existing highway and utility ROW. • Potential habitat and disturbance effects at mineral licks. o Effects expected to be largely mitigated by route selection. • Collision risk for nesting and migrating raptors and waterfowl. o Effects can be partially mitigated by route selection and visual deterrents. No effects expected for Muskrat and Beaver.
	Caribou Ranges	**Low**	The project overlaps with three Caribou Herd ranges: Carcross, Atlin (peripheral), and Laberge (peripheral). Most of the project utilizes existing highway and utility ROW, and would have minimal incremental effects to existing development. Small sections of new linear feature development could result in increased disturbance and mortality by humans, and facilitated predation by natural predators.
Stewart River – Keno	Species at Risk & Habitat	**Low**	Three occurrences of species of concern have been recorded within 500 m of the proposed project. These include Collared Pika, Slack Sedge, and Hudson Bay Sedge. Additional wildlife species that may occur based on habitat and range are: Olive-sided Flycatcher, Horned Grebe, Red-necked Phalarope, Rusty Blackbird, and Short-eared Owl. Overall, project effects on SAR are expected to be low and mostly mitigatable via route selection and site-level BMPs.
	Protected & Conservation Areas	**Low**	The project runs just outside Devil's Elbow Habitat Protection Area, along existing road ROW. New transmission lines may pose a collision risk to concentrations of birds using the HPA.
	Wildlife Key Areas	**Medium**	The project overlaps with 6 Wildlife Key Areas: • Black Bear – spring range (1). • Bald Eagle raptor– summer breeding (2). • Golden Eagle – summer breeding (1). • Waterfowl – summer breeding and moult (3). Potential project effects include: • New linear features could result in increased disturbance and mortality by humans to black bears. o Effects expected to be minimal because route follows existing highway and utility ROW. • Collision risk for nesting and migrating raptors and waterfowl. o Effects can be partially mitigated by route selection and visual deterrents.
	Caribou Ranges	**No Linkage**	

5.0 TERRESTRIAL FOOTPRINT & LAND USE

5.1 RATING CRITERIA AND DATA SOURCES FOR EN-4: TERRESTRIAL FOOTPRINT AND LAND USE

The rating system outlined in Figure C 5-1 was adopted to guide evaluations of each resource project option for each of the Terrestrial Footprint & Land Use indicators.

Figure C 5-1: Summary of Assessment Rating Criteria for Terrestrial Footprint & Land Use

Indicator	Low	Medium	High
Footprint Terrestrial Area including access & new flooding (Total km2) (En4-1)	< 0.5 km^2	0.5-1.0 km^2	> 1.0 km^2
Linear Development for roads, transmission (km) (En4-2)	< 10 km	10 – 100 km	> 100 km
Permafrost (En4-3)	< 2 km^2 affected by project, or no linkage to permafrost	>2 km^2 affected by project	Permafrost potential to be a material constraint to project
Wetlands (En4-4)	< 0.1 km^2 affected by project or no linkage to wetlands	0.1– 1.0 km^2 affected by project	> 1.0 km^2 affected by project or other potential for major concern

Indicators for Terrestrial Footprint and Land Use were selected to highlight the range of two terrestrial footprint indicators (Footprint Terrestrial Area and Linear Development distance) for the various project resource options, and to quantify the extent of potential project effects and overlap with two types of potentially sensitive environmental areas: Permafrost and Wetlands.

The following are noted regarding the rating scheme and thresholds used for the assessment:

- **Terrestrial Area Footprint (En4-1):** Estimates of terrestrial area footprints include all project components including facilities, access roads, transmission corridors, and, for hydro-related projects, new flooding (i.e., existing water areas were not included). Where the sizes of certain project components were not specified in the project description, industry standard right-of-way widths and buffer sizes were used (Table CA 2-1). For flooded areas, the estimated area from the project description was used. No new hydrological modelling was conducted to estimate the footprints associated with water level changes. Footprint areas were summed for all components within projects (e.g. area of facilities plus area of new roads plus area of transmission corridors).[4] These footprint assessments do not provide any information as to which valued terrestrial

[4] Estimated footprint areas for Terrestrial Area Footprint (En4-1) do not correspond to the areas estimated for Footprint Land Area Impact (S2-1), reflecting differences in assumptions and methods used to develop each estimate.

components may be affected by each project or resource option. The rating criteria were selected simply to help assign resource projects to clearly separate groups based on this indicator.

- **Linear Development for Roads and Transmission (En4-2):** Linear developments primarily consist of access roads and transmission corridors. Lengths of all linear developments were summed for all components within projects (e.g. length of roads plus length of transmission corridors). These linear footprint assessments do not provide any information as to which valued terrestrial components may be affected by each project or resource option. The rating criteria were selected simply to help assign resource projects to clearly separate groups based on this indicator.

- **Permafrost (En4-3):** Potential project effects associated with permafrost were estimated by assessing the extent of overlap between the Terrestrial Area Footprint and modelled permafrost occurrence. The permafrost model that was used was the Yukon Permafrost Probability Map (Bonnaventure et al. 2012). The permafrost area was calculated by weighting the Terrestrial Area Footprint (En4-1) by the modelled probability of permafrost occurring. This method may dilute the extent by which a specific permafrost effect area may be concentrated in a material portion of the project footprint area. The dominant permafrost class (isolated patches [<10%], sporadic discontinuous [10-50%], extensive discontinuous [50-90%], or continuous [>90%) was also noted for each project.

  This evaluation was from the perspective of potential environmental effects associated with permafrost degradation affected by the projects. Construction and engineering factors associated with project development and permafrost were not considered as part of this assessment. Also, the effects of permafrost change associated with climate change were not considered in this assessment due to the complexity and uncertainty of those patterns of permafrost change. However, planners should be aware that widespread changes to permafrost are occurring across the planning area. Those changes have effects from site-level to regional scales, and could have significant effects for each project, depending on the local distribution of permafrost.

  Notwithstanding the uncertainty associated with regional changes in permafrost, no red (high) ratings were applied, reflecting the lack of evidence that permafrost related issues would pose a material constraint to any project, in terms of potential environmental effects. A threshold of 200 ha (2 km^2) was selected to classify projects as green (low) or yellow (medium) ratings, based on the observed distribution of values across projects.

- **Wetlands (En4-4):** Potential project effects associated with wetlands were estimated primarily by assessing the extent of overlap between the Terrestrial Area Footprint and 1:50,000 scale wetland mapping available from Geomatics Yukon. Ratings also considered whether the project overlapped any wetland complexes that had been identified at the territory level (e.g., Yukon Environment 2008). A green rating is applied for projects with less than 10 ha (0.1 km^2) of estimated wetland area affected, and a yellow rating is applied for projects with estimated wetland area affected between 10 and 100 ha (between 0.1 and 1.0 km^2). No resource projects are rated red with affected wetland area in excess of 100 ha (1.0 km^2).

  Wetland area estimates appear to be most significant for hydro renewable projects. Waterbodies associated with hydro renewable projects may contain unmapped wetlands that would be affected by changes in water levels, including small wetlands, long thin wetlands, and wetlands

fringing ponds and lakes. This potential issue is not reflected in the current ratings, and more work would be needed to map such areas where appropriate should a hydro project go forward to more detailed review.

For indicators within the Terrestrial Footprint and Land Use criteria, ratings were based primarily on the aerial extent of the indicator measure. The break points used to differentiate between green (low), yellow (medium), and red (high) ratings were selected based on the range of extents that occurred across the proposed projects. In this context, ratings represent more of a relative comparison across projects, than references to specific benchmarks.

Footprint indicators for overall area and linear distances for access are applicable to all resource options other than those that involve no new land areas, e.g., hydro storage enhancements and existing hydro generation refurbishment or maintenance. Assessments were based on geospatial GIS files without adjustment for potential spatial configuration of components.

Table C 5-1 presents the resource project option information for two indicators (Footprint Terrestrial Area [En4-1] and Linear Development [En4-2]). These indicators provide an overview of the relative terrestrial footprint requirements of each resource option without addressing which valued terrestrial elements are being affected. Table C A2-2 in Attachment 2 provides each of the four indicator results for each resource option.

Table C 5-1: Terrestrial Footprint & Land Use: Footprint Terrestrial Area & Linear Development

Resource Option	Project / Site	Footprint Terrestrial Area (En4-1) (km^2)	Linear Development (roads, trans.) (En4-2) (km)
Fossil Thermal	Whitehorse Landfill	0.20	N/A
	Takhini Substation	0.20	0.31
Non-Fossil Thermal Generation	Biogas - Whitehorse	0.20	0.31
	Waste to Energy (Whitehorse)	0.20	N/A
	Wood Biomass (Haines Junction Facility, Timber Harvesting)	0.20 facility Unknown harvesting[1]	N/A
Energy Storage Facilities	Takhini Energy Storage	0.20	N/A
Solar PV	Haines Junction	0.25	N/A
	Whitehorse	0.50	N/A
Wind Farms	Cyprus Mine Hill	1.13	20.1
	Kluane Lake	1.00	11.2
	Miller's Ridge	2.23	41.0
	Mt. Sumanik	1.13	22.8
	Sugarloaf Mountain	1.21	13.9
	Tehcho (Ferry Hill)	1.18	14.0
	Thulsoo Mountain	2.28	64.3
Geothermal	McArthur Springs	2.61	87.0
	Vista Mountain	0.28	6.3
Hydro - Pumped Storage	Atlin-Black Mountain	2.43	4.7
	Canyon-Ittlemit	6.92	15.4
	Lindeman – Fraser	4.65	22.6
	Racine – Moon	5.66	31.0
	Racine – Mt. Brown	6.64	30.0
	Squanga – Dalayee	3.01	13.1
	Faro – Vangorda Pit	10.87	22.9
	Moon Lake (Tutshi – Moon)	4.99	8.5
Small Hydro	Drury Lake	2.33	15.5
	Finlayson River	19.36	33.2
	Atlin/Pine Creek	3.09	15.0
	Tutshi-Windy Arm	3.78	30.2
	Wolf River	3.25	60.4
	Anvil Creek	2.27	19.2
Other Hydro	Gladstone Diversion	3.61	54.5
	Hydro Storage Enhancements (Southern Lakes, Mayo Lake)	N/A	0
	Mayo Lake Outlet Channel Dredging	0.20	0

Resource Option	Project/Site	Footprint Terrestrial Area (En4-1) (km^2)	Linear Development (roads, trans.) (En4-2) (km)
	Refurbish/enhance existing hydro (Mayo A, Aishihik re-runnering)	N/A	0
Transmission Corridors	Aishihik – Destruction Bay	10.41	173.6
	Faro – Watson Lake	25.63	427.2
	Whitehorse – Atlin	10.33	171.7
	Whitehorse – Skagway	10.27	170.8
	Whitehorse – Teslin	10.48	174.4
	Stewart River – Keno	11.42	190.0

Notes:
1. Area associated with timber harvesting unknown but expected to be thousands of hectares.
2. Footprints associated with hydro renewable projects are driven by reservoirs; estimates of those extents are preliminary.

5.2 EVALUATIONS

The following terrestrial evaluations regarding concerns focuses mainly on the Terrestrial Footprint and Land Use indicators related to permafrost and wetlands (as these indicators address potential specific effect concerns).

5.2.1 Resource Options with No Material Concerns regarding Terrestrial Footprint and Land Use

The following resource project options are rated green (low or not applicable) for each of the terrestrial footprint and land use indicators:

- **Fossil Thermal: Diesel and LNG** (Whitehorse Landfill and Takhini Substation location options);
- **Non-fossil Thermal: Biogas, Waste-to-Energy, Wood Biomass** (Whitehorse and Haines Junction location options);
- **Energy Storage Facilities** (Takhini Substation);
- **Solar PV** (Haines Junction site);
- **Geothermal** (Vista Mountain);
- **Hydro Storage Enhancements** (Mayo Lake);
- **Mayo Lake Outlet Channel Dredging;** and
- **Existing Hydro Refurbishments / Maintenance** (Mayo A, Aishihik Re-runnering).

If the basic footprint indicators Footprint Terrestrial Area (En4-1) and Linear Development (En4-2) as provided in Table C 5-1 are excluded, the following additional resource options are rated green (low or not applicable) for each of the two remaining footprint and land use indicators (Permafrost [En4-3] and Wetlands [En4-4]):

- **Solar PV** (Whitehorse quarry site);
- **Wind Farms** (all site options);
- **Geothermal** (McArthur Springs);
- **Pumped Storage** (Atlin-Black Mountain, Lindeman-Fraser);
- **Small Hydro** (Drury Lake,[5] Atlin-Pine Creek [Surprise Lake], Tutshi-Windy Arm, Anvil Creek); and
- **Transmission Corridors** (Whitehorse-Atlin, Whitehorse-Skagway, Whitehorse-Teslin).

[5] See Appendix E, Table E 3-1, which rated Drury Creek red with regard to extent of permafrost in the project footprint, based on geotechnical risks and presence of permafrost noted in previous KGS reports on this small hydro site.

5.2.2 Hydro Renewable Generation

5.2.2.1 Pumped Storage

As reviewed in Attachment 2, Table C A 2-2, the following pumped storage projects have yellow ratings:

- Canyon-Ittlemit: rated yellow for Permafrost (En4-3) with an expected area of 3.89 km^2;
- Racine-Moon: rated yellow for Wetlands (En4-4) with an expected area of 0.96 km^2;
- Racine-Mt. Brown: rated yellow for Permafrost (En4-3) with an expected area of 3.07 km^2;
- Squanga-Dalayee: rated yellow for Wetlands (En4-4) with an expected area of 0.12 km^2;
- Faro-Vangorda Pit: rated yellow for Permafrost (En4-3) with an expected area of 7.18 km^2 and rated yellow for Wetlands (En4-4) with an expected area of 0.40 km^2; and
- Moon Lake (Tutshi-Moon): rated yellow for Wetlands (En4-4) with an expected area of 0.94 km^2.

5.2.2.2 Small Hydro

As reviewed in Attachment 2, Table C A 2-2, the following small hydro projects have yellow ratings:

- Finlayson River: rated yellow for Permafrost (En4-3) with an expected area of 16.15 km^2; and
- Wolf River: rated yellow for Wetlands (En4-4) with an expected area of 0.19 km^2.

5.2.2.3 Hydro Storage Enhancements – Southern Lakes

As reviewed in Attachment 2, Table C A 2-2, Southern Lakes Storage Enhancement has a red rating for Wetlands (En4-4), based on the quality rather than the quantity of wetlands potentially affected by changes in water levels at different seasons, including wetlands at M'Clintock Bay, Lewes Marsh and Nares Lake.

5.2.2.4 Other Hydro - Gladstone Diversion

As reviewed in Attachment 2, Table C A 2-2, Gladstone Diversion has a yellow rating for Permafrost (En4-3) with an expected area of 2.57 km^2.

5.2.3 Transmission Corridors

As reviewed in Attachment 2, Table C A 2-2, the following transmission corridor projects have yellow ratings for Permafrost (En4-3):

- Aishihik-Destruction Bay (Burwash): rated yellow for Permafrost (En4-3) with an expected area of 3.83 km^2; this expected or average estimate may well understate the significance of permafrost challenges for a material segment of this corridor (see Appendix E, Table E 3-1, which highlights permafrost as a material challenge for segments of this corridor based on the Midgard report's estimate of 14,789 ha of extensive discontinuous as well as 6078 ha of sporadic discontinuous permafrost in the 500 m corridor examined for that study).

- Faro-Watson Lake: rated yellow for Permafrost (En4-3) with an expected area of 14.94 km^2.
- Stewart-Keno City: rated yellow for Permafrost (En4-3) with an expected area of 7.89 km^2; planning for this specific corridor has advance to complete YESAB assessment for a preferred route that improves the existing line's location through these challenging areas.

6.0 AIR QUALITY

6.1 RATING CRITERIA AND DATA SOURCES FOR EN-5: AIR QUALITY

The rating system outlined in Figure C 6-1 was adopted to guide evaluations of each resource project option for each of the Air Quality indicators.

Figure C 6-1: Summary of Assessment Rating Criteria for Air Quality

Indicator	Low	Medium	High
GHG Emissions En5-1	Total GHG <50 kg CO_2e.MWh [20 & 100 year GWP]	Total GHG >50 and <500 kg CO_2e.MWh [20 & 100 year GWP]	Total GHG >500 kg CO_2e.MWh [20 & 100 year GWP]
Other Air Emissions En5-2	Non-thermal option, or no linkage	Thermal generation	N/A

Indicators for Air Quality as defined in Table C 6-1 focus on the intensity of emissions per unit of energy generated or transmitted, e.g., kg of emissions per kWh or per MWh. The ratings and evaluation are based on information as provided by Yukon Energy's studies, as reviewed below:

- **Information Sources**: The scope for the resource studies carried out for Yukon Energy, as referenced in Appendix A, did not address air emission intensity for any of the options. The only Yukon Energy study on Air Emissions is provided by ArticCan Energy Services (ACES), "Lifecycle Assessment for Energy Resource Options in Yukon Territory – Final Report", September 6, 2016 (the "ACES Report"). A summary of the results of the ACES Report is provided in Table C 6-1.
- **Non-GHG Air Emissions**: All non-thermal resource options assessed in this study will have no air emission effects as an integral element of operation, and therefore are rated green for Other Air Emissions (En5-2). In contrast, thermal generation resource options (e.g., fossil fuel thermal generation [diesel or LNG] or non-fossil fuel generation [municipal solid waste, biomass, biogas]) will each have air emissions. It is assumed for these thermal generation options (as well as for any other option where air emissions may occur during construction or operation) that all air emissions will be required to comply with regulations such that no material adverse effects are expected, i.e., no red ratings are applicable. In the absence of detailed assessments of potential non-GHG air emissions for each thermal generation option, each thermal generation resource option is rated yellow under non-GHG emissions (Other Air Emissions [En5-2]).
- **GHG Emissions** – The ACES Report as summarized in Table C 6-1 addresses, per MW.h equivalent of useful net energy delivered (including heat as well as electricity) over a technology option life, total GHG emissions (kg CO_2e [carbon dioxide equivalent]) from all sources (including greenhouse gas [GHG] emissions related to construction of facilities, operation in Yukon, and operation activities required outside of Yukon, but excluding "downstream" emissions from plant decommissioning and related activities). GHG emissions are estimated using the Global Warming

Potential (GWP) for both the 20 year and 100 year time horizons, using GWP factors taken from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (ARS).[6]

The ACES Report notes that the most widely accepted time scale for reporting GWP values is 100 years, which adequately represents most GHGs due to their significantly long lifetime and was used under the Kyoto Protocol. The shorter 20 year GWP value is included in the ACES Report to examine global warming potential effects over shorter timeframes in order to address the immediate effects of short-lived methane on global temperatures.[7]

The ACES Report reports GWP values with and without biogenic CO_2 emissions. Biogenic CO_2 emissions in biogas and biomass pathways originate from biogas combustion and biomass gasification life cycle stages, and without these biogenic CO_2 emissions the overall CO_2 emissions for these options fall significantly. Material CO_2 emission reduction estimates also occur for hydro options when biogenic CO_2 emissions are excluded.[8]

Table C 6-1 shows the following GHG emissions estimates for each technology, with and without biogenic CO2 emissions and for both 100 year and 20 year GWP values:

- Fixed GHG intensity (kg CO_2e/MWh) is calculated based on the total plant fixed emissions[9] divided by the total energy delivered by the plant over its expected life. Table C 6-1 shows this estimate calculated per the assumptions provided and as reported in the ACES Report. Reductions in actual energy delivered over the plant life result in an increase in GHG intensity for "fixed emissions", i.e., these emissions are locked prior to plant operation. Variances can occur in fixed emissions within a technology or resource option depending on the source of materials, the specific technology method selected, etc.[10]
- Variable GHG emissions (kg CO_2e/MWh) as shown in Table C 6-1 are as reported in the ACES Report, and reflect GHG emissions for plant operation (including production and transportation to the plant of any fuel source used). Variable emissions per year typically vary annually depending on actual plant operation; however, for some technologies (e.g., hydro plants) the variable emissions relate to land inundated and may therefore not be affected as directly by actual hydro generation (and may decline over time as land inundation impacts on GHG emissions decline).
- Variable emissions per MWh will also vary depending on operation practices and on total energy delivered per MWh of power generation, i.e., if heat is also delivered the GHG intensity per unit of delivered energy will decline.

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[6] For more information and full discussion on the issues, see: ArticCan Energy Services (ACES), “Lifecycle Assessment for Energy Resource Options in Yukon Territory – Final Report”, September 6, 2016 (the "ACES Report").
[7] Ibid. for full discussion of 100 Year and 20 Year GWP.
[8] Ibid. for full discussion of issues related to inclusion and exclusion of biogenic CO2 emissions. Burning of biomass, or flooding of organic areas, releases CO2 emissions that can be recaptured by planting and growing new vegetation - issues arise related to the time scales of these two activities.
[9] Fixed plant emissions as estimated in the ACES Report (kg CO2e per plant) reflect GHG emissions for plant construction or manufacture, transmission line construction, materials acquisition and transportation, site preparation, and resource extraction (diesel and LNG). These GHG emissions occur from activities conducted prior to operation of the generation or transmission resource option.
[10] The ACES Report notes, by way of example, significant fixed GHG emission variances for different wind and storage battery technologies.

The ACES Report provides estimated GHG intensity for a specific scope design for different resource options examined (see Table C 6-1). The ACES report does not address the enhanced hydro storage resource options, the Mayo Lake Outlet Channel Dredging option, or options to refurbish existing hydro generation at Mayo and Aishihik.

Ratings in Figure C 6-1 for resource option GHG emissions (En5-1) are based on a simple scale to highlight the extent by which the Yukon Energy resource options differ for this indicator.

- **Including biogenic CO_2 emissions:** When assessed on a relative basis as per Table C 6-1 with biogenic CO_2 emissions, the resource options typically fall into either green (low) rating at <50 kg CO_2e/MWh lifecycle emissions, or red (high) rating at >500 kg CO_2e/MWh lifecycle emissions, regardless as to whether evaluated on the 20 year or 100 year GWP. None of the technology options evaluated in Table C 6-1 with biogenic VO_2 emissions fall into the yellow [medium] rating for GHG emissions.
- **Excluding biogenic CO_2 emissions:** When assessed on a relative basis as per Table C 6-1 without biogenic CO_2 emissions, the only changes that occur are reductions in GHG emissions for the following resource options (ratings are the same for both 20 year and 100 year GWP):
    - Waste-to-energy and Biogas resource options - ratings for these options change from red to yellow.
    - Biomass - ratings for this option change from red to green.
    - Pumped Storage, Small Hydro and Other Hydro (Gladstone Diversion) - ratings for these options remain unchanged (green ratings).

The GHG ratings applicable to a technology option per Table C 6-1 are assumed to apply for all other Yukon Energy resource options of that same technology, e.g., the wind rating for Mt. Sumanik is assumed to apply for all other wind options, the small hydro rating for Drury Lake is assumed to apply for all other small hydro options.

The ACES Report identifies the following factors that can vary the GHG emission estimates from the Table C 6-1 intensities:

1. **Modify Heat Energy Assumed to be consumed:** Table C 6-1 highlights assumed heat energy for biomass and municipal solid waste (MSW) waste-to-energy resource options, i.e., heat energy assumed to be used is 2.4 times the assumed equivalent electricity generation for MSW options and 3.1 times for the biomass option. Reductions in assumed heat energy use for the biomass and MSW waste-to-energy options would result in a material increase in GHG emission intensity. Conversely, assuming similar heat energy use for diesel and LNG options would result in a material decrease in GHG emission intensity. In summary, potential use of heat waste energy from thermal generation is desirable, where feasible, regardless of the resource option – and it can be argued that these resource options should be assessed based on comparable assumptions as regards use of available heat energy.
2. **LNG Combustion Emissions:** The ACES Report notes that emission factors selected for the baseline scenario for LNG combustion (as shown in Table C 6-1) are in the upper range of emissions and are therefore conservative. The ACES Report notes that actual natural gas GHG

emissions would likely be lower based on actual operating conditions of each unit. The ACES Report notes that GHG combustion operation emissions assuming 2016/217 B.C. Best Practices Methodology for Qualifying Greenhouse Gas Emissions (Ministry of Environment, May 2016) would be only 46% of the baseline scenario operation emissions for 20 year GWP (reduction of 456.4 kg CO_2e/MWh to 390.49 kg CO_2e/MWh) and 68% of the baseline scenario operation emissions for 100 year GWP (reduction of 184.2 kg CO2e/MWh, to 390.08 kg CO2e/MWh). Such reductions as a single measure would still leave LNG rated red (high) based on Figure C 6-1 when non-operation emissions are included.

3. **Transmission Line Capacity Utilization:** Table C 6-1 indicates the very high level of electricity transmission capacity utilization assumed for estimates of GHG emissions intensity for transmission corridor options. The ACES Report notes that reduction of the assumed use to 40% of transmission capacity (230 kV) would more than double the estimated GHG intensity per MWh for this option. Even at much lower levels of use, kg CO_2e/MWh for transmission continue to be rated green or low based on Figure C 6-1.

Table C 6-1: Summary of GHG Emissions from Resource Options (20 and 100 Year GWP)

Technology	Annual Power Energy (net) GWh/yr.	Annual Heat Energy (net) GW.hth/yr.	Operating Years	GHG Emissions with Biogenic CO2						Excluding Biogenic CO2	
				20 Year GWP			100 Year GWP			20 Year GWP	100 Year GWP
				Fixed GHG (kg CO2e/MWh)	Variable GHG (kg CO_2e/MWh)	Total GHG (kg CO_2e/MWh)	Fixed GHG (kg CO_2e/MWh)	Variable GHG (kg CO_2e/MWh)	Total GHG (kg CO_2e/MWh)	Total GHG (kg CO_2e/MWh)	Total GHG (kg CO_2e/MWh)
Diesel, 5 MW	39.4	-	20.0	0.4	1058.5	**1058.9**	0.4	950.7	**951.1**	**1058.9**	**951.1**
LNG, 5 MW	39.4	-	20.0	0.7	1050.1	**1050.8**	0.6	727.0	**727.7**	**1050.8**	**727.7**
Waste to energy: MSW & Biomass	10.0	23.70	25.0	9.2	666.0	**675.2**	8.9	654.1	**663.0**	**319.3**	**307.1**
Waste to energy: MSW	10.0	23.70	25.0	9.2	699.8	**709.1**	8.9	687.9	**696.8**	**453.7**	**441.4**
Biogas	0.9	-	20.0	10.5	1151.2	**1161.7**	10.1	1005.8	**1015.9**	**259.6**	**113.8**
Biomass	2.6	8.06	20.0	3.2	769.3	**772.5**	3.1	768.9	**772.0**	**17.7**	**17.2**
Storage Battery: lithium ion	2.8	-	20.0	16.2	-	**16.2**	14.7	-	**14.7**	**16.2**	**14.7**
Solar: 5 MW	5.2	-	30.0	43.1	0.1	**43.2**	38.9	0.1	**39.0**	**43.2**	**39.0**
Wind: Mt. Sumanik, 6 MW	14.6	-	25.0	10.0	0.7	**10.7**	9.6	0.7	**10.3**	**10.7**	**10.3**
Geothermal: McArthur Springs, 5.5 MW	32.1	-	30.0	4.6	0.0	**4.6**	4.2	0.0	**4.2**	**4.6**	**4.2**
Pumped Storage: Moon Lake, 20.2 MW	54.0	-	65.0	4.6	18.8	**23.4**	4.6	10.6	**15.1**	**17.7**	**9.5**
Small Hydro: Drury Lake, 8.1 MW	31.7	-	65.0	3.3	17.3	**20.6**	3.2	9.8	**13.0**	**15.3**	**7.7**
Other Hydro: Gladstone Diversion	29.7	-	65.0	0.1	21.3	**21.4**	0.1	12.0	**12.1**	**15.0**	**5.6**
Transmission Corridor: Whitehorse-Skagway	3880.7	-	55.0	0.1	0.0	**0.2**	0.1	0.0	**0.2**	**0.2**	**0.2**

Source: ArticCan Energy Services (ACES), "Lifecycle Assessment for Energy Resource Options in Yukon Territory – Final Report", September 6, 2016. Tables in the report and appendices (with changes as provided by Yukon Energy).

6.2 EVALUATIONS

6.2.1 Resource Options with No Material Concerns re: Air Quality

All non-thermal generation resource options are assumed to have no material concerns (green rating) for non-GHG air emissions (En5-2).

The following non-thermal generation resource options are also rated green or low for GHG emissions based on the Figure C 6-1 criteria for En5-1 and the estimated GHG emissions intensity as estimated in Table C 6-1 with and without biogenic CO2 emissions for both 20 year and 100 year GWP:

- Storage Battery options examined in the current resource planning;
- All Solar PVs examined in the current resource planning;
- All Wind site options at 6 MW to 20 MW examined in the current resource planning;
- All Geothermal site options examined in the current resource planning;
- All Pumped Storage site options examined in the current resource planning;
- All Small Hydro site options examined in the current resource planning;
- All Other Hydro options examined in the current resource planning (including Gladstone Diversion, Hydro Storage Enhancements, Mayo Lake Outlet Channel Dredging, Refurbish/enhance existing hydro facilities); and
- All transmission corridor options examined in the current resource planning.

In the case of hydro generation options (e.g., pumped storage, small hydro, diversion project), the level of GHG emissions is reduced if biogenic CO_2 emissions are excluded rather than included. However, with or without CO_2 emissions, green (low) ratings continue to apply for each hydro resource option.

6.2.2 Thermal Generation Resource Options

The remaining resource options that are not rated green (low) are thermal generation resource options.

Each thermal generation resource option is rated yellow for Other Air Emissions (En5-2).

Each of the fossil fuel thermal generation options is rated red (high) for GHG Emissions (En5-1), based on the Figure C 6-1 criteria and the estimated GHG emissions intensity as estimated in Table C 6-1. The 100 year GWP total GHG [CO_2/MWh] are shown below for each option with no use of heat energy as assumed in Table C 6-1, i.e., material use of available heat energy will materially reduce total GHG intensity per MWh for each option:

- **Fossil Thermal**
    - Diesel generation (951.1 kg CO_2/MWh).
    - LNG generation (727.7 kg CO_2/MWh).

Each of the non-fossil thermal generation options is rated red or high for GHG emission (En5-1) when biogenic CO2 emissions are included, based on the Figure C 6-1 criteria and the estimated GHG emissions intensity as estimated in Table C 6-1. If biogenic CO2 emissions are excluded, ratings for these options are reduced to yellow (medium) (waste-to-energy and biogas) or green (low) (biomass). The 100 year GWP total GHG (CO_2/MWh) are shown below for each option, with and without biogenic CO_2 emissions, with full use of heat energy as assumed in Table C 6-1, i.e., materially lower levels of heat energy use will materially increase total GHG intensity per MWh:

- **Non-Fossil Thermal (Renewable Thermal Generation)**
  - Waste to-energy
    - Including biogenic CO_2 emissions: 663.0 kg CO_2/MWh for MSW & Biomass, 696.8 kg CO_2/MWh for only MSW.
    - Excluding biogenic CO_2 emissions: 307.1 kg CO_2/MWh for MSW and Biomass, 441.4 kg CO_2/MWh for only MSW.
  - Biogas
    - Including biogenic CO_2 emissions: 1,005.8 kg CO_2/MWh.
    - Excluding biogenic CO_2 emissions: 113.8 kg CO_2/MWh.
  - Biomass
    - Including biogenic CO_2 emissions: 772.0 kg CO_2/MWh.
    - Excluding biogenic CO_2 emissions: 17.2 kg CO_2/MWh.

7.0 REFERENCES

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ATTACHMENT 1:

Fisheries Information

Table C A1-1: Summary of Common and Scientific Names of Fish Species that occur in the Yukon Energy Power Review Study Area

Common Name	Scientific Name	BC/Yukon Species Codes
Longnose Sucker	*Catostomus catostomus*	LSU
Largescale Sucker	*C. macrocheilus*	CSU
Lake Whitefish	*Coregonus clupeaformis*	LW
Least Cisco	*C. sardinella*	CS
Squanga Whitefish	*C. sp*[1]	SQ
Slimy Sculpin	*Cottus cognatus*	CCG
Lake Chub	*Couesius plumbeus*	LKC
Northern Pike	*Esox lucius*	NP
Arctic Lamprey	*Lethenteron camtschaticum*	AL
Burbot	*Lota lota*	BB
Round Whitefish	*Prosopium cylindraceum*	RW
Pygmy Whitefish	*P. coulteri*	PW
Bull Trout	*Salvelinus confluentus*	BT
Dolly Varden	*S. malma*	DV
Lake Trout	*S. namaycush*	LT
Inconnu	*Inconnu*	IN
Arctic Grayling	*Thymallus arcticus*	GR

[1]Not officially designated as a species or subspecies; however, they appear to be genetically distinct from sympatric populations of Lake Whitefish (Government of Canada 2016).

Table C A1-2: Summary of Fish Species Information

Project	Fish Species	Comments	Type of Fisheries*	References
Waste-to-energy generation		No major creek on access road or actual site.		
Wood biomass generation (Haines Junction)		No major creek on access road or actual site.		
Biogas generation		No site specifications.		
Fossil thermal generation – Takhini Substation		No major creek on access road or actual site.		
Solar - Whitehorse Quarry site (120 acres)		No major creek on access road or actual site.		
Solar - Haines Junction site north of dump (65 acres)		No major creek on access road or actual site.		
Geothermal - Vista Mountain		No major creek on site or near access road. The only water body close to site is a small pond to the south.		
Geothermal - McArthur Springs	N/A	The potential road would cross several creeks close to Summit Lake, Woodburn Lake and the head waters of Little Kalzas River area. No fish information is available for the area.		
Pumped storage - Tutshi-Moon (Midgard report)	BB, CCG, CS, GR, IN, LSU, LT, NP, RW.	All fish listed are from Tutshi Lake. No game fish in Moon Lake according to Gerd at Alpine Aviation.	Recreational and traditional fisheries.	Single Waterbody Query – BC Ministry of Environment.

Project	Fish Species	Comments	Type of Fisheries*	References
Pumped storage – Tutshi-Moon (KP report)	BB, CCG, CS, GR, IN, LSU, LT, NP, RW.	All fish listed are from Tutshi Lake. No game fish in Moon Lake according to Gerd at Alpine Aviation.	Recreational and traditional fisheries.	Single Waterbody Query – BC Ministry of Environment.
Pumped storage – Racine-Moon	BB, RW, GR, LT.	All fish listed are from Racine Lake. No game fish in Moon Lake according to Gerd at Alpine Aviation.	Recreational and traditional fisheries.	Single Waterbody Query – BC Ministry of Environment.
Pumped storage – Racine-Mt. Brown	BB, RW, GR, LT.	All fish listed are from Racine Lake.	Recreational and traditional fisheries.	Single Waterbody Query – BC Ministry of Environment.
Pumped storage – Lindeman-Fraser	LT, GR, LW.	All fish listed are from Lindeman Lake. More species are suspected to be found in Lindeman, no information was available for Fraser.	Recreational and traditional fisheries.	Environment Canada – Catalogue of Aquatic Resources of the Upper Yukon River Drainage (Whitehorse Area).
Pumped storage – Squanga-Dalayee	LT, GR, BB in Dalayee Lake (Taiga Journeys) LW, NP, CCG were also found in a creek between Dalayee Lake and Squanga Lake (FISS 2003) SQ, NP are also known to be in Squanga Lake.	Likely to find more species in Dalayee Lake, a change in water levels could affect lake trout and other species that might be living in the lake. Squanga Whitefish are genetically unique species of Lake Whitefish that have a restricted distribution in northern BC and southern Yukon. They are currently listed on SARA Schedule 3 as species of Special Concern.	Recreational and traditional fisheries.	FISS 2003 Taiga Journeys (pers. Comm.). Environment Yukon – Burbot Population Assessment Squanga Lake 2013 (Barker et al. 2014b).

Project	Fish Species	Comments	Type of Fisheries*	References
Pumped storage – Atlin-Black Mountain	GR, LT, LW, NP, RW, BB, CS, LSU, LKC, CSU.	All species listed are from Atlin Lake.	Commercial, recreational and traditional fisheries.	Single Waterbody Query – BC Ministry of Environment.
Pumped storage – Canyon-Ittlemit	LT (Ittlemit) LT, NP, RW, LW, BB LSU and CCG in Canyon Lake.	Lake trout living in Ittlemit lake could be affected.	Recreational and traditional fisheries.	EDI fish and fish habitat report for Champagne and Aishihik.
Pumped storage – Faro-Vangorda Pit (With storage)	GR, BB, CH (juveniles), LKC, LSU, CCG, RW (in lower 4 km of Vangorda only). RW, BB, CH in Blind Creek.	Blind Creek is a known Chinook spawning stream with returns that are counted annually at a weir.	Possible CH commercial fishery, Recreational and traditional fisheries.	EDI – Faro Mine Fish and Fish Habitat Literature Review (Vangorda). FISS Database (Blind Creek).
Small hydro – Drury Lake(With storage)	CH (in Creek), LT, GR, NP.	Juvenile CH may use the creek as natal habitat depending on the extent of spawning. LT, GR, NP are found in Drury Lake.	Possible CH commercial fishery. Recreational and traditional fisheries.	EDI - Little Salmon Carmacks First Nation Salmon Knowledge Study. Drury Lake Fishing Lodge.
Small hydro – Finlayson (With storage)	LT, GR, NP, WF, BT.	All the species listed other than BT are found in the lake, while BT is found in the river just below the lake.	Recreational and traditional fisheries.	Environment Yukon.
Small hydro – Atlin-Pine Creek (Surprise Lake) (With storage)	GR, CCG.	All the species listed are found in Surprise Lake or in the upper section of Pine Creek.	Recreational and traditional fisheries.	Biological Assessment of the Atlin Hydroelectric Project.
Small hydro – Tutshi-Windy Arm (With storage)	BB, CCG, GR, LT, NP, RW, IN, LSU, CS.	All the species listed are found in Tutshi Lake.	Recreational and traditional fisheries.	Single Waterbody Query – BC Ministry of Environment.
Small hydro – Wolf river (Run of river)	GR, LT, RW, CCG, BB, LW, NP, LSU, WSU, CH.	Chinook salmon have been identified spawning as far upstream as the outlet of Wolf Lake.	Possible CH commercial fishery. Recreational and traditional fisheries.	EDI – Compilation and mapping of fisheries information within the Teslin Tlingit Traditional Territory.

Project	Fish Species	Comments	Type of Fisheries*	References
Small Hydro – Anvil Creek	LT, NP, GR, WF	Documented near the outlet of Anvil Lake. Species are likely present in lake as well.	Recreational fishery is documented – some locals from Faros have cabins on lake. Species that are targeted by traditional fisheries are present	FISS Database (Blind Creek)
Southern Lakes Enhanced Project	LW, CS, RW, GR, LT, CH, NP, LSU, BB, CCG.	All fish listed are found in the southern lakes and would need to be considered for any water level changes.	Commercial, recreational and traditional fisheries	AECOM – Fish species presence in the Yukon River Drainage.
Mayo Lake Enhanced Project	GR, LW, NP, LT, BB, RW, CCG, LSU.	All fish listed were found in Mayo River and would need to be considered for any water level changes.	Recreational and traditional fisheries.	EDI – Mayo Lake Aquatic Baseline Studies 2009.
Mayo A possible changes	GR, LW, NP, LT, BB, RW, CCG, LSU, PW.	All fish listed were found in Mayo and would need to be considered for any water level changes.	Recreational and traditional fisheries	EDI – Mayo Lake Aquatic Baseline Studies 2009.
Transmission - Whitehorse-Atlin corridor	LW, CS, RW, GR, LT, CH, NP, LSU, BB, CCG.	Transmission line would follow existing road. It would cross the McClintock River which is salmon habitat.	Commercial, recreational and traditional fisheries.	EDI Ta'an Salmon Information Gathering/Workshop Summary Report. AECOM – Fish species presence in the Yukon River Drainage.
Transmission – Whitehorse – Skagway corridor	LW, CS, RW, GR, LT, CH, NP, LSU, BB, CCG (Yukon River).	Transmission line would follow existing road. So it will cross many streams, including the Yukon River in Carcross.	Commercial, recreational and traditional fisheries.	AECOM – Fish species presence in the Yukon River Drainage.

Project	Fish Species	Comments	Type of Fisheries*	References
Transmission – Whitehorse – Teslin corridor	LW, CS, RW, GR, LT, CH, NP, LSU, BB, CCG, IN, CM, DV, PW, LKC, SQ.	Transmission line would follow existing road. It would cross the McClintock River and Teslin River. The McLintock River has Chinook Salmon spawning habitat, while the Teslin river has both Chinook and Chum salmon spawning habitat.	Commercial, recreational and traditional fisheries.	AECOM – Fish species presence in the Yukon River Drainage. EDI Ta'an Salmon Information Gathering/Workshop Summary Report.
Transmission – Faro – Watson Lake corridor (More info needed from YE)	LW, CS, RW, GR, LT, CH, NP LSU, BB, CCG, BT, PW, LKC all likely to occur.	Transmission line would follow existing road. Crosses Pelly River and tributaries as well as many streams in the Liard River watershed.	Commercial, recreational and traditional fisheries.	DFO – FISS Yukon.
Transmission – Aishihik – Burwash Landing corridor	LW, RW, GR, LT, NP, LSU, CCG, BB, RB, DV.	Transmission line would follow existing road. Most fish found on the different crossings along this road are noted.	Commercial, recreational and traditional fisheries.	EDI – Overview fish and fish habitat for the Champagne and Aishihik Traditional Territory.
Wind farm – Cyprus Mine		The turbines would be located at high elevation, away from creeks or other water bodies. The access road passes close to a small creek flowing into Rose Creek, but no fish have been found in area.		DFO – FISS Yukon.
Wind farm - Kluane	LT, RW, CCG, GR, LW, NP, LSU, BB, IN.	All the turbines and access road would be very close to existing Alaska Highway and would not cross any streams.		Barker et al. 2014a.

Project	Fish Species	Comments	Type of Fisheries*	References
Wind farm – Miller's Ridge	In Nordenskiold River: CH, CM, LT, GR, RW, LW, LSU, NP, BB, AL, CCG.	Access road and turbines would not cross any streams. The transmission line would cross the Nordenskiold River South of Carmacks.	Possible commercial fisheries for CH and CM. Recreational and traditional fisheries.	Tsawnjik Chu Nordenskiold – Habitat Protection Area Management Plan.
Wind farm - Sugarloaf	In Yukon River: LW, CS, RW, GR, LT, CH, NP, LSU, BB, CCG.	Access road and turbines don't cross any major streams, but the proposed transmission likely would cross the Yukon River.	Commercial, recreational and traditional fisheries.	AECOM – Fish Species presence in Yukon River Drainage (Lindsey et al. 1981).
Wind farm - Sumanik		Access road follows a small creek which has been sampled downstream from the proposed road and no fish were found. (DFO) Turbines are not close to any streams.		DFO – FISS Yukon ID: 80093044.
Wind farm – Tehcho		Access road already established, turbines up high with no streams in proximity.		
Wind farm – Thulsoo		Access road does not cross any streams, all turbines have no streams in proximity.		

*Type of fisheries is inferred by the fish species present.

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ATTACHMENT 2:

Terrestrial Information

Table C A2-1: Summary of Disturbance Footprints Associated with Project Feature Types

Feature	Disturbance Footprint
Access Road	10 m each side of centreline (20 m ROW total footprint)
Canal	70 m (140 m total footprint)
Control Dam	10 m radius
Dam Crest	15 m radius
Forebay	15 m radius
Heat Transfer Line	15 m (30 m total footprint)
Intake	15 m radius
Interconnection Line	15 m (30 m total footprint)
Low Pressure Pipe	15 m (30 m total footprint)
Penstock	100 m ROW footprint
Powerhouse	15 m radius (circular footprint)
Saddle Dam	15 m radius
Transmission Line	30 m each side of centreline (100 m ROW footprint)
Weir	15 m radius
Wind Turbine	50 m radius

A summary of ratings for Terrestrial Footprint and Land Area indicators is provided below.

Table C A2-2: Terrestrial Footprint and Land Area Indicators by Resource Option

Resource Option / Project	Terrestrial Development (km^2)	Linear Development (roads, trans., km)	Permafrost (mean probability and weighted area km^2)	Wetlands (km^2)
Fossil Thermal				
Whitehorse Landfill	0.20	N/A	**Sporadic Discontinuous, Mean=0.20, Area=0.01**	**0**
Takhini Substation	0.20	0.31	**Sporadic Discontinuous, Mean=0.23, Area=0.02**	**0**
Non-Fossil Thermal Generation				
Biogas - Whitehorse	0.20	0.31	**Sporadic Discontinuous, Mean=0.20, Area=0.01**	**0**

Resource Option / Project	Terrestrial Development (km^2)	Linear Development (roads, trans., km)	Permafrost (mean probability and weighted area km^2)	Wetlands (km^2)
Waste to Energy (Whitehorse)	0.20	N/A	**Sporadic Discontinuous, Mean=0.20, Area=0.01**	**0**
Wood Biomass (Haines Junction Facility)	0.20	N/A	**Sporadic Discontinuous, Mean=0.19, Area=0.00**	**0**
Wood Biomass (Timber Harvesting)	Unknown[1]	N/A	N/A	N/A
Energy Storage Facilities				
Takhini Energy Storage	0.20	N/A	**Sporadic Discontinuous, Mean=0.23, Area=0.02**	**0**
Solar PV				
Haines Junction	0.25	N/A	**Sporadic Discontinuous, Mean=0.18, Area=0.04**	**0**
Whitehorse	0.50	N/A	**Sporadic Discontinuous, Mean=0.18, Area=0.09**	**0**
Wind Farms				
Cyprus Mine Hill	1.13	20.1	**Extensive Discontinuous, Mean=0.75, Area=0.85**	**0**
Kluane Lake	1.00	11.2	**Extensive Discontinuous, Mean=0.51, Area=0.51**	**0**
Miller's Ridge	2.23	41.0	**Extensive Discontinuous, Mean=0.66, Area=1.73**	**0**
Mt. Sumanik	1.13	22.8	**Extensive Discontinuous, Mean=0.78, Area=1.03**	**0**
Sugarloaf Mountain	1.21	13.9	**Sporadic Discontinuous, Mean=0.47, Area=0.57**	**0**

Resource Option / Project	Terrestrial Development (km^2)	Linear Development (roads, trans., km)	Permafrost (mean probability and weighted area km^2)	Wetlands (km^2)
Tehcho (Ferry Hill)	1.18	14.0	**Extensive Discontinuous, Mean=0.55, Area=0.65**	**0**
Thulsoo Mountain	2.28	64.3	**Continuous, Mean=0.78, Area=1.77**	**0**
Geothermal				
McArthur Springs	2.61	87.0	**Extensive Discontinuous, Mean=0.70, Area=1.71**	**0**
Vista Mountain	0.28	6.3	**Sporadic Discontinuous, Mean=0.22, Area=0.06**	**0**
Pumped Storage				
Atlin-Black Mountain	2.43	4.7	**Sporadic Discontinuous, Mean=0.25, Area=0.69**	**0**
Canyon-Ittlemit	6.92	15.4	**Extensive Discontinuous, Mean=0.52, Area=3.89**	**0.09**
Lindeman – Fraser	4.65	22.6	**Sporadic Discontinuous, Mean=0.08, Area=0.36**	**0.10**
Racine – Moon	5.66	31.0	**Sporadic Discontinuous, Mean=0.19, Area=1.08**	**0.96**
Racine – Mt. Brown	6.64	30.0	**Extensive Discontinuous, Mean=0.43, Area=3.07**	**0.09**
Squanga – Dalayee	3.01	13.1	**Sporadic Discontinuous, Mean=0.17, Area=0.51**	**0.12**
Faro – Vangorda Pit	10.87	22.9	**Extensive Discontinuous, Mean=0.66, Area=7.18**	**0.40**

Resource Option / Project	Terrestrial Development (km^2)	Linear Development (roads, trans., km)	Permafrost (mean probability and weighted area km^2)	Wetlands (km^2)
Tutshi – Moon	4.99	8.5	**Sporadic Discontinuous, Mean=0.13, Area=0.78**	**0.94**
Small Hydro				
Drury Lake	2.33	15.5	**Extensive Discontinuous, Mean=0.61, Area=0.29**	**0**
Finlayson River	19.36	33.2	**Extensive Discontinuous, Mean=0.68, Area=16.15**	**0.08**
Atlin-Pine Creek (Surprise Lake)	3.09	15.0	**Isolated Patches, Mean=0.06, Area=0.09**	**0**
Tutshi-Windy Arm	3.78	30.2	**Isolated Patches, Mean=0.07, Area=0.04**	**0.05**
Wolf River	3.25	60.4	**Sporadic Discontinuous, Mean=0.16, Area=0.51**	**0.19 Nitsutlin Delta**
Anvil Creek	2.27	19.2	**Extensive Discontinuous, Mean=0.64, Area=1.46**	**0**
Other Hydro				
Gladstone Diversion	3.61	54.5	**Extensive Discontinuous, Mean=0.71, Area=2.57**	**0**
Hydro Storage Enhancements				
Mayo Lake	N/A	0	**N/A**	**N/A**
Southern Lakes	N/A	0	**N/A**	**Size N/A M'Clintock Bay Lewes Marsh Nares Lake**
Mayo Lake Outlet Channel Dredging	0.20	0	**N/A**	**N/A**

Resource Option / Project	Terrestrial Development (km^2)	Linear Development (roads, trans., km)	Permafrost (mean probability and weighted area km^2)	Wetlands (km^2)
Transmission Lines				
Aishihik – Destruction Bay	10.41	173.6	**Sporadic Discontinuous, Mean=0.44, Area=3.83**	**0.02 Swede Johnson Wetland; Kloo and Sulpur Lakes**
Faro – Watson Lake	25.63	427.2	**Extensive Discontinuous, Mean=0.58, Area=14.94**	**0.40 Frances Lake**
Whitehorse – Atlin	10.33	171.7	**Isolated Patches, Mean=0.13, Area=1.13**	**0.07 M'Clintock Bay Lewes Marsh**
Whitehorse – Skagway	10.27	170.8	**Isolated Patches, Mean=0.12, Area=0.95**	**0.14 Nares Lake**
Whitehorse – Teslin	10.48	174.4	**Isolated Patches, Mean=0.13, Area=1.27**	**0.02 M'Clintock Bay Lewes Marsh; Teslin Lake Outlet**
Stewart – Keno City	11.42	190.0	**Extensive Discontinuous, Mean=0.69, Area=7.89**	**0.04 McQuesten and Devil's Elbow**

Notes:
1. Area associated with timber harvesting unknown but expected to be thousands of hectares.
2. Footprints associated with hydro renewable projects are driven by reservoirs; estimates of those extents are preliminary.

APPENDIX D:
SOCIAL EVALUATION TECHNICAL REPORT

TABLE OF CONTENTS

1.0 INTRODUCTION D-1

2.0 FIRST NATION LANDS D-3

2.1 RATING CRITERIA AND DATA SOURCES FOR S1: FIRST NATION LANDS D-3

2.2 EVALUATION D-4

3.0 TRADITIONAL LIFESTYLE D-7

3.1 RATING CRITERIA AND DATA SOURCES FOR S2: TRADITIONAL LIFESTYLE D-7

3.2 EVALUATION D-11

3.2.1 Resource Options with No Material Concerns re: Traditional Lifestyle D-11

3.2.2 Hydro Generation D-11

4.0 HERITAGE RESOURCES D-13

4.1 RATING CRITERIA AND DATA SOURCES FOR S3: HERITAGE RESOURCES D-13

4.2 EVALUATION D-16

4.2.1 Resource Options with No Material Concerns re: Heritage Resources D-16

4.2.2 Non-Hydro Renewables D-16

4.2.3 Hydro Generation D-17

5.0 TOURISM, RECREATION AND OTHER RESOURCES AND LAND USE D-19

5.1 RATING CRITERIA AND DATA SOURCES FOR S4: TOURISM, RECREATION, AND OTHER RESOURCES AND LAND USE D-19

5.2 EVALUATION D-21

5.2.1 Resource Options with No Material Concerns re: Tourism, Recreation and Other Resources and Land Use D-21

5.2.2 Non-Hydro Renewable Generation D-23

5.2.3 Hydro Renewable Generation D-28

6.0 CULTURAL AND COMMUNITY WELL-BEING D-40

6.1 RATING CRITERIA AND DATA SOURCES FOR S5: CULTURAL AND COMMUNITY WELL-BEING D-40

6.2 EVALUATION D-46

6.2.1 Resource Options with No Material Concerns re: Cultural and Community Well-Being D-46

6.2.2 Fossil Thermal - LNG D-46

6.2.3 Non-Hydro Renewable Generation D-47

6.2.4 Hydro Renewable Generation D-47

6.2.5 Transmission Corridor Options D-48

7.0 REFERENCES D-50

LIST OF TABLES

Table D 1-1: Resource Options Evaluation Matrix – Social Criteria & Indicators D-2
Table D 2-1: Resource Project Options Assessment for First Nation Lands Indicator D-6
Table D 3-1: Other Criteria Considered in Evaluation of Traditional Lifestyle D-8
Table D 3-2: Traditional Lifestyle: All Indicators D-10
Table D 4-1: Heritage Resource: All Indicators D-15
Table D 5-1: Other Criteria Considered in Evaluation of Tourism, Recreation, and Other Resource and Land Use D-20
Table D 5-2: Resource Project Options with Green Ratings for All Tourism, Recreation and Other Resources & Land Use Indicators D-22
Table D 5-3: Summary of Assessment for Non-Fossil Thermal Generation - Biomass D-24
Table D 5-4: Summary of Assessment for Wind Farms D-25
Table D 5-5: Summary of Assessment for Geothermal - McArthur Springs D-28
Table D 5-6: Summary of Assessment for Pumped Storage (excluding Vangorda Pit) D-29
Table D 5-7: Summary of Assessment for Small Hydro Projects D-34
Table D 5-8: Summary of Assessment for Gladstone Diversion D-39
Table D 6-1: Issues and Other Criteria Considered in Evaluation of Cultural and Community Well-Being D-41
Table D 6-2: Cultural and Community Well-Being: Infrastructure and Services D-43
Table D 6-3: Cultural and Community Well-Being: Public Safety, Worker Interaction, Human and Community Health D-44
Table D 6-4: Cultural & Community Well-Being: Community, First Nation & Personal Development D-45
Table D 6-5: Resource Project Options with No Material Concerns D-46

LIST OF FIGURES

Figure D 2-1: Summary of Rating Criteria for First Nation Lands D-3
Figure D 3-1: Summary of Rating Criteria for Traditional Lifestyle D-7
Figure D 4-1: Summary of Rating Criteria for Heritage Resources D-13
Figure D 5-1: Summary of Rating Criteria for Tourism, Recreation, and Other Resources and Land Use D-19
Figure D 6-1: Summary of Rating Criteria for Cultural and Community Well-Being D-40

1.0 INTRODUCTION

Social criteria and indicators for evaluating resource options as finalized in Appendix B, are copied below in Table D 1-1.

The technical social evaluation of each resource option is addressed in Appendix D, with separate sections for each of the social criteria in Table D 1-1.

At the start of each section of Appendix D, the distinct issues, rating criteria and data sources for each criteria are summarized. As outlined in Section 7 of Appendix B, the ratings for the evaluation of each indicator are classified in terms of high, medium, and low as follows:

- **High (Red when non-positive - no colour when positive effect)** means the resource option has a high expected effects linkage to the indicator (depending on the indicator, the likely effects may be adverse, beneficial or simply signify linkage/overlap without much additional guidance);
- **Medium (Yellow when non-positive - no colour when positive effect)** means the resource option has potential expected linkage to the indicator that falls between low and high ratings; and
- **Low (Green when non-positive - no colour when positive effect)** means the resource option likely has minimal, if any, expected effects linkage to the indicator (again, depending on the indicator, any potential minimal effects may be adverse, beneficial or simply signify no linkage / overlap with the indicator, i.e., no effects pathway).

No linkage or Not Applicable, which is shown as green, is separated out in the social evaluations to identify circumstances where there is no apparent or likely link between a resource project option and a given social indicator.

As each resource project option was reviewed, it was assumed that standard best management practices (BMPs) would be applied during the construction and operation stages to mitigate adverse effects and enhance positive effects. Where standard BMPs are expected to prevent any likely effect of concern on an indicator, a green or low effect rating was adopted.

Table D 1-1: Resource Options Evaluation Matrix – Social Criteria & Indicators

ID	Criteria	Indicator	Metric ID	Metric
Social Criteria				
S1	**First Nation Lands**	Settlement Lands, Interim Protected Lands	S1-1	Overlap and/or access with these lands (Y/ Potential/N)
S2	**Traditional Lifestyle**	Footprint land area impact	S2-1	Total area (ha) of direct land loss
		Land area loss re Traditional Lifestyle	S2-2	Total area (ha) of Traditional Use land area loss
		Land Quality Effects on Traditional Lifestyle	S2-3	Indirect effects on land or access for such pursuits (+/- and L/M/H)
		Cabins, Camps & Structures	S2-4	Number of cabins, camps, homesteads, etc. in footprint (corridor for linear access) that may be affected (n)
		Country Foods	S2-5	Effects to the opportunity to harvest country foods (+/- and L/M/H)
S3	**Heritage Resources**	Heritage Resource Potential	S3-1	Density (number of discrete) known or potential archeological, palaeontological, ethnological, prehistoric, or historic resources (L/M/H)
			S3-2	Importance/Cultural Value of heritage resources, including areas of land containing heritage resources. (L/M/H)
S4	**Tourism, Recreation & Other Resources and Land Use**	Recreational Values	S4-1	Effect on nature and scale of existing and new Recreational Values. (+/- and L/M/H)
		Tourism Values	S4-2	Effect on nature and Scale of Tourism Values. (+/- and L/M/H)
		Aesthetics	S4-3	Effect on auditory or visual aesthetics. (+/- and L/M/H)
		Non-renewable Resources	S4-4	Effect on Non-Renewable Resources. (+/- and L/M/H)
		Other Renewable Resources	S4-5	Effect on other Renewable Resources. (+/- and L/M/H)
		Land Use & Renewable Resources Plans	S4-6	Consistent with Land Use& Renewable Resources Plans (Y/N, NA)
S5	**Cultural and Community Well Being**	Infrastructure & Services	S5-1	Effect on Infrastructure & Services (+/- and L/M/H)
		Public Safety, Worker Interaction, Human and Community Health	S5-2	Risks to Community Health & Safety - construction & operation (L/M/H)
		Community, First Nation & Personal Development	S5-3	Effects on local jobs, business, training & development (+/- and L/M/H)

2.0 FIRST NATION LANDS

2.1 RATING CRITERIA AND DATA SOURCES FOR S1: FIRST NATION LANDS

The rating system outlined in Figure D 2-1 below was adopted to guide evaluations of each resource project option for the First Nation Lands indicator.

Figure D 2-1: Summary of Rating Criteria for First Nation Lands

Indicator	Low	Medium	High
Settlement Lands, Interim Protected Lands (S1-1)	No overlap with Settlement Lands or Interim Protected Lands	Potential overlap with Settlement Lands or Interim Protected Lands	Expected overlap with Settlement Lands or Interim Protected Lands

The Settlement Lands and Interim Protected Lands indicator as defined in Table D 1-1 focuses on the presence or absence of an overlap (Yes/No rating), with the option of a potential effect (if there is uncertainty). "Overlap" in this context references the footprint required for the resource option lands, access rights-of-way (ROW) (road and transmission), any required buffer lands, and whether any of the footprint requires use of any settlement lands or interim protected lands in Yukon (or any known reserve blocks in British Columbia).

An initial question is whether a generation resource site footprint is expected to overlap (red), or might potentially overlap (yellow), with First Nation lands as defined. Separately, a related question is whether new road and/or transmission access required for a resource option is expected to overlap, or might potentially overlap, with First Nation lands as defined. In this case, it becomes relevant to assess if the overlap is expected/required (a red [high] rating) or merely a potential option within the 500m area assumed for selecting a final 60m ROW (a yellow [medium] rating).

The approach and assumptions used in evaluating potential effects on the First Nation Lands indicator are:

- In applying the rating system, available information was considered regarding resource project options description.
- The evaluations of each resource option for this indicator identify resource project option overlaps with Settlement or Interim Protected Lands that must be addressed (and reserve blocks for projects in BC). It is noted that such overlaps are not necessarily adverse and could have positive effects as well as adverse effects (i.e., in certain cases the affected First Nation may not be opposed to the development, recognizing that there may be the potential for positive effects due to projects being located on settlement land, such as benefits to the First Nation through project agreements).
- Existing information is not likely, without consultation with the First Nation, to provide any useful basis for assessing the extent that there may be material concerns in this regard that are not

likely to be mitigated. Accordingly, the assessment focuses only on the extent to which an overlap is expected versus may only potentially occur (without being a likely requirement).

- This indicator focuses only on First Nation lands where a project must obtain some form of permit for actual use. Consultation with First Nations with regard to project effects on traditional lands is a separate requirement that continues to apply in connection with almost all resource options.

2.2 EVALUATION

Table D 2-1 provides a summary of all resource options indicating for each option whether it has no overlap with Settlement or Interim Protected Lands (green [low] rating) or is expected to have an overlap with Settlement or Interim Protected Lands (red [high] rating). A yellow (medium) rating is provided for situations where there is uncertainty with the potential for the resource option to have an overlap that cannot be avoided with Settlement or Interim Protected Lands. This rating reflects the existence of First Nation lands within the area potentially affected by a project's footprint, including access roads and/or transmission where it is not clear in the available information that there are options for final routing and/or project location that may avoid overlap with such lands.[1]

Table D 2-1 indicates that the largest group of projects is rated green (low) because there is no overlap.

The next largest groups of project sites is rated yellow, highlighting the potential overlap with settlement lands or interim settlement lands without a separate report confirming that an overlap is in fact required for the resource option. The specific assessments of future projects will determine the exact issues to be addressed in each instance, potentially in the manner adopted for the Stewart-Keno City Transmission project (as noted in Table D 2-1).

The following 13 resource options are rated red (high) in Table D 2-1, and the components leading to this rating are noted below where feasible:

- Two wind farm projects (Kluane Lake and Sugarloaf Mountain) are rated red (high), based on information supported by the specific resource option report indicating that each option requires overlap with Settlement Lands for the generation site component.
- The three potential new transmission corridors rated red (high) have segments where First Nation Settlement Lands are adjacent to both sides of the proposed corridor located along an existing highway, e.g., this situation has been identified for multiple points along corridors from Whitehorse to Carcross and from Whitehorse to Jake's Corner or Teslin.
- Southern Lakes Enhanced Storage project is rated red to reflect affected water bodies adjacent to various Settlement Lands, where potential edge effects have been highlighted for the project.
- Gladstone Diversion is rated red to reflect the linear features' potential overlap with Settlement Lands.

[1] Existing information for a potential resource project option typically does not allow for a clear conclusion that flexibility exists to avoid First Nation lands. First Nation lands may create constraints for even transmission line routing that must be addressed, and that cannot be avoided by BMPs in the same way as many environmentally sensitive areas.

- Canyon-Ittlemit is rated red to note that potential overlaps with Settlement Land would occur in the context of existing issues with local First Nations with regard to current Aishihik generation.
- Anvil Creek small hydro is rated red to reflect that the transmission connection to the grid would overlap with Interim Protected Lands (without any apparent practical routing option to avoid this overlap).
- Four other hydro generation options are rated red to reflect potential segments of Settlement Lands that may affect routing options and discussions for new transmission connections needed to connect with the existing grid, plus specific potential Settlement Land overlaps that may affect the Vangorda Pit pumped storage development on currently undeveloped lands.

Table D 2-1: Resource Project Options Assessment for First Nation Lands Indicator

	ResourceOptions	No Overlap with Settlement or Interim Protected Lands	Potential Overlap with Settlement or Interim Protected Lands	Expected Overlap with Settlement or Interim Protected Lands
		Low	**Medium**	**High**
Fossil Fuel Thermal (Diesel or LNG)	Whitehorse Landfill	No Overlap		
	Takhini Substation		Yes	
Non-Fossil Thermal	Biomass (Haines Junction)	No Overlap		
	Waste-to-Energy (Whitehorse)	No Overlap Expected		
	Biogas (Whitehorse)	No Overlap		
Energy Storage Facility (Takhini)		No Overlap		
Solar PV	Whitehorse	No Overlap		
	Haines Junction	No Overlap		
Wind Farms	Cyprus Mine Hill	No Overlap		
	Kluane Lake			Yes[2]
	Millers Ridge		Yes	
	Mt. Sumanik	No Overlap		
	Sugarloaf Mountain			Yes[2]
	Tehcho (Ferry Hill)	No Overlap		
	Thulsoo Mountain	No Overlap		
Geothermal	McArthur		Yes	
	Vista Mountain		Yes	
Pumped Storage	Moon Lake (Tutshi-Moon)	No Overlap		
	Racine - Moon	No Overlap		
	Lindeman – Fraser	No Overlap		
	Racine – Mt. Brown		Yes	
	Atlin – Black Mountain		Yes	
	Squanga - Dalayee			Yes[2]
	Canyon - Ittlemit			Yes[2]
	Faro – Vangorda Pit			Yes[2]
Small Hydro	Drury Lake		Yes	
	Tutshi – Windy Arm	No Overlap		
	Wolf River			Yes[2]
	Finlayson River			Yes[2]
	Anvil Creek			Yes[2]
	Atlin/Pine Creek		Yes	
Other Hydro	Gladstone Diversion			Yes[2]
	Southern Lakes			Yes[2]
	Mayo Lake	No Overlap		
	Mayo Lake Dredging	No Overlap		
Refurbish Existing Hydro Generation	Mayo A	No Overlap		
	Aishihik re-runnering	No Overlap		
Transmission Corridors	Aishihik-Burwash		Yes	
	Faro – Watson Lake		Yes	
	Whitehorse – Atlin			Yes[2]
	Whitehorse – Skagway			Yes[2]
	Whitehorse – Teslin			Yes[2]
	Stewart - Keno City		Yes[1]	

Notes:

1. Reference to one parcel where the existing line has an existing right of way, and no objection to having a new line also use this area (options existed for routing if the First Nation settlement land use not acceptable).
2. See text for discussion of components and information that lead to each red rating.

3.0 TRADITIONAL LIFESTYLE

3.1 RATING CRITERIA AND DATA SOURCES FOR S2: TRADITIONAL LIFESTYLE

The rating system outlined in Figure D 3-1 was adopted to guide evaluations of each resource project option for each of the Traditional Lifestyle indicators.

Figure D 3-1: Summary of Rating Criteria for Traditional Lifestyle

Indicator	Low	Medium	High
Footprint Land Area Impact (S2-1)[1]	<10 ha of land area affected, or not applicable	Between 10 and 100 ha of land area affected	>100 ha of land area affected
Land Area Loss re: Traditional Lifestyle[2] (S2-2)	< 500 ha of potential traditional lifestyle land area loss, or not applicable	Between 500 and 2500 ha of potential traditional lifestyle land area loss	Over 2500 ha of traditional lifestyle land area loss
Land Quality Effects on Traditional Lifestyle (S2-3)	No known or only minor concerns, or not applicable	Known minor concerns that require further work	Known significant concerns that may be very difficult to mitigate[3]
Cabins, Camps, & Structures (S2-4)[4]	Less than 26 Cabins, Camps or other Structures within the right-of-way or buffer area[5], or not applicable	Between 26 and 50 Cabins, Camps or other Structures within the right-of-way or buffer area[5]	Over 50 Cabins, Camps or other Structures within the right-of-way or buffer area[5]
Country Foods (S2-5)	No known concerns or only minor concerns, or not applicable	Known minor concerns that require some further work	Known significant concerns that may be difficult to mitigate[6]

Notes:
1. This indicator is similar to, but not the same as, the environmental indicator En4-1. See text for discussion of the differences.
2. This indicator considers total area (ha) of access loss (i.e., amount of land lost to use and lost to access). The assessment assumes that roads to facilities are gated in order to restrict access to each facility.
3. Examples: adverse impacts on known sacred places, burial grounds, graves.
4. May include indirect impacts on quality of life.
5. For smaller projects, only consider footprint. For larger projects such as pumped storage or small hydro, a buffer of 100 m has been included. A low rating for the larger projects would apply where there are no known sites or low potential for sites within the 100 m buffer.
6. Examples: adverse impacts on known special species, habitat or land; known special spawning grounds or collection areas.

The Traditional Lifestyle indicators as defined in Table D 1-1 focus on the scale of impact (L/M/H), including total area or number of structures impacted, and (for Land Quality Effects on Traditional Lifestyle [S2-3] and Country Foods [S2-5]) whether the effect is positive or negative. Unless otherwise explicitly noted, the evaluations of each resource option for these indicators address only negative effects. Figure D 3-1 provides ratings for assessing relative magnitude of the effect(s) of a resource option on each indicator.

In applying the rating system, available information regarding resource project option descriptions was considered, as well as known types of effects that the various types of projects can have on the social environment.

Traditional Lifestyle indictors have been evaluated based on information available from:

- A combination of known heritage resources and Yukon Historic Sites Inventory (YHSI) resources; cabins, camps, and structures; and high value natural resources; and
- Known traditional lifestyle valued components for other project studies.

In addition, as outlined in Table D 3-1, other environmental and/or social criteria assessments were considered where relevant for each of the S2 indicators.

Table D 3-1: Other Criteria Considered in Evaluation of Traditional Lifestyle

S2 Criteria - Indicators	Other Criteria Considered
Footprint Land Area Impact	En4-1: Footprint Terrestrial Area, including Access and New Flooding
Land Area Loss re: Traditional Lifestyle	En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat En3-2: Protected and Conservation Areas En3-3: Wildlife Key Areas En3-4: Caribou Ranges
Land Quality Effects on Traditional Lifestyle	En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat En3-2: Protected and Conservation Areas En3-3: Wildlife Key Areas En3-4: Caribou Ranges
Cabins, Camps, & Structures	N/A
Country Foods	En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat En3-2: Protected and Conservation Areas En3-3: Wildlife Key Areas En3-4: Caribou Ranges

The following are noted with regard to the assessment approach adopted for each indicator:

- **Footprint Land Area Impact (S2-1)** – Footprint Land Area Impact is a quantitative metric that considers only direct land loss. The total footprint or land area affected may not be permanently lost for the purposes of traditional lifestyle activities (assessed separately below). Accordingly, this indicator is used only as background information and is not directly adopted for the assessment of effects on the Land Quality Effects on Traditional Lifestyle indicator.[2] The rating criteria were selected simply to help assign resource project options to clearly separate groups based on the indicator.
- **Land Area Loss regarding Traditional Lifestyle** – This metric assesses the amount of the footprint or land area that is permanently lost or that can no longer be accessed for traditional lifestyle activities (e.g., an access road or site area that is gated or closed off).

[2] Estimated footprint areas for S2-1 do not correspond to the areas estimated for En4-1, reflecting differences in assumptions and methods used to develop each estimate.

- **For projects located within Whitehorse or Haines Junction** (i.e., fossil thermal, non-fossil thermal [biomass, biogas and waste-to-energy] and other renewable, including solar and storage battery), the total access lost is expected to equal the total area of direct land lost due to the project. This assumes that the areas for the project are gated and access to the site is controlled. However, for each of these sites there are less than 50 ha of total land area affected and consequently effects are expected to be low.
- **Wind projects or geothermal projects located outside of urban centres** – The total area of land loss for these projects ranges between 28 ha (Vista Mountain) and 261 ha (McArthur Springs). The assessment assumes that access roads and the project site are gated with restricted access. Adverse effects are expected, but are anticipated to be low.
- **Small hydro and pumped storage projects -** These projects have higher total area of land affected by the project when reservoir or surface area of affected lakes are considered. Consequently, while the total area of the project may be high, the effects on traditional lifestyle activities, including access to lakes or shoreline areas may not be as large or significant. The assessment considers only the incremental effect on land area due to the project and does not consider the existing surface area of the lake or reservoir.
- **Transmission projects -** The total area loss relating to traditional lifestyle activities will likely be much smaller. The project may create new access into previously inaccessible areas and could have both positive and negative effects on traditional activities.

- **Land Quality Effects on Traditional Lifestyle** – This indicator considers indirect effects on traditional areas or traditional lifestyle activities due to the loss of access or other concerns related to the project. This considers the effects related to footprint and land area effects, as well as land area loss related to traditional lifestyle.
- **Cabins, Camps and Structures** – This is a quantitative indicator that considers the number of dwellings (e.g., cabins, camps) that are either within a project ROW or within a 100m buffer of a project ROW for hydro and pumped storage projects.
- **Country Foods** – This considers the effects on the ability to harvest available country foods (including hunting, trapping, fishing and plant collection activities).

Table D 3-2 summarizes the assessment of the resource options with regard to the indicators for the Traditional Lifestyle criteria.

Table D 3-2: Traditional Lifestyle: All Indicators

Resource Options	Footprint Land Area Impact (S2-1) (ha)	Land Area Loss re: Traditional Lifestyle (S2-2) (ha)	Land Quality Effects on Traditional Lifestyle (S2-3) (L,M,H)	Cabins, Camps, & Structures (S2-4)	Country Foods (S2-5) (L,M,H)
Fossil Thermal (Diesel or LNG)					
Whitehorse Landfill	7	7	L	0	N/A
Takhini Substation	7	7	L	0	N/A
Non-Fossil Thermal					
Waste to Energy (Whitehorse)	1 or 2	1 or 2	L	0	N/A
Biogas (CHP) (Whitehorse Landfill)	1 or 2	1 or 2	L	0	N/A
Biomass (Haines Junction)	2	2	L	5	N/A
Other Non-Hydro Renewable					
Storage Battery (Takhini Substation)	1	1	L	0	N/A
Solar PV: Whitehorse Fixed Tilt: 10 MW	48	48	L	0	N/A
Solar PV: Haines Junction Fixed Tilt: 5 MW	23	23	L	0	N/A
Wind: Cyprus Mine Hill, 20 MW	114	114	L	1	N/A
Wind: Kluane Lake, 20 MW	100	100	L	0	N/A
Wind: Millers Ridge, 20 MW	213	213	L	0	N/A
Wind: Mt. Sumanik , 20 MW	132	132	L	0	N/A
Wind: Sugarloaf Mountain, 20 MW	121	121	L	8	N/A
Wind: Tehcho (Ferry Hill), 20 MW	118	118	L	3	N/A
Wind: Thulsoo Mountain, 20 MW	228	228	L	0	L
Geothermal: McArthur Springs	261	261	L	0	L
Geothermal: Vista Mountain	28	28	L	0	N/A
Hydro Generation					
Pumped Storage: Moon Lake (Tutshi-Moon)	5946	0-500	L	0	L
Pumped Storage: Racine - Moon	1814	0-500	L	1	L
Pumped Storage: Lindeman-Fraser	1006	0-500	L	12	L
Pumped Storage: Racine - Mt. Brown (15 MW)	1743	0-500	L	0	L
Pumped Storage: Racine - Mt. Brown (25 MW)	1743	0-500	L	3	L
Pumped Storage: Atlin - Black Mountain (15 MW)	51711	0-500	L	0	L
Pumped Storage: Atlin - Black Mountain (25 MW)	51711	0-500	L	0	L
Pumped Storage: Squanga - Dalayee	2438	0-500	L	0	M
Pumped Storage: Canyon - Ittlemit	2380	0-500	M	0	L
Pumped Storage: Vangorda Pit	1088	1088	L	1	L
Small Hydro: Drury Lake	2663	190	L	0	L
Small Hydro: Tutshi - Windy Arm	68	310	L	0	L
Small Hydro: Wolf River	325	0	L	6	L
Small Hydro: Finlayson River	15543	540	M	0	M
Small Hydro: Anvil Creek	227	0-500	L	2	L
Small Hydro: Atlin/Pine Creek	3553	0-500	L	7	L
Other Hydro: Gladstone Diversion	667	0-500	M	6	H
Other Hydro: Southern Lakes Storage	54527	0-500	M	~380	L
Other Hydro: Mayo Lake Storage	9665	0	L	0	L
Other Hydro: Mayo Dredging	N/A	N/A	N/A	0	L
Aishihik Re-runnering	N/A	N/A	N/A	0	N/A
Mayo A Refurbishment	NA	NA	NA	0	NA
Transmission Corridors					
Transmission: Whitehorse - Atlin (138 kV)		0-500	L		L
Transmission: Whitehorse - Skagway (230 kV)	1027	0-500	L	47	L
Transmission: Whitehorse - Teslin (138 kV)	1049	0-500	L	16	L
Transmission: Faro - Watson Lake (230 kV)	2563	0-500	L	21	L
Transmission: Aishihik - Destruction Bay (230 kV)	1042	0-500	L	9	L
Transmission: Stewart-Keno City (138 kV & substations)	1143	0-500	L	9	L

3.2 EVALUATION

3.2.1 Resource Options with No Material Concerns re: Traditional Lifestyle

The first indicator in Table D 3-2 (Footprint Land Area Impact [S2-1]) does not directly address effects on traditional lifestyle, and is therefore not considered in this assessment beyond providing background information. The following resource project options have a green (low) rating for each of the four remaining indicators assessed in Table D 3-2, indicating no material basis for concerns regarding the Traditional Lifestyle criteria:

- Fossil fuel thermal generation (diesel and LNG, each in Whitehorse);
- Non fossil thermal generation (biomass at Haines Junction, biogas and waste-to-energy in Whitehorse);
- Energy storage facility (batteries) at Takhini Substation;
- Solar PV at Whitehorse and Haines Junction;
- Wind farms at each of the 7 sites included in this evaluation;
- Geothermal generation at McArthur Springs and Vista Mountain (near Takhini Substation) – it is assumed that any sensitive areas may be avoided with moveable footprint access and transmission line;
- Pumped storage hydro generation options, except for Squanga-Delayee, Canyon-Ittlemit and Vangorda Pit;
- Small hydro options, except for Finlayson River;
- Other hydro options, except for Gladstone Diversion and Southern Lakes Storage Enhancement;
- Hydro refurbishment/maintenance (Mayo A and Aishihik); and
- Transmission corridors (each of the project options included in this evaluation, except for the Whitehorse-Skagway Transmission Corridor).

3.2.2 Hydro Generation

3.2.2.1 Pumped Storage

The following yellow (medium) ratings are assessed for three pumped storage project options:

- Squanga-Dalayee - a yellow (medium) rating for potential effects on Country Foods (S2-5) related to effects to game outfitting[3] and perceived high game habitat;

[3] Outfitting is also discussed in the evaluations for Land Use and Renewable Resource Plans and Tourism.

- Canyon-Ittlemit - a yellow (medium) rating for potential effects of Land Quality Effects on Traditional Lifestyle (S2-3) related to high food values and perceived high game habitat, and game outfitting concerns; and
- Vangorda Pit - a yellow (medium) rating for Land Area Loss regarding Traditional Lifestyle (S2-2) – although this area is adjacent to the disturbed ground of the Vangorda Pit area, this footprint is basically undisturbed and would affect a relatively large amount of land and stream basin.

3.2.2.2 Small Hydro

The Finlayson River option is rated yellow (medium) for Land Area Loss regarding Traditional Lifestyle (S2-2), Land Quality Effects on Traditional Lifestyle (S2-3), and potential effects on Country Foods (S2-5). This option would overlap with a moderate amount of land area (in the yellow/medium category), and has known significant values for wetlands, game and fisheries.

3.2.2.3 Other Hydro

Red (high) ratings are provided for the following indicators and projects (assessments are made prior to consideration of potential mitigation that may be developed for each project):

- Gladstone Diversion - a red (high) rating for potential effects on Country Foods (S2-5). A significant concern here is based on the federal fisheries concerns of potential risk of disease (due to potential interbasin pathogen transfer) and perceived high values of indirect effects similar to previous concerns at the Aishihik Generating Station, such as changes in water levels and related possible effects.
- Southern Lakes Enhanced Storage - a red (high) rating for potential effects on Cabins, Camps and Structures (S2-4). The cabins, camps and structures values are the highest of all the resource options and reflect a high level of private and First Nations concerns, possible effects to graves and perceived concerns of ground water effects and erosion.

The same two resource options also have a yellow (medium) rating for potential effects on Land Quality Effects on Traditional Lifestyle (S2-3).

3.2.2.4 Transmission Corridors

The Whitehorse-Skagway transmission corridor resource option has yellow (medium) rating for potential effects on Cabins, Camps and Structures (S2-4). It is likely that the project routing would be selected to address any such potential effects.

4.0 HERITAGE RESOURCES

4.1 RATING CRITERIA AND DATA SOURCES FOR S3: HERITAGE RESOURCES

The rating system outlined in Figure D 4-1 was adopted to guide evaluations of each resource project option for each of the Heritage indicators.

Figure D 4-1: Summary of Rating Criteria for Heritage Resources

Indicator	Low	Medium	High
Density of Heritage Resources (S3-1)	Few known or expected heritage sites[1] (approximately <2) within or near project right-of-way or buffer area[2]	Small number of known heritage sites within or near ROW or buffer (approximately>2 and <25); high potential for archeological sites	High number of heritage sites within or near ROW or buffer (approximately >25)
Importance/ Cultural Value of Heritage Resources (S3-2)	No known sites of cultural value (or only minor concerns) within or near project right-of-way or buffer area[2]	Presence of known minor sites with concerns that require further work	Presence of known sites or potential sites with known significant concerns[3]

Notes:
1. Heritage site or heritage resources includes YHSI sites, paleontological sites, and archeological sites or other sites of cultural value.
2. For smaller projects, the evaluation only considers footprint. For larger projects, such as pumped storage or small hydro, a buffer of 100 m has been included. A low rating for the larger projects would apply where there are no known heritage sites or low potential for heritage sites within the 100m buffer. Transmission projects are rated low if route selection is likely to avoid any effects on heritage sites.
3. Examples: known significant sites and resources, sacred places, burial grounds, graves. This indicator does not include parks, as parks are included in the environmental indicator Protected and Conservation Areas (En3-2).

The Heritage Resources indicators as defined in Table D 1-1 focus on the scale of effect (L/M/H), including total area or number of heritage resources (and important heritage resources) affected. Unless otherwise explicitly noted, the evaluations of each resource option for these indicators address only negative effects. Figure D 4-1 provides ratings for assessing relative magnitude of effect of a resource activity on each indicator. “Heritage resources” include known archeological sites, known YHSI sites, known paleontological sites, known areas of archeological potential and areas of ethnographical potential.

In applying the rating system, available information was considered regarding resource project option descriptions, as well as known types of effects that the various types of projects can have on the social environment.

Heritage Resources indicators have been evaluated based on information available from:

- Previously recorded archeological, paleontological and historic sites in Yukon and British Columbia and YHSI records.

The approach and assumptions used in evaluating potential effects on Heritage Resources indicators are:

- Looked for overlap between resource project option sites and the following:
    - Known archeological sites;
    - Known YHSI sites;
    - Known paleontological sites;
    - Known areas of archeological potential; and
    - Areas of ethnographical potential.
- Combined number of sites and resources by total hectares (ha).
- Considered whether there were sites of specific cultural value or importance.

Table D 4-1 summarizes the assessment of the resource options with regard to the indicators for the Heritage Resource criteria. Resource options rated yellow or red for any indicator are highlighted with the colour rating. The considerations in each evaluation are reviewed in Section 4.2 below.

Table D 4-1: Heritage Resource: All Indicators

	Density of Heritage Resources (S3-1 - combined number of sites & resources by area)	Importance / Cultural Value (S3-2 - Summary of Overall Concerns)
Fossil Thermal (Diesel or LNG)		
Whitehorse Landfill		
Takhini Substation		
Non-Fossil Thermal		
Waste to Energy (Whitehorse)		
Biogas (CHP) (Whitehorse Landfill)		
Biomass (Haines Junction)		
Other Non-Hydro Renewable		
Storage Battery (Takhini Substation)		
Solar PV: Whitehorse Fixed Tilt: 10 MW		
Solar PV: Haines Junction Fixed Tilt: 5 MW		
Wind: Cyprus Mine Hill, 20 MW		
Wind: Kluane Lake, 20 MW		
Wind: Millers Ridge, 20 MW		
Wind: Mt. Sumanik , 20 MW		
Wind: Sugarloaf Mountain, 20 MW		
Wind: Tehcho (Ferry Hill), 20 MW		
Wind: Thulsoo Mountain, 20 MW		
Geothermal: McArthur Springs		
Geothermal: Vista Mountain		
Hydro Generation		
Pumped Storage: Moon Lake (Tutshi-Moon)		
Pumped Storage: Racine - Moon		
Pumped Storage: Lindeman-Fraser		
Pumped Storage: Racine - Mt. Brown (15 MW)		
Pumped Storage: Racine - Mt. Brown (25 MW)		
Pumped Storage: Atlin - Black Mountain (15 MW)		
Pumped Storage: Atlin - Black Mountain (25 MW)		
Pumped Storage: Squanga - Dalayee		
Pumped Storage: Canyon - Ittlemit		
Pumped Storage: Vangorda Pit		
Small Hydro: Drury Lake		
Small Hydro: Tutshi - Windy Arm		
Small Hydro: Wolf River		
Small Hydro: Finlayson River		
Small Hydro: Anvil Creek		
Small Hydro: Atlin/Pine Creek		
Other Hydro: Gladstone Diversion		
Other Hydro: Southern Lakes Storage		
Other Hydro: Mayo Lake Storage		
Other Hydro: Mayo Dredging		
Aishihik Re-runnering		
Mayo A Refurbishment		
Transmission Corridors		
Transmission: Whitehorse - Atlin (138 kV)		
Transmission: Whitehorse - Skagway (230 kV)		
Transmission: Whitehorse - Teslin (138 kV)		
Transmission: Faro - Watson Lake (230 kV)		
Transmission: Aishihik - Destruction Bay (230 kV)		
Transmission: Stewart-Keno City (138 kV & substations)		

4.2 EVALUATION

4.2.1 Resource Options with No Material Concerns re: Heritage Resources

The following resource project options have a green (low) rating for each of the heritage resources indicators reviewed in Table D 4-1, indicating no material basis for concerns regarding the Heritage Resources criteria:

- Fossil fuel thermal generation (diesel and LNG, each in Whitehorse);
- Non fossil thermal generation (biomass in Haines Junction, biogas and waste-to-energy in Whitehorse);
- Energy storage facility (batteries) at Takhini Substation;
- Solar PV in Whitehorse and Haines Junction;
- Wind farms at Cyprus Mine Hill and Kluane Lake;
- Geothermal generation at Vista Mountain (near Takhini Substation);
- Pumped storage hydro generation options at Moon Lake (Tutshi-Moon), Racine-Moon, Racine-Mt. Brown, and Vangorda Pit;
- Small hydro options at Drury Lake and Wolf River;
- Other hydro options – Mayo Lake Storage Enhancement and Mayo Dredging;
- Hydro refurbishment/maintenance (Mayo A and Aishihik); and
- Transmission corridors – Faro-Watson Lake.

4.2.2 Non-Hydro Renewables

4.2.2.1 Wind Farms

All of the wind farm options are rated green (low) for Density of Heritage Resources (S3-1). Although there are no heritage sites known today in these footprints, the following five wind farm options are rated yellow (medium) for Importance/Cultural Value of Heritage Resources (S3-2) due to the predicted high potential areas that the footprints overlap:

- Miller's Ridge;
- Mt. Sumanik;
- Sugarloaf Mountain;
- Tehcho (Ferry Hill); and
- Thulsoo Mountain.

4.2.2.2 Geothermal – McArthur Springs

McArthur Springs geothermal is rated green (low) for Density of Heritage Resources (S3-1) and rated yellow (medium) for Importance/Cultural Value of Heritage Resources (S3-2). A medium rating is based on expected level of sites and resources.

4.2.3 Hydro Generation

4.2.3.1 Pumped Storage

The following three pumped storage sites are rated yellow (medium) for Density of Heritage Resources (S3-1) and for Importance/Cultural Value of Heritage Resources (S3-2):

- Lindeman-Fraser – Chilkoot Trail National Historic Site and related resources and areas of potential;
- Squanga-Dalayee - structures close to footprint on Dalayee Lake and structures near footprint on Squaqnga Lake, significant heritage potential; and
- Canyon-Ittlemit - reference to previous Champagne and Aishihik First Nations (CAFN) concerns regarding Aishihik Generating Station.

The Atlin-Black Mountain pumped storage site is rated red (high) for Density of Heritage Resources (S3-1) and green (low) for Importance/Cultural Value of Heritage Resources (S3-2).

4.2.3.2 Small Hydro

The Finlayson River and Anvil Creek small hydro sites are each rated yellow (medium) for Density of Heritage Resources (S3-1) and for Importance/Cultural Value of Heritage Resources (S3-2) due to significant heritage and paleontological potential. The Anvil Creek site ratings reflect high archaeological potential along Anvil Lake shore, along Anvil and Blind Creek, and Pelly River valley.

The Tutshi-Windy Arm and Atlin-Pine Creek small hydro sites are each rated yellow (medium) for Density of Heritage Resources (S3-1) and green (low) for Importance/Cultural Value of Heritage Resources (S3-2).

4.2.3.3 Other Hydro - Gladstone Diversion and Southern Lakes Storage Enhancement

Gladstone Diversion is rated yellow (medium) for Density of Heritage Resources (S3-1) and for Importance/Cultural Value of Heritage Resources (S3-2) due to moderate amount of sites and CAFN concerns.

Southern Lakes Storage Enhancement is rated red (high) for Density of Heritage Resources (S3-1) and for Importance/Cultural Value of Heritage Resources (S3-2), due to high number of sites and Carcross/Tagish First Nation (CTFN) concerns.

4.2.3.4 Transmission Corridors – Other Than Faro-Watson Lake

Each of the transmission corridors other than Faro-Watson Lake is rated yellow (medium) for Density of Heritage Resources (S3-1), reflecting the potential for a notable number of heritage resource sites along such corridors.

The Whitehorse-Skagway Transmission Corridor is also rated yellow (medium) for Importance/Cultural Value of Heritage Resources (S3-2), reflecting the Chilkoot Trail National Historic Park of Canada and Klondike Gold Rush National Historic Site (USA) and related resources, as well as BC and Alaska Historic Site concerns.

5.0 TOURISM, RECREATION AND OTHER RESOURCES AND LAND USE

5.1 RATING CRITERIA AND DATA SOURCES FOR S4: TOURISM, RECREATION, AND OTHER RESOURCES AND LAND USE

The rating system outlined in Figure D 5-1 was adopted to guide evaluations of each resource project option for each of the tourism, recreation, and other resources and land use indicators.

Figure D 5-1: Summary of Rating Criteria for Tourism, Recreation, and Other Resources and Land Use

Indicator	Low	Medium	High
Recreational Values (S4-1)	No nearby/ affected recreational sites, or not applicable[1]	Project visible or audible – do not expect major change in recreational activities	Project overlaps with site(s)/ may necessitate a major change in recreational activities
Tourism Values (S4-2)	No nearby/ affected tourism opportunities, or not applicable[1]	Project overlaps with site – do not expect major change in activities	Project overlaps with site(s)/ may necessitate a major change in tourist activities
Aesthetics (S4-3)	Project not visible/audible from known valued viewpoints/ communities, or not applicable	Project visible or audible from known valued viewpoints/ communities - not expect major aesthetic value change	Project location may disrupt/ disturb valued viewpoint/ community-noted aesthetic value of area
Non-renewable Resources (S4-4)	No overlap with claims and current extraction activities, or not applicable[1]	Project overlaps with known claims - not expect major change in ability to undertake activity	Project overlaps and may affect ability to undertake resource extraction activity
Other Renewable Resources (S4-5)	No overlap with known renewable resource activities, or not applicable	Project overlaps with known renewable resource activity - not expect major change in the activity	Project overlaps and may affect the ability to undertake renewable resource activity
Land Use and Renewable Resource Plans (S4-6)	Project does not overlap with such plans, or not applicable	Project overlaps with such plans – not in conflict nor a cause a major change in activity	Project is located in zone with conflicting usage designation

Note:
1. Projects may also have a positive effect on recreational values, tourism values, and non-renewable resources (e.g., access enabled by transmission lines or access roads). These indicators do not include parks per se, as parks are included in the environmental indicator Protected and Conservation Areas (En3-2). Activities in and tourism associated with parks are discussed in evaluations where relevant.

The Tourism, Recreation, and Other Resources and Land Use indicators as defined in Table D 1-1 focus generally on whether the effect of the resource option on the indicator is positive or negative, and the relative magnitude of the effect (L/M/H). Unless otherwise explicitly noted, the evaluations of each resource option for these indicators have identified only negative effects. Figure D 5-1 provides ratings for assessing relative magnitude of effect from a resource option on each indicator, including provision

for a possible yellow (medium) magnitude effect that differs from red (high) magnitude (even for S4-6, where the indicator assumes a Yes/No or Not Applicable rating). Overall, the social evaluations tend to treat "not applicable" in the same manner as the environmental evaluations treat "no linkage."

Tourism, Recreation, and Other Resources and Land Use indicators have been evaluated based on information available from:

- **Yukon Environment:** Community-based Work Plans (for Renewable Resource Council), wildlife management plans, trapping concessions, campground locations, forestry plans;
- **Department of Tourism and Culture:** tourism information;
- **Community Websites:** Official Community Plans, Zoning by-laws, tourism and recreation information, infrastructure and services;
- **Yukon Department of Energy, Mines and Resources:** Claims information;
- **Geomatics Yukon:** Spatial data; and
- **DataBC:** Spatial data.

Summary baseline information for population centres near resource options are included in Attachment 1. Information includes population counts, applicable land use plans, infrastructure and services.

In addition to outside sources, results from other evaluations were considered. Table D 5-1 presents the other environmental, social, and economic criteria inform the evaluations in this section.

Table D 5-1: Other Criteria Considered in Evaluation of Tourism, Recreation, and Other Resource and Land Use

S4 Criteria - Indicators	Other Criteria Considered
Recreational Values (S4-1)	En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat En3-2: Protected and Conservation Areas En3-3 Wildlife Key Areas En3-4 Caribou Ranges
Tourism Values (S4-2)	En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat En3-2: Protected and Conservation Areas En3-3 Wildlife Key Areas En3-4 Caribou Ranges
Aesthetics (S4-3)	N/A
Non-renewable Resources (S4-4)	N/A
Other Renewable Resources (S4-5)	N/A
Land Use and Renewable Resource Plans (S4-6)	En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat En3-2: Protected and Conservation Areas En3-3 Wildlife Key Areas En3-4 Caribou Ranges

The approach and assumptions used in evaluating potential effects on Tourism, Recreation, and Other Resources and Land Use indicators are:

- Looked for geographic overlap between resource project option sites and known recreational sites, tourist sites, mineral and oil and gas claims, designated areas in planning and resource management documents.
- Direct spatial overlap would result in at least a medium ranking because it is assumed that it could potentially result in some change in activity or desirability of engaging in the activity at that site. A red rating results if there is a potential for major change in the indicator.
- There is not necessarily a linkage related to aesthetics solely because a site is a greenfield site. The site must be visible and infrastructure must have an effect on a landscape that someone values (e.g., be visible from a viewpoint popular for wildlife viewing).
- In light of the remote location of most of the projects, the focus for recreation and tourism is on outdoor activities (e.g., hiking, fishing, camping) and it assumed that individuals engaging in these activities value undisturbed landscapes.

Limitations to the evaluation include:

- Recreational and tourism values are personal and subjective. Changes to a recreational or tourist experience because of project development may adversely affect the experience for one individual but not have an effect on another individual's experience. For evaluating changes in recreational and tourism experiences, the evaluation focuses primarily on physical proximity as assessable with desktop research, i.e., no interviews or field work was feasible.
- All projects fall within an area overseen by a Renewable Resource Council (RRC). The status of community-based fish and wildlife work plans were at different stages at the time of these evaluations and some RRCs do not complete multi-year work plans. The evaluations for Land use and Renewable Resource Plans (S4-6), therefore, incorporate plans where they are known. It is assumed that the appropriate RRC will be engaged should a given project be advanced.

5.2 EVALUATION

5.2.1 Resource Options with No Material Concerns re: Tourism, Recreation and Other Resources and Land Use

Table D 5-2 provides a summary of the resource project options with green (low) ratings for each of the tourism, recreation and other resources and land use indicators. Brief supporting information and analysis is provided in the table on the application of the Tourism, Recreation, and Other Resources and Land Use indicators to these resource options.[4]

[4] Detailed review of mapping or local plan information has not been done for these resource options. If and when a resource option is subject to more detailed feasibility and planning review, it is possible that specific issues may arise that will need to be addressed in order to proceed.

Table D 5-2: Resource Project Options with Green Ratings for All Tourism, Recreation and Other Resources & Land Use Indicators

Resource Project Options	Comments re: All Indicators being Green
Fossil Fuel Thermal (Diesel or LNG)	
Whitehorse Landfill	Brownfield site with current industrial use; zoned for public utilities.
Takhini Substation	Adjacent to brownfield site (substation). No apparent conflicts; however, planning issues must be addressed.[1]
Non-Fossil Thermal	
Waste-to-Energy (Whitehorse)	Assumed brownfield site without any conflicts.
Biogas (Whitehorse)	Brownfield site; zoned for public utilities.
Energy Storage Facility	
Takhini Substation	Adjacent to brownfield site (substation). No apparent conflicts; however, planning issues must be addressed.[1]
Solar PV	
Whitehorse	Brownfield site (abandoned mine site); zoned for heavy utilities and future planning.
Haines Junction	Semi-open site near landfill, no apparent conflict.
Wind Farms	
Cyprus Mine Hill	Brownfield site, no apparent conflicts.
Mt. Sumanik	Proximity to Whitehorse; no apparent conflicts. However, planning issues must be addressed.[2]
Tehcho (Ferry Hill)	No apparent conflicts.
Geothermal	
Vista Mountain	Near brownfield site (Takhini Substation); No apparent conflicts; however, planning issues must be addressed.[1]
Pumped Storage	
Vangorda Pit	Faro mine site (brownfield site); No apparent conflicts; however, planning issues must be addressed.[3]
Hydro Storage Enhancements	
Mayo Lake	No apparent conflicts with any indicator.
Southern Lakes	No apparent conflicts with any indicator; borders multiple development zones.[4]
Mayo Outlet Channel Dredging	No apparent conflicts with any indicator.[4]
Refurbish/ Enhance Existing Hydro	Existing generating station site; no conflicts.
Mayo A	
Aishihik re-runnering	
Transmission Corridors	BMPs/routing by highway/assume can avoid conflicts with any indicator, e.g., assume avoid potential conflict with Caribou Hotel in Carcross which is near proposed centerlines for Whitehorse-Skagway corridor.
Aishihik-Burwash[5]	
Faro – Watson Lake	
Whitehorse – Atlin	
Whitehorse – Skagway[6]	
Whitehorse – Teslin	
Stewart- Keno	

Notes:

1. Infrastructure would be located in zones of the Mayo Road Development Area Regulation (Public Use and Institutional); First Nations Land Use; and Hinterland. 2005/I75.
2. Located in Whitehorse Periphery Development Regulation (Rural Residential 2013/207).
3. Infrastructure would be located in Hinterland zoning for Town of Faro 96-06.
4. Each of these projects may result in some visible changes when mitigation or dredging is being undertaken; BMPs are assumed to address any short-term disruptions, e.g., sustained boat access to Mayo Lake during dredging activities.
5. A section of the centreline for this transmission corridor as shown in the Midgard [2016], (see Appendix A) runs through Kluane National Park; Midgard notes that there is an option between Hwy 1 and Kluane Lake, which would have at least a medium effect on Land Use and Renewable Resource Plans and/or Aesthetics. The Kluane Lake wind farm resource option (and related transmission) is assumed to be in the area between Hwy 1 and Kluane Lake.
6. The Klondike Hwy from Skagway to Whitehorse is a popular drive for its scenery and historical significance, which is the proposed route for the Whitehorse to Skagway transmission line. The highway also abuts the Tsongas National Forest in Alaska (not the Klondike Gold Rush National Historical Park as suggested in Midgard [2016]), which may have an effect on the Aesthetics.

5.2.2 Non-Hydro Renewable Generation

The following non-hydro renewable generation options have at least one of the Tourism, Recreation, and Other Resources and Land Use indicators rated yellow or red, and therefore the resource option is not included in Table D 5-2.

5.2.2.1 Non-Fossil Thermal Generation - Biomass at Haines Junction

For the purpose of this evaluation, the biomass thermal generation resource option plant at Haines Junction is assumed to be located within city limits and likely near the school to take advantage of captured school waste heating load. It would require 400m buffer zones around buildings and potentially 500m to 1,000m buffers for sensitive receptors.

The potential concern regarding this site location for the biomass plant is that it is adjacent to undeveloped land zoned for residential use and on land zoned for community use/commercial.

Table D 5-3: Summary of Assessment for Non-Fossil Thermal Generation - Biomass

Project / Option	Indicator	Ranking	Assessment
Biomass (Haines Junction)	Recreational Values	**Low**	Assuming use of location recommended in Stantec report, which is zoned community use/commercial, the project is not anticipated to overlap with recreational sites/activities. Recreational values are rated low.
	Tourism Values	**Low**	Tourism activities in Haines Junction are assumed to be focused on servicing visitors to the Kluane National Park and Reserve of Canada. While the project may be audible and visible in town, it is not anticipated to change tourist activities nor is it anticipated to overlap with any known tourist sites within town limits.
	Aesthetics	**Medium**	Assumes siting near school, which is downtown and near residential and commercial areas, therefore aesthetics is rated medium.
	Non-renewable Resources	**Low**	No overlap with mineral, placer, or quartz claims.
	Other Renewable Resources	**Low**	No known conflicts.
	Land Use and Renewable Resource Plans	**Medium**	The location recommended in the Stantec report is adjacent to undeveloped land zoned for residential use and on land zoned for community use or commercial. It is anticipated that there will need to be some zoning variance for the project and adjacent residential development will need to be altered. Located in area for Alsek Renewable Resource Council Plan but no overlap with concerns is apparent.

5.2.2.2 Wind Farms

The following wind farm options have at least one of the Tourism, Recreation, and Other Resources and Land Use criteria indicators rated yellow or red, and therefore the resource option is not included in Table D 5-2.[5] The wind farm resource option assumes a 20 MW development on each site, with 10 turbines each of which has a 90-metre rotor diameter and 80-metre height. Ratings for Tourism, Recreation, and Other Resources and Land Use criteria take into consideration potential for concerns about wind farm effects on aesthetics and recreational or tourism values related to visual and auditory effects.

[5] Wind farms at Cyprus Mine Hill, Mt. Sumanik, Tehcho (Ferry Hill) and Thulsoo Mountain are included in Table D 5-2.

Table D 5-4: Summary of Assessment for Wind Farms

Project / Option	Indicator	Ranking	Assessment
Kluane Lake (west shore)	Recreational Values	**Medium**	Changes to landscape may change enjoyment of fishing on Kluane Lake.
	Tourism Values	**Medium**	Changes to landscape may change tourism value of fishing on Kluane Lake.
	Aesthetics	**Medium**	Anticipated to be visible from Alaska Hwy and Kluane Lake. May be visible from Kluane National Park. Potential noise disturbance.
	Non-renewable Resources	**Low**	No overlap with mineral, quartz, or placer claims.
	Other Renewable Resources	**Low**	No known conflicts.
	Land Use and Renewable Resource Plans	**Low**	Located in the Beaver Creek/Burwash/Destruction Bay Annual Limit Region but does not overlap with timber harvest plans or harvest licences. Located in area for Alsek Renewable Resource Council Plan but no overlap with areas of concern is apparent.
Miller's Ridge (west of, & close to, Carmacks)	Recreational Values	**Medium**	Miller's Ridge features a hiking trail that may potentially be affected. However, the Nansen Mine Road routes immediately under and south of the ridge for the wind farm.
	Tourism Values	**Medium**	Potentially precludes part of the hiking trail on Miller's Ridge but overall tourism in and around Carmacks should not be materially altered outside of Miller's Ridge trail.
	Aesthetics	**Medium**	Visible from Hwy 2 and due to elevated position, potentially visible from Carmacks. Potential noise disturbance.
	Non-renewable Resources	**Low**	Overlaps with 12 expired quartz claims.

Project / Option	Indicator	Ranking	Assessment
	Other Renewable Resources	Low	No known conflicts.
	Land Use and Renewable Resource Plans	Medium	Located in Carmacks West Moose Management Unit, but no activity cited in RRC Work Plan. Located in the Carmacks Annual Limit Region and overlaps with two cutting permits – one for the Village of Carmacks and one for Yukon Government, Department of Highways and Public Works.
Sugarloaf Mountain (southeast of Carcross)	Recreational Values	Low	Potentially affects value of Brute Mountain as hiking destination because infrastructure is anticipated to be visible from top. Do not expect major change in recreational activities.
	Tourism Values	Low	Potentially affects value of Brute Mountain as hiking destination because infrastructure is anticipated to be visible from top. Do not expect major change in tourism activities.
	Aesthetics	Medium	Infrastructure anticipated to be visible from Brute Mountain, which is endpoint for hike valued for its view. Potential noise disturbance.
	Non-renewable Resources	Low	Does not overlap with any leases or claims.
	Other Renewable Resources	Low	No known conflicts.
	Land Use and Renewable Resource Plans	Medium	Project is located in the Carcross Local Area Plan and Carcross Development Area Regulation, with the transmission line as it approaches Carcross from the south currently overlapping with the largest variety of zones: Mixed Residential Commercial, Residential, Tourist Commercial, and Commercial (1976/231). South of Carcross, the transmission line and the northern turbines are in areas zoned as Hinterland, which is a "'catch-all' open space designation that has been applied liberally to lands with no pre-determined purpose, most Settlement Lands, as well as environmentally sensitive lands" (Inukshuk Planning and Development Ltd. 2013). Located in the Whitehorse Annual Limit Region and Whitehorse-Southern Lakes Forest Management Planning Area but does not overlap with any cutting permits or Timber Harvest Plans.
Thulsoo Mountain	Recreational Values	Medium	Current location of project infrastructure may make camping at Otter Falls Campground less desirable, although it may not necessarily necessitate change in activities.

Project / Option	Indicator	Ranking	Assessment
	Tourism Values	Low	Potentially affects Otter Falls Campground and is located in outfitting concession 13 but is not anticipated to materially affect tourist activities.
	Aesthetics	Medium	Project is located in relatively close proximity to Otter Falls Campground and may be visible/audible from site.
	Non-renewable Resources	Medium	Project overlaps with multiple quartz claims, although is not anticipated to require a change in activities.
	Other Renewable Resources	Low	No apparent conflicts.
	Land Use and Renewable Resource Plans	Medium	Project infrastructure overlaps with two fuel wood licences, outfitting concession 13, which is discussed in tourism, and multiple trapping concessions.

5.2.2.3 Geothermal - McArthur Springs

The McArthur Springs project is located in the Ddhaw Ghro Habitat Protection Area. While the management plan for this area is still under development, protection areas are typically created to preserve culturally or environmentally important features (Environment Yukon 2016). According to planning documents the Ddhaw Ghro mountain range has multiple regionally significant features, including unglaciated alpine areas and plant communities, a culturally important hot spring, fannin sheep population, an intact mountain ecosystem, and cultural importance to the Northern Tutchone People (ScienceBase 2006).

Table D 5-5: Summary of Assessment for Geothermal - McArthur Springs

Project / Option	Indicator	Ranking	Assessment
McArthur Springs	Recreational Values	**Medium**	Changes in aesthetics anticipated to reduce attractiveness of area for recreational activities but a new access road in difficult terrain may open up area. New access may be seen as positive (e.g., increased camping, hiking, fishing) or negative (increased hunting in an area where the local RRC is trying to protect wildlife).
	Tourism Values	**Medium**	Changes in aesthetics anticipated to reduce attractiveness of area as a tourist destination but a new access road in difficult terrain may open up area.
	Aesthetics	**High**	Located in a protected area, which has cultural significance to the Northern Tutchone People and is valued for several environmental elements. In light of this, project infrastructure (plant site, production wells, induction well, access road) and operations would alter valued visual and auditory environment.
	Non-renewable Resources	**Medium**	Location designated as mining interest for Selkirk First Nation (SFN). While a new access road in difficult terrain my open up area to new opportunities, it is unlikely that parties will be able to take advantage of opportunities in light of area's status as a protected area.
	Other Renewable Resources	**Medium**	While a new access road in difficult terrain my open up area to new opportunities, it is unlikely that parties will be able to take advantage of opportunities in light of area's status as a protected area.
	Land Use and Renewable Resource Plans	**High**	Located in Mayo District Renewable Resource Council, the Project overlaps with two areas subject to high priority activities: managing the Ethel Lake Caribou Herd and monitoring sheep populations. Located in the Pelly Crossing Annual Limit Region but does not overlap with currently active Timber Harvest Plans or Cutting Permits. Overlaps with three trapping concessions, since project is located in a proposed protected area (Ddhaw Ghro Habitat Protection Area), project is not anticipated to interfere with trapping activities.

5.2.3 Hydro Renewable Generation

The following hydro renewable generation options have at least one of the Tourism, Recreation, and Other Resources and Land Use criteria indicators rated yellow or red, and therefore the resource option is not included in Table D 5-2.

5.2.3.1 Pumped Storage

The only pumped storage option included in Table D 5-2 is Vangorda Pit. Assessment of the remaining pumped storage resource options is provided in Table D 5-6. No attempt is made to assess any variances for specific sites developed at 50 GWh versus 100 GWh storage.

Table D 5-6: Summary of Assessment for Pumped Storage (excluding Vangorda Pit)

Project / Option	Indicator	Ranking	Assessment
Atlin – Black Mountain	Recreational Values	**Low**	According to the Wóoshtin wudidaa Atlin Taku Land Use Plan), the area has high recreational value for local community, including resource gathering and recreation; however, activities are centred on Indian/Porter Lake, Steamboat Mountain, and Fourth of July Creek, which are southeast of the upper reservoir lake. Associated linear infrastructure may make the upper reservoir lake, which may contain burbot, more accessible for recreational fishing.
	Tourism Values	**Low**	Project is located in a new/proposed protected area (Indian Lk – Hitchcock Ck At Ch' according to the Wóoshtin wudidaa Atlin Taku Land Use Plan). While site is located in area, it does not appear to overlap directly with known or currently planned tourism sites/activities.
	Aesthetics	**Low**	Locations noted as valued in the At Ch'ini Sha Protected Area are not in the vicinity of the project location. The project is not anticipated to be visible/audible from known viewpoints and nearby communities. Project infrastructure, however, will cross area with a visual quality objective of preservation, but this primarily applies to forestry practices.
	Non-renewable Resources	**Medium**	Project overlaps with eight mineral claims and one placer claim.
	Other Renewable Resources	**Low**	No known conflicts.
	Land Use and Renewable Resource Plans	**High**	Project is located in a proposed protected area (Indian Lk – Hitchcock Ck according to the Wóoshtin wudidaa Atlin Taku Land Use Plan). Focus of the protected area is Indian Lake and Hitchcock Creek, not the lake being used for upper reservoir. Objectives for protected area are to protect high-value caribou winter habitat, ensure management contributes to health of caribou and sheep populations, maintain high recreational values of area. According to the environmental evaluation, the project occurs within the Atlin and Carcross Caribou herd ranges and in a Wildlife Key Area for thin horn sheep. The evaluation for commercial, recreational, and Aboriginal (CRA) fishery notes that burbot may be present in the upper reservoir lake, which is valued by recreational and aboriginal fisheries. In addition, major hydroelectric development other than local run-of-the-river projects that "supply power to approved uses in the protected areas" are prohibited. The Yukon portion of the Project is located in the Tagish Local Advisory Area, which is represented by a local advisory council. Local advisory councils advise the Minister of Community Services but do not create bylaws or collect taxes.

Project / Option	Indicator	Ranking	Assessment
Canyon – Ittlemit	Recreational Values	**High**	The project does not overlap with known/currently planned recreational activities, although the presence of lake trout in Ittlemit Lake suggests that recreational fishery may be present and Canyon Lake is included in Environment Yukon material on recreational fishing with lake trout and whitefish present. The increase of methylmercury production as a result of the volume increase in Canyon Lake may alter recreational fishing activities as consumption patterns of lake trout may need to be altered.
	Tourism Values	**Medium**	The project is located in Outfitting Concession 13, which advertises hunts for moose, wolverine, wild wood bison, black and grizzly bears, dall sheep, wolf, mountain caribou, and fishing. If outfitter uses Canyon or Ittlemit lakes for fishing activities, they may be required to temporarily use other lakes due to an increase in methylmercury production. Independent tourists may also need to temporarily use other fishing lakes for the same reason. In addition, potential changes to aesthetics along Aishihik Road (route to Otter Falls) may make area less attractive as a tourist site.
	Aesthetics	**Medium**	Project infrastructure may be visible from Aishihik Road, which leads from Canyon to Otter Falls and Aishihik Village.
	Non-renewable Resources	**Low**	No overlap with mineral, placer, or quartz claims or leases.
	Other Renewable Resources	**Low**	No known conflicts.
	Land Use and Renewable Resource Plans	**Medium**	Overlaps with two trapping concessions, although it is not anticipated to require a change in trapping activities. Project is located in the Champagne and Aishihik Traditional Territory Strategic Forest Management Plan in an area that is low priority for planning and merchantable timber (Alsek Renewable Resource Council 2004) and two fuel wood licence areas.
Lindeman – Fraser	Recreational Values	**Medium**	The Chilkoot Trail runs along the west side of Lake Lindeman. The trail is a Historic Site and is likely valued by hikers for its hiking terrain and its place in Canadian history. A limited number of permits are issued. The presence of project infrastructure may not change activities but the change in aesthetics may change the desirability of using the northern part of the trail and the campgrounds next to Lindeman Lake.
	Tourism Values	**Medium**	The Chilkoot Trail runs along the west side of Lake Lindeman and is a tourist destination. The presence of project infrastructure may not

Project / Option	Indicator	Ranking	Assessment
			change activities but the change of in aesthetics may change the desirability of using the northern part of the trail and the campgrounds next to Lindeman Lake.
	Aesthetics	**Medium**	Project infrastructure (powerhouse, transmission line, potentially penstock) would likely be visible from trail and/or two campgrounds on the west side of Lindeman Lake but is not anticipated to disrupt known views.
	Non-renewable Resources	**Low**	No overlap with mineral, placer, and coal claims and leases.
	Other Renewable Resources	**Low**	The project is not anticipated to have any effect on other renewable resources.
	Land Use and Renewable Resource Plans	**Medium**	Project is located within the Atlin Taku Land Use Plan, although there appears to be no overlap with designated zones so project neither conflicts with nor causes substantive change in activity. Project is located in Chilkoot Trail National Historic Site of Canada. While project may not alter activities, National Historic Sites are regulated by some of the subsections of the *Canada National Parks Act* regarding usage. Since protected areas are included in the environmental evaluation, this has been rated as a medium.
Racine – Moon	Recreational Values	**High**	According to the evaluation of CRA fishery, multiple species are present in Racine Lake, while no fish are present in Moon Lake. Impoundment may increase methylmercury production, which could alter fishing patters as consumption patterns may need to be changed. The dam may obstruct flows between Racine Lake and Tagish Lake may also change flows at Racine Falls, which is a recreational site.
	Tourism Values	**Medium**	In addition to being used for recreational activities, the general area is used by an outfitter for hunting and fishing, but the project is not anticipated to materially alter activities.
	Aesthetics	**Low**	Since Racine Lake and Moon Lake are removed from major waterways and not near communities, it is anticipated that the presence of the project will not be visible or audible from known viewpoints and communities.
	Non-renewable Resources	**Medium**	Project overlaps with two mineral claims.
	Other Renewable Resources	**Low**	No known conflicts.

Project / Option	Indicator	Ranking	Assessment
	Land Use and Renewable Resource Plans	High	The eastern part of Racine Lake, Racine Creek, and Racine Falls are part of the Racine Falls Resource Management Area, which falls within the Atlin Land Use Plan. Racine Falls is a Goal 2 area by BC's Protected Areas Strategy, which is for special features and means that it is "set aside primarily to protect rare or vulnerable features." The dam may obstruct flows between Racine Lake and Tagish Lake may also change flows at Racine Falls, which is a recreational site.
Racine – Mt. Brown	Recreational Values	High	According to the evaluation of CRA fishery, multiple species are present in Racine Lake, while there is no fish sampling information for the unnamed lake that would be the upper reservoir. Impoundment may increase methylmercury production, which could alter fishing patters as consumption patterns may need to be changed. The dam may obstruct flows between Racine Lake and Tagish Lake and may also change flows at Racine Falls, which is a recreational site.
	Tourism Values	Medium	In addition to being used for recreational activities, the general area is used by an outfitter for hunting and fishing, but the project is not anticipated to materially alter activities.
	Aesthetics	Low	Since Racine Lake and Mt. Brown Lake are removed from major waterways and not near communities, it is anticipated that the presence of the project will not be visible or audible from known viewpoints and communities.
	Non-renewable Resources	Medium	Overlaps with two mineral claims.
	Other Renewable Resources	Low	No known conflicts.
	Land Use and Renewable Resource Plans	High	The eastern part of Racine Lake, Racine Creek, and Racine Falls are part of the Racine Falls Resource Management Area, which falls within the Atlin Land Use Plan. Racine Falls is a Goal 2 area by BC's Protected Areas Strategy, which is for special features. These areas are "set aside primarily to protect rare or vulnerable features." The dam may obstruct flows between Racine Lake and Tagish Lake and may also change flows at Racine Falls, which is a recreational site.
Squanga – Dalayee	Recreational Values	High	Campground with boat launch is located at Squanga Lake. Fish species present in Squanga and Dalayee lakes and the stream reach between them are important to CRA fisheries. Since impoundment of both lakes could increase the production of methylmercury, the project may alter fishing practices on both lakes.
	Tourism Values	Medium	The presence of project infrastructure may make the area less attractive for tourism; however, the project is not likely to alter activities.

Project / Option	Indicator	Ranking	Assessment
	Aesthetics	**Medium**	Project infrastructure may be visible or audible from the Squanga Lake campgrounds, making it less attractive as a camping ground; however, the project should not alter activities.
	Non-renewable Resources	**Medium**	Overlaps with 9 expired and 27 active quartz claims.
	Other Renewable Resources	**Low**	No known conflicts.
	Land Use and Renewable Resource Plans	**Medium**	Located in the Carcross/Tagish Renewable Resource Council. Overlaps with five trapping concessions.
Moon Lake (Tutshi – Moon)	Recreational Values	**Low**	Tutshi and Tagish lakes both contain multiple fish species that are important to the CRA fisheries. According to the environmental analysis, water levels are not anticipated to change at Tutshi Lake and are therefore not expected to change at Tagish Lake. Therefore, changes in fishing practices are not anticipated to be affected.
	Tourism Values	**Low**	The general area is used by an outfitter that has infrastructure on and near Tagish Lake. The presence of the project, though, is not currently anticipated to alter outfitting activities.
	Aesthetics	**Medium**	Project infrastructure is located in an area with a Visual Quality Objective of Retention. While these guidelines apply primarily to forestry practices, the provide context for areas that are deemed "scenic." However, the project does not require a dam on Tutshi Lake.
	Non-renewable Resources	**Medium**	The Midgard report indicates mineral claims in downstream portion of project area. Project overlaps with nine claims.
	Other Renewable Resources	**Low**	The Midgard report did not indicate any other renewable resource interests that might affect the project. Tenure of a Commercial Licence to Occupy for Guide Outfitters does not preclude other licenses on the project area.
	Land Use and Renewable Resource Plans	**Medium**	The eastern arm of Tutshi Lake is in the Tutshi Lake Protected Area, which is a culturally significant area for Carcross/Tagish First Nation and is used by members. Review would likely be needed to address any interests or concerns related to the project effects in this area of Tutshi Lake.

Project / Option	Indicator	Ranking	Assessment
			The western part of Tutshi Lake is part of a Use, Recreation and Enjoyment of the Public (UREP) map reserve. A UREP is on Crown land outside of Provincial Forests to guard against unwarranted disposition or unplanned use, which (in this area) would compromise current or potential recreation values or uses. The Midgard report notes that this map reserve exists on the downstream portion of the project, but does not suggest that the project would be compromised by this map reserve. The Midgard report notes that a protected area tenure exists on the downstream portion of Tutshi Lake, which explicitly precludes development of any hydroelectric projects or any water control facility. The Midgard report notes that this protected area is outside the project area.

5.2.3.2 Small Hydro Projects

Assessment of the all small hydro resource options is provided in Table D 5-7.

Table D 5-7: Summary of Assessment for Small Hydro Projects

Project / Option	Indicator	Ranking	Assessment
Drury Lake	Recreational Values	**High**	According to environmental evaluation, project area is a known site of CRA fisheries. Any changes required to fishing activities due to increase in methylmercury production may affect recreational value of area as activities will need to change.
	Tourism Values	**High**	Drury Lake is used by a fishing outfitter for trout, northern pike, and arctic grayling fishing. If changes to fishing activities are required as a result of increased methylmercury production, the outfitter may need to temporarily halt usage of Drury Lake or limit usage to hunting expeditions. Drury Lake falls within Outfitting Concession 14, which is advertised for hunting the following animals: stone sheep, moose and caribou, and bear and wolf.
	Aesthetics	**Low**	It is not anticipated that project infrastructure will be visible from known viewpoints.
	Non-renewable Resources	**Low**	Project overlaps with four expired quartz claims.
	Other Renewable Resources	**Low**	No known conflicts.

Project / Option	Indicator	Ranking	Assessment
	Land Use and Renewable Resource Plans	**Medium**	Project is located in single trapping concession and outfitter concession. The latter is discussed under tourism values. Project is located in the Southeast Yukon Forest Management Area (draft), but not within cutting permits and timber harvest plans.
Tutshi-Windy Arm	Recreational Values	**High**	Tutshi Lake is used for fishing, boating, and camping. Impoundment may lead to an increase in methylmercury production, which could temporarily change the use of Tutshi Lake as a recreational fishing location. Changes in the water level may also affect the boating on the lake and the boat launch at the southern end of the lake.
	Tourism Values	**Low**	Tutshi Lake has several known tourism sites, including the Yukon Suspension Bridge and campgrounds; however, project infrastructure is not anticipated to overlap with sites or alter activities.
	Aesthetics	**Medium**	Project infrastructure may be visible to individuals using the lake for boating and/or fishing but is not anticipated to cause major aesthetic changes.
	Non-renewable Resources	**Low**	No overlap with mineral tenures.
	Other Renewable Resources	**Low**	No known conflicts.
	Land Use and Renewable Resource Plans	**Medium**	The eastern arm of Tutshi Lake is in the Tutshi Lake Protected Area, which is a culturally significant area for Carcross/Tagish First Nation and is used by members. Review would likely be needed to address any interests or concerns related to the project effects in this area of Tutshi Lake as control dam is currently proposed at eastern end of lake and an access road would run along the northern side of the lake. The western part of Tutshi Lake is part of Use, Recreation and Enjoyment of the Public (UREP) map reserve. A UREP is on Crown land outside of Provincial Forests to guard against unwarranted disposition or unplanned use, which (in this area) would compromise current or potential recreation values or uses. The Midgard report notes that this map reserve exists on the downstream portion of the project, but does not suggest that the project would be compromised by this map reserve.
Wolf River	Recreational Values	**Medium**	Known fish species occurring in the Wolf River (see environmental evaluation) are important to recreational fishery and the river was cited as a high-value recreation area (Teslin Strategic Forest Management Plan). Project infrastructure is not anticipated to alter recreational activities on the river.

Project / Option	Indicator	Ranking	Assessment
	Tourism Values	**Medium**	Located in Outfitter Concession 19, although according to the Yukon Outfitters Association website, no outfitter is currently associated with the concession. The Wolf River is important for river trip outfitters but project infrastructure is not anticipated to disrupt activities.
	Aesthetics	**Low**	Project infrastructure is not anticipated to be visible/audible from known viewpoints.
	Non-renewable Resources	**Low**	Project does not overlap with known mineral tenure.
	Other Renewable Resources	**Low**	No known conflicts.
	Land Use and Renewable Resource Plans	**Medium**	Located in Teslin Renewable Resource Council area. Overlaps with three single holder traplines but is not expected to alter activities. Located in the Teslin Traditional Territory Forest Resource Management Area and within two cutting permits (held by the Teslin Tlingit Council and Village of Teslin), and the Sawmill Road Demonstration Forest Timber Harvest Plan, but is not anticipated to interfere with forestry activities.
Finlayson River	Recreational Values	**High**	Finlayson Lake is a recreational fishery site with Lake Trout, Artic Grayling, Northern Pike, and Whitefish present. Since impoundment could increase methylmercury production, recreational fishing activities may also need to change. In addition, changes to downstream flows could affect fish populations, making the lake a less attractive recreational site.
	Tourism Values	**High**	The Finlayson Lake Wildlife Viewpoint is not anticipated to be affected by project infrastructure on Finlayson Lake. There is a wilderness lodge located on Frances Lake. Depending on its location, project infrastructure may be visible and have an adverse effect on its ability to attract tourists. Project is located in Outfitting Concession 20, which is used for large game hunting. In light of the proximity of project infrastructure to the highway, project is not anticipated to alter outfitting activities.
	Aesthetics	**Low**	Finlayson Lake has a wildlife viewpoint at the northern end. Project infrastructure is anticipated to be at the southern end of the lake and therefore should not alter or detract from the view.

Project / Option	Indicator	Ranking	Assessment
	Non-renewable Resources	Medium	Project overlaps with one active and two expired placer claims and 18 expired and 82 active quartz claims, but project is not anticipated to affect activities.
	Other Renewable Resources	Low	No known conflicts.
	Land Use and Renewable Resource Plans	Medium	Project overlaps with outfitting concession 20, which is discussed under tourism. Project overlaps with one group trapping concession and seven individual concessions. Project overlaps with an active fuel wood licence and timber resources licence, and two issued fuel wood licences. Project is located in multiple annual limit regions (Watson Lake, Carmacks, Ross River-Faro) and the Southeast Yukon Forest Management Plan (draft) but is not anticipated to affect activities.
Anvil Creek	Recreational Values	High	Anvil Lake is the site of a known recreational fishery and there are cabins present on the lake. Since impoundment could increase methylmercury production, recreational fishing activities may also need to change.
	Tourism Values	Medium	Project is located in outfitting concession 9, which is known for big game hunting at remote, fly-in locations. Project infrastructure is not anticipated to overlap with activities.
	Aesthetics	Medium	There are cabins present on Anvil Lake. Depending on location, project infrastructure may be visible.
	Non-renewable Resources	Medium	Project overlaps with 22 quartz claims, but project is not anticipated to affect activities.
	Other Renewable Resources	Low	No known conflicts.
	Land Use and Renewable Resources	Medium	Project overlaps with outfitting concession 9, which is discussed under tourism. Project overlaps with one group trapping concession. Project is located in Ross River-Faro annual limit region and the Draft Faro Area of Interest and the Southeast Yukon Forest Management Plan (draft) but is not anticipated to affect activities.

Project / Option	Indicator	Ranking	Assessment
Atlin-Pine Creek (Surprise Lake)	Recreational Values	**High**	At the southwest end of Surprise Lake is a maintained recreation site, including campsites and boat launch. Project infrastructure, depending on the placement of the powerhouse, may affect the use of the campsite and boat launch and may affect the desirability of using the site. There are several trails/recreation sites along Pine Creek, which infrastructure may affect as well.
	Tourism Values	**High**	Changes to recreational values may have an adverse effect on tourism values at the same site, changing the desirability of visiting these sites and activities in the area.
	Aesthetics	**High**	Project infrastructure could be visible and/or audible.
	Non-renewable Resources	**High**	Project overlaps with 10 placer leases, and 109 claims (placer and mineral combined).
	Other Renewable Resources	**Low**	No overlaps anticipated.
	Land Use and Renewable Resource Plans	**Low**	Project located in the Atlin Taku Land Use Plan but does not appear to overlap with any designated zones.

5.2.3.3 Gladstone Diversion

The Gladstone Diversion resource option would divert water from the headwaters of Gladstone Creek into Isaac Creek, which flows into Sekulmun Lake and then Aishihik Lake.

Past studies by Yukon Energy of this resource option identified potential adverse effects to fish and fish habitat related to potential pathogen transfer (from diversion of waters from one watershed into another) as well as loss of Arctic Grayling spawning and rearing habitat in streams between the lakes and in Gladstone Creek.

As reviewed in Section 4.3 of Appendix A, past work by YEC has indicated concerns from the Department of Fisheries and Oceans (DFO) as well as from local First Nations. YEC reported that the results of a full year of baseline studies provided no evidence to support a concern regarding interbasin pathogen transfer. YEC has continued to work with local First Nations to seek support for this project.

Table D 5-8 provides a summary assessment of the project effects Tourism, Recreation and Other Resources and Land Use:

Table D 5-8: Summary of Assessment for Gladstone Diversion

Project / Option	Indicator	Ranking	Assessment
Gladstone Diversion	Recreational Values	**Medium**	Known fish species occurring in the project area (see environmental evaluation) are important to recreational fishery and could be affected by project development.
	Tourism Values	**Low**	Project is predominantly in outfitting concession 12, which is relatively small, with the eastern most reach of the project in outfitting concession 13. Project development is not anticipated to change outfitting activities or affect other tourist activities.
	Aesthetics	**Medium**	The project occurs within the traditional territory of three First Nations: Champagne and Aishihik First Nations, Kluane First Nation, and White River First Nation. There is a potential for project to be visible and/or audible from viewpoints valued by First Nations.
	Non-renewable Resources	**Medium**	Project overlaps with placer leases, placer claims, and quartz claims.
	Other Renewable Resources	**Low**	No overlaps anticipated.
	Land Use and Renewable Resource Plans	**Medium**	Project overlaps with Champagne and Aishihik FRMP but does not appear to overlap with areas of concern. Overlaps with two timber harvest licences. Overlaps with four single trapping concessions. Project's overlap with outfitting concessions discussed in tourism.

6.0 CULTURAL AND COMMUNITY WELL-BEING

6.1 RATING CRITERIA AND DATA SOURCES FOR S5: CULTURAL AND COMMUNITY WELL-BEING

The rating system outlined in Figure D 6-1 was adopted to guide evaluations of each resource project evaluation for each of the cultural and community well-being indicators.

Figure D 6-1: Summary of Rating Criteria for Cultural and Community Well-Being

Indicator	Low	Medium	High
Infrastructure and Services (S5-1)	Minimal stress to infrastructure and services[1]	Moderate stress to infrastructure and services (Does not require added management)	Material stress to infrastructure and services (Requires added management)
Public Safety, Worker Interaction, Human and Community Health (S5-2)	Minimal risk re: human and community health	Moderate risk re: human and community health	Material risk re: human and community health
Community, First Nation, and Personal Development (S5-3) [Positive effects - no colour]	Minimal development opportunity [Low Positive]	Moderate development opportunity [Medium Positive]	Material development opportunity [High Positive]

Note:
1. Projects may also have a positive effect on cultural and community well-being.

The cultural and community well-being indicators as defined in Table D 1-1 focus generally on whether the effect of the resource option on the indicator is positive or negative (Public Safety, Worker Interaction and Community Health [S5-2] only looks at the risk of negative effects) and the relative magnitude of the effect (L/M/H). Unless otherwise explicitly noted (e.g., S5-3 evaluates positive effects), the evaluations of each resource option for these indicators have identified only negative effects. Table D 6-1 provides ratings for assessing relative magnitude of effect from a resource option on each indicator, including the provision for a possible medium magnitude effect that differs from high magnitude. Each resource option tends to have some effect on each of these indicators.

Summary baseline information for population centres near resource options is included in Attachment 1. Information includes population counts, applicable land use plans, infrastructure and services.

In addition to outside sources, results from other evaluations were considered. Table D 6-1 presents the issues and other criteria considered for the S5 criteria evaluations in this section. Based on the rating system, assessments focused on risks, rather than benefits, related to the magnitude of project effects (i.e., larger and longer absolute effects in this instance receive higher ratings) relative to local community infrastructure, services, workforces, lifestyle, culture and values.

Table D 6-1: Issues and Other Criteria Considered in Evaluation of Cultural and Community Well-Being

S5 Criteria – Indicators	Considerations
Infrastructure & Services	Stress on infrastructure and services in existing communities from project and project workforce during construction and operation, including roads/highways, police, health, waste facilities, water supply, accommodations (overlap with public safety and worker interaction). A proxy metric for evaluating resource option effects on this indicator is capital spending and activities in Yukon estimates and operation work force and activities. There is also a potential also for positive effects (if project provides new infrastructure, access, services). Other indicators considered include: • En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat; • En2-1: Consumptive Water Use; • Ec1-1: Yukon Opportunities During Construction; and • Ec1-2: Yukon Opportunities during Operation.
Public Safety, Worker Interaction, Human and Community Health	The evaluation of this indicator considers risks to public safety and worker interaction during construction and operation can be affected by size of project workforces, composition of workforce (i.e., local/non-local), size of near-by communities (There is overlap with the same metrics needed for infrastructure and services). Risks to human and community health include: direct effects during construction and operation on country foods, quality of air and/or water, and community safety. Other indicators considered include: • En1-3: Commercial, Recreational or Aboriginal Fishery Species and Habitat; • En5-2: Other Air Pollutants; • S2-5: Country Foods; • Ec1-1: Yukon Opportunities During Construction; and • Ec1-2: Yukon Opportunities during Operation.
Community, First Nation and Personal Development	The evaluation of this indicator focuses on potential for positive effects (if project provides opportunities for training, development, First Nation development agreements, etc.). It also considers risks to traditional lifestyle, values, culture (including traditional lifestyle), as well as effects on local jobs, business, training and development. Other indicators considered in this evaluation include: • S1-1: Settlement Lands, Interim Protected Lands; • S2-2: Land area loss re Traditional Lifestyle; • S2-5: Country Foods; • S3: Heritage Resource Potential; • S4-3: Aesthetics; • Ec1-1: Yukon Opportunities During Construction; and • Ec1-2: Yukon Opportunities during Operation.

Assessments focused on the risks related to the magnitude of project effects, including the amount of management likely needed to address stresses and risks, as well as specific development opportunities to be managed. Smaller projects and projects in certain locations (e.g., major centres and/or remote locations) tended to be of no material concern for the cultural and community well-being indicators, given the scale of the project construction[6] relative to the scale of potentially affected community infrastructure and services, worker interaction, and overall public safety. Projects with potentially large labour requirements near smaller and/or remote communities, especially those with multi-year construction periods, are expected to present more risks to local community infrastructure and services, lifestyle, culture and values. In contrast, projects near Whitehorse are anticipated to present no material concerns regarding cultural and community well-being indicators because Whitehorse is large enough to absorb a temporary, non-local workforce up to a certain size in terms of infrastructure, services and amenities.

In contrast to construction phase activities, operation phase activities are expected in all instances to have minimal effects on infrastructure and services, worker interaction and public safety.[7] Table D 6-2 summarizes the assessment with regard to indicator S5-1.

With regard to human and community health effects, the evaluation also focused on direct effects during operation on country foods, quality of air and/or water, and (if any issue) community safety. Overall, air and water related effects on health are expected to be minimal from construction and operation of resource options due to BMPs requirements and restrictions. In contrast, human and community health effects from limitations on use of country food (due to methylmercury effects on fish or other factors) are a specific concern that could require added management activity. Table D 6-3 summarizes the assessment with regard to indicator S5-2.

Community, First Nation and Personal Development effects consider all of the available information. Table D 6-4 summarizes the assessment with regard to Community, First Nation and Personal Development (S5-3), relying on Table E 2-3 from Appendix E, which summarizes community and other development opportunities for each resource option and provides the same evaluations for each resource option.

[6] Determination of resource options scale relied on the economic evaluations in Appendix E, and in particular Table E 2-1, Local Economic Impact: Yukon Opportunities during Construction. The larger a project's capital cost and impact on Yukon's gross domestic product (GDP), the larger in scale it is assumed to be.
[7] Table E 2-2 in Appendix E reviews information on expected non-fuel operating costs and jobs related to each resource option.

Table D 6-2: Cultural and Community Well-Being: Infrastructure and Services

	Magnitude of Project (Capex $million)	Percent of Capex ex. Major Equipment	Proximity to Communities	Duration of Construction	GDP impacts in Yukon - Jobs	Comments	Low	Medium	High
Fossil Thermal									
Diesel: 20 MW - Whitehorse	62	71%	Whitehorse	1-2 years	192	Minimal risks	■		
Diesel: 20 MW - Takhini	62	71%	Whitehorse	1-2 years	192	Minimal risks	■		
LNG: 20 MW - Whitehorse	100	60%	Whitehorse	1-2 years	257	Minimal risks	■		
LNG: 20 MW - Takhini	100	60%	Whitehorse	1-2 years	257	Minimal risks	■		
Non-Fossil Thermal									
Waste to Energy	35	26%	Whitehorse	1-2 years	38	Minimal risks	■		
Biogas (CHP)	7	74%	Haines Junction	1 year	21	Minimal risks	■		
Biomass 0.5 MW Boiler / Steam Turbine	11	73%	Whitehorse	1-2 years	34	Minimal risks	■		
Other Non-Hydro Renewable									
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	49	3%	Whitehorse	na	7	Minimal risks	■		
Solar PV: Whitehorse Fixed Tilt: 10 MW	36	27%	Whitehorse	36 weeks	40	Minimal risks	■		
Solar PV: Haines Junction Fixed Tilt: 5 MW	13	38%	Haines Junction	36 weeks	20	Minimal risks	■		
Wind: Cyprus Mine Hill, 20 MW	69	65%	Faro	2 years	186	Moderate risk during construction		■	
Wind: Kluane Lake, 20 MW	62	61%	Haines Junction	3 years	157			■	
Wind: Millers Ridge, 20 MW	73	67%	Carmacks	4 years	203			■	
Wind: Mt. Sumanik , 20 MW	64	62%	Whitehorse	5 years	166	Minimal risks	■		
Wind: Sugarloaf Mountain, 20 MW	62	61%	SE of Carcross	6 years	157	Moderate risk during construction		■	
Wind: Tehcho (Ferry Hill), 20 MW	64	62%	Stewart Crossing	7 years	166			■	
Wind: Thulsoo Mountain, 20 MW	72	67%	Canyon Creek and Champagne	8 years	199			■	
Geothermal: McArthur Springs (3.8 MW Av.)	121	95%	Pelly Crossing & Stewart Crossing	2.5 years	473	Moderate risk during construction		■	
Geothermal: Vista Mountain (1.6 MW Av.)	42	90%	Whitehorse	2 years	155	Minimal risks	■		
Hydro Generation									
Pumped Storage: Moon Lake (Tutshi-Moon)	218	94%	27 km from Carcross	4 years	878	Material risks during construction			■
Pumped Storage: Racine - Moon	473	53%	27 km from Carcross	4 years	1084				■
Pumped Storage: Lindeman-Fraser	484	72%	Fraser, BC - close	4 years	1509				■
Pumped Storage: Racine - Mt. Brown	284	78%	remote - 27 km from Carcross	4 years	956				■
Pumped Storage: Racine - Mt. Brown	486	81%	remote - 27 km from Carcross	4 years	1698				■
Pumped Storage: Atlin - Black Mountain	254	76%	42 km Atlin; 51 km Jake's Corner	4 years	831				■
Pumped Storage: Atlin - Black Mountain	464	82%	42 km Atlin; 51 km Jake's Corner	4 years	1649				■
Pumped Storage: Squanga - Dalayee	613	76%	Jake's Corner - close	4 years	2017				■
Pumped Storage: Canyon - Ittlemit	691	90%	Canyon Creek and Champagne	4 years	2686				■
Pumped Storage: Vangorda Pit	524	78%	Faro - close	4 years	1764				■
Small Hydro: Drury Lake	103	41%	between Faro and Little Salmon	3 years	182	Material risks during construction			■
Small Hydro: Tutshi - Windy Arm	133	45%	27 km from Carcross	3 years	259				■
Small Hydro: Wolf River	234	52%	Teslin 23 km	3 years	522				■
Small Hydro: Finlayson River	283	74%	128 km Ross River; 188 km Faro	3 years	897				■
Small Hydro: Anvil Creek	116	43%	Faro - close	3 years	286				■
Small Hydro: Atlin/Pine Creek	80	83%	Atlin - close	3 years	286				■
Other Hydro: Gladstone Diversion	40	80%	Destruction Bay	2 years	138	Moderate risk during construction		■	
Other Hydro: Southern Lakes Storage	11	90%	Mayo	na	41	Minimal risks	■		
Other Hydro: Mayo Lake Storage	approx 5	90%	Mayo	no construction	19	Minimal risks	■		
Other Hydro: Mayo Dredging	approx 15	50%	Mayo	1 season	32	Minimal risks	■		
Aishihik Re-runnering	5	50%	Canyon Creek & Champagne	na	10	Minimal risks	■		
Mayo A Refurbishment	27	50%	Mayo - close	na	59	Minimal risks	■		
Transmission Corridors									
Transmission: Whitehorse - Atlin (138 kV)	158	80%	each line runs by multiple communities	1-2 years	545	Minimal risks due to BMPs (e.g., accommodation plans), mobile nature of the construction workforce with short time period in any area)	■		
Transmission: Whitehorse - Skagway (230 kV)	251	80%		1-2 years	866		■		
Transmission: Whitehorse - Teslin (138 kV)	165	80%		1-2 years	569		■		
Transmission: Faro - Watson Lake (230 kV)	597	80%		1-2 years	2060		■		
Transmission: Aishihik - Destruction Bay (230 kV)	241	80%		1-2 years	832		■		
Transmission: Stewart-Keno City (138 kV & substations)	86	80%		1-2 years	291		■		

1. Capex, percentage of Capex not major equipment, and GDP Yukon job estimates from Appendix E, Table E2-1.

Table D 6-3: Cultural and Community Well-Being: Public Safety, Worker Interaction, Human and Community Health

	Project Magnitude during Construction [Appendix E, Table E2-1]		Proximity to Community	Comments	Evaluation		
	Construction cost ($million)	GDP impacts in Yukon - Jobs			Low	Medium	High
Fossil Thermal							
Diesel: 20 MW - Whitehorse	62	192	Whitehorse	Minimal risks	■		
Diesel: 20 MW - Takhini	62	192	Whitehorse	Minimal risks	■		
LNG: 20 MW - Whitehorse	100	257	Whitehorse	Minimal risks	■		
LNG: 20 MW - Takhini	100	257	Whitehorse	Minimal risks	■		
Non-Fossil Thermal							
Waste to Energy	35	38	Whitehorse	Minimal risks	■		
Biogas (CHP)	7	21	Haines Junction	Minimal risks	■		
Biomass 0.5 MW Boiler / Steam Turbine	11	34	Whitehorse	Minimal risks	■		
Other Non-Hydro Renewable							
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	49	7	Whitehorse	Minimal risks	■		
Solar PV: Whitehorse Fixed Tilt: 10 MW	36	40	Whitehorse	Minimal risks	■		
Solar PV: Haines Junction Fixed Tilt: 5 MW	13	20	Haines Junction	Minimal risks	■		
Wind: Cyprus Mine Hill, 20 MW	69	186	Faro			■	
Wind: Kluane Lake, 20 MW	62	157	Haines Junction	Moderate risk during construction		■	
Wind: Millers Ridge, 20 MW	73	203	Carmacks			■	
Wind: Mt. Sumanik , 20 MW	64	166	Whitehorse	Minimal risks	■		
Wind: Sugarloaf Mountain, 20 MW	62	157	SE of Carcross			■	
Wind: Tehcho (Ferry Hill), 20 MW	64	166	Stewart Crossing	Moderate risk during construction		■	
Wind: Thulsoo Mountain, 20 MW	72	199	Canyon Creek and Champagne			■	
Geothermal: McArthur Springs (3.8 MW Av.)	121	473	Pelly Crossing & Stewart Crossing	Moderate risk during construction		■	
Geothermal: Vista Mountain (1.6 MW Av.)	42	155	Whitehorse	Minimal risks	■		
Hydro Generation							
Pumped Storage: Moon Lake (Tutshi-Moon)	218	878	27 km from Carcross	Material risks during construction			■
Pumped Storage: Racine - Moon	473	1,084					■
Pumped Storage: Lindeman-Fraser	484	1,509	Fraser, BC - close				■
Pumped Storage: Racine - Mt. Brown	284	956	remote - 27 km from Carcross				■
Pumped Storage: Racine - Mt. Brown	486	1,698					■
Pumped Storage: Atlin - Black Mountain	254	831	42 km Atlin; 51 km Jake's Corner	Material risks during construction; risk of methylmercury effects on fishery during operation could require added management			■
Pumped Storage: Atlin - Black Mountain	464	1,649					■
Pumped Storage: Squanga - Dalayee	613	2,017	Jake's Corner - close				■
Pumped Storage: Canyon - Ittlemit	691	2,686	Canyon Creek and Champagne				■
Pumped Storage: Vangorda Pit	524	1,764	Faro - close	Material risks during construction			■
Small Hydro: Drury Lake	103	182	between Faro and Little Salmon				■
Small Hydro: Tutshi - Windy Arm	133	259	27 km from Carcross				■
Small Hydro: Wolf River	234	522	Teslin 23 km	Material risks during construction; risk of methylmercury effects on fishery during operation could require added management			■
Small Hydro: Finlayson River	283	897	128 km Ross River; 188 km Faro				■
Small Hydro: Anvil Creek	116	286	Faro - close				■
Small Hydro: Atlin/Pine Creek	80	286	Atlin - close	Material risks during construction			■
Other Hydro: Gladstone Diversion	40	138	Destruction Bay	Moderate risk during construction		■	
Other Hydro: Southern Lakes Storage	11	41	Mayo	Minimal risks	■		
Other Hydro: Mayo Lake Storage	approx 5	19	Mayo	Minimal risks	■		
Other Hydro: Mayo Dredging	approx 15	32	Mayo	Minimal risks	■		
Aishihik Re-runnering	5	10	Canyon Creek & Champagne	Minimal risks	■		
Mayo A Refurbishment	27	59	Mayo - close	Minimal risks	■		
Transmission Corridors							
Transmission: Whitehorse - Atlin (138 kV)	158	545	each line runs by multiple communities	Minimal risks due to BMPs (e.g., accommodation plans), mobile nature of the construction workforce with short time period in any area)	■		
Transmission: Whitehorse - Skagway (230 kV)	251	866			■		
Transmission: Whitehorse - Teslin (138 kV)	165	569			■		
Transmission: Faro - Watson Lake (230 kV)	597	2,060			■		
Transmission: Aishihik - Destruction Bay (230 kV)	241	832			■		
Transmission: Stewart-Keno City (138 kV & substations)	80	291			■		

Notes:

1. Methods and sources for Construction Costs excluding major equipment and jobs are discussed in Appendix E.

Table D 6-4: Cultural & Community Well-Being: Community, First Nation & Personal Development

	Project Size (Capex $million)	Notes re Community & Economic Development Opportunity (from Appendix E, Table E2-3)	Low Positive	Medium Positive	High Positive
Fossil Thermal					
Diesel: 20 MW - Whitehorse	62	No specific local development opportunties.	Low positive		
LNG: 20 MW - Whitehorse	100	Local opportunity to facilitate LNG use to displace other fossil fuel use in Whitehorse/Yukon.		Medium positive	
Non-Fossil Thermal					
Waste to Energy	35	Local opportunity to use renewable and (except for biogas) to supply waste heat to displace fossil fuel use. High operating jobs for Waste to Energy.		Medium positive	
Biogas (CHP)	7			Medium positive	
Biomass 0.5 MW Boiler / Steam Turbine	11			Medium positive	
Other Non-Hydro Renewable					
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	49	Minimal direct local development impact. Might facilitate solar or wind.	Low positive		
Solar PV: Whitehorse Fixed Tilt: 10 MW	36	Minimal direct local development impact.	Low positive		
Solar PV: Haines Junction Fixed Tilt: 5 MW	13		Low positive		
Wind: Cyprus Mine Hill, 20 MW	69	Moderate local economic development impacts from operations (ex. Mt Sumanik). Proposed Kluane & Sugarloaf Mountain sites are on aboriginal traditional land and assume land lease payments to the local FN; Kluane Lake option also facilitates development of an Aishihik-Destruction Bay Transmission Corridor.		Medium positive	
Wind: Kluane Lake, 20 MW	62				High positive
Wind: Millers Ridge, 20 MW	73			Medium positive	
Wind: Mt. Sumanik , 20 MW	64		Low positive		
Wind: Sugarloaf Mountain, 20 MW	62				High positive
Wind: Tehcho (Ferry Hill), 20 MW	64			Medium positive	
Wind: Thulsoo Mountain, 20 MW	72			Medium positive	
Geothermal: McArthur Springs (3.8 MW Av.)	121	Moderate local economic development impacts from operations (new access road).		Medium positive	
Geothermal: Vista Mountain (1.6 MW Av.)	42	Minimal local economic development impact	Low positive		
Hydro Generation					
Pumped Storage: Moon Lake (Tutshi-Moon)	218	Moderate local economic development impact based on Opex levels. In addition, options other than Squana Delayee, Canyon Ittlemit & Vangorda Pit each facilitate development of a portion of a Transmission Corridor resource option. The Vangorda Pit option may facilitate development of the Grizzly Pit mine deposit.			High positive
Pumped Storage: Racine - Moon	473				High positive
Pumped Storage: Lindeman-Fraser	484				High positive
Pumped Storage: Racine - Mt. Brown	284				High positive
Pumped Storage: Atlin - Black Mountain	254				High positive
Pumped Storage: Squanga - Dalayee	613			Medium positive	
Pumped Storage: Canyon - Ittlemit	691			Medium positive	
Pumped Storage: Vangorda Pit	524			Medium positive	
Small Hydro: Drury Lake	103	Moderate local economic development impact based on Opex level. All options other than Drury Lake and Anvil Creek also facilitate development of a Transmission Corridor (Tutshi-Windy Arm requires portion of Whitehorse-Skagway line, Wolf River and Atlin/Pine Creek facilitate Whitehorse-Atlin line, and Finlayson needs line extending from Faro toward Watson Lake).		Medium positive	
Small Hydro: Tutshi - Windy Arm	133				High positive
Small Hydro: Wolf River	234				High positive
Small Hydro: Finlayson River	283				High positive
Small Hydro: Anvil Creek	116			Medium positive	
Small Hydro: Atlin/Pine Creek	80				High positive
Other Hydro: Gladstone Diversion	40	Minimal local economic development impact; facilitate local First Nation income benefits.			High positive
Other Hydro: Southern Lakes Storage	11	Minimal local economic development impact	Low positive		
Other Hydro: Mayo Lake Storage	approx 5		Low positive		
Other Hydro: Mayo Dredging	approx 15		Low positive		
Aishihik Re-runnering	5	Minimal local economic development impact	Low positive		
Mayo A Refurbishment	27		Low positive		
Transmission Corridors					
Transmission: Whitehorse - Atlin (138 kV)	158	Moderate potential local economic development impact if stimulates small hydro (in Atlin and Teslin areas, or in Moon-Tutshi area); and if (for Whitehorse-Skagway corridor) stimulates sales of summer hydro or wind generation (to cruise ships).		Medium positive	
Transmission: Whitehorse - Skagway (230 kV)	251			Medium positive	
Transmission: Whitehorse - Teslin (138 kV)	165			Medium positive	
Transmission: Faro - Watson Lake (230 kV)	597	Material potential local economic development impacts (displace diesel generation in local communities with hydro, benefits to local businesses and population, opportunity to facilitate new mining and hydro or wind developments).			High positive
Transmission: Aishihik - Destruction Bay (230 kV)	241				High positive
Transmission: Stewart-Keno City (138 kV & substations)	80	Material local economic development impact by replacing end of life line, retains access to hydro generation, facilitates expanded capability for new mine developments in this region.			High positive

1. Capex from Appendix E, Table E2-1.

6.2 EVALUATION

6.2.1 Resource Options with No Material Concerns re: Cultural and Community Well-Being

Table D 6-5 provides a summary of the resource project options with low ratings for each of the cultural and community well-being indicators. Brief supporting information and analysis is provided in the table on the application of the S5 criteria indicators to these resource options.[8]

Table D 6-5: Resource Project Options with No Material Concerns

Resource Project Options	Comments re: All Indicators being Low
Fossil Fuel Thermal (Diesel)	
Whitehorse Landfill	In Whitehorse at a brownfield site with current industrial use; relative magnitude of project is anticipated to be low to medium.
Takhini Substation	Near Whitehorse and adjacent to brownfield site (substation); relative magnitude of project is anticipated to be low.
Energy Storage Facility	
Takhini Substation	Near Whitehorse and adjacent to brownfield site (substation); relative magnitude of project is anticipated to be low.
Solar PV	
Whitehorse	Brownfield site (abandoned mine site); zoned for heavy utilities and future planning. Construction anticipated to last less than a year (low).
Haines Junction	Near Haines Junction landfill. Construction anticipated to last less than a year (low).
Wind Farms	
Mt. Sumanik	Proximity to Whitehorse; no apparent conflicts.
Geothermal	
Vista Mountain	Proximity to Whitehorse; no apparent conflicts.
Hydro Storage Enhancements	
Mayo Lake	No apparent conflicts with any indicator.
Southern Lakes	No apparent conflicts with any indicator.
Mayo Outlet Channel Dredging	No apparent conflicts with any indicator.
Refurbish / Enhance Existing Hydro	
Mayo A	Existing generating station site; no conflicts.
Aishihik re-runnering	Existing generating station site; no conflicts.

6.2.2 Fossil Thermal - LNG

The LNG fossil thermal resource option is rated low (green) with regard to Infrastructure and Services, as well as Public Safety, Worker Interaction, Human and Community Health.

[8] Detailed review of mapping or local plan information has not been done for these resource options. If and when a resource option is subject to more detailed feasibility and planning review, it is possible that specific issues may arise that will need to be addressed in order to proceed.

The LNG fossil thermal resource option is rated medium positive with regard to Community, First Nation and Personal Development to reflect local opportunity to facilitate LNG use to displace other fossil fuel use in Whitehorse/Yukon.

6.2.3 Non-Hydro Renewable Generation

6.2.3.1 Non-Fossil Thermal

Waste-to-energy, biogas and biomass resource options are each rated green (low) with regard to Infrastructure and Services, as well as Public Safety, Worker Interaction, Human and Community Health. Waste-to-energy would provide relatively high level of operating jobs.

These three non-fossil thermal resource options are each rated medium positive with regard to Community, First Nation and Personal Development to reflect local opportunity to use renewable and (except for biogas) to supply waste heat to displace fossil fuel use. Waste-to-energy would provide a relatively high level of operating jobs.

6.2.3.2 Wind Farms

Wind projects located near communities other than Whitehorse, which is all of them excluding Mt. Sumanik, are categorized as either medium or high for the Cultural and Community Health and Well-being indicators because of their relative scale compared to neighbouring communities and the amount of management likely required to minimize potential adverse effects and, in the case of Community, First Nation and Personal Development, enhance positive effects.

The Kluane Lake and Sugarloaf Mountain wind farm resource options are rated high positive for Community, First Nation and Personal Development to reflect opportunities for First Nation lease revenues for two sites (Kluane Lake and Sugarloaf Mountain) and the opportunity to develop the new transmission corridor for the Kluane Lake site, which would allow Destruction Bay and likely Burwash Landing to stop relying on diesel generation.

6.2.3.3 Geothermal - McArthur Springs

The McArthur Springs geothermal resource option has a medium rating for each of the three Cultural and Community Health and Well-being indicators, reflecting the magnitude of its capital expenditures (Capex) and operating expenditures (Opex) costs, as well as any local development opportunities (positive effects) facilitated by the new access road that this option provides to the area.

6.2.4 Hydro Renewable Generation

6.2.4.1 Pumped Storage

Each of the pumped storage resource options has a red (high) rating for Infrastructure and Services effects during construction, reflecting the Capex cost levels (which are generally higher than the levels for all other resource options considered in the current Yukon Energy resource planning). Table D6-2 does not include the Capex costs needed to connect most of these sites (i.e., all sites other than Canyon-

Ittlemit and Vangorda Pit) to the existing grid, and therefore understates the actual construction requirements needed for development of most sites.

Each of the pumped storage resource options has a red (high) rating for Public Safety, Worker Interaction, Human and Community Health, reflecting material risks during construction and (for all options other than Moon Lake [Tutshi-Moon] and Vangorda Pit) the risk of methylmercury effects on fisheries during operation that could require added management.

The Squanga-Dalayee, Canyon-Ittlemit and Vangorda Pit pumped storage options each has a medium positive rating for Community, First Nation and Personal Development, reflecting the expectation that these options will provide moderate local or community development opportunities based on Opex levels. Each of the other pumped storage options has a high positive rating for this indicator, reflecting the opportunity to develop one of the transmission corridor resource options (e.g., Whitehorse-Skagway or Whitehorse-Atlin), and in the case of Tushi-Moon option, to facilitate other small hydro development at Tutshi-Windy Arm.

6.2.4.2 Small Hydro Projects

Each of the small hydro resource options other than Drury Lake and Anvil Creek has a high rating for each of the three Cultural and Community Health and Well-being indicators, reflecting material risks during construction, the risk of methylmercury effects on fisheries during operation that could require added management (this risk does not apply to Atlin/Pine Creek option), and the positive effects opportunity (except for the Drury Lake and Anvil Creek options) to develop one of the transmission corridor resource options (e.g., Whitehorse-Skagway, Whitehorse-Atlin, or Faro-Watson Lake).

Drury Lake and Anvil Creek small hydro have a high (red) rating for each of these indicators other than for Community, First Nation and Personal Development. For this last indicator, Drury Lake and Anvil Creek have a medium positive rating to reflect the moderate level of local development based on the level of Opex spending.

6.2.4.3 Other Hydro - Gladstone Diversion

The Gladstone Diversion resource option has a yellow (medium) rating for Infrastructure and Services, as well as for Public Safety, Worker Interaction, Human and Community Health to reflect moderate risk during construction.

The Gladstone Diversion resource option has a high positive rating for Community, First Nation and Personal Development, reflecting the opportunity to facilitate local First Nation income benefits.

6.2.5 Transmission Corridor Options

Each of the transmission corridor options has a low (green) rating for Infrastructure and Services, as well as for Public Safety, Worker Interaction, Human and Community Health to reflect moderate risk during construction. This reflects minimal risks during construction and operation.

Faro-Watson Lake, Aishihik-Destruction Bay and Stewart-Keno City transmission corridor options are each rated high positive for Community, First Nation and Personal Development, reflecting opportunities to

displace local diesel (or sustain existing transmission capability to do this, as in the case of the Stewart-Keno City option), as well as to facilitate new mining and renewable generation (hydro or wind) development. The three remaining transmission corridor options (Whitehorse-Atlin, Whitehorse-Skagway, and Whitehorse-Teslin) are each rated medium positive for Community, First Nation and Personal Development, reflecting potential local development effects if they facilitate renewable generation (pumped storage or small hydro) and, in the case of the Skagway connection, the sale of summer renewable generation (hydro or wind) to cruise ships.

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ATTACHMENT 1:

Baseline Information for S4 and S5 Indicators

Table D A1-1: Baseline Information for Whitehorse, Yukon

Projects	Waste-to-energy, biogas, solar generation, Vista Mountain Geothermal, Sumanik Wind Farm, Diesel Plant, LNG Facility, energy storage facility.
Population	29,057
Traditional Territory	Kwanlin Dun and Ta'an Kwach'an traditional territories.
Available Recreation Activities	Standard suite of recreational activities available, outdoor activities include skiing at Mt. Sima. Facilities include Canada Games Centre, arena, recreation centre, multiple parks, trail network.
Tourist Activities	Standard suite of tourist activities.
Applicable Land Use Plans	Whitehorse Official Community Plan; Whitehorse and Southern Lakes Forest Resources Management Plan; Mayo Street Development Area; Whitehorse Periphery Development Area; Laberge Renewable Resource Council.
Community Infrastructure and Services	Multiple primary and secondary schools, Yukon College, library services, daycare, RCMP detachment, professional fire department, emergency medical services, hospital, health centre, both First Nations offer health and social services, dental services, hearing services, landfill, water and wastewater services.

Table D A1-2: Baseline Information for Haines Junction, Yukon

Projects	Biomass, solar generation, Kluane Lake Wind Farm[1], Thulsoo Mountain Wind Farm, Canyon-Ittlemit Pumped Storage.
Population	896
Traditional Territory	Champagne-Aishihik.
Available Recreation Activities	Hiking, camping, and fishing, trail network, recreation complex with indoor ice arena, summer pool, curling link, community hall.
Tourist Activities	Hiking, camping, and fishing; Kluane National Park.
Applicable Land Use Plans	Beaver Creek/Burwash/Destruction Bay FRMPA, Haines Junction Official Community Plan.
Community Infrastructure and Services	K-12 school, Yukon College campus, library services, RCMP detachment, volunteer fire service, emergency medical services, health centre, dental services, Champagne and Aishishik First Nations Health and Social Services, landfill, water and wastewater services, recycling.

Note:
1. Kluane Lake Wind Farm is located in Kluane First Nation traditional territory.

Table D A1-3: Baseline Information for Carmacks, Yukon

Projects	Miller's Ridge Wind Farm.
Population (includes surrounding area, including Marsh Creek)	548
Traditional Territory	Little Salmon/Carmacks First Nation.
Available Recreation Activities	Community recreation complex (with pool), mountain biking, cross-country skiing, snowmobile hiking.
Tourist Activities	Museum, interpretive centre, hiking.
Applicable Land Use Plans	Community-based Fish and Wildlife Work Plan Little Salmon Carmacks First Nation Traditional Territory, 2012-2017; Carmacks Annual Limit Region.
Community Infrastructure and Services	K-12 school, Yukon College campus, library services, RCMP detachment, volunteer fire services, emergency medical services, health services, Little Carmacks/Salmon First Nation health and family services, dental services, daycare, municipal landfill site, water and wastewater services.

Table D A1-4: Baseline Information for Faro, Yukon

Project	Cyprus Hill Wind Farm, Faro Pit Pumped Storage, Vangorda Pit Pumped Storage, Finlayson and Anvil Creek Small Hydro.
Population	388
Traditional Territory	Kaska Dena, Ross River Dena Council.
Available Recreation Activities	Summer pool, indoor ice arena, trail network, hiking, wildlife viewing, camping, fishing, and hunting.
Tourist Activities	Hiking, wildlife viewing, camping, fishing, and hunting.
Applicable Land Use Plans	Ross River – Faro Annual Limit Region; Draft Southeast Yukon Forest Management.
Community Infrastructure and Services	K-12 school, Yukon College campus, library services, RCMP detachment, volunteer fire service, emergency medical services, health centre, youth dental services, waste and wastewater services, landfill, gymnasium.

Table D A1-5: Baseline Information for Carcross, Yukon

Projects	Sugarloaf Mountain Wind Farm, Tutshi-Windy Lake Small Hydro, Racine-Mt. Brown Pumped Storage, Lindemann-Fraser Pumped Storage, Tutshi-Moon Pumped Storage, Racine-Moon Pumped Storage, Squanga-Dalayee Pumped Storage.
Population	771
Traditional Territory	Carcross/Tagish First Nation.
Available Recreation Activities	Hiking, mountain biking, camping, skiing, snowmobiling, ice fishing.
Tourist Activities	Same as recreational activities, wildlife viewing, heritage buildings, on Southern Lakes Circuit Drive.
Community Infrastructure and Services	K-9 school, Yukon College campus, RCMP detachment, volunteer fire service, health centre, social services, youth dental services, childcare services, landfill, water and wastewater services, summer community pool, drop-in at school gymnasium.

Table D A1-6: Baseline Information for Stewart Crossing, Yukon

Projects	Tehcho (Ferry Hill) Wind Farm.
Population	25
Traditional Territory	NND Traditional Territory.
Community Infrastructure and Services	Closest health centre is in Pelly Crossing, gas station, emergency services located in Mayo.

Table D A1-7: Baseline Information for Teslin, Yukon

Projects	Wolf River
Population	499
Traditional Territory	Teslin Tlingit Council.
Available Recreation Activities	Recreation complex and programming, including indoor ice arena, baseball diamond, skateboard park; trail network, skiing, boating, fishing, hiking.
Tourist Activities	Museum, on Southern Lakes Circuit Drive, Teslin Tlingit Heritage Centre, museum, fishing, hunting, Nisutlin River Delta National Wildlife Area.
Applicable Land Use Plans	Teslin Tlingit Council has a Department of Lands and Resources that oversees land and resource use.
Community Infrastructure and Services	Pre-K to Grade 9 school, Yukon College campus, Health Centre, RCMP detachment, volunteer fire service, emergency medical services, gravel airport, water and wastewater services, landfill.

Table D A1-8: Baseline Information for Atlin, British Columbia

Projects	Atlin-Black Mountain Pumped Storage, Atlin (Pine Creek) Small Hydro, Surprise Small Hydro.
2011 Population	402 (Stikine Region Regional District Electoral Area).
Traditional Territory	Taku River Tlingit First Nation.
Available Recreation Activities	Camping, boating (motorized, canoes, kayaks), fishing, hunting.
Tourist Activities	Camping, boating (motorized, canoes, kayaks), fishing, hunting, annual music festival.
Applicable Land Use Plans	Atlin Taku Land Use Plans Use, Recreation and Enjoyment of the Public Reserves (UREP) – Tutshi Lake and River.
Community Infrastructure and Services	Health clinic, RCMP, fire department, BCEHS, school, college campus.
Local Business	Grocery stores, hardware store, gas station, restaurants, laundromat, air transportation, and construction services.

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APPENDIX E:
ECONOMIC EVALUATION
TECHNICAL REPORT

TABLE OF CONTENTS

1.0 INTRODUCTION E-1

2.0 LOCAL ECONOMIC IMPACTS E-3

2.1 RATING CRITERIA AND DATA SOURCES FOR EC1: LOCAL ECONOMIC IMPACTS E-3

2.2 EVALUATIONS E-10

2.2.1 Resource Options with No Material Concerns re: Local Economic Impacts E-10

2.2.2 Fossil Fuel Thermal Generation E-10

2.2.3 Non-Hydro Renewable Generation E-10

2.2.4 Hydro Generation E-11

2.2.5 Transmission Corridors E-12

3.0 CLIMATE CHANGE RISK E-14

3.1 RATING CRITERIA AND DATA SOURCES FOR EC2: CLIMATE CHANGE RISK AFFECTING RESOURCE FINANCIAL ATTRIBUTES E-14

3.2 EVALUATIONS E-16

3.2.1 Resource Options with No Material Concerns re: Climate Change Risk E-16

3.2.2 Non-Hydro Renewable Generation E-16

3.2.3 Hydro Renewable Generation E-17

3.2.4 Transmission Corridors E-18

LIST OF TABLES

Table E 1-1: Resource Options Evaluation Matrix – Economic Criteria & Indicators E-2
Table E 2-1: Local Economic Impact: Yukon Opportunities during Construction E-7
Table E 2-2: Local Economic Impact: Yukon Opportunities during Operation E-8
Table E 2-3: Local Economic Impact: Community and Other Development Opportunity E-9
Table E 3-1: Climate Change Risk: Indicator Evaluation of Resource Options E-15

LIST OF FIGURES

Figure E 2-1: Summary of Rating Criteria for Local Economic Impacts E-3
Figure E 3-1: Summary of Rating Criteria for Climate Change Risk E-14

1.0 INTRODUCTION

Economic criteria and indicators for evaluating resource options as finalized in Appendix B are copied below in Table E 1-1.

The technical economic evaluation of each resource option is addressed in Appendix E, with separate sections for each of the economic criteria in Table E 1-1.

At the start of each section of Appendix E, the distinct issues, rating criteria and data sources for each criteria are summarized. As outlined in Section 7 of Appendix B, the ratings for the evaluation of each indicator are classified in terms of high, medium, and low as follows:

- **High (red when non-positive - no colour when positive effect)** means the resource option has a high expected effects linkage to the indicator (depending on the indicator, the likely effects may be adverse, beneficial or simply signify linkage/overlap without much additional guidance);
- **Medium (yellow when non-positive - no colour when positive effect)** means the resource option has potential expected linkage to the indicator that falls between low and high ratings; and
- **Low (green when non-positive - no colour when positive effect)** means the resource option likely has minimal, if any, expected effects linkage to the indicator (again, depending on the indicator, any potential minimal effects may be adverse, beneficial or simply signify no linkage/overlap with the indicator, i.e., no effects pathway).

No linkage or Not Applicable, which is shown as green, is separated out in the economic evaluations to identify circumstances where there is no apparent or likely link between a resource project option and a given economic indicator.

As each resource project option was reviewed, it was assumed that standard best management practices (BMPs) would be applied during the construction and operation stages to mitigate adverse effects and enhance positive effects. Where standard BMPs are expected to prevent any likely impact of concern on an indicator, a green or low impact rating was adopted.

Table E 1-1: Resource Options Evaluation Matrix – Economic Criteria & Indicators

ID	Criteria	Indicator	Metric ID	Metric
Economic Criteria				
Ec1	**Local Economic Impacts**	Yukon Opportunities during Construction	Ec1-1	Capital Cost - Civil and Other Local Share (L/M/H)
		Yukon Opportunities during Operation	Ec1-2	Operation Costs - Yukon Labour & Business Opportunity (L/M/H)
		Community & Other Development Opportunity	Ec1-3	Community, Industry Development Opportunity (L/M/H)
Ec2	**Climate Change Risk Affecting Resource Financial Attributes**	Susceptibility to Extreme Weather Events/Conditions	Ec2-1	Susceptible to Extreme Heat/Drought (L/M/H)
			Ec2-2	Susceptible to Extreme Precipitation - flood/snow
			Ec2-3	Susceptible to Extreme Wind Events (L/M/H)
			Ec2-4	Susceptible to Ice Related Processes/Events (L/M/H)
		Conditions Susceptible to Climate Change	Ec2-5	Extent of Permafrost in project footprint (L/M/H)

2.0 LOCAL ECONOMIC IMPACTS

2.1 RATING CRITERIA AND DATA SOURCES FOR EC1: LOCAL ECONOMIC IMPACTS

The rating system outlined in Figure E 2-1 was adopted to guide evaluations of each resource project option for each of the local economic impacts indicators. The rating system was selected in each instance based on the range of resource options under review and the objective to highlight clear differences in relative economic effects based on differences in capital expenditure (Capex), operating expenditure (Opex) or other specific community and development economic effect factors. Effects are positive for each indicator, and therefore no colours are used for rating of these indicators.

Figure E 2-1: Summary of Rating Criteria for Local Economic Impacts

Indicator	Low Positive	Medium Positive	High Positive
Yukon Opportunities during Construction (Ec1-1)	Capex <$100M, Yukon GDP <$50M (approximate range)	Capex $100 -$200M, Yukon GDP $50-$100M (approximate range)	Capex >$200M, Yukon GDP >$100M (approximate range)
Yukon Opportunities during Operation (Ec1-2)	Non-fuel Opex <$1.0M/yr.	Non-fuel Opex $1 to $2M/yr.	Non-fuel Opex >$2.0M/yr.
Community & Other Development Opportunity (Ec1-3)	Minimal development opportunity	Moderate development opportunity	Material development opportunity

The local economic impacts indicators as defined in Table E 1-1 focus on the relative magnitude of the local economic impact (L/M/H) for each resource project option. The evaluation examines the relative magnitude of absolute positive effect for each resource option (e.g., total dollars per project rather than dollars per kWh or percentages of overall project Capex or Opex going to local effects), assuming that this will be the most important basis for comparative evaluation. Where relevant, other factors may also be noted, e.g., development of new access for a region, use of local feedstocks for fuel.

Local Economic Impact criteria indicators have been evaluated based on the following:

- Yukon Energy project studies for the resource options (as reviewed in Appendix A). This assessment generally adopted costs as provided by others without attempting to address possible inconsistencies.
- Yukon input-output model based on 2010 Statistics Canada multipliers. The industry selected may not always be the proper industry that matches to the construction of the resource option.
- Results from other evaluations, including Social Criteria S4-4 (Non-renewable Resources) and S5-3 (Community, First Nation and Personal Development).

- Summary background Yukon economy information (see Attachment 1 to this appendix).

The following approach and assumptions were used in the evaluation process:

- **Yukon Opportunities during Construction** (see Table E 2-1 for the detailed information used):
    - The total capital construction cost (Capex), usually in 2016$, was identified for each resource project option based on the available Yukon Energy resource options studies.
        - In the few cases where no estimate was readily available (e.g., Mayo Lake Storage and Mayo Lake Outlet Channel Dredging), Table E 2-1 shows that approximate amounts were adopted for the evaluation.
        - These estimates were used as one key metric of construction-phase local economic impacts (separating all projects into three groups, i.e., less than $100 million Capex (low), between $100 and $200 million Capex (medium) and over $200 million Capex (high).
    - Separately, the local portion of the Capex and related gross domestic product (GDP) impacts in Yukon was estimated for each resource project option based on the available Yukon Energy resource studies and the Yukon input-output model based on Statistics Canada multipliers:
        - Where feasible from the available Yukon Energy resource options studies, the portion of the Capex identified for major equipment was removed (assuming that such equipment costs will be spent outside Yukon) in order to provide an indicator of the civil and other costs that local businesses and population can participate in by carrying out activities such as clearing, roads, building and structures (unless brought from outside of Yukon).[1] This indicator may understate economic leakage from Yukon for construction costs, e.g., installation of major equipment may often involve a specialized work force and management brought into Yukon only for the duration of time needed for this specific work.[2]
        - In cases where no estimate was readily available of the major equipment portion of Capex, Table E 2-1 shows the assumed percentages that were adopted for the evaluation.
        - After the above initial identification of the construction costs that facilitate local business and population participation, the Yukon input-output model was used to

[1] It was recognized that looking only at major equipment was a crude indicator of non-local Capex spending. However, review of available information indicated that information on civil or other "local" spending was much less consistently available.
[2] The Stewart-Keno City transmission project, for example, indicates the major equipment costs are 20 to 25% of substation and transmission line Capex cost estimates. However, these costs plus costs for installation equal to 64% of overall transmission line Capex costs.

estimate the impact to Yukon GDP, employment income within Yukon and jobs that construction activities can create.[3]

- These estimates were used as a separate key metric of local economic impacts during construction (separating all projects into three groups, i.e., less than $50 million Yukon GDP impact (low), between $50 and $100 million Yukon GDP impact (medium), and over $100 million Yukon GDP impact (high).

- The results of the GDP assessment rating were compared with the total Capex rating and were found to generally yield consistent results. In the few cases where there was some variance, judgement was used to provide a final rating of the resource option for economic opportunity impacts during construction in Yukon.

- **Yukon Opportunities during Operation** (see Table E 2-2 for the detailed information used):
  - After review of available information in the Yukon Energy studies, the analysis focused on non-fuel operations and maintenance (O&M) cost estimates (Opex) for each option as the best available overall indicator of potential resource option operating spending impacts on the Yukon economy.[4] Where relevant and feasible, other operation features were also noted, e.g., use or local feedstocks for fuel, numbers of jobs.
  - Table E 2-2 identifies where assumptions were required to assess non-fuel Opex for an option.
  - The O&M estimates were used as a key metric of operation local economic impacts (separating all projects into three groups, i.e., less than $1 million per year Opex (low), between $1 and $2 million per year Opex (medium), and over $2 million per year Opex (high).

- **Community and Other Development Opportunity** (see Table E 2-3 for the detailed assessment):
  - Consideration was given to any specific new opportunities that each resource option would provide to community and other developments. This includes effects from new roads, transmission lines and business opportunities during operation of the resource option. Projects with notable specific new opportunities to be addressed and managed were rated high.
  - Rating of resource options for Community and Other Development Opportunity (Ec1-3 economic indicator) yields a similar assessment in practice to the rating of resource options for Community, First Nation, and Personal Development (S5-3).

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[3] Direct and indirect, based on the Yukon input-output model (2010 Statistics Canada multipliers) http://economics.gov.yk.ca/impact.aspx [detailed industry multipliers: "electric power engineering construction" for hydro, thermal and transmission options, "other engineering construction" for all other options]. There would also be a construction GDP employment impact for the cost of major equipment based on the local wholesale margin and multipliers; however, it is not practical at this stage to estimate these values and, even though it would indicate a slightly higher multiplier impacts in Yukon, such a change would not appear to affect the overall evaluation ranking of the resource options.

[4] Annual operating spending changes over time for some resource options: a) to reflect inflation and b) other factors such as reduced annual generation, etc. To avoid inconsistency the first year annual operating cost was used for the ranking purposes.

The economic evaluation of resource options does not show any useful basis for separate assessment of many sub-options for specific resource options, including Whitehorse landfill versus Takhini substation locations for fossil fuel thermal options, different technologies for the storage battery option, and various smaller scale options of the solar options in Whitehorse and Haines Junction.

Table E 2-1: Local Economic Impact: Yukon Opportunities during Construction

	Installed Capacity, MW	Annual Average Energy GW.h	Construction cost[4] ($ million)			Construction GDP impact ($ million, excl. jobs) - direct plus indirect within Yukon				Evaluation				
			Total Construction cost[4]	Major Equipment costs	% of Major Equipment costs	Construction cost excl. Major Equipment costs	GDP basic prices	Labour income	Jobs	Capex (million$)	GDP values (million$)	Low Positive Capex<$100M GDP<$50M (approx.)	Medium Positive Capex$100-200M GDP$50-100M (approx.)	High Positive Capex>$200M GDP>$100M (approx.)
Fossil Thermal														
Diesel: 20 MW - Whitehorse	20.0	up to >166	62.48	17.96	29%	44.52	28.65	11.11	192	62	29	Low Positive		
LNG: 20 MW - Whitehorse	20.0	up to >166	100.12	40.51	40%	59.61	38.36	14.88	257	100	38	Low Positive		
Non-Fossil Thermal														
Waste to Energy	1.6	10	34.60	25.50	74%	9.10	3.69	2.47	38	35	4	Low Positive		
Biogas (CHP)	0.2	0.4	6.98	1.80	26%	5.18	2.10	1.41	21	7	2	Low Positive		
Biomass 0.5 MW Boiler / Steam Turbine	0.5	3	11.28	3.04	27%	8.24	3.35	2.24	34	11	3	Low Positive		
Other Non-Hydro Renewable														
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	8.0	0.04	49.48	47.75	97%	1.72	0.70	0.47	7	49	1	Low Positive		
Solar PV: Whitehorse Fixed Tilt: 10 MW	10.0	10	35.64	26.09	73%	9.54	3.87	2.59	40	36	4	Low Positive		
Solar PV: Haines Junction Fixed Tilt: 5 MW	5.0	5	12.82	7.92	62%	4.90	1.99	1.33	20	13	2	Low Positive		
Wind: Cyprus Mine Hill, 20 MW	20.0	50	69.00	24.00	35%	45.00	18.27	12.21	186	69	18	Low Positive		
Wind: Kluane Lake, 20 MW	20.0	48	62.00	24.00	39%	38.00	15.43	10.31	157	62	15		Medium Positive[4]	
Wind: Millers Ridge, 20 MW	20.0	57	73.00	24.00	33%	49.00	19.89	13.30	203	73	20	Low Positive		
Wind: Mt. Sumanik , 20 MW	20.0	42	64.00	24.00	38%	40.00	16.24	10.86	166	64	16	Low Positive		
Wind: Sugarloaf Mountain, 20 MW	20.0	32	62.00	24.00	39%	38.00	15.43	10.31	157	62	15	Low Positive		
Wind: Tehcho (Ferry Hill), 20 MW	20.0	33	64.00	24.00	38%	40.00	16.24	10.86	166	64	16	Low Positive		
Wind: Thulsoo Mountain, 20 MW	20.0	54	72.00	24.00	33%	48.00	19.49	13.03	199	72	19	Low Positive		
Geothermal: McArthur Springs (3.8 MW Av.)	3.8	25	120.50	6.40	5%	114.10	46.32	30.97	473	121	46		Medium Positive	
Geothermal: Vista Mountain (1.6 MW Av.)	1.6	11	41.50	4.15	10%	37.35	15.16	10.14	155	42	15	Low Positive		
Hydro Generation														
Pumped Storage: Moon Lake (Tutshi-Moon)	20.2	54	217.60	14.00	6%	203.60	131.03	50.81	878	218	131			High Positive
Pumped Storage: Racine - Moon	15.0	50	473.00	221.63	47%	251.37	161.77	62.74	1084	473	162			High Positive
Pumped Storage: Lindeman-Fraser	15.0	50	483.80	133.98	28%	349.82	225.13	87.31	1509	484	225			High Positive
Pumped Storage: Racine - Mt. Brown	15.0	50	284.00	62.45	22%	221.55	142.58	55.29	956	284	143			High Positive
Pumped Storage: Atlin - Black Mountain	15.0	50	253.80	61.21	24%	192.59	123.94	48.06	831	254	124			High Positive
Pumped Storage: Squanga - Dalayee	25.0	100	613.40	145.91	24%	467.49	300.86	116.67	2017	613	301			High Positive
Pumped Storage: Canyon - Ittlemit	25.0	100	691.20	68.52	10%	622.68	400.73	155.40	2686	691	401			High Positive
Pumped Storage: Vangorda Pit	40.0	134	523.80	114.94	22%	408.86	263.13	102.04	1764	524	263			High Positive
Small Hydro: Drury Lake	8.1	32	103.30	61.10	59%	42.20	27.16	10.53	182	103	27	Low Positive		
Small Hydro: Tutshi - Windy Arm	7.2	57	133.20	73.27	55%	59.93	38.57	14.96	259	133	39		Medium Positive	
Small Hydro: Wolf River	20.0	96	233.80	112.72	48%	121.08	77.92	30.22	522	234	78			High Positive
Small Hydro: Finlayson River	17.6	138.90	282.50	74.62	26%	207.88	133.78	51.88	897	283	134			High Positive
Small Hydro: Anvil Creek	9.8	41.30	115.98	49.60	43%	66.38	42.72	16.57	286	116	43		Medium Positive	
Small Hydro: Atlin/Pine Creek	5.7	36.3 to Yukon	79.70	13.38	17%	66.32	42.68	16.55	286	80	43		Medium Positive[4]	
Other Hydro: Gladstone Diversion	N/A	36.60	40.00	8.00	assume 20%	32.00	20.59	7.99	138	40	21	Low Positive		
Other Hydro: Southern Lakes Storage	1.0	6.40	10.50	1.05	assume 10%	9.45	6.08	2.36	41	11	6	Low Positive		
Other Hydro: Mayo Lake Storage	N/A	2 to 4	approx. 5	0.50	assume 10%	4.50	2.90	1.12	19	5	3	Low Positive		
Other Hydro: Mayo Dredging	N/A	1 to 2	approx. 15	7.50	assume 50%	7.50	4.83	1.87	32	15	5	Low Positive		
Aishihik Re-runnering	1.00	3	4.70	2.35	assume 50%	2.35	1.51	0.59	10	5	2	Low Positive		
Mayo A Refurbishment	2.30	10	27.40	13.70	assume 50%	13.70	8.82	3.42	59	27	9	Low Positive		
Transmission Corridors	Transfer Capacity													
Transmission: Whitehorse - Atlin (138 kV)	97.0	N/A	158.00	31.60	assume 20%	126.40	81.35	31.55	545	158	81		Medium Positive	
Transmission: Whitehorse - Skagway (230 kV)	443.0	N/A	251.00	50.20	assume 20%	200.80	129.23	50.11	866	251	129			High Positive
Transmission: Whitehorse - Teslin (138 kV)	95.0	N/A	165.00	33.00	assume 20%	132.00	84.95	32.94	569	165	85		Medium Positive	
Transmission: Faro - Watson Lake (230 kV)	190.0	N/A	597.00	119.40	assume 20%	477.60	307.36	119.19	2060	597	307			High Positive
Transmission: Aishihik - Destruction Bay (230 kV)	484.0	N/A	241.00	48.20	assume 20%	192.80	124.08	48.12	832	241	124		Medium Positive	
Transmission: Stewart-Keno City (138 kV & substations)	N/A	N/A	86.00	18.50	22%	67.50	43.44	16.85	291	80	43	Low Positive		

1. Yukon GDP impact analysis are based on Yukon input-output model available at http://economics.gov.yk.ca/impact.aspx [2010 Statistics Canada multipliers, simple multipliers (direct plus indirect) within Yukon applied to estimated construction cost excluding major equipment; detailed aggregation for industry "Electric power engineering construction" for thermal, hydro & transmission options; "Other engineering construction" for all other options].

2. The construction cost estimates for some options do not provide breakdown of the costs to identify amount related to major equipment, and even when estimates are provided they may not provide reliable or consistent numbers for the GDP analysis. For example, the major equipment cost for Waste to Energy option shown in the table above is the cost for "complete facility installed and commissioned", which may include other construction related costs. For Storage Battery options the major equipment cost includes "Capital cost" plus "replacement cost" [this assumes replacement of all batteries after 15 years for lead acid batteries and after 20 years for lithium ion batteries]. No breakout of equipment costs is provided for transmission corridor options, or certain other projects as noted. The capital cost for these options would require further breakdown in order to estimate major equipment related costs to be excluded for the GDP analysis.

3. Most of the pumped storage hydro options (as well as the Atlin/Pine Creek small hydro option) are located in the northern BC close to the Yukon border. The locations are very close to Yukon compared to any other major population centres in BC and access to the construction site would be from Yukon. Therefore, all capital spending and employment opportunities are assumed to be within Yukon resources.

4. Kluane Lake Wind and Atlin/Pine Creek Small Hydro ratings reflect need for material transmission Capex not included in this table (see Appendix A, section 5.1). No capital costs are yet included for most of the transmission needed to connect certain options to grid: Kluane wind farm ($241 million Aishihik-Destruction Bay transmission corridor); all pumped storage options other Vangorda Pit and Canyon-Ittlemit (estimated capex ranges from $100 to $125 million); all small hydro other than Drury Lake and Anvil Creek (estimated capex ranges from $94 to $221 million).

Table E 2-2: Local Economic Impact: Yukon Opportunities during Operation

	Installed Capacity, MW	Annual Average Energy GW.h	Operation cost ($ million, excludes feedstock/fuel costs)		Notes	Evaluation			
			Annual Operation Cost	Jobs		Nonfuel Opex $M/yr	Low Positive Non-fuel Opex <$1M/yr	Medium Positive Non-fuel Opex $1 to 2 M/yr	High Positive Non-fuel Opex >$2M/yr
Fossil Thermal									
Diesel: 20 MW - Whitehorse	20.0	up to >166	up to 1.19	N/A	Non-fuel O&M likely to be well under $1 million/yr with actual usage. Fuel sourced from outside Yukon, and used when required.	up to 1.19	Low Positive		
LNG: 20 MW - Whitehorse	20.0	up to >166	up to 1.19	N/A		up to 1.19	Low Positive		
Non-Fossil Thermal									
Waste to Energy	1.6	10	3.36	18	Fuel feedstocks from local sources (cost excluded here). Economics assume year-round operation. Except for biogas, assumes sale of waste heat.	3.36			High Positive
Biogas (CHP)	0.2	0.4	0.26	N/A		0.26	Low Positive		
Biomass 0.5 MW Boiler / Steam Turbine	0.5	3	0.62	5		0.62	Low Positive		
Other Non-Hydro Renewable									
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	8.0	0.04	0.26	N/A		0.26	Low Positive		
Solar PV: Whitehorse Fixed Tilt: 10 MW	10.0	10	0.37	N/A		0.37	Low Positive		
Solar PV: Haines Junction Fixed Tilt: 5 MW	5.0	5	0.14	N/A		0.14	Low Positive		
Wind: Cyprus Mine Hill, 20 MW	20.0	50	1.36	2	Wind farm options earn medium positive rating, except for the two options with FN land lease payments. Assumes employ two technicians working out of an office near any of wind farm. About 20% of O&M costs are fixed; variable costs include maintenance costs and royalties. Two site options [Kluane Lake & Sugarloaf Mountain] are on aboriginal traditional land and assume land lease payments to the local FN (reflected in high positive rating). Kluane Lake required new transmission to Haines Junction or Aishihik area.	1.36		Medium Positive	
Wind: Kluane Lake, 20 MW	20.0	48	1.31	2		1.31			High Positive
Wind: Millers Ridge, 20 MW	20.0	57	1.44	2		1.44		Medium Positive	
Wind: Mt. Sumanik , 20 MW	20.0	42	1.12	2		1.12		Medium Positive	
Wind: Sugarloaf Mountain, 20 MW	20.0	32	0.98	2		0.98			High Positive
Wind: Tehcho (Ferry Hill), 20 MW	20.0	33	0.97	2		0.97		Medium Positive	
Wind: Thulsoo Mountain, 20 MW	20.0	54	1.39	2		1.39		Medium Positive	
Geothermal: McArthur Springs (3.8 MW Av.)	3.8	25	1.30	N/A		1.30		Medium Positive	
Geothermal: Vista Mountain (1.6 MW Av.)	1.6	11	0.58	NA		0.58	Low Positive		
Hydro Generation									
Pumped Storage: Moon Lake (Tutshi-Moon)	20.2	54	1.90	N/A	All sites (except Moon and Vangorda Pit) annual O&M cost estimated at 2.0% of capital cost before IDC plus $0.005/kW.h for generation and pumped energy. Moon option O&M cost as per Midgard report, with provision specifically for BC resource fees. Vangorda Pitt O&M cost adjusted from EMC[2] Picacho report to provide $0.005/kW.h cost for pumped storage.	1.90		Medium Positive	
Pumped Storage: Racine - Moon	15.0	50	9.20	N/A		9.20			High Positive
Pumped Storage: Lindeman-Fraser	15.0	50	9.50	N/A		9.50			High Positive
Pumped Storage: Racine - Mt. Brown	15.0	50	5.80	N/A		5.80			High Positive
Pumped Storage: Atlin - Black Mountain	15.0	50	5.20	N/A		5.20			High Positive
Pumped Storage: Squanga - Dalayee	25.0	100	12.50	N/A		12.50			High Positive
Pumped Storage: Canyon - Ittlemit	25.0	100	13.90	N/A		13.90			High Positive
Pumped Storage: Vangorda Pit	40.0	134	2.40	N/A		2.40			High Positive
Small Hydro: Drury Lake	8.1	32	2.10	N/A	Small hydro option annual O&M cost estimated at 2.0% of capital cost before IDC plus $0.005/kW.h variable cost for generation. Atlin/Pine Creek rated High Positive after considering need for added O&M on transmission required to connect to Yukon grid.	2.10			High Positive
Small Hydro: Tutshi - Windy Arm	7.2	57	2.79	N/A		2.79			High Positive
Small Hydro: Wolf River	20.0	96	4.88	N/A		4.88			High Positive
Small Hydro: Finlayson River	17.6	139	6.02	N/A		6.02			High Positive
Small Hydro: Anvil Creek	9.8	41	2.39	N/A		2.39			High Positive
Small Hydro: Atlin/Pine Creek	5.7	36.3 avail to Yukon	1.77	N/A		1.77			High Positive
Other Hydro: Gladstone Diversion	N/A	37	likely<1.0	N/A		likely<1.0	Low Positive		
Other Hydro: Southern Lakes Storage	1.0	6	likely<1.0	N/A		likely<1.0	Low Positive		
Other Hydro: Mayo Lake Storage	N/A	2 to 4	likely<1.0	N/A		likely<1.0	Low Positive		
Other Hydro: Mayo Dredging	N/A	1 to 2	likely<1.0	N/A		likely<1.0	Low Positive		
Aishihik Re-runnering	1.00	3	likely<0.5	N/A		likely<0.5	Low Positive		
Mayo A Refurbishment	2.30	10	likely<0.5	N/A		likely<0.5	Low Positive		
Transmission Corridors	Transfer Capacity								
Transmission: Whitehorse - Atlin (138 kV)	97.0	N/A	0.24	N/A	Ongoing O&M includes labour costs, brushing costs, and other non-labour costs, adjusted for corridor length and difficulty factors.	0.24	Low Positive		
Transmission: Whitehorse - Skagway (230 kV)	443.0	N/A	0.29	N/A		0.29	Low Positive		
Transmission: Whitehorse - Teslin (138 kV)	95.0	N/A	0.24	N/A		0.24	Low Positive		
Transmission: Faro - Watson Lake (230 kV)	190.0	N/A	0.61	N/A		0.61	Low Positive		
Transmission: Aishihik - Destruction Bay (230 kV)	484.0	N/A	0.22	N/A		0.22	Low Positive		
Transmission: Stewart-Keno City (138 kV & substations)	N/A	N/A	likely<0.2	N/A		likely<0.2	Low Positive		

Table E 2-3: Local Economic Impact: Community and Other Development Opportunity

	Evaluation			
	Notes	**Low Positive**	**Medium Positive**	**High Positive**
Fossil Thermal				
Diesel: 20 MW - Whitehorse	No specific local development opportunities.	**Low Positive**		
LNG: 20 MW - Whitehorse	Local opportunity to facilitate LNG use to displace other fossil fuel use in Whitehorse/Yukon.		**Medium Positive**	
Non-Fossil Thermal				
Waste to Energy	Local opportunity to use renewable and (except for biogas) to supply waste heat to displace fossil fuel use. High operating jobs for Waste to Energy.		**Medium Positive**	
Biogas (CHP)			**Medium Positive**	
Biomass 0.5 MW Boiler / Steam Turbine			**Medium Positive**	
Other Non-Hydro Renewable				
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)	Minimal direct local development impact. Might facilitate solar or wind.	**Low Positive**		
Solar PV: Whitehorse Fixed Tilt: 10 MW	Minimal direct local development impact.	**Low Positive**		
Solar PV: Haines Junction Fixed Tilt: 5 MW		**Low Positive**		
Wind: Cyprus Mine Hill, 20 MW	Moderate local economic development impacts from operations (ex. Mt Sumanik). Proposed Kluane & Sugarloaf Mountain sites are on aboriginal traditional land and assume land lease payments to the local FN; Kluane Lake option also facilitates development of an Aishihik-Destruction Bay Transmission Corridor.		**Medium Positive**	
Wind: Kluane Lake, 20 MW				**High Positive**
Wind: Millers Ridge, 20 MW			**Medium Positive**	
Wind: Mt. Sumanik , 20 MW		**Low Positive**		
Wind: Sugarloaf Mountain, 20 MW				**High Positive**
Wind: Tehcho (Ferry Hill), 20 MW			**Medium Positive**	
Wind: Thulsoo Mountain, 20 MW			**Medium Positive**	
Geothermal: McArthur Springs (3.8 MW Av.)	Moderate local economic development impacts from operations (new access road).		**Medium Positive**	
Geothermal: Vista Mountain (1.6 MW Av.)	Minimal local economic development impact.	**Low Positive**		
Hydro Generation				
Pumped Storage: Moon Lake (Tutshi-Moon)	Moderate local economic development impact based on Opex levels. In addition, options other than Squanga Dalayee, Canyon Ittlemit & Vangorda Pit each facilitate development of a portion of a Transmission Corridor resource option. The Vangorda Pit option may facilitate development of the Grizzly Pit mine deposit.			**High Positive**
Pumped Storage: Racine - Moon				**High Positive**
Pumped Storage: Lindeman-Fraser				**High Positive**
Pumped Storage: Racine - Mt. Brown				**High Positive**
Pumped Storage: Atlin - Black Mountain				**High Positive**
Pumped Storage: Squanga - Dalayee			**Medium Positive**	
Pumped Storage: Canyon - Ittlemit			**Medium Positive**	
Pumped Storage: Vangorda Pit			**Medium Positive**	
Small Hydro: Drury Lake	Moderate local economic development impact based on Opex level. All options other than Drury Lake and Anvil Creek also facilitate development of a Transmission Corridor (Tutshi-Windy Arm requires portion of Whitehorse-Skagway line, Wolf River and Atlin/Pine Creek facilitate Whitehorse-Atlin line, Finlayson needs line extending from Faro toward Watson Lake).		**Medium Positive**	
Small Hydro: Tutshi - Windy Arm				**High Positive**
Small Hydro: Wolf River				**High Positive**
Small Hydro: Finlayson River				**High Positive**
Small Hydro: Anvil Creek			**Medium Positive**	
Small Hydro: Atlin/Pine Creek				**High Positive**
Other Hydro: Gladstone Diversion	Minimal local economic development impact; facilitate local First Nation income benefits.			**High Positive**
Other Hydro: Southern Lakes Storage	Minimal local economic development impact.	**Low Positive**		
Other Hydro: Mayo Lake Storage		**Low Positive**		
Other Hydro: Mayo Dredging		**Low Positive**		
Aishihik Re-runnering	Minimal local economic development impact.	**Low Positive**		
Mayo A Refurbishment		**Low Positive**		
Transmission Corridors				
Transmission: Whitehorse - Atlin (138 kV)	Moderate potential local economic development impact if stimulates small hydro (in Atlin and Teslin areas, or in Moon-Tutshi area); and if (for Whitehorse-Skagway corridor) stimulates sales of summer hydro or wind generation (to cruise ships).		**Medium Positive**	
Transmission: Whitehorse - Skagway (230 kV)			**Medium Positive**	
Transmission: Whitehorse - Teslin (138 kV)			**Medium Positive**	
Transmission: Faro - Watson Lake (230 kV)	Material potential local economic development impacts (displace diesel generation in local communities with hydro, benefits to local businesses and population, opportunity to facilitate new mining and hydro or wind developments).			**High Positive**
Transmission: Aishihik - Destruction Bay (230 kV)				**High Positive**
Transmission: Stewart-Keno City (138 kV & substations)	Material local economic development impact by replacing end of life line, retains access to hydro generation, facilitates expanded capability for new mine developments.			**High Positive**

2.2 EVALUATIONS

2.2.1 Resource Options with No Material Concerns re: Local Economic Impacts

Tables E 2-1 to E 2-3 show a low positive rating for each of the local economic impact indicators for the following resource project options:

- Fossil fuel thermal - diesel generation options.
- Non-hydro renewable:
    - Storage Battery;
    - Solar PV; and
    - Geothermal - Vista Mountain.
- Hydro Generation:
    - Other Hydro – Southern Lakes Enhanced Storage, Mayo Lake Enhanced Storage, and Mayo Lake Outlet Channel Dredging; and
    - Refurbishment/Maintenance – Aishihik Rerunnering, Mayo A Refurbishment.

2.2.2 Fossil Fuel Thermal Generation

2.2.2.1 LNG Thermal Generation

Liquefied natural gas (LNG) thermal generation in Whitehorse has a low positive rating for both construction and operation Yukon opportunities.

This resource option has a medium positive rating for community and other development opportunities, reflecting local opportunities facilitated by this option (through its development of an LNG supply chain) to use LNG to displace other fossil fuel use in Whitehorse/Yukon.

2.2.3 Non-Hydro Renewable Generation

2.2.3.1 Non-Fossil Thermal Generation

Each of the non-fossil thermal generation resource options has a low positive rating for Yukon opportunities during construction, and each option other than Waste to Energy also has a low positive rating for Yukon opportunities during operation. Waste to Energy has a high positive rating for Yukon opportunities during operation, reflecting its high annual Opex cost level and the level of operation jobs.

Each of the non-fossil thermal generation resource options has a medium positive rating for community and other development opportunities, reflecting local opportunities to use renewable energy resources, as well as local opportunities (except for biogas) to use waste heat to displace fossil fuel use.

2.2.3.2 Wind Farms

Each of the wind farm resource options other than Kluane Lake has a low positive rating for Yukon opportunities during construction. Kluane Lake has a medium positive rating for Yukon opportunities during construction, reflecting the additional development (not reflected in the Kluane Lake costs as estimated in the Table E 2-1) for the new transmission line required to connect the Kluane Lake wind far to the existing grid at Haines Junction or the WAF 138 kV grid near Aishihik.

Each of the wind farm options other than Kluane Lake and Sugarloaf Mountain have a medium positive rating for Yukon opportunities during operation and (except for Mt. Sumanik) for community and other development opportunity. The medium positive ratings reflect the level of annual Opex costs and the expectation that these costs will provide some local opportunities. Mt. Sumanik has a low positive rating for community and other development opportunity to reflect its proximity to Whitehorse and the extent to which this proximity will reduce the overall effect on local community development.

The high positive ratings for Kluane Lake and Sugarloaf Mountain for Yukon opportunities during operation and for community and other development opportunity reflect opportunities for First Nation lease revenues for the two sites (Kluane Lake and Sugarloaf Mountain) and the opportunity to develop the new transmission corridor for the Kluane Lake site, which will allow Destruction Bay and likely Burwash Landing to stop relying on diesel generation.

2.2.3.3 Geothermal - McArthur Springs

The McArthur Springs geothermal resource option has a medium positive rating for each of the three Local Economic Impact indicators, reflecting the magnitude of its Capex and Opex costs, as well as any local development opportunities facilitated by the new access road that this option provides to the area.

2.2.4 Hydro Generation

2.2.4.1 Pumped Storage

Each of the pumped storage resource options has a high positive rating for Yukon opportunities during construction, reflecting the Capex cost levels (which are generally higher than the levels for all other resource options considered in this Resource Plan). Table E 2-1 does not include Capex costs needed to connect most of these sites (i.e., all sites other than Canyon-Ittlemit and Vangorda Pit) to the existing grid, and therefore understates the actual Capex cost requirements needed for development of most sites.

Each of the pumped storage resource options other than Tutshi-Moon has a high positive rating for Yukon opportunities during operation, reflecting the Opex cost levels, which are generally higher than the levels for all other resource options considered in this Resource Plan. The Tutshi-Moon site has a medium positive rating for Yukon opportunities during operation. These operation opportunities are expected to be focused inside the facility and the utility.

The Squanga-Dalayee, Canyon-Ittlemit and Vangorda Pit pumped storage options each has a medium positive rating for community and other development opportunity, reflecting the expectation that these

options will provide moderate local or community development opportunities based on Opex levels. Each of the other pumped storage options has a high positive rating for this indicator reflecting opportunity to develop one of the Transmission Corridor resource options (e.g., Whitehorse-Skagway or Whitehorse-Atlin), and (in the case of Tutshi-Moon option) to facilitate other small hydro development at Tutshi-Windy Arm.

2.2.4.2 Small Hydro

Based on Capex cost levels and estimates of Yukon GDP effects, the following small hydro resource ratings occur for Yukon opportunities during construction:

- Wolf River and Finlayson River have a high positive rating;
- Tutshi-Windy Arm, Anvil Creek and Atlin/Pine Creek options have a medium positive rating (the Atlin/Pine Creek medium rating reflects the additional development [not reflected in the Kluane Lake costs as estimated in the Table E 2-1] for the new transmission line needed to connect the project to the Yukon grid at Jakes Corner); and
- Drury Lake has a low positive rating.

Each of the small hydro resource options has a high positive rating for Yukon opportunities during operation, reflecting the Opex cost levels (the Atlin/Pine Creek rating reflects Opex expected for required new transmission connection as well as the hydro facility expansion). These operation opportunities are expected to be focused inside the facility and the utility.

Drury Lake and Anvil Creek small hydro has a medium positive rating for community and other development opportunity to reflect the level of Opex spending. Each of the other small hydro options has a high positive rating to reflect that it facilitates the development of a specific transmission corridor.

2.2.4.3 Other Hydro - Gladstone Diversion

The Gladstone Diversion resource option has a low positive rating for Yukon opportunities during construction and operation, and a high positive rating for community and other development opportunity. The high positive rating reflects the opportunity to facilitate local First Nation income benefits.

2.2.5 Transmission Corridors

Based on Capex cost levels and estimates of Yukon GDP effects, the following transmission corridor resource ratings occur for Yukon opportunities during construction:

- Whitehorse-Skagway and Faro-Watson Lake each have a high positive rating;
- Whitehorse-Atlin, Whitehorse-Teslin, and Aishihik-Destruction Bay each have a medium positive rating; and
- Stewart-Keno City has a low positive rating.

Based on Opex cost levels, each of the transmission corridor options has a low positive rating for Yukon opportunities during operation.

Faro-Watson Lake, Aishihik-Destruction Bay and Stewart-Keno City transmission corridor options are each rated high positive for local community and other development opportunities, reflecting opportunities to displace local diesel (or sustain existing transmission capability to do this, as in the case of the Stewart-Keno City option), as well as to facilitate new mining and renewable generation (hydro or wind) development. The three remaining transmission corridor options (Whitehorse-Atlin, Whitehorse-Skagway, and Whitehorse-Teslin) are each rated medium positive, reflecting potential local development impacts if they facilitate renewable generation (pumped storage or small hydro) and, in the case of the Skagway connection, the sale of summer renewable generation (hydro or wind) to cruise ships.

3.0 CLIMATE CHANGE RISK

3.1 RATING CRITERIA AND DATA SOURCES FOR EC2: CLIMATE CHANGE RISK AFFECTING RESOURCE FINANCIAL ATTRIBUTES

The rating system outlined in Figure E 3-1 was adopted to guide evaluations of each resource project option for each of the climate change risk indicators. These assessments address the extent to which financial attributes of the resource options are potentially affected by various climate change risk factors.

Figure E 3-1: Summary of Rating Criteria for Climate Change Risk

Indicator	Low	Medium	High
Susceptible to Extreme Weather/Events Conditions (Ec2-1) Extreme Heat/Drought (Ec2-2) Extreme Precipitation (Ec2-3) Extreme Wind Events (Ec2-4) Ice Related Processes	Not Specifically Susceptible, or Not Applicable	Potentially Susceptible	Specifically Susceptible
Conditions Susceptible to Climate Change - Extent of Permafrost in Project Footprint (Ec2-5)	Not Specifically Susceptible, or Not Applicable	Potentially Susceptible	Specifically Susceptible

The climate change risk indicators as defined in Table E 1-1 focus on the relative magnitude of the risk (L/M/H) for each resource project option. Green (low) shows minimal concerns, meaning that the resource option is not specifically susceptible to the specified risk or the risk is not applicable to the resource option. In contrast, red (high) identifies resource options that are known to be specifically susceptible to the risk (and thus at risk for relatively high adverse economic effects, either in design, construction or operation). Yellow (medium) addresses resource options where there is uncertainty as to the relative magnitude of the risk, based on current information.

Climate Change Risk criteria indicators have been evaluated based on information available from:

- Yukon Energy project studies for the resource options (as reviewed in Appendix A); and
- Results from other evaluations, including environmental criteria En4-3 (Permafrost).

Many resource options are not specifically susceptible to climate change risks beyond what might be called "normal" susceptibility, i.e., exposures to risks of extreme weather events similar to the exposure of other community activities. The evaluation is directed at identifying resource options where the specified risk is clearly of direct and special importance relative to the risk exposure for the other resource options relevant to the current Resource Plan evaluation. See Table E 3-1 for the detailed evaluation.

Table E 3-1: Climate Change Risk: Indicator Evaluation of Resource Options

	Susceptibility to Extreme Weather Events/Conditions (L/M/H)				Conditions Susceptible to Climate Change
	Notes	Extreme Heat/Drought	Extreme Precipitation - flood/snow	Extreme Wind Events	Ice Related Processes/Events	Extent of Permafrost in Project Footprint
Fossil Thermal						
Diesel: 20 MW - Whitehorse		Low	Low	Low	Low	Low
LNG: 20 MW - Whitehorse		Low	Low	Low	Low	Low
Non-Fossil Thermal						
Waste to Energy		Low	Low	Low	Low	Low
Biogas (CHP)		Low	Low	Low	Low	Low
Biomass 0.5 MW Boiler / Steam Turbine		Medium	Low	Low	Low	Low
Other Non-Hydro Renewable						
Storage Battery: 8 MW/40 MWh (lithium ion, 5hrs)		Low	Low	Low	Low	Low
Solar PV: Whitehorse Fixed Tilt: 10 MW	When working in cold climates, the voltage changes as a function of temperature becomes a critical design component.	Low	Low	Low	Low	Low
Solar PV: Haines Junction Fixed Tilt: 5 MW		Low	Low	Low	Low	Low
Wind: Cyprus Mine Hill, 20 MW	Turbine output will decrease below -30°C (all sites other than Kluane Lake) and wind turbines generally stop working below 40°C. For all sites other than Kluane Lake, 10% loss assumed for icing impacts. Kluane Lake transmission access also likely affected by permafrost conditions. Assume wind resource potentially susceptible to extreme wind events.	Low	Low	Medium	High	Low
Wind: Kluane Lake, 20 MW		Low	Low	Medium	Low	High
Wind: Millers Ridge, 20 MW		Low	Low	Medium	High	Low
Wind: Mt. Sumanik , 20 MW		Low	Low	Medium	High	Low
Wind: Sugarloaf Mountain, 20 MW		Low	Low	Medium	High	Low
Wind: Tehcho (Ferry Hill), 20 MW		Low	Low	Medium	High	Low
Wind: Thulsoo Mountain, 20 MW		Low	Low	Medium	High	Low
Geothermal: McArthur Springs (3.8 MW Av.)	Potential permafrost conditions affecting road / transmission access.	Low	Low	Low	Low	Medium
Geothermal: Vista Mountain (1.6 MW Av.)		Low	Low	Low	Low	Low
Hydro Generation						
Pumped Storage: Moon Lake (Tutshi-Moon)	Hydro resource options are specifically susceptible to drought, and therefore each of these options is rated on this basis. There is inadequate information to rate any material differences among these projects - however, storage can assist resiliency, along with capacity being set well below maximum potential. Potential permafrost conditions are assumed for options requiring material new transmission development.	High	Low	Low	Low	Medium
Pumped Storage: Racine - Moon		High	Low	Low	Low	Medium
Pumped Storage: Lindeman-Fraser		High	Low	Low	Low	Medium
Pumped Storage: Racine - Mt. Brown		High	Low	Low	Low	Medium
Pumped Storage: Racine - Mt. Brown		High	Low	Low	Low	Medium
Pumped Storage: Atlin - Black Mountain		High	Low	Low	Low	Medium
Pumped Storage: Atlin - Black Mountain		High	Low	Low	Low	Medium
Pumped Storage: Squanga - Dalayee		High	Low	Low	Low	Medium
Pumped Storage: Canyon - Ittlemit		High	Low	Low	Low	Low
Pumped Storage: Vangorda Pit		High	Low	Low	Low	Low
Small Hydro: Drury Lake	Hydro resource options are specifically susceptible to drought. Storage can assist resiliency, along with capacity for some options being set well below maximum potential. Geotechnical risk and the presence of permafrost noted for Drury Lake option. Permafrost risk assumed for new transmission.	High	Low	Low	Low	High
Small Hydro: Tutshi - Windy Arm		High	Low	Low	Low	Medium
Small Hydro: Wolf River		High	Low	Low	Low	Medium
Small Hydro: Finlayson River		High	Low	Low	Low	Medium
Small Hydro: Anvil Creek		High	Low	Low	Low	Medium
Small Hydro: Atlin/Pine Creek		High	Low	Low	Low	Medium
Other Hydro: Gladstone Diversion	Gladstone Diversion assumed to be susceptible to drought risk (red rating). It is assumed that drought related risks are only moderate for the storage enhancement options.	High	Low	Low	Low	Low
Other Hydro: Southern Lakes Storage		Medium	Low	Low	Low	Low
Other Hydro: Mayo Lake Storage		Medium	Low	Low	Low	Low
Other Hydro: Mayo Dredging		Low	Low	Low	Low	Low
Aishihik Re-runnering	The viability or design of these options is assumed not to be susceptible to these risks.	Low	Low	Low	Low	Low
Mayo A Refurbishment		Low	Low	Low	Low	Low
Transmission Corridors						
Transmission: Whitehorse - Atlin (138 kV)	Potential risks include additional snow clearing costs from heavy snow, structure & conductor damage, contact between phases and transmission structure or guys, phase contact with trees or buildings, trees falling into line (wind event related risks), forest fire ignition (extended heat/drought risk). Permafrost in project footprint would increase capital costs (specific risk for Aishihik-Destruction Bay option).	Low	Medium	Medium	Medium	Medium
Transmission: Whitehorse - Skagway (230 kV)		Low	Medium	Medium	Medium	Medium
Transmission: Whitehorse - Teslin (138 kV)		Low	Medium	Medium	Medium	Medium
Transmission: Faro - Watson Lake (230 kV)		Medium	Medium	Medium	Medium	Medium
Transmission: Aishihik - Destruction Bay (230 kV)		Medium	Medium	Medium	Medium	High
Transmission: Stewart-Keno City (138 kV & sub.)		Medium	Medium	Medium	Medium	Medium

3.2 EVALUATIONS

3.2.1 Resource Options with No Material Concerns re: Climate Change Risk

Tables E 3-1 shows a green rating for each of the climate change risk indicators for the following resource project options:

- Fossil fuel thermal options (diesel and LNG).
- Non-hydro renewable:
    - Non-fuel thermal options (waste to energy, biogas and biomass);
    - Storage Battery;
    - Solar PV;
    - Geothermal - Vista Mountain;
    - Other Hydro - Mayo Outlet Channel Dredging; and
    - Refurbishment/Maintenance - Aishihik Rerunnering, Mayo A Refurbishment).

3.2.2 Non-Hydro Renewable Generation

3.2.2.1 Biomass

The biomass generation option has a yellow (medium) rating for susceptibility to extreme heat/drought (e.g., forest fires). Biomass generation has a green (low) rating for all other Climate Change Risk indicators.

3.2.2.2 Wind Farms

Each of the wind farm site options has a green (low) rating for susceptibility to extreme heat/drought, as well as extreme precipitation (flood/snow). All wind farm sites other than Kluane Lake have a green rating as well for the extent of permafrost in project footprint (Kluane Lake has a red [high] rating based on extensive discontinuous permafrost affecting the new transmission routing needed for this option).

Each of the wind farm site options has a yellow (medium) rating for susceptibility to extreme wind events.

Each of the wind farm site options other than Kluane Lake has a red (high) rating for susceptibility to ice-related processes/events (Kluane Lake has a green [low] rating).

3.2.2.3 Geothermal - McArthur Springs

McArthur Springs has a green (low) rating for all four indicators regarding susceptibility to extreme weather events/conditions.

McArthur Springs has a yellow (medium) rating for the extent of permafrost in project footprint, reflecting potential permafrost conditions affecting new road and transmission access to this site.

3.2.3 Hydro Renewable Generation

3.2.3.1 Pumped Storage

With regard to susceptibility to extreme water events/conditions, each of the pumped storage resource options has the following ratings:

- Extreme heat/drought - red (high) rating, reflecting specific susceptibility to drought; and
- Extreme precipitation (flood/snow), extreme wind events, and ice-related processes/events - green (low) rating.

With regard to the extent of permafrost in project footprint, each option other than Canyon-Ittlemit and Vangorda Pit has a medium rating reflecting potential permafrost conditions affecting material new transmission access development requirements. Canyon-Ittlemit and Vangorda Pit have a green rating, reflecting proximity to existing transmission.

3.2.3.2 Small Hydro

With regard to susceptibility to extreme water events/conditions, each of the small hydro resource options has the following ratings:

- Extreme heat/drought - red (high) rating, reflecting specific susceptibility to drought; and
- Extreme precipitation (flood/snow), extreme wind events, and ice-related processes/events - green (low) rating.

With regard to the extent of permafrost in project footprint, each option other than Drury Lake has a medium rating reflecting potential permafrost conditions affecting material new transmission access development requirements. Drury Lake has a red (high) rating based on geotechnical risks and presence of permafrost noted in previous KGS reports.

3.2.3.3 Other Hydro (excluding Mayo Outlet Channel Dredging)

Each of these resource options has a green (low) rating regarding susceptibility to extreme precipitation (flood/snow), extreme wind events, ice-related process/events, and the extent of permafrost in the project footprint.

Regarding susceptibility to extreme heat/drought conditions, Gladstone Diversion has a red (high) rating, and each of the enhanced storage options (Mayo Lake and Southern Lakes) has a yellow (moderate) rating (reflecting the modest nature of these enhancements within the overall existing hydro generation regime).

3.2.4 Transmission Corridors

The transmission corridor options tend (by their linear nature) to be susceptible to extreme weather events and/or permafrost condition risks. Accordingly, each of these resource options has a yellow (medium) rating for all of the climate risk indicators, with the following exceptions:

- Regarding susceptibility to extreme heat/drought, which increases forest fire risks, the Whitehorse-Atlin, Whitehorse-Teslin, and Whitehorse-Skagway transmission corridor options are rated green (low) reflecting the extent that each route covers well developed areas and/or mountain areas.
- Regarding susceptibility to the extent of permafrost in project footprint, the Aishihik-Destruction Bay transmission corridor option has a red (high) rating, reflecting the extensive discontinuous permafrost affecting the new transmission routing needed for this option.

ATTACHMENT 1:

Baseline Information

In 2015, Yukon's population grew for the 12th consecutive year,[1] and as of June 2015, Yukon's population was estimated at 37,343,[2] (an approximate 20% increase over the last ten years, representing an annual average increase of 1.8%). Notably, the City of Whitehorse accounted for over 77% of the total population in Yukon at 28,872, and Whitehorse's population gains accounted for the majority of overall population growth in Yukon in 2015 over 2014 (about 85% of the annual change).

As of November 2015, the Yukon labour force averaged 21,200,[3] up 700 from 2014 level. The unemployment rate was 4.2%, the lowest unemployment rate amongst Canadian provinces and territories, and lower than the national unemployment rate of 7.1%. For the same period in the prior year the territorial unemployment rate was at 4.4%.

The service-producing sector accounted for about 84% of total employment, while 16.0% were employed in the goods-producing sector. Approximately 39.5% of working Yukoners were employed by one of the levels of government in the territory, while the remaining 60.5% were employed in the private sector with about 26.2% as self-employed.

In 2014, Yukon's real gross domestic product (GDP) contracted for a second consecutive year (after nine consecutive year over year increases), decreasing by approximately 0.8% to $2.264 billion. An annual decline in mineral production as a result of weak mineral prices and an ongoing slowdown in the global mining industry was the primary contributor to the reduction in GDP.[4] In summary:

- GDP from mining, quarrying and oil and gas extraction was a significant contributor to Yukon's economy at 19% of total GDP in 2014 (at $2007); however, it was down from an estimated contribution of over 21% in 2012 and 2013;
- GDP related to Public Administration contributed about 21% to 22% to Yukon's GDP over the last five years (2010-2014), highlighting the important role the public sector plays in Yukon's economy; and
- The construction sector also provides notable impact to GDP with about 7% to 7.5% contribution to Yukon's GDP over the last three years (2012-2014), declining from 10%-11% in 2010 and 2011.

Whitehorse is the largest electricity load centre[5] and accounts for largest portion of Yukon businesses. In 2013, Whitehorse businesses accounted for about 77% of all territorial businesses surveyed and about 82% of employees.[6] Government activity provides considerable economic stability to the Whitehorse area, with Whitehorse serving as the headquarters for territorial and federal government offices. The

[1] Review of the impact of Faro Mine in the 1980s and 1990s shows that closure of a large mine development may impact the overall Yukon population. The 2013 Yukon Economic Outlook also notes that following the final closure of the Faro mine in 1998, Yukon experienced six consecutive years of declining population, which saw the population fall just below 30,000 in 2003.
[2] Yukon Bureau of Statistics, Population Report June 2015.
[3] Source: Yukon Bureau of Statistics. 2015. Yukon Employment November 2015. Retrieved from: http://www.eco.gov.yk.ca/stats/pdf/employment_nov15.pdf [accessed on December 18, 2015].
[4] Source: Statistics Canada. 2015. CANSIM Table 379-0030 Gross domestic product (GDP) by North American Industry Classification System (NAICS), chained 2007 dollars. Retrieved from: http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=3790030 [accessed December 17, 2015].
[5] In 2015, Whitehorse residential and commercial energy sales accounted for about 67% of total Yukon-wide retail electricity sales including both AEY and Yukon Energy sales (source for Whitehorse and AEY sales is AEY 2016-17 GRA, Table 3 on page 2-4).
[6] Source: Government of Yukon Socio-Economic Web Portal http://www.sewp.gov.yk.ca/subject (accessed on June 24, 2016).

public sector was the largest source of employment in 2011, employing about 27% of the total population aged 15 years and over.[7] Tourism has also become a major source of economic growth for the city. Outside of the public sector, the following sectors were the largest sources of employment in 2011: 12.8% of the population aged 15 years and over were employed in the retail trade, 9.0% employed in construction, 7.1% in accommodation and food services, and 6.9% in health care and social assistance.

[7] Source: Government of Yukon Socio-Economic Web Portal http://www.sewp.gov.yk.ca/subject (accessed on June 24, 2016).

Appendix 5.3
Southern Lakes Enhanced Storage Concept Studies

2017 INTEGRATED RESOURCE PLAN

SOUTHERN LAKES ENHANCED STORAGE CONCEPT

PLANNING OVERVIEW

FEBRUARY 2017

YUKON ENERGY

EXECUTIVE SUMMARY

PROJECT OVERVIEW & BACKGROUND

The Southern Lakes Enhanced Storage Concept (SLESC or the Concept) envisions increasing the licenced water storage range on the Southern Lakes (SL) in order to increase the production of winter energy at the Whitehorse Rapids Generating Station (WRGS).

No new infrastructure needs to be built to realize the Concept benefits, only a change to the allowable winter storage limits on the SL and the implementation/construction of mitigation measures.

BENEFITS

- The Concept represents a low cost source of winter renewable energy introduced by enhancing YEC's existing infrastructure. As such, the Concept is complementary to YEC's prior commitments and disclosures to the YUB and the Yukon Public – both of which emphasize maximizing the generation from YEC's existing assets.
- The Concept:
  - Provides a low cost source of firm winter energy of up to 9.9 GWh/year at a levelized cost of 9 cents/kWh;
  - Displaces nearly 5,100 tonnes of GHG emissions each year under average water conditions, assuming a split of 75% natural gas and 25% diesel generation;[1]
  - Maximizes production from existing assets and natural resources;
  - Can be implemented in near term (winter 2019 or 2020);
  - Provides a lasting benefit to some landowners who are already impacted by the effects of rising water levels in the Southern Lakes. Project mitigation would address existing problems with shoreline erosion and high groundwater; and,
  - Has a lower environmental impact than a greenfield hydroelectric project.

[1] Thermal equivalent of 9.9 GWh project power benefit at 75% natural gas (451 tonnes/GWh CO_2e) and 25% diesel (700 tonnes/GWh of GHGs) equates to nearly 5,100 tonnes CO_2e.

FEASIBILITY STUDY KEY FINDINGS/CONSIDERATIONS

- There are high human and environmental values contained in the Concept study area (Southern Lakes system). Some residents have concerns about, or have voiced opposition to the Concept. Others have indicated an interest in proceeding with a project.
- Baseline environmental and socio-economic studies, preliminary effects assessments, and conceptual mitigation designs for the Concept are complete.
- After 6+ years of study the character of the potential Concept effects is well understood. The likely effects are subtle, and are mostly additive to pre-existing effects of seasonal erosion and groundwater effects to low-lying properties that result from water levels on the system during the unregulated period (spring – fall). Technically and economically feasible mitigation options exist for identified adverse effects.
- No significant effects are predicted to accrue to valued aquatic or terrestrial habitats or species.

PROJECT STATUS

At this time baseline studies have been completed and a preliminary effects assessment has been conducted. Remaining work is mostly technical and involves the completion of a field level heritage resources impact assessment, the finalization of a detailed monitoring and adaptive management plan, with the associated stakeholder consultations. Discussions are ongoing with both Carcross/Tagish First Nation (C/TFN) and the Kwanlin Dun First Nation (KDFN) as potential YESAA decision bodies and with Ta'an Kwach'an Council (TKC) as the Concept study area includes their traditional territory as well. Yukon Energy is interested to know the perspectives of these first nations on the technical merits of the Concept before proceeding with further planning and assessment in 2017. Following these activities, YEC will have sufficient information to prepare a project proposal for assessment under the Yukon Environmental and Socio-economic Assessment Act (YESAA).

TABLE OF CONTENTS

1.0 Introduction 1
1.1 Project Overview 1
2.0 Planning Activity Details 3
2.1 Overview of Recent Planning Activities/Objectives 3
2.2 Planning Activity Results and Status 4
3.0 Mitigation Design & Updated Costs 4
3.1 Erosion 4
3.2 Groundwater 6
4.0 community engagement and Home-Owner Support 6
4.1 Erosion 6
4.2 Groundwater 7
5.0 Monitoring & Adaptive Management Plan 8
5.1 Overview 8
5.2 Monitoring Program 9
5.3 Adaptive Management Program 10
6.0 Project Economics 11
6.1 Project Costs 11
6.2 Operating Costs 12
6.3 Concept Renewable Energy Value & Levelized cost of Energy 12
7.0 FN Engagement 13
8.0 Project Timeline 14

LIST OF TABLES

Table 1 Estimated costs for Adaptive Management Program (2016$) 11
Table 2 Southern Lakes ESP Project Development Costs 11
Table 4 Summary of Economic Analysis - Southern Lakes ESP 12

LIST OF FIGURES

Figure 1 Limitations of Existing Water Storage Range 2
Figure 2 Effect of Increased Storage Range on Winter Energy Production 2
Figure 3 General Attitudes of Erosion Landowners Who Attended Group Engagement (Round 2) Meetings (n = 33) 7
Figure 4 Groundwater Impacted Landowner Project Acceptance (n=53) 8

LIST OF PLATES

Plate 1 Example of Shoreline Protection Using Rip Rap 5

LIST OF APPENDICES

Appendix A - Erosion and Groundwater Engagement Info Packages

1.0 INTRODUCTION

1.1 PROJECT OVERVIEW

In 2009, Yukon Energy restarted its examination of the Southern Lakes Enhanced Storage Project (the Project). The Project would increase winter generation at the existing Whitehorse Rapids Generating Station (WRGS) by increasing the amount of water available for power production in winter. The additional winter flow in the river will come from the proposed increase in the volume of water stored upstream in the southern lakes. This extra storage will then be available to augment flow in the Yukon River during the winter when the demand for electricity is greatest.

To achieve this, the Concept envisions expanding the storage range on the Southern Lakes by decreasing the licenced low supply level (LSL) by up to 10 cm, and by increasing the licenced full supply level (FSL) by up to 30 cm. No other operational changes are necessary to achieve the increased storage.

The only observable changes to lake levels during the regulated period (August to May) would be a slightly higher fall and early winter water level in the lakes, but no higher than what is often seen in the unregulated summer period. By winter there would be little difference in water levels as compared to present levels.

The expansion of the low supply level would mean that water levels in Marsh Lake in the spring would be up to 10 cm lower than historical/present. This difference would only be observed for a few weeks in late April and early May, and only observed on Marsh Lake, with little observable influence on Tagish Lake or Bennett Lake.

Figure 1 demonstrates how the change in the operational range can provide additional power generation at the Whitehorse station.

Figure 1 Limitations of Existing Water Storage Range

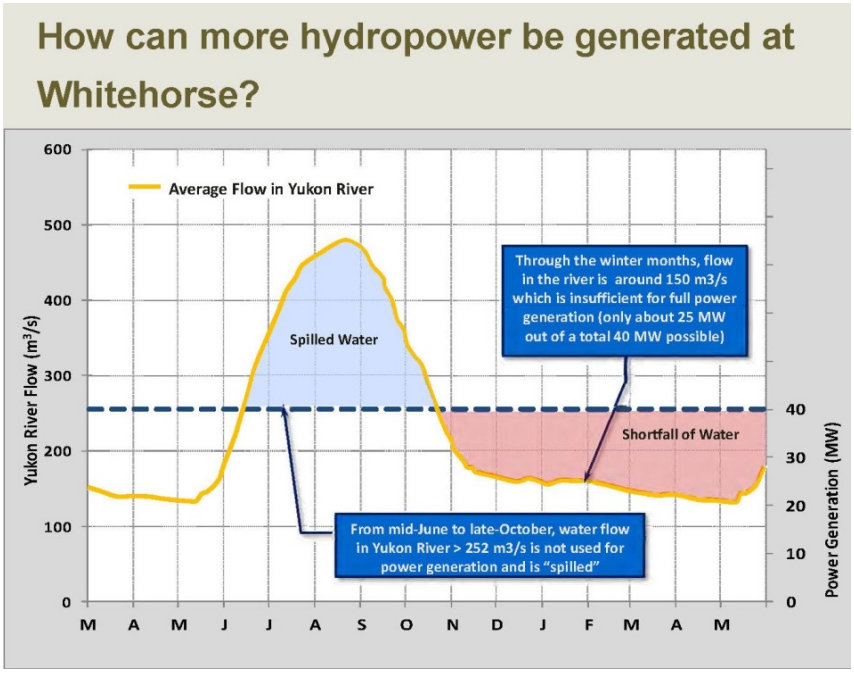
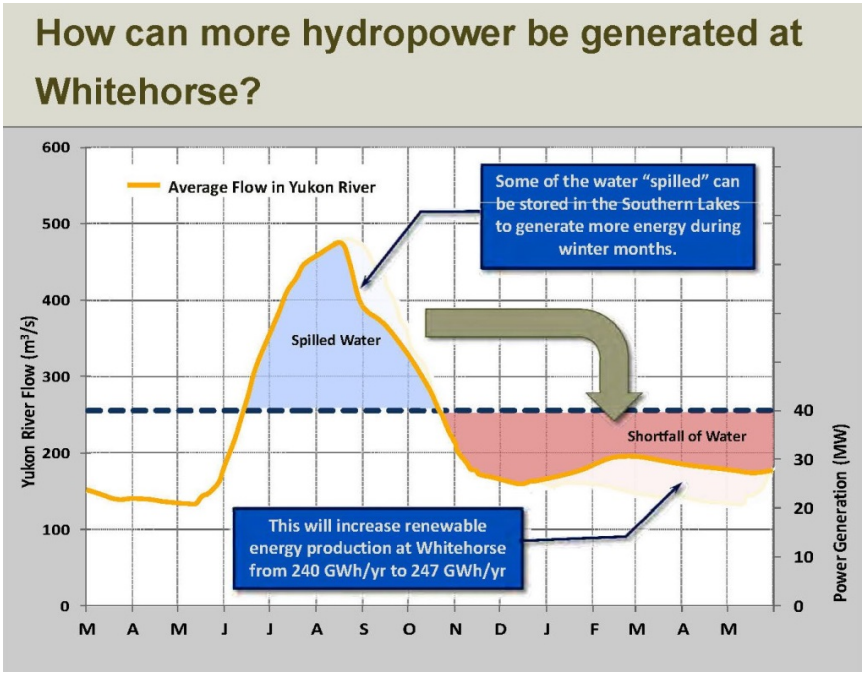


Figure 2 Effect of Increased Storage Range on Winter Energy Production



2.0 PLANNING ACTIVITY DETAILS

2.1 OVERVIEW OF RECENT PLANNING ACTIVITIES/OBJECTIVES

Work in recent years has been focused on narrowing down any remaining uncertainties regarding potential project effects, views/interests of potentially affected stakeholders, likely mitigation requirements and methods, and monitoring adaptive management plan requirements. Estimation of costs to implement mitigation and provide monitoring and adaptive management was also undertaken.

Key tasks included:

- *Erosion Program*
  - Complete erosion modelling.
  - Landowner contact and engagement for mitigation design.
  - Finalize mitigation options and forecast costs.
- *Groundwater Program*
  - Confirm specific properties potentially affected.
  - Land owner engagement for mitigation design.
  - Finalize mitigation options and forecast costs.
- *Monitoring and Adaptive Management Planning*
  - Determine key areas requiring pre-project effects prediction and post-project mitigation success confirmation.
  - Develop broad program requirements, frequency, and costs.
  - Develop draft cooperative/collaborative monitoring plan execution and reporting components (e.g., work with C/TFN, KDFN, TKC, regulators to draft plan tasks and review plan results).
- *Information Adequacy Program*
  - Update gap analysis and fill key info gaps.
  - Engage Regulators to confirm assessment approach and preliminary findings.
  - Discus draft mitigation, monitoring, and adaptive management plans.
- *Communications Program*
  - Targeted outreach to all stakeholders and Yukoners to relay key messages and develop better project understanding via house mailings.

- *FN Engagement & Consultation Program*
  - Consultation and engagement to develop common understating of potential project effects and mitigation.
  - Explore compensation requirements and benefit opportunities.
  - Seek to lever mutually beneficial renewable energy or other outcomes from engagement vis-à-vis the project Concept and other interests of Yukon Energy and/or FNs.
  - Seek acceptance of Concept 'in principle' and green light to proceed to the YESAA review stage.

2.2 PLANNING ACTIVITY RESULTS AND STATUS

All program activities, except for the First Nations engagement program, have been completed as of Q1 2017. Additional time is needed conclude the technical reviews with C/TFN, KDFN, and TKC for the Concept and the plan to proceed to assessment and permitting. It is expected that this work will be concluded by end of Q2 2017.

3.0 MITIGATION DESIGN & UPDATED COSTS

3.1 EROSION

The erosion program involved an intensive engagement and technical effort to identify, explore, and narrow down the optimal mitigation options for shoreline erosion protection in the areas potentially impacted by the Concept. A range of options are available for mitigation of erosion-related project effects, and 9 mitigation options were explored individually and with shoreline groups of potentially affected property owners.

The process of review and selection of an appropriate/acceptable mitigation solution was conducted in 2 rounds using a Structure Decision Making (SDM) process. In Round 1 Yukon Energy met with individual property owners to review the Concept and its potential effects, and to review various options to mitigate erosion effects. Round 2 included bringing together individuals from each discrete shoreline neighborhood together as a shoreline unit group to review and work toward consensus on a preferred mitigation option(s). Over 40 round-one meetings were held, with over 75% of landowners participating. Five round-two meetings were held with groups of residents from each potentially affected shoreline area. Over 85% of potentially affected property owners were engaged in at least one meeting to explore the Concept and potential mitigation options.

Mitigation in the form of engineered rip rap (hard, angular rock) was the dominant choice of homeowners who indicated a strong preference toward a solution that would be effective against erosion, durable, and low maintenance. One neighborhood indicated a preference for groins as a mitigation solution, although

the feasibility and acceptability of such a solution is not considered optimal and requires further discussions with subject area residents. A sample of mitigation options used in Round 1 consultations is presented in Appendix A.

Plate 1 Example of Shoreline Protection Using Rip Rap

YEC also instructed the project consultants (Hemmera) to review the work completed by the previous planning consultant (AECOM) regarding the assessment of areas recommended for erosion protection. All previously identified areas were confirmed, with some expansion to the overall length of required shoreline erosion protection in some areas (refer to the discussion below).

Updated erosion mitigation costs are estimated at $6.0M (feasibility or Conceptual-level estimate, with an associated accuracy of +/- 15% to 30%). This updated estimate is increased from the previous estimate of approximately $3.1M. The budget increase for erosion mitigation was a result of a number of changes:

Increase in construction costs: Updated engineering design work completed by Northwest Hydraulic Consultants (NHC) in 2015 has increased the length of shoreline requiring protection, and more conservative unit cost estimates for the shoreline mitigation have been used. The previous mitigation cost estimates completed by AECOM in 2012 utilized a value of $790 per metre of shoreline protected with rip rap. Northwest Hydraulic Consultants concluded that AECOM's cost estimates for construction were low, and revised the unit cost to $1,300 per metre. This updated unit cost was thought to be more realistic and was based on NHC's recent experience with similar projects. In addition, NHC's estimate of shoreline needing mitigation is 3,457 metres, an increase of 1,187 metres from the AECOM estimate of 2,270 m. The increase in shoreline length is partly related to the inclusion of beach features at the ends of each mitigation area, as opposed to prior calculations of required mitigation length based on property boundaries at the end of each beach section. In addition, NHC included a number of gaps in what is otherwise continuous shoreline armouring of Army Beach (e.g., mitigation will be needed at several sections of Army Beach with public access easements that adjacent property owners have not addressed).

Increase in in contingency: The previous estimate of $3.1M included a 20% contingency. However, NHC has increased the contingency allowance to 30% to more appropriately account for the current level of engineering definition of the mitigation designs.

The cost and design definition will be updated at the preliminary design phase, which in scheduled for 2018 as part of preparations for permitting. A further round of detailed design will be completed in 2019 following permitting, and will consider any regulatory requirements coming out of the assessment and permitting processes. Detailed design will generate design specifications to be used as inputs for the construction tendering stage.

3.2 GROUNDWATER

Preliminary groundwater surveying work completed in 2010-2014 estimated that somewhere between 75 and 100 properties might be affected by the Concept. Intensive survey work completed in 2015 confirmed that only 53 properties would need mitigation for project-related groundwater effects.

Required mitigation will take the form of raised septic fields, septic tank replacement and/or anchoring, installation or enhancement of basement/crawlspace sump pumps. A single property will require some foundation insulation. In many cases the effects of unregulated high summer water levels already impact these properties. With the Concept the duration of such impacts would increase and therefore Yukon Energy would address these effects. In addition to construction and installation of physical mitigation infrastructure as outlined above, one time compensation payments will be calculated and paid to some affected land owners for costs associated with increased wear and tear on equipment and increased electricity costs associated with some installations (e.g., increased annual duration of sump pump operation). These costs are factored into the mitigation cost estimate below.

Estimated groundwater mitigation costs are approximately $1.2M, reduced from an earlier estimate of $1.35M. The decrease in the estimated costs was caused by the decrease in the number of properties that would be impacted. These cost estimates are considered to have an expected precision variance of +/- 15% to 30%.

4.0 COMMUNITY ENGAGEMENT AND HOME-OWNER SUPPORT

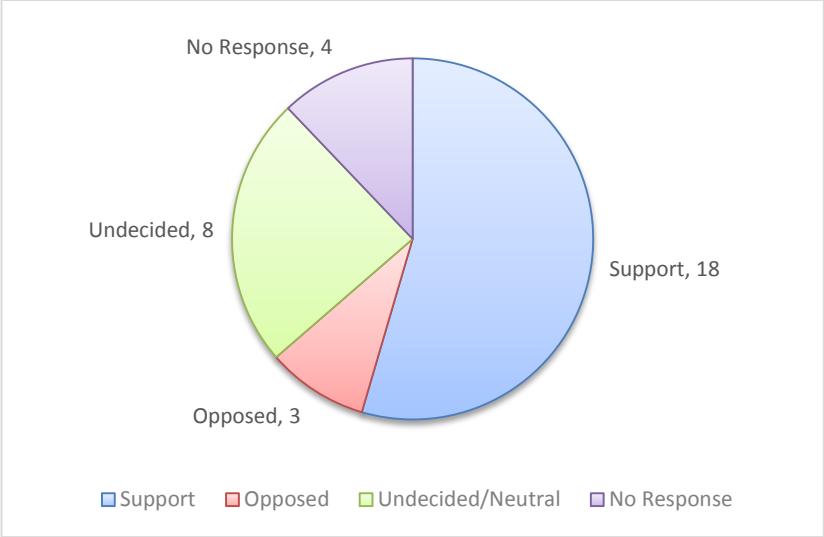
YEC has completed an extensive program of community engagement on the Southern Lakes ESP since 2010, including numerous public meetings, workshops, and an outreach and public education program.

4.1 EROSION

General attitudes towards the project Concept were surveyed as part of the engagement on erosion mitigation designs with property owners potentially impacted by the Concept. The results of this survey

are presented in Figure 3. Of those property owners who participated in the group mitigation evaluation meetings 55% (18 individuals) indicated support for the mitigation and the project. Of the remaining participants, 9% (3 individuals) were not in favor of the project, with 24% (8 individuals) indicated they were undecided, and 12% (4 individuals) did not respond. Only 1 respondent indicated they couldn't accept the mitigation if the project were to proceed (i.e., of the 3 respondents opposed to the project, only one was opposed to the mitigation if the project did in fact proceed). In most cases the mitigation would be installed on Crown Land (i.e. below the ordinary high-water mark, which is owned by the Crown in most cases).

Figure 3 General Attitudes of Erosion Landowners Who Attended Group Engagement (Round 2) Meetings (n = 33)



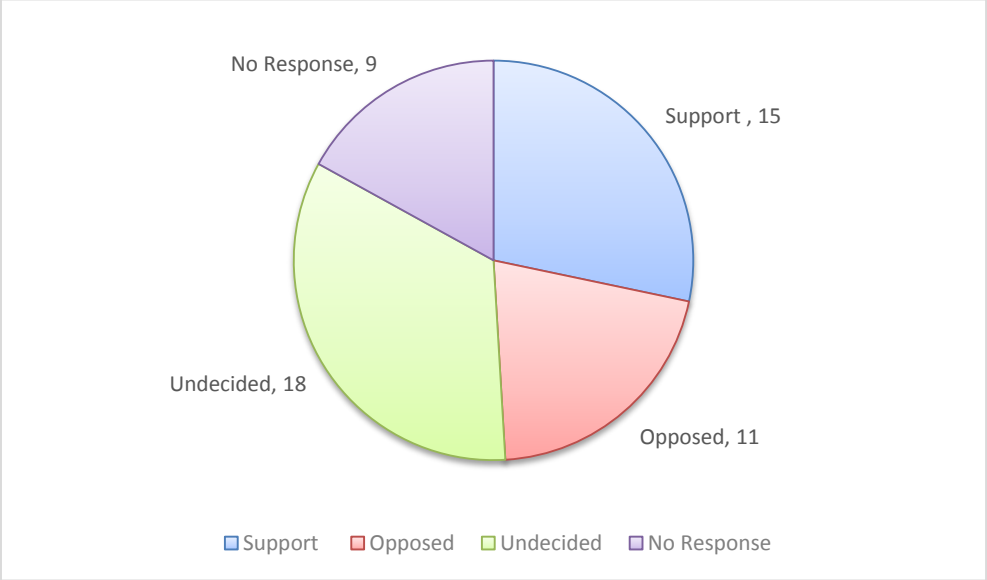
4.2 GROUNDWATER

General attitudes towards the project Concept were also surveyed as part of the engagement on groundwater mitigation designs with property owners potentially impacted by the Concept. The results of this survey are presented in Figure 4. The groundwater program involved engagement with 153 properties that were assessed to be within the zone of influence of the Concept. Of those, 53 properties were confirmed to be likely to need mitigation if the Concept were to proceed.

- In all, 157 telephone conversations and formal meetings were held with potentially affected property owners regarding groundwater.
- 71 properties were physically surveyed to confirm infrastructure elevations and 12 "complex" properties were evaluated by an engineer for geotechnical/structural potential effects.
- At only one of the 12 complex properties assessed was it determined that mitigation would be required to address the potential effects of the project.

Of those property owners who participated in the initial assessment and follow-up mitigation meetings, 28% (15 individuals) explicitly indicated support for the mitigation and the project. Of the remaining participants, 21% (11 individuals) were not in favor of the project, with 34% (18 individuals) indicated they were undecided, and 17% (9 individuals) either did not respond or could not be contacted. Some property owners in the 'undecided' category stated that they would reserve their final acceptance or refusal of Yukon Energy's offer to provide mitigation to a point in time where they would be engaged for discussions regarding the detailed mitigation work/construction plan following the YESAA assessment. Other stakeholders in the 'undecided' or 'neutral' category were otherwise indifferent to the project and/or the proposed mitigation.

Figure 4 Groundwater Impacted Landowner Project Acceptance (n=53)



All stakeholders will have an opportunity to provide input and information to the regulators during both the YESAA assessment process and the water board licencing process.

5.0 MONITORING & ADAPTIVE MANAGEMENT PLAN

5.1 OVERVIEW

A detailed monitoring and adaptive management program will form an integral part of the implementation of the Southern Lakes ESP, and the mitigation of risk post-implementation. While draft components have been prepared, a final detailed monitoring and adaptive management program requires input from stakeholders and as yet has not been completed. Work is planned in 2017 to complete a plan

suitable for assessment under YESAA in collaboration from key stakeholders. An overview of the scope of this plan, and the general principles that will be applied in the development of the plan are outlined in sections 5.1 and 5.2, below.

5.2 MONITORING PROGRAM

The monitoring program will include elements that allow Yukon Energy to assess two things:

1. The observed effects on fish, wildlife and wetland environments, compared to the predicted effects made during the assessment.
2. The effectiveness of implemented erosion and groundwater mitigation measures.

Consequently, monitoring is proposed in the following key areas:

- Heritage Resources
- Erosion Mitigation Effectiveness (incl. sites with mitigation and unmitigated control sites)
- Groundwater Mitigation Effectiveness (incl. sites with mitigation and unmitigated control sites)
- Fish and Wildlife
- Wetlands

The following principles will be followed in the development of a detailed monitoring program:

a) The monitoring program will be sensitive and provide timely results for decision-making. YEC will collaborate directly with affected first nations and others to carry out the monitoring plan and to jointly review the results of the annual reporting.
b) Monitoring will also include the use of control sites to ensure Yukon Energy and others are able to discern effects that may be caused by the project or effects that are caused by factors other than those influenced by the project (e.g., erosion caused by peak summer water levels above the Concept full supply level).

The estimated monitoring program costs are as follows:

- Years 1-3 = $167,000/year
- Years 4-5 = $120,000/year
- Years 6-10 = $70,000/year
- Years 10+ = $40,000/year

5.3 ADAPTIVE MANAGEMENT PROGRAM

The adaptive management program will define the steps or measures that YEC will take in response to unexpected negative outcomes in the key areas covered by the monitoring program (e.g., if the actual effects predictions on fish/wildlife/wetland environments are worse than predicted, or if the erosion and groundwater mitigation measures are not fully effective).

The adaptive management program will define both the specific actions (to the extent possible) and the financial commitment that YEC will make in response to any negative impacts, up to an including reversal of the project (i.e., reversion to the current storage range on the Southern Lakes system).

The following general principles will be followed in the development of the detailed adaptive management plan:

a) YEC will consult with key stakeholders (FN's, Environmental NGO's, homeowners) on the development of the adaptive management plan. It is important that these stakeholders have a clear understanding of the way the monitoring will be undertaken and what the results will direct Yukon Energy to do in response.
b) The adaptive management plan will be as specific as possible, defining clear responses to specific outcomes. As such, the plan will attempt to limit YEC's financial risk by defining the scope and value of additional actions, and associated expenditures, that the corporation will incur in response to defined negative outcomes.
c) In addition, the total (cumulative) financial commitment to cover potential adaptive management responses will be capped at a fixed amount, where after a reversion to the previous storage range, or something in between, would be the remaining option to address any unexpected impacts (i.e., reverse the effects).
d) YEC will consider creating a multi-stakeholder committee, or use some form of independent oversight mechanism to evaluate unsolicited complaints from the public regarding perceived project impacts. It will be critical that the process to evaluate such complaints and administer any resulting mitigation be transparent, fact-based, and unbiased.

For the purposes of financial modeling of the overall project, Yukon Energy has assumed a worst case financial commitment of $3.3M ($2016) to cover potential adaptive management responses. A break-down of the $3.3M budget allocation for adaptive management is provided in Table 1:

Table 1 Estimated costs for Adaptive Management Program (2016$)

Item	Estimated Costs (2016$)	Assumptions
Adaptive management costs for groundwater mitigation	$0.05M	Percentage of installed systems require replacement/maintenance (5%-25% depending on the type of mitigation installed)
Adaptive management responses for erosion	$2.67M	10% of initial costs to repair installed mitigation after a 1 in 50+ year storm event Up to one third of the non-mitigated erosion sites being monitored to require mitigation within a few years post-implementation
Lake trout and/or other wildlife species habitat enhancements and studies	$0.60M	
	$3.32M	

The forecast cost of the adaptive management responses will be reviewed as part of the development of the detailed adaptive management program and as part of Yukon Energy's stagegate project review process.

6.0 PROJECT ECONOMICS

6.1 PROJECT COSTS

A summary of the total upfront costs of the project are presented below in Table 2.

Table 2 Southern Lakes ESP Project Development Costs

Item	Total Costs (2016$)	Notes
Planning, Assessment & Permitting – Committed to date	$6.50M	
Planning, Assessment, Permitting & Preliminary/Detailed Engineering– Future	$1.75M	
Project Implementation – Erosion Mitigation	$6.00M	1, 2
Project Implementation – Groundwater Mitigation	$1.00M	1, 2

Subtotal – Capital Cost	$15.25M	
Post-Implementation Adaptive Management	$3.32M	3, 4
Total	$18.57 M	

Notes:
1. Compensation to FN's for increased duration of inundation of settlement land included.
2. Cost areas will be for design and construction of erosion and groundwater effect mitigation.
3. These costs for cover potential adaptive management responses will be incurred over time, but are expressed as 2016$.
4. Post-Implementation adaptive management responses have been estimated based on professional judgement of potential unexpected effects and/or rates of mitigation failure. While erosion, fish and wildlife, heritage resources, and groundwater adaptive management responses are included in the estimates, the erosion component represents over 75% of the dollars assigned here.

6.2 OPERATING COSTS

Operating costs include monitoring, land use fees associated with FN land inundation, and any other project costs such as benefit payments. These costs are estimated to range from $50,000 per year in later years and up to $270,000 in the early years post-implementation.

6.3 CONCEPT RENEWABLE ENERGY VALUE & LEVELIZED COST OF ENERGY

The Concept delivers incremental winter renewable energy, which displaces more costly thermal energy. Power benefit calculations estimate that 9.9 GWh per year of thermal energy under the High Industrial Activity Scenario from the 20-Year Load and Peak Demand Forecast presented in the 2016 Resource Plan be displaced by the project under average water conditions.

Estimates of the costs and benefits, and the resulting levelized cost of energy of the Concept are presented in Table 4.

Table 3 Summary of Economic Analysis - Southern Lakes ESP

Present Value of Costs 2016 $000's	$23,126
Present Value of Benefits 2016 $000's	$30,020
Project Real LCOE at $2016 /kW.h	$0.09
Benefit/Cost Ratio	1.3

Notes:
1. Values are real LCOE numbers (inflation free).
2. Assumes 2% inflation rate
3. Economic life of the project set to 34 years
4. Assumes real discount rate of 3.38%, nominal 5.45%,
5. Assumes 8.25% nominal return rate and Debt/Equity ratio of 60%/40%
6. Energy benefit assumed constant at 9.9 GWh/yr fully utilized

7. Based on 20-yr load forecast for the High Industrial Activity Scenario. This load forecast was also used for Mayo Lake Enhanced Storage Project.

In the case modelled, the levelized cost of energy represents the lowest costs renewable energy option currently available to Yukon Energy, and compares favourably to LNG at 17.4 c/kW.h. The Concept also has the added benefit of avoiding nearly 5,100 tonnes of thermal GHG emissions each year, which would otherwise be emitted with equivalent thermal energy.[2]

7.0 FN ENGAGEMENT

All first nations whose traditional territory and/or settlement lands fall within the regional study area have been engaged periodically since the studies began in 2009. This includes the Kwanlin Dun First Nation, (KDFN), Carcross/Tagish First Nation (C/TFN), Ta'an Kwach'an Council (TKC), and the Taku River Tlingit (TRT). Efforts have been made to share information regarding the purpose and need for the project, the baseline studies and preliminary impact assessments, proposed mitigation, monitoring, and adaptive management commitments, and to identify and understand interests and concerns of the FNs.

First Nations engagement has been focused primarily with C/TFN and KDFN, as no significant adverse effects have been identified to the interests of the TKC or the TRT. C/TFN and KDFN will also likely be Decision Bodies under the YESAA assessment, along with other governments (e.g., YG, DFO).

Engagement activities to date have identified several key issues for FNs related to the Concept including:

- Shoreline erosion and related effects on private property and settlement lands, water quality, riparian and nearshore aquatic habitats for such valued components as moose, caribou, and aquatic furbearers.
- Shoreline heritage resources located in zone of influence of existing/potential erosion.
- Inundation of low lying shoreline areas on settlement land or otherwise:
    - A draft compensation framework based on a 'land rental value' has been shared with C/TFN and KDFN, but more work is needed to negotiate an agreement in this regard.
    - Approximately 7 hectares of additional KDFN settlement land would see an increased duration of wetting in the fall of each year.
    - Approximately 45 hectares of additional C/TFN settlement land would see an increased duration of wetting in the fall of each year.

[2] Thermal equivalent of 9.9 GWh project power benefit at 75% natural gas (451 tonnes/GWh CO_2e) and 25% diesel (700 tonnes/GWh of GHGs) equates to nearly 5,081 tonnes CO_2e.

- No new/additional settlement land parcels would be wetted, i.e., only parcels wetted under the existing FSL would be wetted longer under the Concept FSL.
- The additional period of wetting of settlement lands is on average about 93 days per year and occurring in the late summer and fall.
- Inundated areas have only been mapped for Marsh Lake as the steep topography of the shorelines at Tagish Lake and Bennett Lake indicates that only very minimal increases in shoreline inundation will occur there.

At this point in the planning Yukon Energy has been able to provide technical responses to previously identified interests and concerns with the Concept. The key steps now are to respond to follow up questions and concerns and seek feedback from the FNs on whether they would consider Yukon Energy has exercised sufficient due diligence and has done enough work to move to the YESAA assessment stage.

8.0 PROJECT TIMELINE

If a decision were made to proceed with the Project at the next stagegate (tentatively scheduled for Q2 2017), a submission could be made to the YESAAA Whitehorse Designated Office by the end 2017. Following a 6-8-month assessment process an application to the Yukon Water Board would be made with the potential to have an amended licence by the end of 2018. Work could then begin to tender and undertake the physical mitigation construction in 2018 and 2019. Construction of shoreline protection would need to be undertaken in the later winter and early spring so that the work could be done during dry conditions from the lake side of the shore as opposed to the land side. This will minimize disturbance to the shoreline and private property. Use of the additional storage would then be feasible for the fall of 2019 or 2020.

APPENDIX A

EROSION & GROUNDWATER ENGAGEMENT INFORMATION PACKAGES

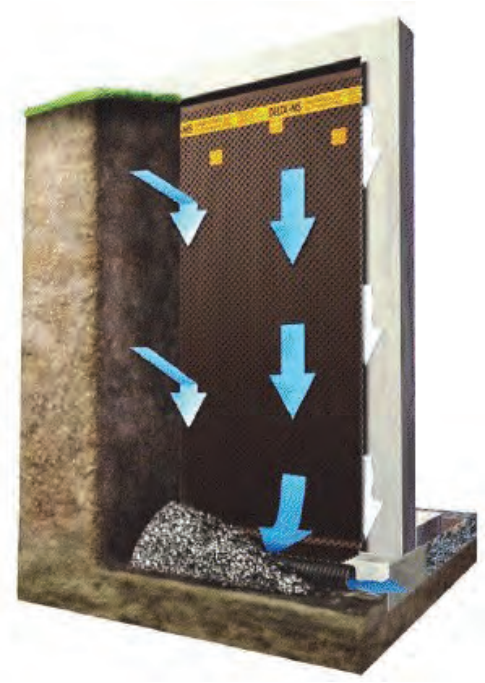
YUKON ENERGY

Basement/Crawlspace Waterproofing

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • FACT SHEET 5

How could groundwater rise affect my home?

The proposed concept would involve holding back (storing) more water in the Southern Lakes during the fall, which may result in a slightly longer duration of seasonal high groundwater levels in some areas around the lakes. On some properties this could exacerbate flooding or dampness already experienced in some basements/crawlspaces during seasonal high water levels, or it could cause flooding or dampness in a few basements/crawlspaces that have not previously experienced such groundwater effects.



Typical basement/crawlspace waterproofing installation

Mitigation Solution – Basement/Crawlspace Waterproofing

Basement and crawlspace waterproofing is a mitigation option to manage the potential impacts of groundwater rise, such as flooding and dampness. A typical waterproofing installation involves excavating down to the foundation around the perimeter of the home, cleaning and repairing cracks in the foundation walls, and installing a waterproofing membrane, a weeping tile and drainage gravel.

Benefits

Increased property value though improvements (up to $21,000)

Reduces damage to property (e.g. flood damage)

Discourages mold in basements/crawlspaces

Drawback

Requires access around building foundation (e.g., tree removal)

Significant temporary modification to property during installation

Will basement/crawlspace waterproofing work for you and your property?

Can it be installed around your basement/ crawlspace?

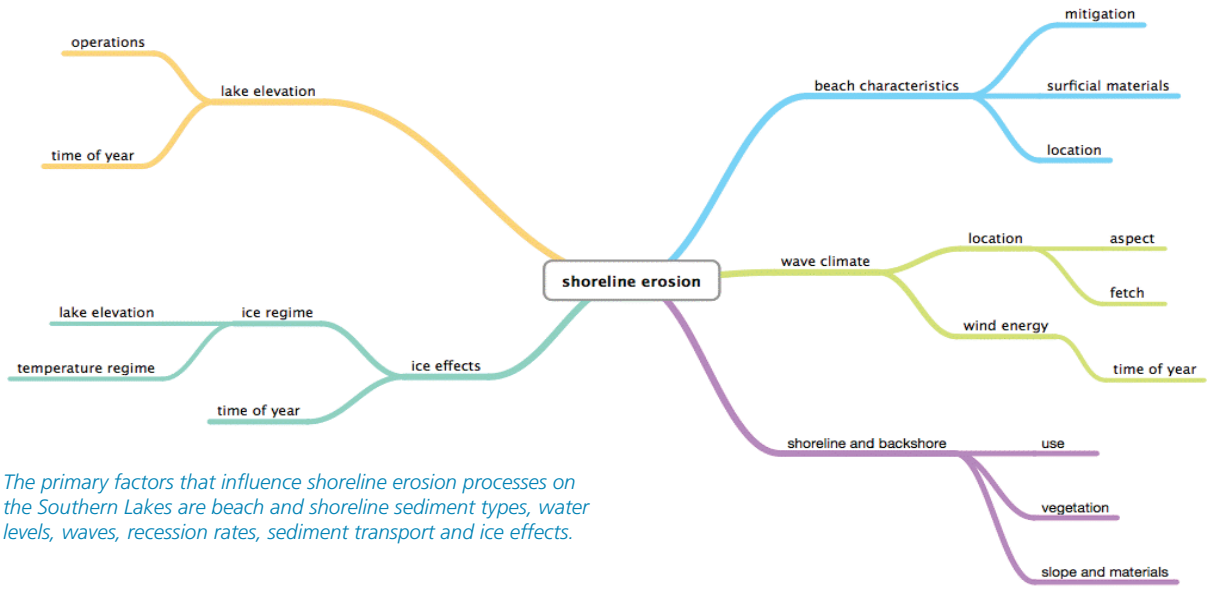
Is there good access?

Is the site accessible with conventional excavation equipment?

Basement/crawlspace waterproofing examples

Erosion Program

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 1



The primary factors that influence shoreline erosion processes on the Southern Lakes are beach and shoreline sediment types, water levels, waves, recession rates, sediment transport and ice effects.

Introduction

Over the last several years, Yukon Energy has engaged regularly with Yukoners and done significant research on the idea of increased water storage in the lakes south of Whitehorse. The Corporation has worked hard to understand the potential environmental and socio-economic impacts that could occur as a result of the concept.

Over the next few months, this research will be reviewed and used to decide whether to move the concept forward to the YESAA environmental and socio-economic assessment phase.

Wave-induced currents along the shoreline transport beach sediment in and out of, or along the shoreline causing sand deposits and erosion.

Summary of the Concept

Electricity demand in Yukon is highest during the cold, dark winter months, which is also the time of year when water levels in our lakes and rivers are naturally low. In order for Yukon Energy to produce enough hydroelectricity for Yukoners during the winter the Corporation must hold back (or store) water in Marsh, Tagish and Bennett Lakes during the fall, when water levels are higher.

Right now, the amount of water Yukon Energy is allowed to store (Full Supply Level) is not always enough to meet energy demands in winter, so fossil fuels are burned to make up the difference.

The Southern Lakes Enhanced Storage Concept would involve changing Yukon Energy's water license so the Corporation could store up to 30 centimeters more water in the fall and early winter and use up to an additional 10 cm of water below the current level in the spring.

This water would be available for winter energy production when it's needed the most, and would provide cost-effective and environmentally responsible energy. The concept would not increase naturally-occurring high water levels that occur in the Southern Lakes and the additional water storage would not be carried over year-to-year.

YUKON ENERGY

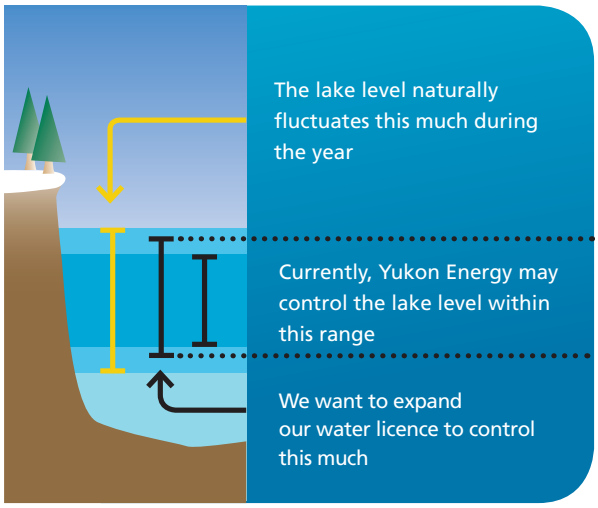
Erosion Program

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 2

Potential Impacts to Properties Related to Erosion

There are already naturally-occurring erosion issues in some areas of the Southern Lakes. The Corporation's previous erosion studies identified six shoreline areas containing multiple properties that are currently experiencing erosion and may experience additional erosion as a result of the concept.

The proposed increase to the Full Supply Level will result in additional shoreline areas of up to 30 vertical centimeters being inundated for a longer period of time each year. This additional period of higher lake levels may result in additional shoreline erosion due to wave action. It is important to note that the proposed increase is well below the natural high water level that occurs each year in late summer.



Shoreline erosion along the Southern Lakes is site-specific and depends on the location and aspect of the property, as well as the characteristics of the shoreline. Such natural characteristics include the slope of the foreshore and bluffs, and the type of material in these areas such as sand and gravel. The presence of vegetation also affects the rate of erosion.

Initial Meeting (one-on-one)
- Discuss shoreline erosion on property
- Discuss YEC shoreline erosion mitigations
- Get your feedback

Design a preliminary shoreline-unit specific erosion mitigation plan

Follow-up meeting (one-on-one or groups)
- Review prepared preliminary shore-line-unit specific erosion mitigation plan
- Incorporate com-ments and feedback for final design

Final mitigation plans and landowner feedback are reported to Yukon Energy and used in decision making on whether to proceed with a project assessment and permitting

Landowner Engagement Process

An important part of this next step is engaging with landowners who may experience erosion on their properties as a result of the concept.

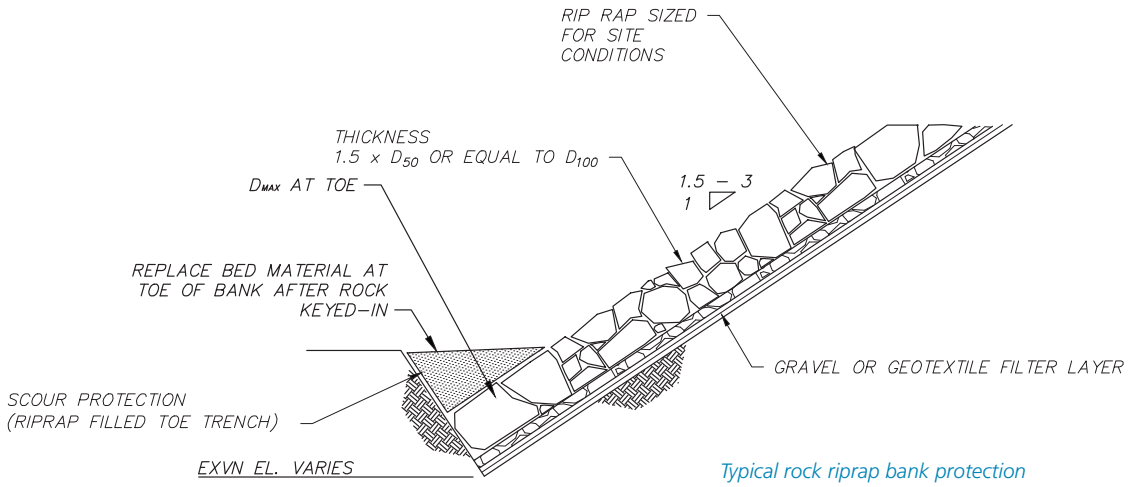
Yukon Energy will use your input as well as the input of your neighbours to help develop one consistent erosion mitigation plan for your shoreline unit. If implemented, this plan would combat existing erosion as well as any potential concept-related erosion and would provide a long-term benefit should the concept move forward.

Please note that it is not necessary for you to support the Southern Lakes Enhanced Storage Concept to participate in this engagement process. This process allows us to fully understand the issues and costs related to potential mitigation of shoreline erosion, which will provide Yukon Energy with a more accurate estimate of the costs and benefits of the project for the assessment process and Yukon ratepayers.

YUKON ENERGY

RipRap

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 3



Typical rock riprap bank protection

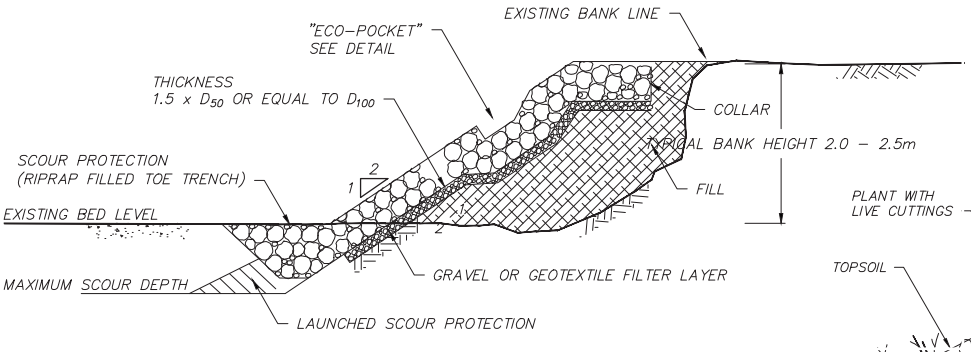
Typical riprap involves using quarried angular rock to protect eroding slopes. The size of the rock and the thickness of the armour layer depend on the extent of the erosive forces on the slope. An underlayer is used between the rock and eroding slope to keep fine sediments from eroding away between the spaces in the rocks. The toe of the riprap can either be excavated into the bottom of the slope or an apron can be constructed to avoid excavation. Riprap is typically used where erosion is extensive or in proximity to infrastructure, and construction requires access for large and heavy machinery (e.g., excavators and dump trucks). In order to make this option feasible a good source of quality rock needs to be available in reasonable proximity to the site.

Advantages	Disadvantages
Highly effective protection	Artificial and unnatural appearance
Very low maintenance	Does not provide valuable habitat
Effective on high and steep slopes with significant erosion	Access required for large and heavy equipment
Requires minimal manual labour	High initial cost

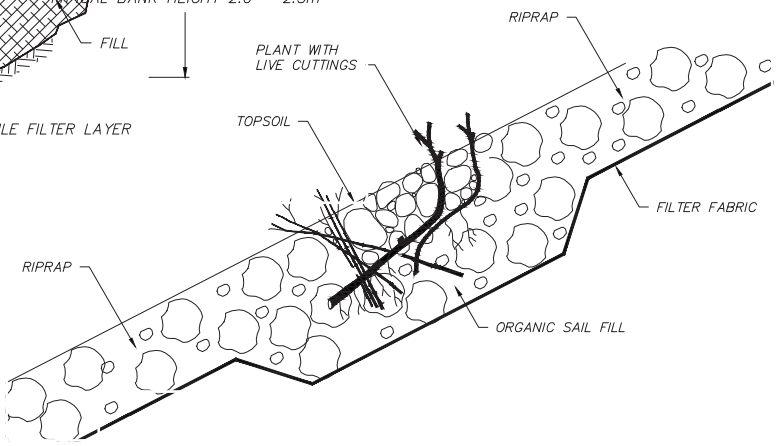
YUKON ENERGY

Vegetated RipRap

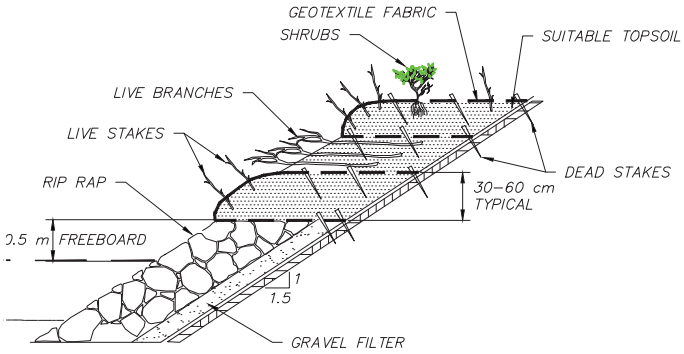
SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 4



Typical riprap with vegetated ecopocket



Vegetated riprap is the same as typical riprap with the addition of vegetation within and or above the riprap slope. Vegetation can be in the form of "eco-pockets" which are small pockets of soil and vegetation in various locations on the surface of the rock slope. The planting of stakes or live cuttings in the spaces between the rocks are also an effective planting option. The top of the riprap slope can be planted with grass seed, brush, stakes or live cuttings or trees.



Typical riprap with vegetated soil wrap

Advantages	Disadvantage
Highly effective protection	Somewhat artificial and unnatural appearance
Low maintenance	Access required for large and heavy equipment
Effective on high and steep slopes with significant erosion	Requires more manual labour than typical riprap
More natural appearance and provides better habitat than typical riprap	Some maintenance required for vegetation

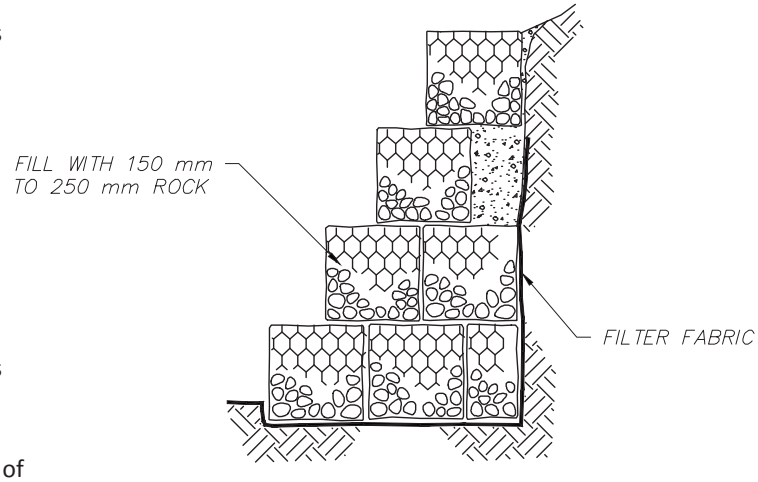
Revised July 2015

YUKON ENERGY

Gabion Baskets (Standard & Vegetated)

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 5

Gabion baskets are box shaped wire mesh containers that are filled with rock and stacked on top of each other to a desired height to provide protection on steep slopes. The baskets arrive from the manufacturer flattened and are assembled on site using manual labour. Small or medium sized machinery is used to fill each basket with rocks approximately 15 cm in diameter. Quarried angular rock is preferred but rounded rock can be used. The bottom row of baskets are buried into the toe of the slope and the baskets can be stacked numerous rows high. For the vegetated option stakes or live cuttings are placed between or within the baskets. Gabion baskets are typically used in areas where a high level of protection is needed but where large quality rock is not available for riprap.



Typical gabion bank protection

Advantages

Highly effective protection

Low maintenance on non-vegetated option

Effective on high and steep slopes with significant erosion

Good option where large rock is not available

Large and heavy equipment not required

Disadvantages

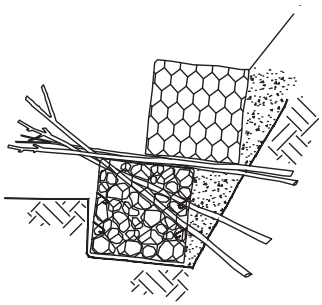
Gabion wire will corrode over time depending on conditions

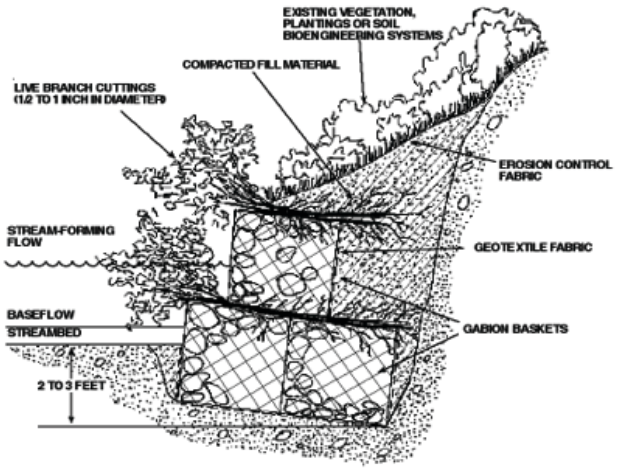
Artificial and unnatural appearance (non-vegetated option)

Does not provide valuable habitat (non-vegetated option)

Requires machinery

Requires manual labour, especially for vegetated option



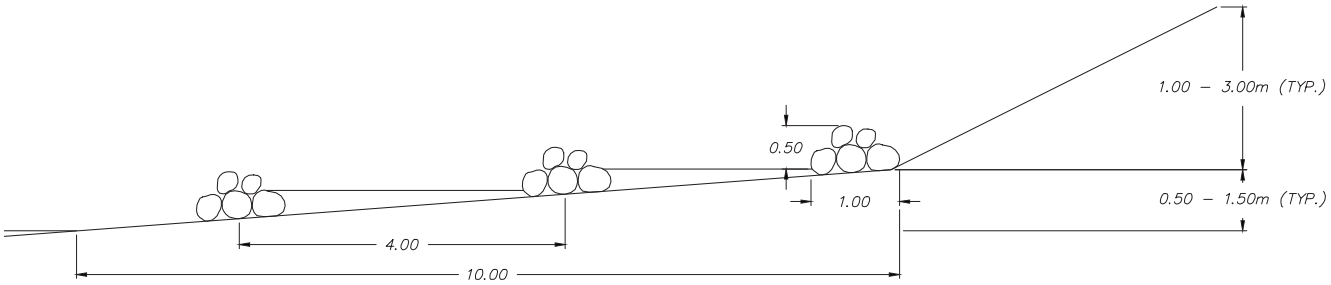


Typical vegetated gabion bank protection

YUKON ENERGY

Groynes (Perpendicular & Parallel)

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 6



Parallel groynes

Groynes are structures that extend into the water to protect the shoreline from erosion by disrupting the flow of water, wave action or longshore transport of sediment. Groynes can be walls made of timber or logs but are typically made of large rock similar to that used for riprap. Perpendicular groynes are only effective where beaches or bluffs are degrading due to waves and currents running parallel or near parallel to the shoreline resulting in longshore transport of sediment. Parellel groynes are only effective where onshore and offshore processes dominate.

Advantages

Highly effective protection depending on transport scenario

Very low maintenance

Requires minimal manual labour

Disadvantages

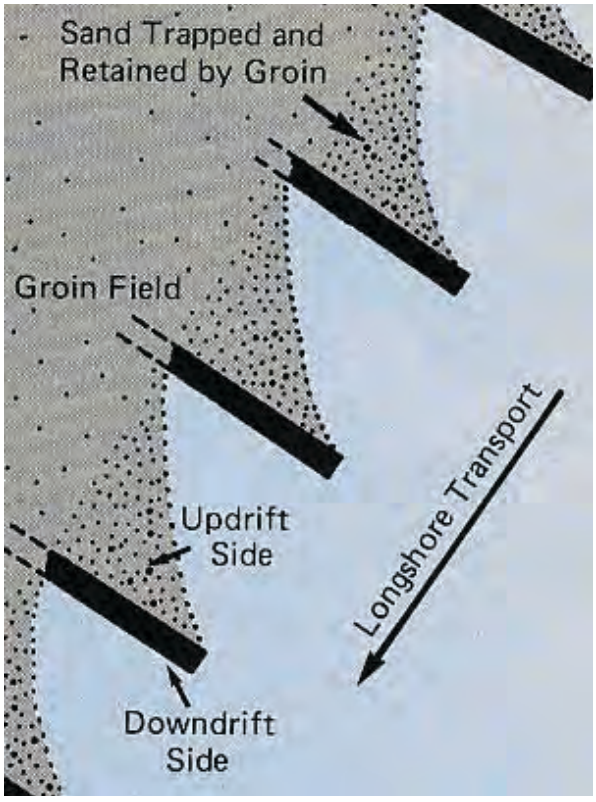
Only effective under specific transport scenarios

High initial cost

Artificial and unnatural appearance

Does not provide valuable habitat

Access required for large and heavy equipment

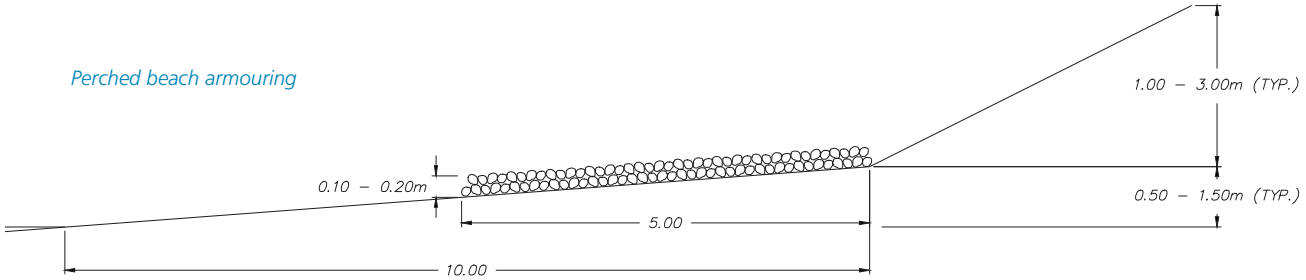


YUKON ENERGY

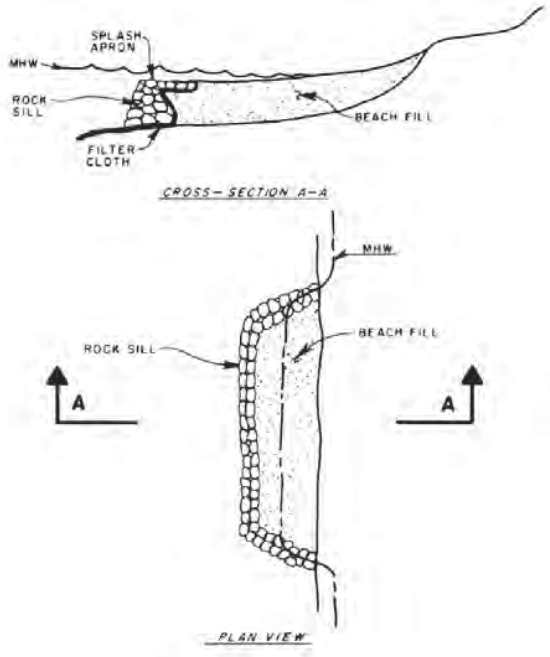
Perched Beach

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 7

Perched beach armouring



A perched beach involves protecting an eroding beach by armouring the shoreline with a rock sill along with beach fill on the landward side of the armour. An alternate method involves laying a thin layer of armour protection on the surface of the beach to prevent additional degradation from occurring. With the beach fill option an armoured berm is constructed with large rock and the beach fill can either be backfilled beach material or left empty to gradually fill with natural beach material. With the alternate method the entire beach or portions of the beach along the shoreline can be covered with rock.



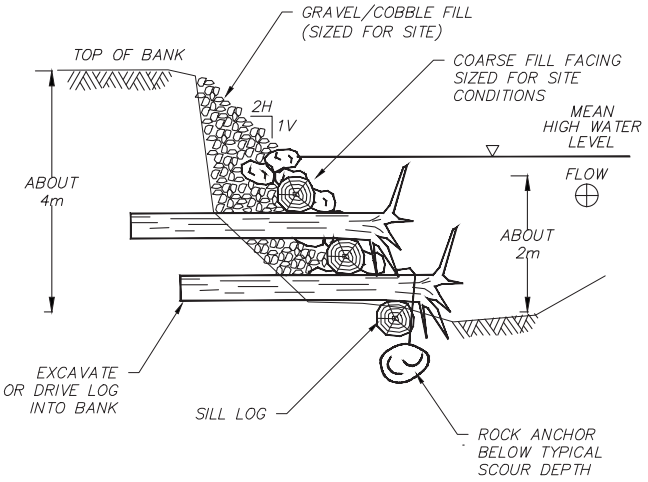
Advantages	Disadvantages
Reduces wave effects	Impacts existing beach and foreshore area
Installed on existing foreshore	Does not directly protect backshore slopes
Does not impact backshore slopes	Somewhat artificial and unnatural appearance
Highly effective protection under longshore or onshore/ offshore transport scenarios	Does not provide valuable habitat
Low maintenance	Access required for large and heavy equipment
Requires minimal manual labour	

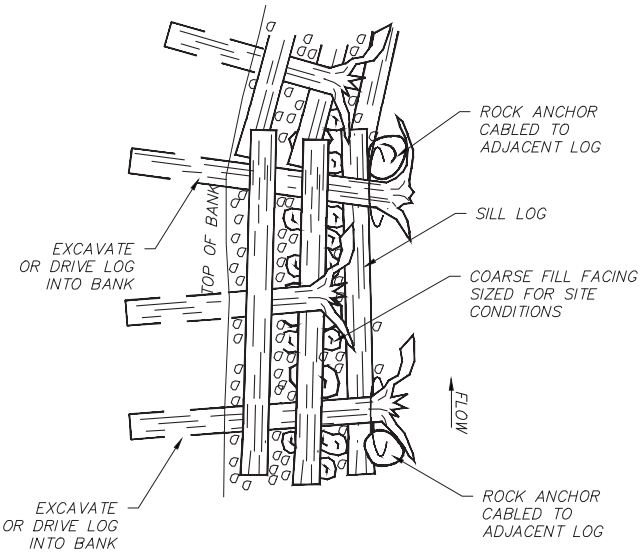
Cribwall

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 8

A cribwall is a wall made of logs or timber to protect a vertical or near vertical eroding slope. For a high level of protection the wall can be built vertically with alternating logs parallel and perpendicular to the slope and backfilled with rock. See drawings below for an example of this method.

The toe of the wall can be buried into the ground for additional protection. For a less engineered option a series of logs can be laid beside each other or stacked to provide a moderate level of protection as shown in the photo below. The logs can also be cabled together or anchored into the ground to provide more durable protection.





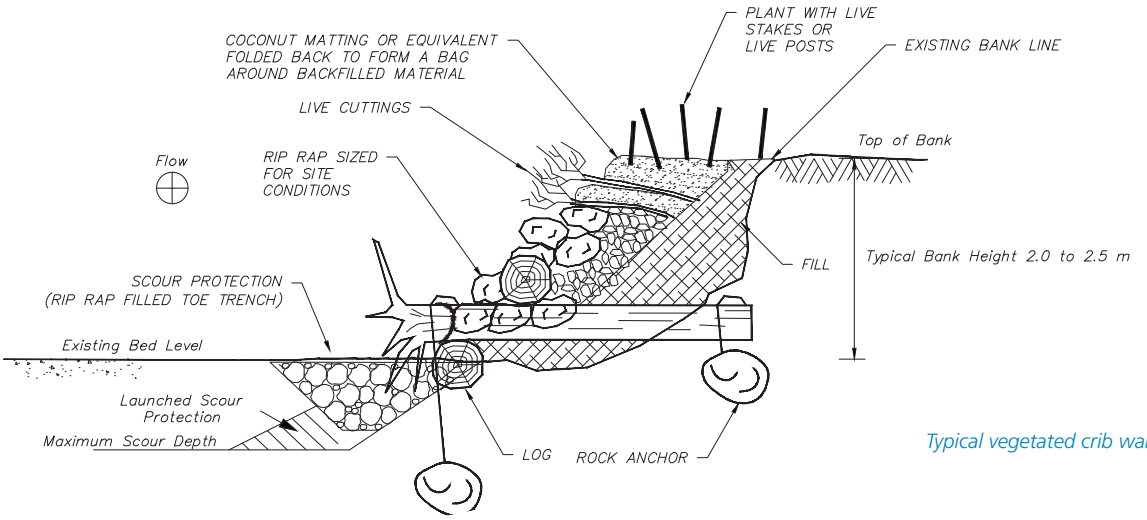
Typical crib wall

Advantages	Disadvantages
Good for poor or limited machine access	Not ideal option if available logs are small and deciduous
Provides habitat	Moderate level of protection
Can be built with manual labour	

YUKON ENERGY

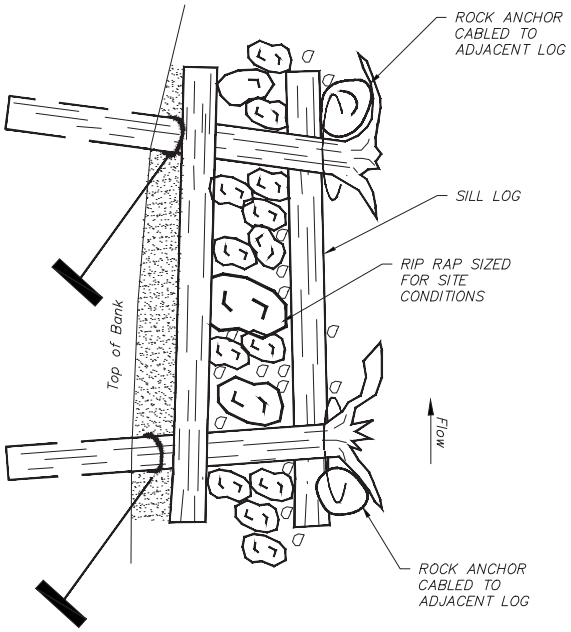
Vegetated Cribwall

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 9



Typical vegetated crib wall

Vegetated cribwalls are similar to standard cribwalls but with the addition of vegetation incorporated into the wall. The vegetation can be stakes or live cuttings incorporated into the spaces between the logs. The top of the cribwall can be planted with grass seed, brush, stakes or live cuttings or trees. If not naturally occurring, a growing medium (soil or bags filled with soil would need to be added for the planting at the top of the cribwall.



Advantages

- Good for poor or limited machine access
- Provides valuable habitat
- Can be built with manual labour
- Uses natural materials
- Ideal for log-based foreshores
- Effective slope protection
- Effective on high and steep slopes with significant erosion
- More natural appearance and provides better habitat than typical cribwalls

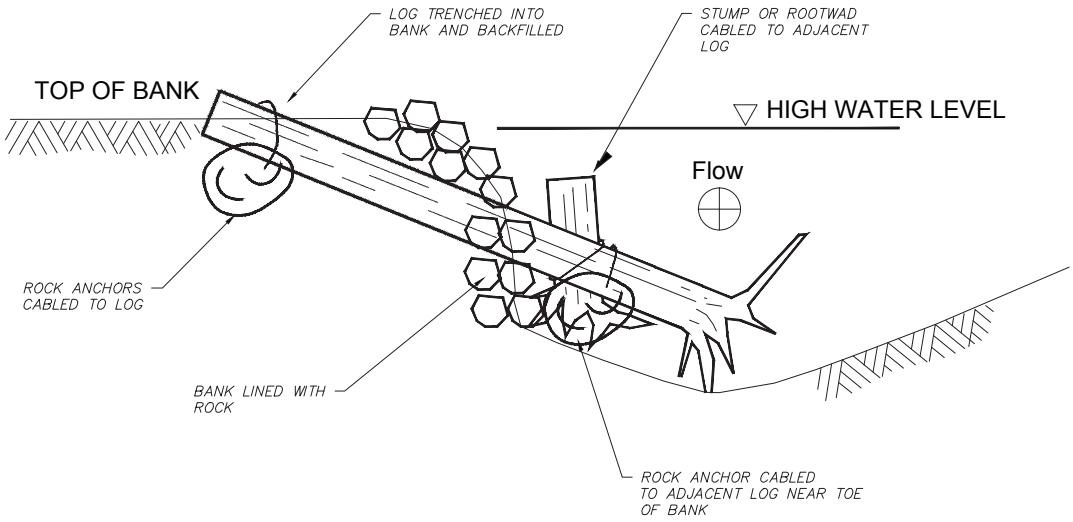
Disadvantages

- Not ideal option if available logs are small and deciduous
- Moderate level of protection
- Limited design life in harsh environments
- Limited structure strength
- Requires excavation to embed/fill/build
- Will require maintenance to replace vegetation that does not survive
- Requires more manual labour than typical cribwalls

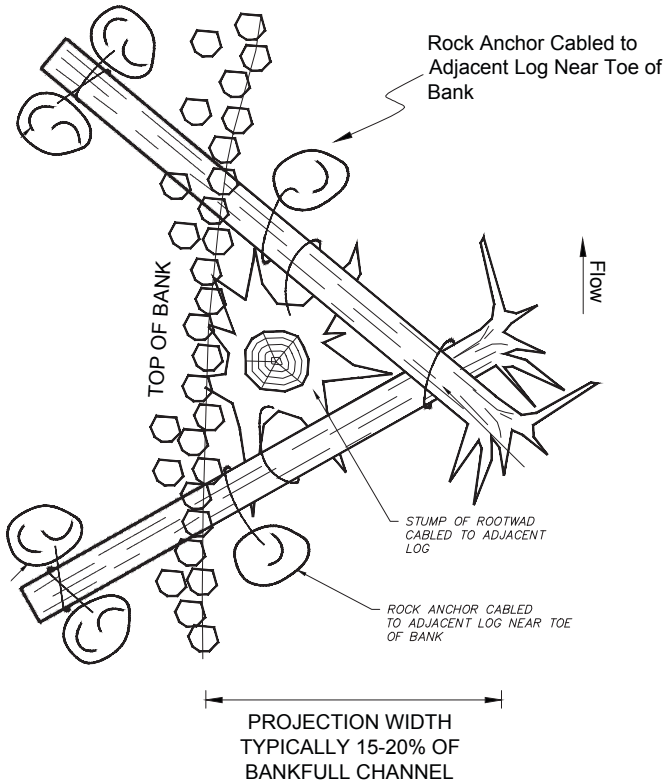
YUKON ENERGY

Large Woody Debris Structures

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 10



Large Woody Debris (LWD) structures are a collection of logs that are clustered together to provide protection for eroding slopes. The logs may have the root wad attached and they are typically cabled together and or anchored into the slope or anchored to large boulders. They can be quite natural in appearance and provide habitat for fish and wildlife. They do not provide a high level of protection but are inexpensive to construct and are low maintenance. This option is not appropriate when the eroding slope is high and steep or the erosive forces are significant.

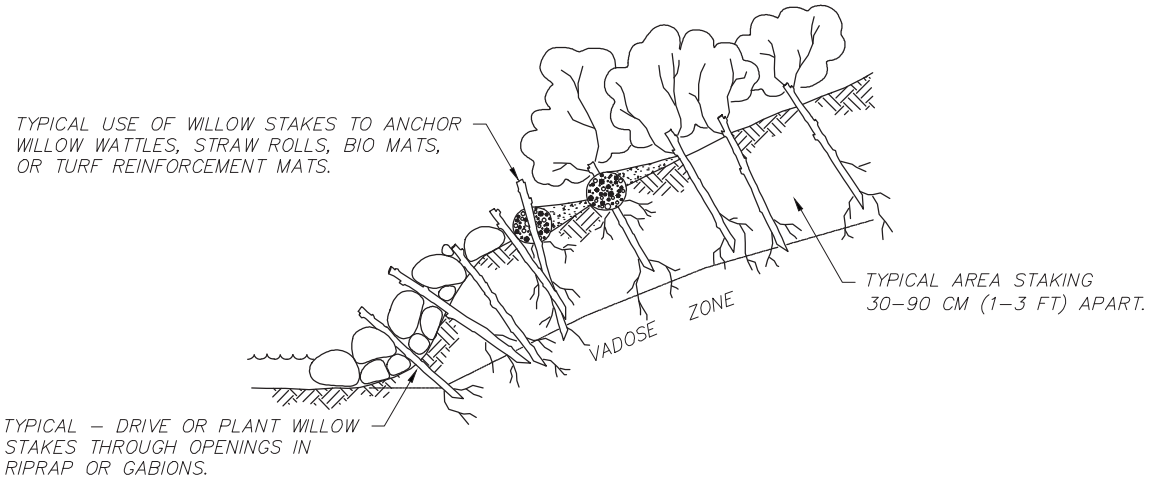


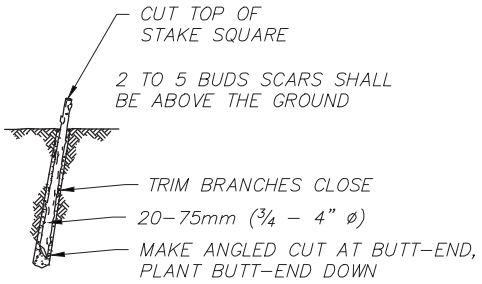
Advantages	Disadvantages
Good for poor or limited machine access	Not ideal option if available logs are small and deciduous
Natural appearance and provides valuable habitat	Minimal level of protection

YUKON ENERGY

Live Staking

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 11





Live Staking involves cutting vegetation from a nearby source and planting the cuttings on the eroding slope or beach to decrease the rate of erosion. This method is only effective where the extent of erosion is not significant. Ideal growing conditions are required for this option. The stakes are only effective after they have established which can take several years depending on the growing conditions. This option is very natural looking when the stakes are established and can be constructed with manual labour. This option is ideal where access is difficult for large and heavy machinery.

Advantages

Provides additional protection over time as vegetation establishes

High ecological value

Low cost

No large or heavy machinery required

Natural appearance and provides valuable habitat

Disadvantages

High failure rate in initial years

Limited installation period

High initial maintenance for replanting

Requires suitable soil for growing

Requires moisture in the soil for growing

Brush Layering

SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 12

Brush layering involves cutting vegetation from a nearby source and planting the brush cuttings in dense layers on the eroding slope and then backfilling with soil. This method is only effective where the extent of erosion is not significant. Ideal growing conditions are required for this option. The brush layers are only effective after they have established which can take several years depending on the growing conditions. This option is very natural looking when the brush layers are established and can be constructed manually. This option is ideal where access is difficult for large and heavy machinery.

Advantages

Provides additional protection over time as vegetation establishes

High ecological value

Low cost

No large or heavy machinery required

Natural appearance and provides valuable habitat

Disadvantages

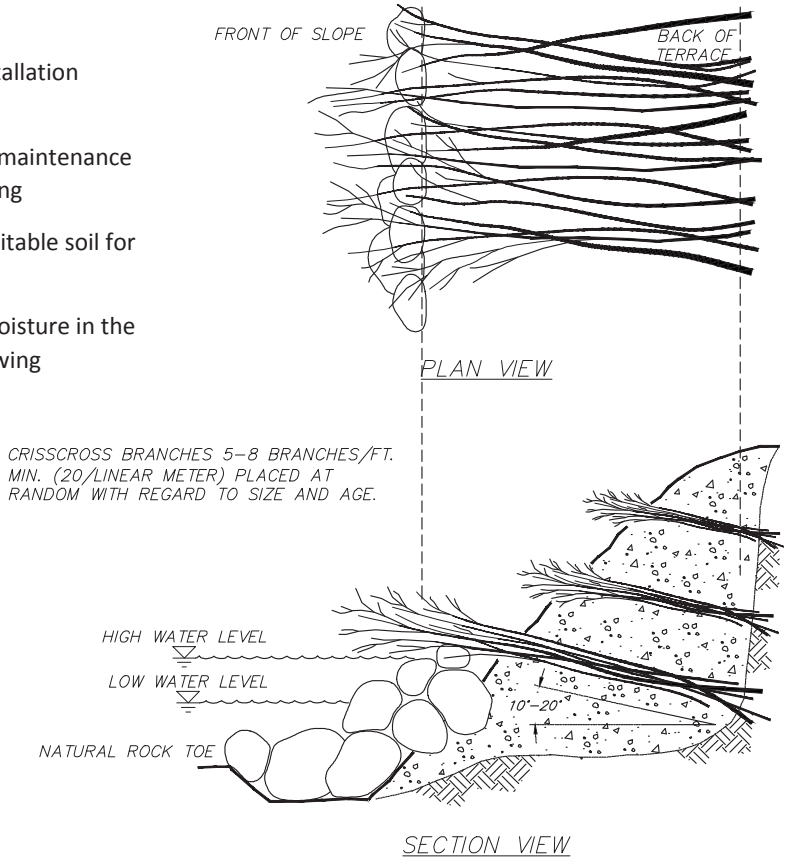
High failure rate in initial years

Limited installation period

High initial maintenance for replanting

Requires suitable soil for growing

Requires moisture in the soil for growing



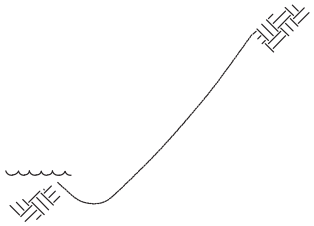
YUKON ENERGY

Brush Matting

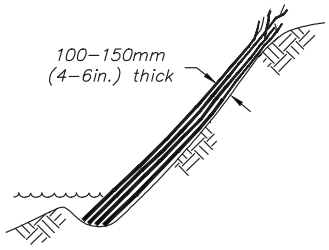
SOUTHERN LAKES ENHANCED STORAGE CONCEPT • EROSION 13

Brush matting involves cutting vegetation from a nearby source and planting the brush cuttings in dense layers on the eroding slope. The cuttings are densely placed side by side and secured together with twine or rope to create a mattress like structure. This method is only effective where the extent of erosion is not significant. Ideal growing conditions are required for this option. The brush matting is only effective after the vegetation has established which can take several years depending on the growing conditions. This option is very natural looking when the brush matting is established and can be constructed with manual labour. This option is ideal where access is difficult for large and heavy machinery.

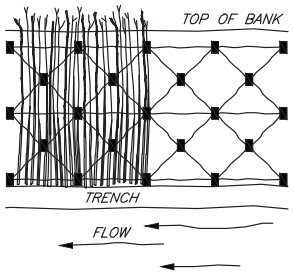
Advantages	Disadvantages
Provides additional protection over time as vegetation establishes	High failure rate in initial years
High ecological value	Limited installation period
Low cost	High initial maintenance for replanting
No large or heavy machinery required	Requires suitable soil for growing
Natural appearance and provides valuable habitat	Requires moisture in the soil for growing



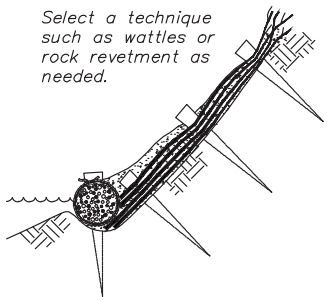
Step 1: Excavate trench and grade bank.



Step 2: Place willow branches making sure that the butt ends reach the bottom.



Step 3: Place stake (notched) on 1.0m (3ft.) centers and secure the mattress with twine, rope or wire.



Step 4: Drive the stakes deeply into the bank to tightly compress the branches against the soil. Cover and partially bury the mattress to encourage rooting.

Appendix 5.4
Mayo Lake Enhanced Storage Concept Project Proposal

Mayo Lake Enhanced Storage Project

YESAA Project Proposal

Volume 1 of 4:

PROJECT PROPOSAL

July 2015

Submitted by:

Yukon Energy Corporation

TABLE OF CONTENTS

CHAPTER 1
1.0 PROJECT INTRODUCTION AND OVERVIEW 1-1
1.1 OVERVIEW 1-1
1.2 PROPONENT INFORMATION 1-3
1.3 PROJECT PURPOSE AND BACKGROUND 1-3
1.4 REQUIRED AUTHORIZATIONS AND REGULATORY APPROVALS 1-4
1.5 ALTERNATIVES TO THE PROJECT 1-4
1.6 SUBMISSION ORGANIZATION AND CONTENT 1-5

CHAPTER 2
2.0 PROJECT LOCATION 2-1
2.1 GEOGRAPHIC LOCATION 2-1
2.2 LAND TENURE WITHIN THE PROJECT REGIONAL STUDY AREA 2-3
2.3 TRADITIONAL TERRITORY 2-4
2.4 CONSISTENCY WITH OTHER PLANS 2-4
2.4.1 Current Land Use & Management Plans 2-5
2.4.2 Project Consistency with Other Plans 2-6

CHAPTER 3
3.0 ASSESSMENT APPROACH 3-1
3.1 OVERVIEW OF APPROACH 3-1
3.2 ASSESSMENT FRAMEWORK 3-2
3.3 DETERMINING SIGNIFICANCE OF RESIDUAL EFFECTS 3-4
3.4 SOURCES OF INFORMATION 3-7

CHAPTER 4
4.0 FIRST NATION AND OTHER COMMUNITY AND PUBLIC ENGAGEMENT 4-1
4.1 OVERVIEW 4-1
4.2 PRINCIPALS AND APPROACH TO CONSULTATION 4-2
4.2.1 Guiding Principals 4-2
4.3 METHODS 4-4
4.3.1 Face-to Face Interaction 4-4
4.3.2 Electronic, Paper, and Other Media Communication 4-4
4.4 REVIEW OF PUBLIC INVOLVEMENT ACTIVITIES 4-5
4.4.1 Activities Involving NND 4-5
4.4.2 Activities Involving Local and Municipal Government, Regional and Local Resource Management Organizations, and other Governments 4-6
4.4.3 Activities Involving Local Stakeholders and Other Publics 4-7
4.5 INDEPENDENT ADVISOR REVIEW 4-8
4.6 KEY ISSUES AND PERSPECTIVES HEARD TO DATE 4-9
4.7 FUTURE STEPS IN PUBLIC CONSULTATION 4-26

CHAPTER 5

5.0 ENVIRONMENTAL AND SOCIO-ECONOMIC SCAN 5-1
5.1 OVERVIEW 5-1
5.2 EXISTING ENVIRONMENTAL SETTING 5-2
5.2.1 General Physiography, Surficial Geology/Soil Conditions and Climate 5-2
5.2.2 Water Resources and Aquatic Species in the Region 5-4
5.2.3 Vegetation and Wildlife Common to the Region 5-7
5.3 EXISTING SOCIO-ECONOMIC CONDITIONS 5-10
5.3.1 Population 5-10
5.3.2 Local and Regional Economy 5-11
5.3.3 Resource Use 5-11
5.3.4 The Social and Cultural Context 5-13
5.4 EXISTING AND PLANNED DEVELOPMENTS 5-14
5.4.1 The Existing Mayo Hydro Generation and Mayo Hydro Enhancement Facilities and Loads 5-14
5.4.2 Other Existing and Planned Development 5-15

CHAPTER 6

6.0 PROJECT DESCRIPTION 6-1
6.1 PROJECT IDENTIFICATION/SCOPE OF PROJECT 6-1
6.1.1 Overview and Background 6-1
6.1.2 Identification of Key Project Aspects 6-2
6.2 PROJECT TIMELINE AND LIFESPAN 6-5
6.3 ALTERNATIVES 6-6
6.3.1 Alternatives to the Project 6-6
6.3.2 Alternative Ways of Undertaking the Project 6-7
6.4 OPERATION PHASE – WATER MANAGEMENT 6-9
6.4.1 Mayo Lake Water Levels 6-11

CHAPTER 7

7.0 ENVIRONMENTAL AND SOCIO-ECONOMIC EFFECTS ASSESSMENT 7-1
7.1 OVERVIEW OF APPROACH 7-1
7.2 IDENTIFICATION OF VALUED COMPONENTS 7-2
7.2.1 Environmental Valued Components 7-4
7.2.2 Socio-Economic Valued Components 7-6
7.3 ASSESSMENT OF EFFECTS 7-7
7.3.1 Assessment of Effects on Environmental Valued Components 7-7
7.3.2 Assessment of Effects on Socio-Economic Valued Components 7-33
7.3.3 Other Potential Effects 7-46

CHAPTER 8
8.0 ADAPTIVE MANAGEMENT AND MONITORING 8-1
8.1 INTRODUCTION 8-1
8.2 MONITORING PLAN 8-1
8.3 ADAPTIVE MANAGEMENT PLAN 8-2
8.4 EXTERNAL TECHNICAL EXPERT REVIEW PROCESS 8-4

CHAPTER 9
9.0 GLOSSARY & REFERENCES 9-1
9.1 GLOSSARY OF ACRONYMS AND TERMS 9-1
9.1.1 List of Acronyms 9-1
9.1.2 List of Terms 9-2
9.2 REFERENCES 9-10
9.2.1 LIST OF REFERENCES 9-10

CHAPTER 10
10.0 ACKNOWLEDGEMENT & CERTIFICATION 10-1

LIST OF TABLES

CHAPTER 1

TABLE 1-1 Regulatory Permits and Approvals 1-4

CHAPTER 2

TABLE 2-1 Land Use and Management Plans 2-5

CHAPTER 4

TABLE 4-1 Interests and Concerns Raised by Stakeholders and Members of the Public and Areas Where Feedback from Public Involvement Activities Was Considered in the Environmental and Socio-Economic Assessment Process 4-11

CHAPTER 5

TABLE 5-1 First Nation of Na-Cho Nyak Dun Chief and Council 5-11

CHAPTER 6

TABLE 6-1 Simulated Weekly Average Water Levels and Use of Additional Storage (Metre) 6-11

CHAPTER 7

TABLE 7-1 Environmental Valued Components Considered for the Assessment of the Mayo Lake Enhanced Storage Project 7-4

TABLE 7-2 Socio-Economic Valued Components Considered for the Assessment of the Mayo Lake Enhanced Storage Project 7-6

TABLE 7-3 Environmental Effects Assessment 7-9

TABLE 7-4 Comparison of Spring Stopover Habitat Availability for Migratory Birds During Weeks 18 – 22 (Average); 442 GWH Load Scenario 7-29

TABLE 7-5 Socio-Economic Effects Assessment 7-35

TABLE 7-6 Modeled Mayo Lake Outflows 7-39

TABLE 7-7 Mid-September Water Levels at 442 GW.H/YR Load Scenario 7-39

LIST OF FIGURES

CHAPTER 2

FIGURE 2-1 Regional Study Area 2-2

CHAPTER 5

FIGURE 5-1 Mayo Lake Control Structure 5-1
FIGURE 5-2 Erosions Conditions Along the Mayo Lake Shoreline 5-4
FIGURE 5-3 December 2014 Mayo Population Distribution 5-10

CHAPTER 6

FIGURE 6-1 Mayo Lake Benefits at 442 GW.H/Year Load 6-8
FIGURE 6-2 Mayo Lake Benefits at 545 GW.H/Year Load 6-8
FIGURE 6-3 Average Water Levels by Month Derived From Water Modeling (1981 – 2008) (Assuming Grid Load of 442 GW.H/Year) 6-13
FIGURE 6-4 Average Water Levels by Month Derived From Water Modeling (1981 – 2008) (Assuming Grid Load of 545 GW.H/Year) 6-14
FIGURE 6-5 Modeled Mayo Lake Water Levels at 442 GW.H/Year, by Water Year 1981 to 2008 6-15
FIGURE 6-6 Modeled Mayo Lake Water Levels at 545 GW.H/Year, by Water Year 1981 to 2008 6-16

CHAPTER 7

FIGURE 7-1 Lake Trout Egg Collector 7-13
FIGURE 7-2 Collecting Lake Trout Eggs 7-14
FIGURE 7-3 Lake Trout Egg Incubators Deployed in the Lake Bed 7-14
FIGURE 7-4 Lake Trout 7-15
FIGURE 7-5 Deepwater Lake Trout Spawning Habitat Before Rehabilitation 7-17
FIGURE 7-6 Deepwater Lake Trout Spawning Habitat After Rehabilitation 7-17
FIGURE 7-7 Lake Whitefish Spawning Area in a Tributary to Mayo Lake (Upper Roop Creek) 7-19
FIGURE 7-8 Early Spring Lake Whitefish Rearing Habitat in Nelson Arm 7-20
FIGURE 7-9 Lake Whitefish Fry 7-20
FIGURE 7-10 Beach Seining for Lake Whitefish 7-21
FIGURE 7-11 Roop Lakes Wetland Complex 7-23
FIGURE 7-12 Shallow Water Littoral Area of Mayo Lake (Roop Arm) 7-25
FIGURE 7-13 Bird Species Frequently Observed at Mayo Lake/Roop Lakes During Migration. From Left to Right: Bald Eagle, Trumpeter Swan, Northern Pintail and Pectoral Sandpiper 7-27
FIGURE 7-14 Aerial View of WKA 2734 at the East End of Roop Arm 7-28
FIGURE 7-15 Active Beaver Lodge and Food Cache in Mayo Lake (Nelson Arm) During 2014 7-31
FIGURE 7-16 Cow Moose at Roop Lakes 7-32
FIGURE 7-17 Lower Roop Creek 7-38
FIGURE 7-18 Mayo Lake Boat Launch 7-40
FIGURE 7-19 Lake Trout 7-41
FIGURE 7-20 Barge Transporting Heavy Equipment on Mayo Lake 7-43

CHAPTER 8

FIGURE 8-1 AMP Evaluation Framework 8-4

LIST OF APPENDICES

CHAPTER 1

APPENDIX 1A: Adequacy Review Report of Supplement IR July 23, 2009

APPENDIX 1B: YESAB Response Table

CHAPTER 2

APPENDIX 2A: Land Tenure Tables

APPENDIX 2B: Na-Cho Nyak Dun Settlement Lands

APPENDIX 2C: Water Licences

APPENDIX 2D: Land Use

APPENDIX 2E: Consistency With Other Plans

APPENDIX 2F: Yukon Water Board Licence Mayo 2011

CHAPTER 4

APPENDIX 4A: List of Potentially Affected or Interested Publics

APPENDIX 4B: Newsletters and Posters

APPENDIX 4C: Activities Involving NND

APPENDIX 4D: Activities Involving Municipal and Other Governments

APPENDIX 4E: Activities Involving Local Stakeholders and Other Publics

CHAPTER 5

APPENDIX 5A: Aquatic Environment

APPENDIX 5B: Mayo Lake Erosion Assessment

APPENDIX 5C: Existing Projects and Activities Considered in the Cumulative Effects Assessment

APPENDIX 5D: Heritage Assessment Reports

CHAPTER 6

APPENDIX 6A: Existing Facilities and Water Management

APPENDIX 6B: Modeled Mayo Lake Outflows

CHAPTER 8

APPENDIX 8A: Monitoring Plan

APPENDIX 8B: Adaptive Management Plan

APPENDIX 8C: Report of Expert Advisor to the Technical Group, Dr. R.A. Bodaly – Final Report March 13, 2013

CHAPTER 1
PROJECT INTRODUCTION AND OVERVIEW

TABLE OF CONTENTS

1.0 PROJECT INTRODUCTION AND OVERVIEW 1
1.1 OVERVIEW 1
1.2 PROPONENT INFORMATION 3
1.3 PROJECT PURPOSE AND BACKGROUND 3
1.4 REQUIRED AUTHORIZATIONS AND REGULATORY APPROVALS 4
1.5 ALTERNATIVES TO THE PROJECT 4
1.6 SUBMISSION ORGANIZATION & CONTENT 5

LIST OF TABLES

Table 1-1: Regulatory Permits and Approvals 4

APPENDICES

Appendix 1A: Adequacy Review Report of Supplement IR July 23, 2009

Appendix 1B: YESAB Response Table

1.0 PROJECT INTRODUCTION AND OVERVIEW

1.1 OVERVIEW

The Mayo Lake Enhanced Storage Project (the Project) is located in the Yukon interior, at Mayo Lake and lies within the Traditional Territory of the First Nation of Na-Cho Nyak Dun (NND). The Project proposes to reduce reliance on fossil fuel generation by increasing bottom storage in Mayo Lake through reducing the licenced Low Supply Level subject to a reservoir Monitoring and Adaptive Management Plan to guide water management decisions.

In February 2009, Yukon Energy initially proposed the Project as part of the Mayo Hydro Enhancement Project (Mayo B) Project Proposal to the Yukon Environmental and Socio-Economic Assessment Board (YESAB); however, the Mayo Lake Project was withdrawn in July 2009 in response to YESAB's determination of the need for additional fisheries and wetlands baseline studies (see Appendix 1A for the July 2009 YESAB Adequacy Review Report). Yukon Energy has undertaken additional fieldwork between 2009 and 2014 and has now fully addressed YESAB's July 2009 information requests (see Appendix 1B for a concordance table).

Yukon Energy undertook a public involvement program in order to incorporate community input in the Project design and environmental assessment, as well as to meet requirements for public consultation in an effective and meaningful manner, and as a standing corporate principle for good planning. This included involvement with NND, the Village of Mayo, the Mayo District Renewable Resources Council (MDRRC), residents of Mayo and the surrounding area, various territorial and federal government departments, and other interested parties. Yukon Energy shared information about the Project, including ongoing studies to assist in the assessment of effects, and sought to address concerns and interests of individuals and organizations. Yukon Energy intends to continue its engagement with stakeholders, particularly NND and others in the Mayo area throughout the Yukon Environmental and Socio-Economic Assessment Act (YESAA) process and Project implementation.

Yukon Energy focused the assessment of effects of the Project from a Valued Components perspective. Valued Components (VCs) are elements of the Project's Local and Regional Study Areas that are valued for environmental, scientific, social, aesthetic, or cultural reasons. Final VCs were determined in part based on results of consultation activities with stakeholders. Consideration was also given to whether there was an existing pathway of effect from the Project to the VC or environmental value. The following environmental and socio-economic VCs were included in the effects assessment:

- Environmental VCs
    - Aquatic and Terrestrial Environment
        - Lake Trout
        - Lake Whitefish
        - Fish Community Productivity
        - Roop Lakes
        - Shallow Water Littoral Areas at the ends of Roop and Nelson Arms

        - Ducks, Geese and Migratory Birds
    - Aquatic Mammals
        - Aquatic Furbearers – beaver/muskrat
    - Mammals
        - Moose
- Socio-Economic VCs
    - Traditional and Domestic Resource Use
        - Hunting
        - Fishing
        - Harvest Success
        - Trapping
    - Other Resource Use
        - Placer Mining
        - Tourism, Outfitting, and Outdoor Recreation
        - Private and Commercial Land Use
    - Regional Economy
        - Government Fiscal Flows
        - Utility Ratepayers

Cumulative effects have been fully considered as an integral part of the effects assessment process. The assessment process was completed based on data previously available, as well as Project-specific studies, existing literature, and available local and traditional knowledge collected during the study process.

The Project, including mitigation measures set out in the Project proposal, is not expected to cause any likely significant adverse environmental or socio-economic effects. This conclusion reflects careful consideration of the Project design as well as the consideration of mitigation measures that reduce or eliminate potential adverse effects and the development of a robust monitoring plan and adaptive management plan.

The Project will also have positive environmental and socio-economic effects in a variety of areas. Notably, the Project is expected to provide for reduced greenhouse gas and particulate emissions in the Territory resulting from the displacement of fossil fuel generation emissions. This is consistent with the Energy Strategy for Yukon (Yukon Government 2009a) and the Yukon Government Climate Change Action Plan (Yukon Government 2009b). Both the plan and strategy set reduction of greenhouse gas emissions as a priority.

1.2 PROPONENT INFORMATION

Yukon Energy is the Project Proponent.

Yukon Energy, a public utility, is owned by the Yukon Government through the Yukon Development Corporation (a Crown Corporation), and is subject to rate regulation by the Yukon Utilities Board under the Public Utilities Act (Yukon Government YUB 2002b). Yukon Energy owns and operates the Yukon's integrated transmission system (consisting of a 138 kV line between Whitehorse, Aishihik, Carmacks, Faro and Stewart Crossing and a 69 kV line between Dawson, Stewart Crossing, Mayo and Keno) and generates almost 100% of the power on this isolated grid. It is also the electric utility with primary responsibility for planning and development of new generation and transmission facilities in Yukon.

Yukon Energy has an installed generation capacity of approximately 129 MW. Of this, 92 MW is installed capacity at three hydro facilities: Whitehorse, Aishihik and Mayo. A further 0.8 MW is installed wind generation. The remaining 36 MW is installed fossil fuel thermal generating capacity of which 25 MW is installed in the Whitehorse Thermal Generating Station. Yukon Energy's wholesale customer, Yukon Electrical Company Limited, distributes power to 89% of Yukon retail customers, while Yukon Energy distributes power to the other 11% (approximately 1,900 customers) located primarily in Dawson City, Mayo and Faro.

Yukon Energy management reports to a Board of Directors through the President. Final approval to proceed with the Mayo Lake Project is subject to the approval of the Board of Directors as well as required territorial regulatory approvals.

Yukon Energy is incorporated under, and regulated by, the Business Corporations Act (Yukon Government 2002a), the Public Utilities Act (Yukon Government YUB 2002b) and the Yukon Waters Act (Yukon Government 2003).

The designated contact for the YESAA assessment and subsequent licensing of the Project is Travis Ritchie, Yukon Energy's Manager of Environment, Assessment, and Licensing.

#2 Miles Canyon Road
PO Box 5920
Whitehorse, Yukon Y1A 6S7
Ph: (867) 393-5350
Fax: (867) 393-5323
Email: travis.ritchie@yec.yk.ca

1.3 PROJECT PURPOSE AND BACKGROUND

The Mayo Lake Enhanced Storage Project is proposed to enhance the renewable power generation capability of the existing hydro generating units installed on the Mayo River (see Appendix 6A for a description of existing facilities). The proposed Project is designed to improve energy generation to help displace fossil fuel that would otherwise be required during winter/spring to meet the overall power loads throughout the Integrated Yukon grid. The Project is consistent with Yukon Government policy, as set out in the Energy Strategy for Yukon (Yukon Government 2009a), which includes the goal of increasing

renewable energy supply by 20% by 2020. It also is in alignment with Yukon Government's 2009 Climate Change Action Plan (Yukon Government 2009b), which includes the reduction of carbon emissions.

The Project comprises a revision to the existing licensed range within which Yukon Energy is permitted to operate Mayo Lake, along with a reservoir management framework to guide water management decisions. The Project requires no physical works for water storage beyond those already in-service for the existing Mayo generation, including ongoing maintenance activities of the structure and outlet channel.

The proposed Project is consistent with Yukon Energy's efforts to minimize fossil fuel generation requirements, and to maximize and optimize, where possible, the capability of existing renewable generation assets as a preferred supply alternative as compared to new "greenfield" generation. The Mayo Lake Project will provide a long-term enhancement to the energy output of the Mayo plants, and reduce the future consumption of fossil fuel generation, which is costly and has associated environmental effects.

1.4 REQUIRED AUTHORIZATIONS AND REGULATORY APPROVALS

The Project is subject to an evaluation level assessment by the YESAB Designated Office in Mayo. A review of the Project is also anticipated by the Yukon Water Board under Part 3. Table 1-1 lists the regulatory permits and approvals that have been identified as being potentially required for the Project.

Table 1-1: Regulatory Permits and Approvals

Activity	Authorization	Act or Regulation
Water use	Water Use Licence Amendment	Yukon Waters Act, Water Use Regulations
Serious harm to fish that are part of a commercial, recreational or aboriginal fishery. Serious harm to fish is the death of fish or any permanent alteration to, or destruction of, fish habitat.	Fisheries Act Authorization	Fisheries Act (Sections 35 and 36)
Fish research and surveys	Licence to collect fish for Scientific Purposes; Fish Collection Licence	Fisheries Act; Fisheries (General) Regulations (Sec 51 & 52)

1.5 ALTERNATIVES TO THE PROJECT

The main alternative to the Project is continued reliance on existing fossil fuel generation (using natural gas supplied by liquefied natural gas and/or diesel fuel) to supply the energy that the Project would otherwise displace.

The Project is being pursued by Yukon Energy concurrent with all other identified potential enhancements to existing renewable generation, as well as a broad Demand Side Management (DSM) energy conservation and efficiency program. No one renewable energy project currently under study by Yukon

Energy is expected to meet short and medium-term forecasted demand on its own, and the proposed Project will not displace any other renewable energy option or any DSM option under consideration by Yukon Energy.

As Yukon Energy is a regulated utility with an obligation to supply firm power customer loads, the implications of not proceeding with this Project are as follows:

- Yukon Energy would be required to use fossil fuel generation to provide incremental power requirements that cannot be provided through the proposed Project.
- Long-term power costs in Yukon would be higher than with the proposed Project, affecting all Yukon ratepayers.
- Ongoing greenhouse gas emissions (GHG) would be higher than with the Project.
- Economic development benefits arising to the NND from participation in the proposed Project's economic benefits will not be realized.

1.6 SUBMISSION ORGANIZATION & CONTENT

The Project Proposal has been prepared so as to follow the Proponent's Guide to Information Requirements for Designated Office Project Proposal Submissions in structure and content, in all material respects. As the Proponent's Guide describes in general terms, the form of Project Proposal submissions, it has been applied in this document so as to reflect the specific characteristics of the Project.

The following outlines the chapter organization of this Project Proposal:

- Chapter 1: Project Introduction and Overview
- Chapter 2: Project Location
- Chapter 3: Assessment Approach
- Chapter 4: First Nations and Other Public Consultations
- Chapter 5: Environmental and Socio-Economic Scan
- Chapter 6: Project Description
- Chapter 7: Environmental and Socio-Economic Effects Assessment
- Chapter 8: Monitoring and Follow-up Programs
- Chapter 9: List of Acronyms, Glossary, and References
- Chapter 10: Acknowledgement and Certification

CHAPTER 2

PROJECT LOCATION

TABLE OF CONTENTS

2.0 PROJECT LOCATION 2-1
2.1 GEOGRAPHIC LOCATION 2-1
2.2 LAND TENURE WITHIN THE PROJECT REGIONAL STUDY AREA 2-3
2.3 TRADITIONAL TERRITORY 2-4
2.4 CONSISTENCY WITH OTHER PLANS 2-4
2.4.1 Current Land Use & Management Plans 2-5
2.4.2 Project Consistency with Other Plans 2-6

LIST OF TABLES

Table 2-1: Land Use and Management Plans 2-5

LIST OF FIGURES

Figure 2-1: Regional Study Area 2-2

APPENDICES

Appendix 2A: Land Tenure Tables
Appendix 2B: Na-Cho Nyak Dun Settlement Lands
Appendix 2C: Water Licences
Appendix 2D: Land Use
Appendix 2E: Consistency with Other Plans
Appendix 2F: Yukon Water Board Licence Mayo 2011

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2.0 PROJECT LOCATION

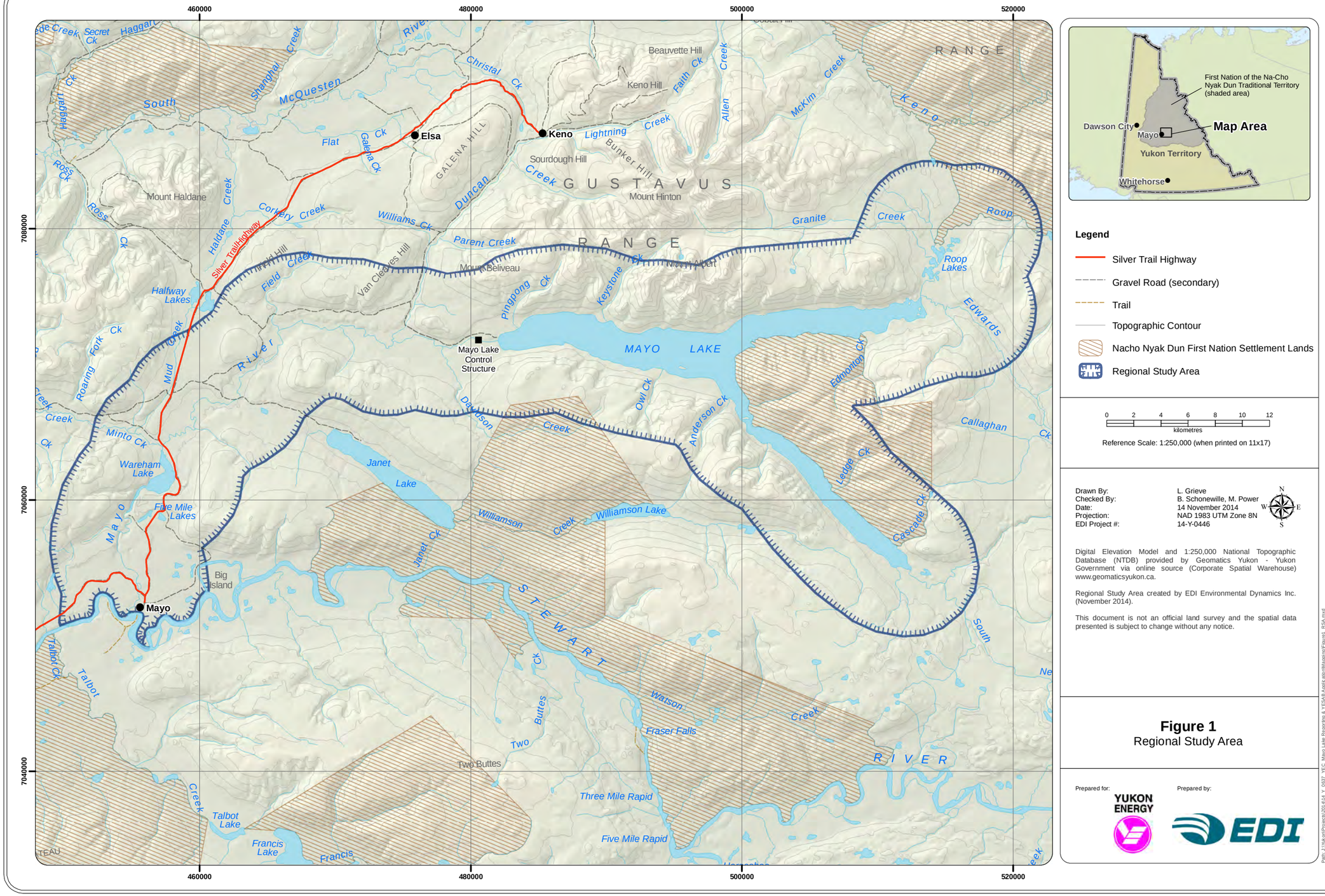
Chapter 2 provides a general geographical setting for the Project Proposal in terms of its location within the Yukon. The chapter sets out information regarding geographic location, land tenure, traditional territory of Yukon First Nations, Yukon Land Use Planning Region and consistency of the proposed Project activities with any existing land and/or resource management plans. It also outlines the Project Regional Study Area for the assessment approach as more fully described in Chapter 3.

2.1 GEOGRAPHIC LOCATION

The proposed Project changes Yukon Energy's licensed operating regime at Mayo Lake in the Yukon interior, northeast of the Village of Mayo. The Project lies within the Traditional Territory of the First Nation of Na-Cho Nyak Dun ("NND") as identified in the NND Final Agreement (NND 1993). The management of First Nation settlement land and resources in the Traditional Territory is guided by the provisions in the NND Final Agreement.

As reviewed in more detail in Chapter 3, the regional study area for the Project Proposal is that portion of the region between the Village of Mayo and Mayo Lake including a 5 km buffer around the lake and upper Mayo River. This Project Regional Study Area also falls within YESAB's Central Yukon Assessment District (Mayo Designated Office). A schematic of the Project Regional Study Area is provided in Figure 2-1.

Figure 2-1: Regional Study Area



The Project is located within the Boreal Cordillera Ecozone and the Yukon Plateau-North ecoregion. This area is generally characterized by tablelands and rolling uplands separated by wide and U-shaped valleys. The Project is also within the Yukon River Major Drainage Area which encompasses approximately 66% of the Yukon Territory and is its largest drainage area. The Mayo River is a tributary of the Stewart River, which in turns flows into the Yukon River.

2.2 LAND TENURE WITHIN THE PROJECT REGIONAL STUDY AREA

A land tenure search within the Project Regional Study Area, focusing on areas in close vicinity (e.g., within 2 km of either shoreline) to Mayo Lake and the Mayo River, is provided in Appendix 2A. Corresponding maps are located in Appendix 2D.

Further information regarding the socio-economic setting as it respects land tenure and associated land use is presented in Appendix 5C. In regard to specific land tenure the following items are noted:

Protected Areas and Parks:

The Project Regional Study Area contains the following protected areas and parks:

- **Five Mile Campground** – Located at 56.8 km of the Silver Trail Highway, the campground is 90 hectares and has 20 campsites. The Project will not interact with use of the campground.
- **Mayo Lake Campground Reserve** – The Project Regional Study Area encompasses the Mayo Lake Campground Reserve.

  Although not a protected area pursuant to legislation or regulation, Yukon Parks holds an 18.2 hectare reserve at the outlet of Mayo Lake, disposition #105M14-003, as well as fee simple lot 1056. The reserve at the lake mouth is not gazetted under the Parks and Land Certainty Act (Yukon Government 2002c). Yukon Parks does not maintain the reserve, or charge fees (A. Jones pers comm. 2008). The public is able to access the water at a boat launch at the reserve.

  The Project is not in the vicinity of any other lands designated under the Parks and Land Certainty Act, National Parks, Special Management Areas, Habitat Protection Areas, Canadian Heritage Rivers, National Wildlife Areas or Wildlife Sanctuaries.
- **Trapping and Outfitting Concession Areas** – There are six trapping concessions within or adjacent to the Project Regional Study Area: those being concessions 74, 84, 85, 86, 89 and 407, the last of which is a community trapping concession. Of the remaining five trapping concessions, three are located along the shoreline of the Mayo Lake, one is on Unnamed Island on Mayo Lake, and another is at the confluence of Davidson Creek and the Mayo River. See Appendix 2A for land tenure tables and Appendix 2D for a map of trapping concessions and owners.

  The Project falls entirely within Yukon Outfitting Concession 7, a 2.2 million hectare area. Concession 7 is held by Rogue River Outfitting, operated by Jim Shockey. A map of the outfitting concession is provided in Appendix 2D.
- **Mineral, Aggregate and Agricultural Claims** – Placer mining is an important economic activity in the Mayo area, to the extent that "[p]lacer mining and mineral exploration provide a non-governmental economic base for the [c]ommunity" (Village of Mayo Integrated Community

Sustainability Plan 2006). Placer and Quartz claims in close vicinity to Mayo Lake and the Mayo River in the Project Regional Study Area are listed in tables and illustrated on maps along with other land dispositions in Appendices 2A and 2D respectively. In addition, Appendix 5C provides details on the water use licenses of projects in close vicinity of Mayo Lake and the Mayo River, including placer mining activities, as supplied by the Yukon Water Board.

There are placer claims on 12 tributaries running into Mayo Lake, and one placer lease on Unnamed Island in the Nelson Arm of Mayo Lake. Duncan Creek and its tributaries Parent Creek, Lightening Creek, and Thunder Gulch descend into the Mayo River from Keno Hill to the north and include heavy placer activity. There are also placer claims on Davidson Creek. As noted in Chapter 5, prior to 2014 there were two or three active placer miners at Mayo Lake (e.g., Owl and Anderson creeks). While placer mining activity around the lake has diminished in recent years, there was at least one active operation in 2014.

In addition to placer mining claims, there are numerous quartz claims surrounding Mayo Lake (see Appendix 2D for maps).

There are no specific agricultural leases, dispositions, or applications within the Project Regional Study Area. Lots 1059 and 1061 near the Wareham bridgehead are fee simple dispositions and are used for agricultural purposes.

- **Water Use Licence Holders** – Numerous Water Licenses exist for activities in close vicinity to Mayo Lake and the Mayo River, primarily related to placer operations (see above). Outside of mining activity, water licenses exist for the Village of Mayo (Type A), Yukon Energy (Type A), Yukon Government (Type B) and for NND (Type B). See Appendix 2C for a list of water licenses within close vicinity of Mayo Lake and the Mayo River.
- **Private Landholdings** – The Project Regional Study Area is dominated by Crown Lands. Private land holdings are shown in the tables in Appendix 2A.

2.3 TRADITIONAL TERRITORY

The proposed Project is located entirely within the traditional territory of the First Nation of Na-Cho Nyak Dun (NND). There are eleven main Settlement Land parcels within the Project Regional Study Area, codified in the 1993 First Nation of Na-Cho Nyak Dun Final Agreement. The largest parcel of Settlement Lands in the area is Lot 1000, NND R-2A lying between the Roop and Nelson Arms of Mayo Lake (see Appendix 2B for a detailed list of NND settlement land parcels; several maps in Appendix 2D include NND Settlement Lands, including the maps detailing Land Tenure of the Mayo Region, Land Tenure for the Village of Mayo, and Quartz Claim Information for Mayo Lake).

2.4 CONSISTENCY WITH OTHER PLANS

The proponent has reviewed publicly available fish and wildlife and community plans in the Project Regional Study Area in order to ensure that the proposed Project is consistent with local plans.

2.4.1 Current Land Use & Management Plans

There is one land use plan currently in place in the Project Regional Study Area – the Village of Mayo Official Community Plan 2005 (Village of Mayo 2005). In addition, there are several management plans that are applicable. These plans include the Village of Mayo Integrated Community Sustainability Plan (Village of Mayo 2006), and the Community Based Fish and Wildlife Management Work Plan for Na-Cho Nyak Dun Traditional Territory 2014-2019 (NND 2014). A summary of the plans considered in relation to the Project is provided in Table 2-1.

Table 2-1: Land Use and Management Plans

Plan	General Description	Objectives Related to Project
Village of Mayo Official Community Plan 2005	Guides aspects of land planning and management, including zoning, development and land use.	Foster local and regional economic diversity, which is environmentally sustainable. Plan collaboratively with NND and other local government.
Village of Mayo Integrated Community Sustainability Plan	Outline the Village of Mayo's vision for an economically and environmentally viable future.	Foresees future resource development in the Mayo area, and seeks to accommodate such development in a sustainable manner.
Community-Based Fish and Wildlife Work Plan for Na-Cho Nyak Dun Traditional Territory 2014-2019	This is the fifth plan, and is based on a collaborative planning exercise between Mayo District Renewable Resources Council, First Nation of Na-Cho Nyak Dun, the Yukon Government - Fish and Wildlife Branch, and citizens of Mayo.	Addresses the following priorities: monitoring and stewardship; habitat; moose; and fisheries in the Mayo area.
Yukon Government Climate Change Plan 2009 and Yukon Government Climate Change Action Plan Progress Report 2012	The plan details actions the Yukon government will undertake to address climate change, within its areas of responsibility-building on the goals set out in the Climate Change Strategy. A progress report on these issues was released in September 2012 to discuss what has taken place, including initiatives that have emerged, during the interim period since the plan was established.	Reduce greenhouse gas emissions and monitor impacts of climate change on water systems in Yukon.

Plan	General Description	Objectives Related to Project
Mayo Watershed Fisheries Act Authorization for Placer Mining	Regulates and establishes sediment discharge standards and conditions for placer mining activities on the Mayo watershed, including Mayo Lake.	Provides for the protection of fish and fish habitat under the Fisheries Act, and establishes habitat suitability classifications for streams and lakes, including Mayo Lake.
Nacho Nyak Dun Tan Sothan – A Good Path Integrated Community Sustainability Plan May 2008	Follow-up to the Integrated Community Sustainability Planning process.	
Yukon Wildland Fire Management	The program aims to protect Yukoners, their communities and resources by enforcing the *Forest Protection Act* and suppressing wildfire from a priority-based approach, which places human life, community value and firefighter safety above all else.	

2.4.2 Project Consistency with Other Plans

The Project planning and assessment took into consideration the objectives of various management plans that are currently in place, and these objectives informed the public involvement and consultations with NND.

Village of Mayo Integrated Community Sustainability Plan and the Village of Mayo Official Community Plan 2005

The Village of Mayo Integrated Community Sustainability Plan (Village of Mayo 2006) and the Village of Mayo Official Community Plan 2005 (Village of Mayo 2005) identify the need to dovetail environmentally and economically sustainable development within Village boundaries, and in the larger Mayo region. Appendix 2E provides a summary of the objectives of the applicable management plans and describes how the Project is consistent with each plan objective. The following provides a summary description showing that the Project is aligned with the objectives and strategies of these management plans.

In Yukon Energy's view, the Project meets the environmental protection and stewardship objectives of the above documents. The Project does not require construction. The Village of Mayo Official Community Plan 2005 states specifically that "[f]uture resource development is anticipated in the Mayo area and the community recognizes the need to prepare in order to maximize and sustain the benefits of resource extraction". The Mayo Lake Enhanced Storage Project is part of ongoing sustainable (renewable) resource use.

Community Based Fish and Wildlife Work Plan for Na-Cho Nyak Dun Traditional Territory 2014-2019

With regard to the Community Based Fish and Wildlife Work Plan for Na-Cho Nyak Dun Traditional Territory 2014-2019 (NND 2014), the plan, in part, identifies the need for local area planning with regard to development in the Mayo area, continued support for the game guardian program (important for monitoring behaviour on the land and encouraging ethical practices), stewardship activities for youth and reporting on animal presence in the Mayo area, such as moose and caribou.

The public involvement process for this Project, which included workshops with local resource users and consultation with NND, contributed to regional dialogue about aquatic and terrestrial fauna and contributed local and traditional knowledge to the assessment. The biophysical studies undertaken as part of preparing this application added to the existing scientific literature on the fauna in the Project Regional Study Area, particularly fish. Lake trout was identified as an environmental component of interest in the Community Based Fish and Wildlife Management Plan. The aquatic field studies addressed lake trout and lake whitefish habitat and populations in Mayo Lake (see Appendix 5A).

Yukon Government Climate Change Plan 2009 and Yukon Government Climate Change Action Plan Progress Report 2012

The Yukon Government's 2009 Climate Change Action Plan (Yukon Government 2009b) seeks to enhance knowledge of climate change, adapt to climate change, reduce greenhouse gas (GHG) emissions, and lead action in response to climate change. The Yukon Government has set a cap on its own GHG emissions by 2010 and a target to reduce its emission by 20 percent by 2015. The Government's goal is to be carbon neutral in 2020 (from YEC's 2012 Strategic Plan). The Mayo Lake Project will reduce greenhouse gas emissions by reducing reliance on thermal generation that will be needed to serve the growing electrical needs of the region and Yukon in general. The Yukon Government's Climate Change Action Plan Progress Report (Yukon Government 2012), published in September 2012, details the progress made on the government's priority climate change actions and on actions that developed during the three years following the Climate Change Action Plan's release.

Mayo Watershed Fisheries Act Authorization for Placer Mining

With regard to the Mayo Watershed Federal Fisheries Act Authorization for placer mining, it sets out the sediment discharge standards and the conditions for related activities such as the construction of access structures, stream diversions, riparian buffers and reclamation requirements within fish habitat and the riparian zones of streams and water bodies.

Yukon Wildland Fire Management

The Yukon Wildland Fire Management aims to protect Yukoners, their communities and resources by enforcing the Forest Protection Act and suppressing wildfire from a priority-based approach which places human life, community value and firefighter safety above all else.

Yukon Energy does not anticipate that the Project will impede the ability of the Protective Services Branch of the Department of Community Services from fulfilling its objectives.

CHAPTER 3
ASSESSMENT APPROACH

TABLE OF CONTENTS

3.0 ASSESSMENT APPROACH 3-1
3.1 OVERVIEW OF APPROACH 3-1
3.2 ASSESSMENT FRAMEWORK 3-2
3.3 DETERMINING SIGNIFICANCE OF RESIDUAL EFFECTS 3-4
3.4 SOURCES OF INFORMATION 3-7

3.0 ASSESSMENT APPROACH

Chapter 3 reviews the assessment approach in the Project Proposal, focusing on the following items:

- Overview of Approach;
- Assessment Framework including Cumulative Effects;
- Determining Significance of Residual Effects;
- Follow Up and Adaptive Management; and
- Sources of Information.

3.1 OVERVIEW OF APPROACH

The Project Proposal has been prepared in accordance with YESAA, the YESAB DO Rules[1] and standard environmental and socio-economic assessment practice. It sets out the information required from Yukon Energy (the Proponent), for an assessment of the Project by the Designated Office. In accordance with the matters to be considered under Section 42(1) of YESAA, likely environmental and socio-economic effects of the Project, as well as likely cumulative adverse environmental and socio-economic effects of the Project and their significance are identified after considering the implementation of proposed mitigation, monitoring and follow-up measures. The submission utilizes and integrates available scientific, traditional knowledge, local knowledge and other information relevant to the assessment of Project effects. The Project will continue to incorporate scientific, local and traditional knowledge as part of the ongoing monitoring and activities under the proposed Adaptive Management Plan.

In accordance with the spirit of YESAA and standard Yukon Energy planning practice, the assessment approach has incorporated an extensive consultation and public involvement process which sought views from the First Nation of Na-Cho Nyak Dun (NND) and residents of Mayo where potential environmental and socio-economic effects of the Project would most likely be experienced (Chapter 4). Early and meaningful ongoing opportunities have been provided to seek views and information about the Project, the environmental and socio-economic planning and the assessment process. Involvement has included NND, Mayo District Renewable Resources Council (MDRCC), other local residents, territorial and federal governments. These consultations have contributed in a material way to the mitigation of adverse environmental and socio-economic effects that could potentially be associated with the Project as well as a consideration of alternatives to the Project or alternative ways of undertaking or operating the Project that would avoid or minimize any significant adverse environmental or socio-economic effects.[2]

The scoping of the Project, as well as a description of Project activities and components, is provided in Chapter 6. The assessment approach addresses the proposed change to the operational licence range and the effects on environmental components applicable to the Project (e.g., land and water environments and associated aquatic and terrestrial life) and socio-economic components (e.g., resource

[1] YESAB Rules refers to the June 2010 Rules for Evaluations Conducted by Designated Offices; and Directive 2: Filing Requirements for Project Proposals Submitted to a Designated Office for Evaluation.
[2] These matters are required to be considered under s. 42(1)(e) and 42(1)(f) of YESAA.

and other land use, economies, and social components including infrastructure and services, cultural/heritage sites and resources, and traditional and other lifestyles).

The Project Proposal ultimately assesses the effects of the proposed change in water management for use of Mayo Lake (see Chapter 7).

As there is no construction phase, the assessment approach focuses on the effects of Project operation. At this time there is no timetable for decommissioning of the existing Mayo facilities, and it is currently not feasible to provide a meaningful assessment of any likely decommissioning plans or the anticipated effects of decommissioning. If at a later date it is determined that the existing Mayo facilities are no longer required, then Yukon Energy would adhere to the legislation and regulations in place at that time and would review decommissioning plans with regulatory authorities, affected First Nations and other local communities.

3.2 ASSESSMENT FRAMEWORK

For the purpose of assessing environmental and socio-economic effects of the Project, current conditions in areas potentially affected by the Project and the projected evolution of these conditions without the Project are considered. As noted in Chapter 6 and 7, the Mayo Lake environment has been previously disturbed when the original Mayo Lake control structure was built and the lake raised by over 5 m. Potential environmental and socio-economic effects of the Project on the existing conditions are predicted separately in the Project Proposal for each environmental and socio-economic component by comparing:

1. **What would be expected without the Project** (i.e., the current and expected future conditions for each environmental and socio-economic component without the Project, including as relevant consideration of other projects or activities that have been or will be carried out without the Project); and
2. **What would be expected with the Project** (i.e., each environmental or socio-economic component as modified or affected by the Project based on direct and indirect effects pathways[3] from the Project to the environmental or socio-economic component, including as relevant consideration of other projects or activities that have been or will be carried out in combination with the Project).

Following from the Project description and determination of the Project scope (Chapter 6), and reflecting standard environmental and socio-economic assessment practice, the assessment framework for the Project Proposal (including cumulative effects assessment) to assess effects of the Project includes the following five basic steps:

1. **Scoping of Assessment:** It is critical at the outset to address assessment scope issues, including selecting valued environmental and socio-economic components (VCs) for the assessment[4].

[3] As reviewed in earlier YESAB Guides, "direct effects" are the initial, immediate effects caused by a specific activity and "indirect effects" are caused by a given action, but occur later in time or further removed in distance.

[4] Valued Environmental and Socio-economic Components (VCs) are elements of the Project Study Region valued for environmental, scientific, social, aesthetic, or cultural reasons. Selecting project-specific VCs (i.e., VCs that could be potentially affected by the Project) is essential for focusing assessments, and for determining the significance of effects.

a) A VC based approach is intended to ensure that potential significant adverse effects to important environmental and social components will be detected and mitigated through the assessment process[5]. This was done initially and in part through the development and implementation of baseline studies and the development of the proposed Monitoring and Adaptive Management Plans in cooperation with NND and in consultation with the MDRRC and the community, regulators and other scientific experts. This selection process of VCs helped to focus the baseline studies and analysis on components deemed to be of particular importance or of special interest to residents or to the ecosystem[6]. Chapter 7 reviews the process used to select VCs; the scoping of baseline and assessment studies for each VC; and the specific methods used to assess potential environmental and socio-economic effects for each VC.

b) The assessment process commenced with the definition of a general geographic location for the Project and a Project Study Region. For assessment purposes the following study areas were defined:

1. **Local Study Area:** represents the much smaller local region examined to assess potential effects of changing water levels and flows on Mayo Lake including the Roop Lakes wetland complex and the upper Mayo River (Wareham Lake to Mayo Lake).

2. **Regional Study Area:** A broader Project Regional Study Area for examining potential environmental and socio-economic effects. The maximum geographic extent of most potential environmental and socio-economic effects is expected to be included in this region. The generic nature of the definition adopted for this regional study area reflects the absence of any specific administrative area available for overall data collection or mapping purposes relevant to this assessment.

   However, it is recognized that the nature of different potential environmental and socio-economic effects requires flexibility in the extent of the study area used for each VC. Specific study areas relevant to each VC, where they are different from the definitions in this chapter, are described in Chapter 7. It should be noted that field studies undertaken early in the Project do not reflect the above definitions; rather they reflect study-specific requirements, and as such definitions such as "study area" used in the field reports in Appendices 5A, 5B and 5D do not in some cases correspond with the Project Proposal definitions indicated above.

[5] It is standard practice to focus an assessment on specific environmental and socio-economic components which are determined to be of particular importance. Measures designed to mitigate adverse effects on major components should serve to also minimize the likelihood of adverse impacts on other environmental and social components.

[6] In this assessment, VCs were determined after consultation with interested parties and experts (particularly NND and government), field studies undertaken on the terrestrial and aquatic environments, socio-economic data collection and consideration of TK and local knowledge as well as any plans and policies applicable to the regional area.

2. **Baseline Conditions:** This is a baseline analysis and includes review of current and evolving future VC conditions without the Project, as affected by past, current and other future projects included in the cumulative effects assessment. Each existing VC is described in the baseline analysis only to the extent needed to predict the effect of the Project on that VC.

3. **Effects and Mitigation:** This describes quantitatively and qualitatively both positive and adverse effects on VCs likely to result from the Project, after consideration of the baseline conditions without the Project as well as proposed mitigation and monitoring measures with the Project beyond those already included in the Project Description. In accordance with YESAA, the scope of this assessment includes an examination of both environmental and socio-economic effects arising from the Project and is described for each VC in Chapter 7.

4. **Cumulative Effects Assessment:** Cumulative Effects Assessment (CEA) is integral to the assessment approach and examines the likely effects of the project in combination with the likely effects of other past, existing and future projects and activities. To be considered a cumulative effect, the other past, existing and future projects being considered in the assessment must affect a VC that is also being affected by the principal project; in this way the projects act cumulatively upon a valued component. The CEA is embedded in the effects assessment in Chapter 7.

5. **Residual Effects and their Significance:** Summarizes the nature and extent of any residual environmental effects of the Project after implementation of proposed mitigation, and includes characterization with rationale as to whether adverse residual environmental and socio-economic effects are significant or not significant. Included as part of mitigation are any plans for responding to any known or predicted residual effects. This assessment is included in Chapter 7.

6. **Adaptive Management and Monitoring:** The proposed Adaptive Management Plan and Monitoring Plan identified in Chapter 6 and detailed in Appendix 8A and 8B are integral to the Project and the assessment of the Project. As stated in Chapter 6, it is the proponent's expectation that these will be included in the amended water use licence for the Project, if the Project were to proceed.

3.3 DETERMINING SIGNIFICANCE OF RESIDUAL EFFECTS

Environmental and socio-economic effects and their significance are identified and determined using standard assessment practice and the requirements of YESAA.

Determining "significance" involves the use of scientific, Traditional and local knowledge, the analysis and interpretation of environmental and socio-economic effects, and consideration of effects of environmental or socio-economic changes caused by the Project on the following (YESAA, s.42):

- The need to protect the rights of Yukon Indian persons under final agreements;
- The special relationship between Indian Yukon persons and the wilderness environment of Yukon; and
- The cultures, traditions, health and lifestyles of Yukon Indian persons and other residents of Yukon.

Mitigation measures and strategies can be important in the assessment of residual effects.

For purposes of effects assessment, the determination of significance of residual effects may involve comparing such effects, including cumulative effects, against thresholds for environmental and socio-economic components such as specified goals or targets, standards or guidelines, carrying capacity, or limits of acceptable change. Land use objectives and trends may also be utilized to determine significance of residual effects. However, it is recognized in standard assessment practice that the assessment of project effects is often hindered by a lack of specific thresholds.

To the greatest degree possible, the significance thresholds identified in this effects assessment are drawn from quantitative data, particularly with regard to the aquatic ecosystem and fish.

The regulatory significance of predicted residual adverse effects on each VC is assessed according to the following criteria (in many cases referencing examples of effect attribute characteristics for aquatic ecosystem components):

- **Direction or Nature of the Effect:** Positive, neutral, or negative/adverse; in the case of socio-economic effects, effects may at times be considered to be both positive/beneficial and negative;

  The assessment of significance for environmental effects typically can determine a clear overall direction of change (positive, neutral or negative/adverse) for a specific VC. In contrast, the assessment of significance for socio-economic effects also considers the following:

  - The relevance of perceptions in affecting how people view changes;
  - Differing perspectives and values among different groups of people about their community and region, as well as their individual and family circumstances (this applies to biophysical affects as well);
  - The problems inherent in assessing separate effects on different aspects or components (i.e., different VCs) of people's lives that each contribute to an overall "effect" on any group of people; and
  - Positive socio-economic effects will not be used to offset any significant negative/adverse environmental effects of a project.

- **Magnitude of the Effect** (the predicted severity or degree of disturbance the residual effect has on a component of the biophysical or socio-economic environment):
  - **Small** (no definable or measurable effect on the VC – the effect is below established thresholds of acceptable change or within the range of natural variability).
  - **Moderate** (the effect on the VC could be detected with a well-designed monitoring program, is outside the normal range of variation (but below established thresholds of acceptable change) and the overall population is still sustainable).
  - **Large** (the effect on the VC would be readily detectable without a monitoring program, is outside the normal range of variation, and exceeds established thresholds of acceptable change and the VC sustainability is threatened).

- **Geographic or Socio-Economic Extent of the Effect:**
    - **Low** (effect is localized within the Local Study Area i.e., effect is limited to localized populations of fish and wildlife or a small portion of the LSA; e.g., beaver populations on Mayo Lake).
    - **Moderate** (effect is within the Local Study Area which includes all of Mayo Lake, Roop wetland complex and the Mayo River).
    - **High** (effect extends beyond Local Study Area to the Regional Study Area; for socio-economic effects, extends to Yukon-wide effects (e.g., effects to ratepayers across the Yukon).
- **Duration of the Effect (how long the effect would last):**
    - **Short-term** (short-term effects lasting less than one generation span or year class of the species affected); e.g., there may be an initial reduction in year class strength at the early fry stage but this is offset by density dependent survival and growth at older life history stages.
    - **Medium-term** (medium-term effects lasting more than one year class, but no more than one-generation span of the species affected); e.g., effect in terms of year class strength is detectible over the longer term in index netting and for the life of the year class.
    - **Long-term** (long-term effect lasting more than one generation of the species affected); e.g., reduction in year class strength and adult spawners effects reproductive capacity of a species.
- **Frequency of the Effect** (how often the effect would occur):
    - **Low** (never, once, seldom);
    - **Moderate** (occasionally e.g., not every year or not in most years); or
    - **High** (continuously - on a regular basis e.g. every year or in most years).
- **Reversibility of the Effect** (is the effect reversible or not reversible):
    - **Reversible:** the effect can be reversed; or,
    - **Irreversible:** the effect cannot be reversed; the effect is permanent or near permanent.
- **Ecological or Socio-Economic Context (sensitivity to environmental or socio-economic disturbance, capacity to adapt to change):**
    - **Low** (VC is resilient to imposed change);
    - **Moderate** (VC has some capacity to adapt to imposed change); or,
    - **High** (VC is fragile and has low resilience to imposed change).

For example, if an environmental VC is known to be highly resilient (i.e., adaptable to changes in environmental conditions and recovers well from such changes or disturbances, e.g., there may be impacts to a year class, but overall the population is healthy and reproductive capacity is not affected),

effects that would otherwise be considered significant may – for the purposes of determination of regulatory significance - be determined as not significant, despite magnitude and/or duration or the extent of the effects. Cumulative effects can be significant in this regard, e.g., if there is a significant increase in harvest of adult spawning fish the missing year classes or reductions in year class strength would be more significant at the population level. Conversely, thresholds or guides may identify highly vulnerable environmental VCs where the loss of even a few individuals may affect the long-term status of the population. Additional factors that may need to be considered for socio-economic VCs include the following:

  - Concurrent effects on other socio-economic VCs affecting the same group of people or others in the same community or region;
  - Effectiveness of mitigation measures and the degree to which the affected people have any control over mitigation (which may affect "vulnerability" in socio-economic terms);
  - The extent to which the socio-economic component is affected by the Project (magnitude, frequency, reversibility of the effects); and
  - Overall confidence in the assessment conclusions after consideration of proposed mitigation measures.

- **Likelihood:** In the event that residual effects on VCs are potentially significant, likelihood is discussed in terms of two criteria: i) the probability of occurrence of the significant adverse effect and ii) the degree of uncertainty. Likelihood differs from frequency in the determination of significance for environmental effects. For example, a building in the 100 year flood zone may only experience flooding during periods of extreme floods (low frequency), but when there are extreme flood events, it is relatively certain the effect will occur (high likelihood).

As addressed in further detail in the Project Description (Chapter 6) and Monitoring and Adaptive Management (Chapter 8), a robust Adaptive Management Plan is integral to the planned operation of the Project and is expected to address issues of uncertainty related to potential project effects and/or mitigation effectiveness, particularly where the effects, if they were to occur, would not result in serious irreversible harm.

Assessment conclusions are supported by technical information, traditional and local knowledge based on experience in Yukon and elsewhere. In this regard, traditional and local knowledge are addressed on an integrated basis throughout the assessment process and on an ongoing basis during operations in the Monitoring and Adaptive Management Process.

3.4 SOURCES OF INFORMATION

The assessment incorporates original studies commissioned by Yukon Energy specific to the Project, including extensive scientific and technical reports and memos on topics relevant to the Project, local knowledge and available experience. Other information sources include meetings with NND resource users, regulatory agencies, the MDRCC, placer miners/land owners on Mayo Lake and existing public and unpublished information.

The assessment process for the Project has included consultation and involvement with potentially affected groups such as NND, local community organizations and individuals, and other interested

groups. This consultation and public involvement has provided the Project Proposal with important information with regard to local knowledge, concerns and interests as well as available experience.

Meetings with territorial and federal government departments were also held to discuss the status of the project and its environmental/socio-economic studies and provide information to assess ongoing changes related to the project.

CHAPTER 4
FIRST NATION AND OTHER COMMUNITY AND PUBLIC ENGAGEMENT

TABLE OF CONTENTS

4.0 FIRST NATION AND OTHER COMMUNITY AND PUBLIC ENGAGEMENT 4-1

4.1 OVERVIEW 4-1
4.2 PRINCIPLES AND APPROACH TO CONSULTATION 4-2
4.2.1 Guiding Principles 4-2
4.3 METHODS 4-4
4.3.1 Face-to-Face Interaction 4-4
4.3.2 Electronic, Paper & Other Media Communication 4-4
4.4 REVIEW OF PUBLIC INVOLVEMENT ACTIVITIES 4-5
4.4.1 Activities Involving NND 4-5
4.4.2 Activities Involving Local and Municipal Government, Regional and Local Resource Management Organizations, and Other Governments 4-6
4.4.3 Activities Involving Local Stakeholders and Other Publics 4-7
4.5 INDEPENDENT ADVISOR REVIEW 4-8
4.6 KEY ISSUES AND PERSPECTIVES HEARD TO DATE 4-9
4.7 FUTURE STEPS IN PUBLIC CONSULTATION 4-26

LIST OF TABLES

Table 4-1: Interests and Concerns Raised by Stakeholders and Members of the Public and Areas where Feedback from Public Involvement Activities was Considered in the Environmental and Socio-Economic Assessment Process 4-11

APPENDICES

Appendix 4A: List of Potentially Affected or Interested Publics
Appendix 4B: Newsletters and Posters
Appendix 4C: Activities Involving NND
Appendix 4D: Activities Involving Municipal and Other Governments
Appendix 4E: Activities Involving Local Stakeholders and Other Publics

4.0 FIRST NATION AND OTHER COMMUNITY AND PUBLIC ENGAGEMENT

An overview of the public and community[1] involvement activities is provided in Section 4.1 of this chapter. Section 4.2 describes the principles and approach to consultation, while Section 4.3 describes the methods used. Section 4.4 reviews the activities undertaken with various stakeholders and Section 4.5 describes the key perspectives and issues that were provided. Section 4.6 explains how the key perspectives and issues influenced the Project planning. Section 4.7 describes what will occur in terms of communication about the Project upon the filing of a Project Proposal to the Mayo Designated Office under Yukon Environmental and Socio-Economic Assessment Act (YESAA).

4.1 OVERVIEW

Yukon Energy developed a public involvement approach in order to incorporate community input in the Project design and effects assessment, to meet the regulatory requirements for public consultation in an effective and credible manner, and as a standing corporate principle for good planning. The process was designed to provide on-going opportunities for potentially affected and interested parties to participate in the Project planning by providing information, allowing for sharing of key perspectives and interests regarding the Project and assisting in devising measures to mitigate potential Project-related effects through the environmental and socio-economic assessment process.

The public involvement process for this Project began in 2008 during the Mayo Hydro Enhancement Project (Mayo B), prior to the Mayo Lake component being removed in order to address information requests from the Yukon Environmental and Socio-Economic Assessment Board (YESAB) during Mayo B's adequacy review. Public involvement for the Mayo Lake Enhanced Storage Project resumed in February 2011, when the Project was re-introduced.

Public involvement focused largely on the public and stakeholders residing in closest proximity to the Project, and to which the potential effects would most likely accrue, including Na-Cho Nyak Dun (NND) the Mayo District Renewable Resources Council (MDRCC) and the Village of Mayo, among other organizations and individuals. This included residents of Mayo, private landowners, and resource users (e.g., fishers, trappers, placer miners). In addition, interested non-government organizations, the Mayo Designated Office (YESAA), and federal and territorial government regulators were included in the consultation.

It is important to note that while these community consultation processes included NND and First Nation citizens, representatives from NND also participated formally in all phases of Project development under the Yukon Energy/NND Project Agreement Technical Working Group in a collaborative working arrangement with Yukon Energy.

A list of the potentially affected or interested publics is provided in Appendix 4A.

[1] The term 'community' in this document refers to both place-based communities, which can be defined geographically, and interest-based communities defined by a common interest or activity, also sometimes referred to as 'stakeholder' group.

4.2 PRINCIPLES AND APPROACH TO CONSULTATION

4.2.1 Guiding Principles

Yukon Energy has developed the following principles for public involvement in project planning and implementation:

- **Value of Public Involvement:** Engaging the public in a participatory manner improves the project planning and assessment and will yield better outcomes for the project.
- **Opportunities for Ongoing Involvement:** Provide opportunities for interested or potentially affected parties to learn about the Project and provide inputs with respect to interests, concerns and opportunities. Where possible, work through the consultation process to resolve issues and enable participants to have inputs recorded at each stage.
- **Opportunities at Various Stages:** Before and after filing a Project Proposal for assessment, and during implementation as part of the adaptive management process provide opportunities for public input through such mechanisms as the YESAA review process, community meetings and the Mayo District RRC.
- **Provide Various Communication Mechanisms:** Provide a variety of mechanisms to communicate and interact with the public.
- **Required Consultation with Aboriginal Peoples:** Recognize the unique status of First Nations who may be affected if the Project is developed. In particular, discuss the location and effects of the Mayo Lake Enhanced Storage Project, which is located in the traditional territory of NND, and seek to involve the First Nation as a partner in the development of the Project.
- **Adaptive Approach:** Adjust the public involvement activities, as required and feasible, throughout the environmental review and planning and implementation process, in response to issues, concerns and challenges. Provide ongoing opportunities for input of local and Traditional Knowledge as part of the Adaptive Management implementation process.
- **Full and Fair Consideration:** Provide clarity on how submitted views and information have been considered and how they have informed Yukon Energy's project planning and assessment.

These principles are consistent with the YESAA intentions and guidance, which direct the proponent to provide notice of the proposed project in sufficient form and detail to allow the party (to be consulted) to prepare its views on the matter, a reasonable period of time for people to prepare their views and fair and full consideration of the views presented. It is expected that the public will have further opportunities to participate in the Project review during the Designated Office evaluation process.

Yukon Energy, in its consultation with NND, also took guidance from the First Nation's Guiding Principles Towards Best Practice Codes for Mineral Interests within Na-Cho Nyak Dun First Nation's Traditional

Territory (Appendix 4C). Among the goals and objectives delineated in this document that were particularly captured in the consultation process was[2]:

- **Keeping the Commitment Strong:** The parties are committed to working together to achieve environmentally sound and socially responsible developments.
- **Information Sharing:** The parties will ensure effective decision making though impartial sharing of accessible and accurate information in a timely manner.
- **Open Consultation:** The parties will work together to establish appropriate cooperative agreements that will encourage and provide opportunities for meaningful participation.
- **Protecting Environmental Integrity:** The parties are committed to protect and maintain environmental integrity and minimize the impact on the environment.

Yukon Energy also followed NND's Cooperative Engagement Process for Economic Activities Proposed in the Traditional Territory of the First Nation of Na-Cho Nyak Dun (2008), included in Appendix 4C. Protocol was followed to engage the Chief and Council and particularly the staff of NND and their advisors in the project planning (described in Section 4.4.1).

Yukon Energy's public involvement activities were guided in part by discussions held early in the feasibility stage of the Mayo Hydro Enhancement Project (Mayo B) with key stakeholders in the vicinity of Mayo (NND, Village of Mayo, and the MDRCC). These discussions were considered in the public involvement process. Additional opportunities for public consultation occurred between 2011 and 2014 prior to the filing of this Project Proposal. Further opportunities to communicate with the public after filing with the Mayo Designated Office will also occur. A detailed account of these activities and events are provided in Section 4.4 and referenced appendices.

4.2.1.1 Opportunities before a Filing of the Application

In February 2011, Yukon Energy re-introduced the Mayo Lake Enhanced Storage Project after conducting several additional studies after the Mayo B filing in 2009 to address deficiencies identified by YESAB. Since February 2011, Yukon Energy has provided several opportunities for stakeholders and the public to learn about the Project, as well as time to consider, prepare, and express their views. Where stakeholders expressed particular concerns, efforts were made to address the issues specifically and in as much detail as possible (based on the status of studies). Feedback was welcomed up to the date of filing, and will continue to be accepted and incorporated into the Project planning throughout the review by the Mayo Designated Office and the public. Where written feedback was submitted by an interested party, Yukon Energy acknowledged receipt and responded to the questions and concerns.

4.2.1.2 Public Communication of the Filing of the Application

Yukon Energy will communicate its filing of a Designated Office Project application under YESAA with the stakeholders identified in Appendix 4A. This will continue the open dialogue that has been established

[2] Since the guidelines were developed specifically for mineral development, not all of the goals and objectives are relevant – for example the goal regarding opportunities and capacity building which strives towards things such as "ensuring NND citizens receive the benefits derived from their mineral endowment".

with local stakeholders such as NND, the MDRRC and local residents to ensure that issues they may have identified about Project implementation are addressed.

4.3 METHODS

Several methods to facilitate public involvement were adopted for the Project. These methods were designed to ensure that Yukon Energy was providing information about the Project in a reasonable manner, as well as providing opportunity to receive information and perspectives from potentially affected and interested parties. The audience and methods used for communication varied and included face-to-face interaction, telephone conversations, and electronic and paper communication.

4.3.1 Face-to-Face Interaction

Face-to-face interactions with NND, stakeholders in Mayo, government, and other parties took a variety of forms depending on the desired level of interaction from the consulted party. Section 4.4 describes the various ways different groups were consulted and details of the activities that occurred.

4.3.2 Electronic, Paper & Other Media Communication

Electronic and paper communications were used to inform stakeholders and interested publics about the project. The details and contents of the project newsletter, posters and fact sheets are provided in Appendix 4B.

Mayo Projects Update Newsletter: Newsletters were produced to inform the community about the Project (see Appendix 4B). The June 2011 newsletter provided an update on the Mayo Hydro Enhancement Project (Mayo B) activities, a summary of the proposed Mayo Lake Enhanced Storage Project including the need for and benefits of the Project, regulatory approvals and reviews required, key studies to date, addressing potential effects and public involvement opportunities. Copies were mailed to identify potentially affected or interested stakeholders, as well as used throughout public involvement activities. The newsletter was also inserted into all Village of Mayo post-boxes and posted on the Yukon Energy website (see Section 4.3.2.3). An October 2014 newsletter provided an update on the Mayo Lake Enhanced Storage Project, and was handed out at the community open house October 28, 2014.

Mayo Lake Posters and Fact Sheets: Project-related posters and fact sheets were developed based on results from additional technical studies and environmental field work, and socio-economic and public consultation activities; and were used at the community meal and information sessions held in Mayo during June 2011, October 2011 and October 2014 (see Appendix 4B).

Yukon Energy Website: In June 2011, Yukon Energy created a link on their website posting a brief description of the Project and providing links to the electronic version of the newsletter. The website was subsequently updated in 2014[3].

Event Notification: To inform the community of public involvement activities, flyers were posted in various locations throughout the community. This included postings at the NND offices, MDRRC offices, and the

[3] http://www.yukonenergy.ca/energy-in-yukon/our-projects-facilities/hydroenhancement/mayo-lake-enhanced-storage-concept.

local Yukon Energy office. Local resource users and placer miners received invitations for their respective meetings.

4.4 REVIEW OF PUBLIC INVOLVEMENT ACTIVITIES

The following sections summarize public involvement activities with various groups of stakeholders. Appendices 4C, 4D, and 4E provide meeting notes and supporting materials used during meetings. In many instances, the same materials were used with different stakeholders. As such, some materials are cross-referenced to the first location in which they appear.

4.4.1 Activities Involving NND

Activities involving NND focused on three primary groups: 1) Chief and Council, 2) the Lands and Resources Department, and 4) NND citizens[4]. A summary of these activities, presentation materials used and meeting notes produced are provided in chronological order in Appendix 4C[5]. Methods of interaction are summarized below.

1. **Meetings with Chief and Council:** As per the guidance provided in the Cooperative Engagement Process for Economic Activities Proposed in the Traditional Territory of the First Nation of Na-Cho Nyak Dun (NND, 2008b), protocol was followed to engage the Chief and Council, and subsequently the Lands and Resource Department. This included a written request for a meeting with Chief and Council during the Mayo Hydro Enhancement Project (Mayo B), a subsequent initial meeting between YEC and the Chief and Council in spring 2011 related to the Project, and finally in a formal engagement process related to the Project.

2. **Meetings with NND Lands and Resources Department:** The Land and Resources Department for NND acted and continue to act as a major point of contact for public involvement. Meetings have been held in both Mayo and in Whitehorse in order to discuss the proposed Project, associated field studies, and proposed mitigation measures with NND staff and its consultants. Where appropriate, NND Lands and Resources staff identified other relevant NND departments (e.g., Heritage) and community members to participate in meetings (e.g., resource users). Joint discussions between the Steering Committee and the Technical Working Group (both committees were established under the NND/YEC Project Agreement; the TWG has representatives from NND Lands and Resources Department), as well as meetings of the Technical Working Group itself were held periodically to share and discuss different aspects of the Project. These groups were made up of NND members and technical advisors, as well as Yukon Energy representatives and consultants. A list of these meetings can be found in Appendix 4C.

[4] It should be noted that a Project Agreement Working Team was established during the Mayo B Project. This group was tasked with working towards Project related agreements including the potential business and investment opportunities for NND related to the Project. This Working Team completed their activities during the Mayo B Project with the culmination of a Project Agreement.
[5] Activities in Appendix 4C focus on engagement since February 2011; for information related to public consultation on Mayo Lake associated with the Mayo B Project Proposal, please refer to Chapter 4 and associated appendices in the Mayo Hydro Enhancement Project filing with the YESAB Executive Committee.

3. **Meetings with NND Membership:** Although the majority of contact with NND focused on the Lands and Resources Department through the Technical Working Group, efforts were also made to inform NND membership about the Project. This included invitations to community meal and information/open house sessions, which were targeted not only at NND, but included the entire community of Mayo. The June 2011 newsletter was also provided to local NND Membership through insertion into post boxes in Mayo.

Various other personal communications occurred with NND Government representatives, largely to facilitate public involvement activities; however, some of these interactions also enhanced the level of understanding about the socio-cultural setting and resource use in the region, as well as the key community interests and concerns regarding the Project. These communications were accomplished in person, by telephone and by email.

4.4.2 Activities Involving Local and Municipal Government, Regional and Local Resource Management Organizations, and Other Governments

Activities with local stakeholders were focused on the Village of Mayo Mayor and Council, and the MDRRC. A summary of these activities, presentation materials used and meeting notes produced are provided in chronological order in Appendix 4D (focusing on activities since February 2011).

1. **Village of Mayo:** Meetings were offered to key staff from the Village of Mayo as well as with the Mayor and Council. These meetings were intended to focus on informing the Village of the Project; and to understand the key issues and concerns that arose from a municipal perspective.
2. **Mayo District Renewable Resource Council:** In addition to meetings with the MDRRC associated with the Mayo B proposal, Yukon Energy met with the MDRRC on October 4, 2011. The meeting focused on informing the MDRRC of the Project as well as to understand the Council's key issues and perspectives. Members of the MDRRC also participated in the project workshop on January 24, 2014. This workshop provided participants with a summary of Project activities that had taken place to date. In addition to the January 2014 workshop, in-community meetings with the MDRRC took place in Mayo on November 13, 2013 and October 28, 2014 prior to filing the YESAB submission.
3. **Other Governments:** Yukon Energy met with interested territorial and federal government departments to discuss details, potential effects, and concerns of the Project. During June 2011, representatives from the Department of Fisheries and Oceans (DFO), Yukon Government (Environment and Fisheries) and the Yukon Environmental and Socio-Economic Assessment Board (YESAB) were invited to a one-day Project introduction meeting (Whitehorse) and a two-day workshop that focused on detailed discussions on project description, valued components and fieldwork studies (Mayo).

   Yukon Energy met with Yukon Government (Environment and Fisheries) in January 2012 to discuss concerns raised by Yukon Government representatives. Yukon Energy also met with representatives from the Canadian Wildlife Service in July 2011 to discuss Project details, mainly focusing on aquatic studies and waterfowl.

   On September 7, 2012, a follow-up meeting was held for the same group of regulators that attended the June 2011 sessions. The purpose of this workshop was to provide an update on

developments of the Project. Prior to the workshop, an orientation session was held for YESAB representatives to update new members to the Mayo Designated Office team who were not familiar with this Project.

An additional workshop was held for regulators on December 19, 2013, to update participants on Project activities that had occurred since the group last met in September 2012. A follow-up session was held on January 24, 2014 for those who were unable to attend the December workshop.

Appendix 4D provides a summary of activities, presentation materials used and meeting notes produced.

4.4.3 Activities Involving Local Stakeholders and Other Publics

Consultation efforts also sought feedback from various local stakeholders, non-government organizations, and private citizens. See Appendix 4E for meeting notes and materials.

Local Stakeholders

Various key person conversations occurred during the Mayo Hydro Enhancement Project (Mayo B) consultation process in 2008. Additional follow-up focused on a resource users' workshop held in Mayo in October 2011 to further discuss key issues specific to the Mayo Lake Enhanced Storage Project. In addition, a meeting was held with local placer miners in October 2011 to discuss potential Project-related effects and concerns.

Efforts were taken to notify potentially interested publics about the consultation events associated with the Project. For example, a notification letter and newsletter were sent out to all trappers, placer miners, lease holders, and landowners in the Mayo area to inform them about the Project.

Other Publics

During the Mayo Hydro Enhancement Project (Mayo B), not all of the identified organizations/individuals with potential interest in the Project felt that holding a meeting was necessary as they had no major concerns. For this reason, consultation with other publics was based on interest shown during the 2008 public involvement process.

On July 6, 2011, Yukon Energy met with the Yukon Conservation Society as part of its public involvement process. Yukon Energy agreed to a follow-up meeting and returned to meet with the Yukon Conservation Society on October 7, 2011.

Community Dinner and Information Sessions

On June 22, 2011 Yukon Energy hosted a community meal and information session for local stakeholders in Mayo, including residents of the Village of Mayo and surrounding areas, as well as NND and MDRRC to re-engage the community on discussion focused on the Mayo Lake Project[6].

This event was designed not only to provide the current understanding of the Project and its components, but to describe what was known about potential effects to date. This event was attended by 35 community members, not including Yukon Energy employees and consultants. Attendees included

[6] Community information sessions were also held under the Mayo Hydro Enhancement Project; see previous YESAB filing for details.

representatives from the MDRRC, YESAB, local resource users and placer miners, and the community at large. Yukon Energy gave a PowerPoint presentation on studies undertaken to date. Newsletters, posters and fact sheets providing more detailed information on the Project were available at the event.

During the June community meal and information session, Yukon Energy committed to hosting a follow-up community session focused on questions and concerns identified at the June session.

The second community dinner and information session was held on October 6, 2011, which included a presentation on additional Project study information, specifically on mitigation, monitoring, and adaptive management, as well as to address concerns raised during the first public meeting. The event was attended by 36 participants including community members, representatives from the MDRRC, and town leadership (total does not include Yukon Energy employees and consultants). Materials from these events are provided in Appendix 4E.

In January 2014 at the workshop with Yukon Government and representatives from the MDRRC, a commitment was made to hold another update meeting in Mayo prior to filing the YESAB submission. An open house was held on October 28, 2014 where a series of Project posters were displayed and the Project environmental assessment team was on hand to speak to questions and concerns. The open house was attended by 17 community participants including members of the MDRRC, NND and the community at large. Materials from this event are provided in Appendix 4E.

4.5 INDEPENDENT ADVISOR REVIEW

In November 2012, the Technical Working Group (TWG) hired Dr. Drew Bodaly as an independent advisor to the TWG to provide expert advice on:

- The potential risks of long-term harm to the lake trout and lake whitefish populations and the fish community from the project;
- The suitability of the monitoring and adaptive management (AMP) plans as a means of addressing and managing uncertainties with respect to potential lake trout and lake whitefish responses to the Project; and
- The ability of the monitoring and AMP to detect unacceptable biological impacts within the context of the adaptive management plan of incremental changes over several years (as proposed by NND) in contrast to larger changes over a short period of time as included in the proposed project (as proposed by Yukon Energy).

The TWG held two workshops with Dr. Bodaly to discuss the Project and the process and expectations of him in his review and provision of expert advice (November 2012); and to review and discuss Dr. Bodaly's draft report (February 2013). At the same time, Yukon Energy's team presented a proposal for changes to the monitoring program to address concerns raised by Dr. Bodaly in his draft report which included interim methods (hydroacoustics) in addition to the originally proposed monitoring of young-of-the-year and adults.

Conference calls and email correspondence with Dr. Bodaly also occurred in a transparent manner (i.e., all members of the TWG received information concurrently). Yukon Energy's team as well as NND's team

provided comments on the final draft report prior to Dr. Bodaly's submission of the Final Report to both parties in March 2013.

Conclusions from the independent advisor process are discussed in Chapter 6. A copy of Dr. Bodaly's final report is provided in Appendix 6B.

4.6 KEY ISSUES AND PERSPECTIVES HEARD TO DATE

Participants in the public involvement activities provided a wide range of issues and perspectives over the course of consultation activities. Some concerns were very specific, while others were more general. Some similar perspectives were raised on numerous occasions, while others were only cited by a single individual or organization.

Key interests, concerns, and perspectives raised during the public involvement process to date have been considered by Yukon Energy and incorporated in the Project design and effects assessment process, where applicable and/or feasible.

Table 4-1 provides a summary of specific issues raised during the public consultation process, including issues not directly related to the proposed Project. Stakeholder concerns are documented in the meeting notes presented in Appendices 4C, 4D, and 4E.

In addition, the following list highlights some of the areas where public influence resulted in refinements to the Project.

- Project Description:
    - Yukon Energy originally proposed operating the lake with a full 1 m storage range, with unconstrained use as required on an annual basis at the start of Project approval and licensing. Through discussion at the Technical Working Group, and hearing concerns raised by regulators, MDRCC and the community of Mayo, the Project Description was amended to incorporate a more restrictive operating range at the start and following measures outlined in the Adaptive Management Plan (see Chapter 6 for a full description). This resulted in the Project being proposed with a start at a half meter lowering of the LSL to 3.09 m for the initial years of Project operation, after which the AMP would be used to determine if and how to proceed with the full metre extra storage or if the storage range should be reduced.
    - The definition and details of the Project's Monitoring Plan and the Adaptive Management Plan were iteratively revised based on discussions with the Technical Working Group, regulators and the MDRRC. In addition, due to voiced concerns about different project approaches and whether the monitoring plan and AMP were robust enough to detect change, the Technical Working Group hired an independent expert to provide his opinion on the plans (see Chapter 6 for further details on the independent review).
- Lake Trout and Lake Whitefish Concerns:
    - Yukon Fisheries had specific concerns/questions related to the study design, statistical validity of the results and the ability to detect changes in abundance of juvenile and adult

fish. As a result, Yukon Energy made numerous changes to study design and monitoring methods to address these concerns.

- Various parities indicated concern with the lack of interim monitoring of fish populations between young-of-the-year and adult life stages. As a result, Yukon Energy updated the monitoring plan to include monitoring of sub-adult fish (via hydroacoustics and small-mesh netting).
- Questions were raised regarding how Yukon Energy would react in the event of long term small reductions in fish recruitment and productivity. The Adaptive Management Plan was revised to include an evaluation that will be undertaken after several years of data collection to identify whether incremental changes are occurring.

- Beaver:
  - Concerns were raised by the MDRRC and local community members and trappers over past and future water level effects on the beaver population around Mayo Lake. Additional fieldwork undertaken as part of the 2014 studies confirmed that the current water level management regime provides limited opportunity for beavers to overwinter in the main body of Mayo Lake under the current management regime. However, there is extensive beaver habitat in tributaries to the lake (including Roop Lakes) and these areas will continue to provide suitable habitat despite water level management on Mayo Lake that will likely adversely affect beavers in the lake proper. Therefore from a regional population perspective, there will be no significant adverse effect on the regional population of beavers.

Table 4-1: Interests and Concerns Raised by Stakeholders and Members of the Public and Areas where Feedback from Public Involvement Activities was Considered in the Environmental and Socio-Economic Assessment Process

Issue/Topic	Interest/Concern Raised	Response
Access – placer claims	General concern from local placer miners regarding the difficulties with accessing the land adjacent to their placer claims when water levels are low especially in early spring.	Operation of the lake will, on average, be lower in the late spring prior to the freshet. However, this often coincides with ice still being on the lake, thus preventing access to properties around the lake. In years when the ice has melted early, access may be affected for a short period of time (i.e., two weeks or less).
	Interest in the possibility of compensation for local placer claims.	Means of mitigating access delays to the lake will be mitigated by access improvements if the project creates significant adverse effects. This may include facilitating discussions with DFO around creation of rock groins and/or landings at claim shoreline.
Access – barge landing, boat launch, individual properties	Local resource users of Mayo Lake expressed interest in either relocating (beyond Ping Pong Creek) or replacing (closer to the main channel) the existing barge landing.	Access delays to the lake will be mitigated by access improvements in the channel if the project creates significant adverse effects.
	General concern was expressed regarding the proximity of the existing boat launch to the Mayo Lake Control Structure. The current location poses a potential safety issue for anyone caught in a current and their engine fails.	Dam safety boom was installed upstream of the Control Structure to ensure boating safety in this regard.

Issue/Topic	Interest/Concern Raised	Response
	It was indicated that for two consecutive years (2010, 2011), it was difficult getting barges to the landing due to lower water levels. There is concern that drawing the lake down further will exacerbate these issues and cause them to occur more frequently.	In general, the lake will be operated at a lower elevation (closer to the new Low Supply Level) on an annual basis. In particular, the lake will be drawn down during the winter months, when there is still ice on the lake. The period of time that water levels are expected to be at their lowest is relatively short, often when ice is still on the main lake, and right before lake levels rise with the spring freshet. Access delays to the lake will be mitigated by access improvements in the channel (e.g., improved boat launch, barge landing) if the project created adverse effects.
	It was indicated that at lower water levels, remaining tree stumps are present in the outlet channel causing safety issues (e.g., near the boat launch and barge landing).	If dredging of the outlet channel is undertaken, a deep water channel will be restored. This will facilitate easier access. If other mitigation is required, tree stumps near the boat launch and barge landing could be removed at the time of dredging to ensure easier access within the channel. Yukon Energy will consult with NND, the Village of Mayo Council and MDRRC on whether tree stump removal is required.
Adaptive Management	Defining adaptive management (e.g., what does Yukon Energy mean by adaptive management).	Adaptive Management is a decision process that involves learning by doing where there is minimal risk of serious, irreversible harm from a management action. It is not a 'trial by error' process. In the event that a change occurs in the lake that extends beyond natural variability and results in substantive adverse effects to the valued component, Yukon Energy will respond by implementing the Adaptive Management Plan, which is dependent on annual monitoring results.

Issue/Topic	Interest/Concern Raised	Response
	Several stakeholders expressed concern that Yukon Energy could have the ability to change the Adaptive Management Plan to favour its own interests.	Regulators (YWB and DFO) have the legal mandate for water management and fish habitat management respectively and will make the ultimate decision in approving the overall Project, including whether the Project can be implemented and under what conditions. Yukon Energy expects that the Adaptive Management Plan will be entrenched in their water licence, which will require the corporation to follow the plan. The Mayo Lake Project Management Committee (MLPMC) will be formed as a result of this Project and will include representatives from Yukon Energy and NND with an Advisory Group which may be comprised of the MDRRC and regulators (YG-Fisheries and DFO) (see Appendix 8B).
Adaptive Management Plan – reporting and decision-making	Concern was expressed by the Mayo District RRC over timely access to information and involvement in decisions.	If the Project proceeds, Yukon Energy will work with NND, MDRRC, stakeholders, and regulators during the monitoring and adaptive management processes to review results. This includes an annual meeting with the MDRRC to report on monitoring results and provide opportunity for local and Traditional Knowledge observations and input. The AMP provides for a cooperative oversight committee, independent monitoring and analysis, external reporting to regulators, the MDRRC and the public, and consultative decision-making regarding changes to the project that may be necessary over time. All results will also be available in annual reports that will be publicly available.

Issue/Topic	Interest/Concern Raised	Response
Alternatives to the Project	Has Yukon Energy considered raising the lake instead of lowering it?	Yes, raising water levels at Mayo Lake was considered during the early stages of assessment. However, it was found that raising the lake would impact heritage resources, increase erosion activity at the west end of the lake and encroach on NND settlement lands. For these reasons, this alternative was rejected. The following illustrate the assessment conclusions – for more detail, please see Appendix 5D (heritage) and 5B (erosion). **Heritage** If the lake level was increased, the heritage assessment indicated that all resources with elevations of 2 m (or within active erosion) would likely be impacted by current and increased wave action and soil loss. **Erosion** In general, raising the FSL by 1 m is expected to result in increased bluff recession rates, particularly at locations that are undergoing active bluff recession under existing conditions (bluff recession rates may return to current rates, or even reduced rates due to increased wave energy dissipation caused by a higher water level fluctuation range across a wider near-shore slope).
Climate Change	A general concern regarding the effects climate change is having on Yukon's bodies of water. It was suggested that creeks are already drying up and water levels are lower than in the past, resulting in fish dying.	Drought years are likely to occur but rules will be instituted to regulate the operation of the lake. Management of the lake will be adjusted while adhering to the rules to account for effects related to climate change. As noted in Chapter 7, Effects on the Environment on the Project, climate change models are predicting increased precipitation. Impacts to VC's from climate change will be detected through ongoing monitoring and adjustments made to water management as prescribed in the Adaptive Management Plan.
Confidentiality/Site Sensitivity	Discussions occurred regarding the Project Proposal potentially revealing information on "good fishing" or "great hunting" locations.	Yukon Energy is sensitive about disclosing information on specific sites used for resource activities in order to protect fish/wildlife. The District Office has rules and processes for keeping information confidential. For this reason, and following the rules established, Yukon Energy will discuss with YESAB that any reports containing this sensitive information be kept confidential.

Issue/Topic	Interest/Concern Raised	Response
Costs and Benefits	Concern that benefits from the Project will not be experienced by ratepayers, but instead be absorbed by Yukon Energy.	As discussed in Chapters 6 and 7 of this application, project benefits are expected to be realized by all utility ratepayers when new industrial loads and on-going domestic load growth can be serviced through additional renewable generation capacity on the system. There will be long-term benefits of providing a lower cost (relative to diesel generation) renewable energy and improving grid reliability. Project effects are expected to be positive, long-term, moderate in magnitude, and expected to extend to the whole of Yukon.
	Concern that the Project will only increase costs for ratepayers.	This Project does not involve any capital costs as there is no associated construction activity; the only cost is associated with the assessment and regulatory process. There will be greater cost to ratepayers if this project does not proceed as Yukon Energy will have to use more expensive diesel generation to meet the demand.
Ducks, Geese and Migratory Birds	Concern about effects on nesting and staging areas at the ends of Roop and Nelson arms with the lower water levels. Will the amount of habitat in the early spring at ends of Roop and Nelson arms change at the time when waterfowl require this habitat.	With the Project, water levels will on average, be lower during the spring. In some years, this may result in changes in the availability of staging areas for migratory birds at the ends of Roop and Nelson arms which are open relatively early during the spring. It is expected that suitable staging habitat will remain in these areas; however, there may be shifts in the relative amounts of habitat types (mudflats, shallow water, deep water). It is expected that the end of Nelson Arm will see less shallow water areas (<2 m) and more mudflats and the end of Roop Arm will see a more shallow water habitat (<2 m). Other wetlands in the region (including Roop Lakes) will not be affected by water level management on Mayo Lake and will continue to provide suitable staging area for migratory birds (see Appendix 5A for more detail).
Effects of the Project on Other Yukon Lakes	Questioned if Wareham Lake is expected to be lowered an additional metre with a 1 metre drawdown at Mayo Lake.	The Mayo Lake Enhanced Storage Project will not affect licenced water levels at Wareham Lake. Wareham Lake has its own regulated levels for the purpose of power production at nearby power plants.

Issue/Topic	Interest/Concern Raised	Response
Erosion	Concern related to erosion occurring on the west-end banks of the lake and the potential for the Project to intensify this problem.	Yukon Energy expects average lake levels will be lower by approximately 0.2 to 0.5 metre during the most prominent windy season (October) on average as a result of the Project, which will help reduce the process of erosion (see Appendix 5B – Appendix 6 of the Erosion Summary Report states that lowering the lake by up to 1 m is "expected to result in lower shore erosion rates for the lower license limit simulation as compared to the base case" (which is the existing conditions)). Any potential re-suspension of sediment that may occur (particularly in areas that have not been typically exposed under current conditions) will be monitored post-Project through turbidity loggers (see Appendix 8A – Monitoring Plan).
	It was suggested that Yukon Energy was not doing an adequate job at reacting to existing changes in Mayo Lake, particularly related to erosion issues. The Mayo River is now experiencing erosion issues and no actions have been taken, causing the problem to only get worse.	As stated above, Yukon Energy expects average lake levels will be lower by approximately 0.2 to 0.5 metre (on average) as a result of the Project, which will help slow down the process of erosion on the lake. Any erosion issues related to the Mayo River are not solely attributable to water levels on Mayo Lake. There are considerable uncontrolled inflows between Mayo Lake and Wareham that affect erosion processes along the river. In addition, weather patterns (wind action), amount of precipitation and natural variability in river channels are factors in changing erosion. With the Project late winter flows in the Mayo River would increase relative to historic, but are well below peak spring/summer flows and are not expected to result in any adverse changes to existing erosive forces in the River.

Issue/Topic	Interest/Concern Raised	Response
Existing Water Licence	Several stakeholders questioned Yukon Energy's ability to assess the implications for fish populations given that they have not consistently used the full 2.59 metre range (existing licence) in the past. How can Yukon Energy know what will happen to the fish (and resource use activities) if Mayo Lake is drawn down an additional metre?	The index netting survey conducted in 2010 included the collection of data on older age classes of fish, some of which originated in years with drawdowns greater than 2.0 m. Since baseline studies began during 2008/2009, Yukon Energy has drawn the lake down more than 2.0 m in 2 out of 6 years and the minimum lake elevation during late winter has been below 2.0 m in 5 out of 6 years. Data collected on juvenile fish during these years has not indicated that the current water level management regime is negatively affecting juvenile fish survival and recruitment. For example, the 2012 year class of lake trout and lake whitefish showed the highest abundance since baseline studies began and during this year, the winter drawdown was 2.02 m and the minimum late winter elevation was 2.01 m below FSL.
Fish Passage (at Mayo Lake)	Interest was expressed regarding the potential to introduce a fish ladder, as a form of compensation, to help address connectivity issues between the Mayo River and Mayo Lake. There was also concern that the fish passage may never be built as it has been discussed in the past with no follow-up action.	Yukon Energy commissioned a sub-working group to conduct studies on Chinook salmon enhancement and a Mayo Lake fish passage at the Mayo Lake control structure. The current control structure will require replacement in the future. Over the next few years, Yukon Energy will need to undertake an economic and operational analysis to determine whether proceeding with passage before reconstruction (targeted for 10 yrs. +) would be a wise use of resources and a prudent expense to pass on to rate payers.
Furbearers (beaver, muskrat, otter)	Questions were asked regarding the effects of low water levels on furbearers and if Yukon Energy has conducted any studies to assess these effects.	Furbearers were part of the original Mayo B assessment; in addition, surveys of beaver lodges around Mayo Lake were completed in 2011 and 2014.

Issue/Topic	Interest/Concern Raised	Response
	Question about potential mitigation for beaver near Mayo Lake.	Through surveys of Mayo Lake during 2011 and 2014, a total of 14 beaver lodges were located on the shoreline of Mayo Lake. During the 2011 survey, there were two active lodges in the main body of Mayo Lake and 3 active lodges outside of the influence of the lake (Nelson and Roop watersheds). During the 2014 survey, one lodge was active and although not surveyed during 2014, the lodges in Roop and Nelson creeks are known to be active in the previous 3 years. It is possible that there may be some localized effects to beavers in the main body of Mayo Lake during years with larger drawdowns and/or lower spring water levels. This will likely result in the abandonment of beaver lodges in the main body of the lake in favour of more suitable overwintering habitats in tributaries to the lake. This issue was reviewed in the impact assessment from a regional perspective. Beaver is a regional species with habitat elsewhere within the Mayo Lake tributaries and upper Mayo River areas. Yukon Energy has determined that although the effect on beaver in Mayo Lake may be negative, it is not a significant adverse effect within the regional population.
	Interest in what effect additional drawdown from the Project would have on furbearers in the area.	It was noted that throughout consultation, beavers appeared to be the main furbearer concern in the area, given that other species are generally adaptable and use the Roop wetland system. There is a possibility that effects of the Project could exclude beaver from accessing their lodges/food caches in the main body of Mayo Lake and result in higher mortality rates due to increased predation. It is expected that any potential effects from a regional perspective would be insignificant; however, the effect on the local number of beaver immediately along the shoreline will be affected. The full range of the lake will not be used every year as Yukon Energy is committing to a 1-in-3 rest rule (see Chapter 6 for details), which will help alleviate some of the stress on beavers in Mayo Lake.

Issue/Topic	Interest/Concern Raised	Response
General concerns about the Project and Project Approach	Community consultation events in the summer and fall of 2011 showed an overall negative reaction to the Project, particularly the potential adverse effects on various environmental values.	Yukon Energy spent considerable time and effort on additional aquatic fieldwork and study in 2012, 2013 and 2014 to be able to better understand Project effects. In addition, the Technical Working Group worked through changes to the Monitoring Plan and the Adaptive Management Plan (AMP) to be more responsive to thresholds. Perhaps more importantly, the project design was changed to lowering the Low Supply Level (LSL) by 0.5 m for the initial years of the Project operation – resulting in a storage range of 3.09 m (the original is 2.59 m), after which the AMP would be used to determine if and how to proceed with the full metre extra storage (i.e., lowering the LSL to 3.59 m) or if the storage range should be reduced.
Lake Trout and Lake Whitefish	Most lake trout spawn at depths of more than 2.0 m, how will the Project affect egg survival?	Egg collector data collected from 2009 to 2014 indicates that the highest egg deposition is at depths of 2.0 – 3.5 m based upon the water level at the time of spawning. Four years of egg incubation studies have been conducted to determine how winter drawdown influences over winter egg survival. The results of these studies have indicated that lake trout eggs are resilient and some survival is possible despite being dewatered for a period of time during winter. For survival to occur, the eggs must be rewatered prior to ice off at the spawning area (during early June). Using this information, we have modelled the effect of the increased storage range on egg survival to help understand Project effects (see Appendix 5A for further detail).

Issue/Topic	Interest/Concern Raised	Response
	No matter what mitigation is undertaken by Yukon Energy, there will still be some decrease in (lake trout) egg survival.	It is possible that there will be some decrease in egg survival during some years; however, this does not mean that there will necessarily be corresponding declines in abundance of juvenile and older lake trout during such years due to density dependant factors and influences of other environmental factors. There will be a thorough monitoring and adaptive management plan in place to ensure that the effect of water level management does not reduce the long term sustainability and health of fish populations in the lake. In the case of lake trout, this includes a suite of monitoring methods to track the species at a variety of ages including: egg survival, young-of-the-year, large juveniles and adults. The monitoring and adaptive management plans ensure that effects, positive or negative, will be quickly detected and water level management adjusted as necessary to address unacceptable effects before long term harm could occur.
	Annual monitoring will only pick up catastrophic declines in survival.	Substantial improvements have been made to the monitoring program to ensure that there is an increased ability to monitor smaller changes in fish abundance and year class strength. Refer to a separate document for more detailed information on the power of the monitoring methods to detect change (see Appendix 5A for further detail). The AMP (Appendix 8B) also includes clauses aimed at monitoring long term small reductions to lake trout and lake whitefish recruitment. The proposed monitoring and AMP approach was reviewed by an independent technical expert who confirmed that with the approach proposed there was minimal risk to fish populations.

Issue/Topic	Interest/Concern Raised	Response
	When Yukon Energy does index netting again in 15 years, there is no way it will be sensitive enough to pick up effects of small ongoing declines in reproduction success and juvenile survival. Yukon Energy can set lots of thresholds for monitoring data, but they need to convince us that they can pick up anything other than a catastrophe.	The monitoring program has been updated to include a combination of SPIN and index netting to monitor adult fish populations. SPIN provides a more sensitive and timely method to track smaller changes in long term adult lake trout numbers. The addition of hydroacoustics (sonar) to the monitoring program will provide a more sensitive and timely method of monitoring older juveniles and sub adults (3 to 8 years old) with the ability to detect smaller changes in fish numbers (see Appendix 5A for further detail). Through the analysis of multiple sources of monitoring data, it will be possible to detect and address small ongoing declines of fish stocks in the lake. Very detailed data analysis and statistics have been conducted using the monitoring data to show the smaller changes in fish abundance and year class strength can be detected (see Appendix 5A for further detail). The AMP (Appendix 8B) also includes clauses aimed at monitoring long term small reductions to lake trout and lake whitefish recruitment.
	Will the amount of shallow water habitat in the early spring at ends of Roop and Nelson arms decrease at the time when juvenile whitefish require this habitat?	Using modelled lake elevation data, Yukon Energy has modelled the amount of shallow water habitat available at the ends of the arms during the spring (see Appendix 5A for further detail). During some years, there will be a decrease in this type of habitat at the end of Nelson Arm; however, there will be an increase in the type of habitat at the end of Roop Arm in most years. While the relative importance and productivity of this shallow water habitat in the two arms is not well established, the influence of water levels on lake whitefish rearing will be a key focus of the monitoring program to ensure that both Roop and Nelson arms continue to produce lake whitefish.
Local and Traditional Knowledge	A suggestion was made to include more local and traditional knowledge in the monitoring plan.	Yukon Energy has revised the monitoring plan to include ongoing collection of local observations across many aspects of the plan through regular MDRRC and community meetings. Collaborative review and discussion of the monitoring program results by all parties will bring together scientific, local and Traditional Knowledge to understand/interpret the results.

Issue/Topic	Interest/Concern Raised	Response
Mayo River – lower section	Concerns over existing winter flow issue (i.e., flooding and icing issues) within the Village of Mayo.	Changes to water management respecting winter flows will not proceed until resolution of the lower Mayo River winter flow issue is satisfactorily resolved.
Mayo River – upper section	Concerns over higher flows down the upper Mayo River, resulting in access issues for undertaking traditional and recreational activities.	With the Project in place, water flows in the upper Mayo River will be similar to the current regime during the majority of the year. Flows during the spring and early summer will on average be slightly lower due to the freshet being used to refill Mayo Lake. Summer, fall and winter flows will be very similar to the current regime with the exception of the late winter where the mid-winter flows will persist later into the year as a result of the increased storage range being used on Mayo Lake. Under the current regime, the late winter flows are often relatively low as the storage range is used up on Mayo Lake, and the flows are typically reduced to ensure that Mayo Lake does not go below the low supply level. A large proportion (approximately 40%) of the overall flow in the upper Mayo River originates from uncontrolled inputs from tributary streams including Duncan and Davidson creeks. Given the seasonal timing of these changes and the influence of uncontrolled flows from tributary streams, issues related to access along the river are not expected to occur as a result of the Project.
Moose	Are there anticipated effects to moose as a result of the Project?	Water level management on Mayo Lake may affect shallow water littoral habitat and shoreline vegetation, particularly at the ends of Roop and Nelson arms which are used as summer moose habitat. Effects to habitat are most likely to include a shift away from the moose's preferred aquatic plant forage (tall erect plants) to less desirable short plants. This effect is highly localized to the ends of Roop and Nelson arms and is determined to be not significant due to the large range of moose and the availability of other more productive habitats in the region which are not influenced by water level management on Mayo Lake (i.e., Roop Lakes).

Issue/Topic	Interest/Concern Raised	Response
Overall Health of Mayo Lake	General inquiries on the overall health of Mayo Lake compared to other Yukon Lakes.	The results of baseline studies conducted to date indicate that lake trout and lake whitefish populations are currently healthy (see below) and their abundance is within the range of other similar Yukon lakes. Based on the 2010 index netting data, there is no evidence of recruitment failure for either species and although there is some variability in year class strength and some evidence of cyclic patterns, these patterns are within the range observed in other Yukon Lakes based on similar index netting surveys during the 1990's and not appear to be tied to water level management. Species composition results from the 2010 index netting survey on Mayo Lake indicate that LT represent 40 percent of the total catch by number and 53 percent by weight while the values for LW are 47 percent of the total catch and 30 percent by weight. While highly variable between lakes, these values are within the range of other large Yukon Lakes based on index netting surveys conducted during the 1990's. In other large Yukon lakes, the abundance of these two species typically represents 80-90 percent of the fish community. The SPIN (Summer Profundal Index Netting) survey results from 2013 indicate that the CPUE and density of lake trout in Mayo Lake is relatively low but within the range of other large Yukon lakes with similar fish communities. Note there are few large/deep lakes that have been surveyed to date that are comparable to Mayo Lake. Both LT and LW populations in Mayo Lake are considered healthy based on good abundance of both old and young fish indicating regular and continuing levels of recruitment and survival to the adult stage under the past water management regime, which is indicative of healthy populations.

Issue/Topic	Interest/Concern Raised	Response
Other Fish Species	Interest was expressed in potential effects on other fish in the lake such as lingcod (burbot) and pike. There was concern that all of the attention was being focused on lake trout and lake whitefish.	Lake trout and lake whitefish were chosen as key focal species because they appear to be the most sensitive to water management change; and as the predominant predator and prey species are the main drivers of the fish community and lake productivity and ecology. The monitoring methods being used to monitor lake trout and lake whitefish will also collect incidental information on other fish species which may be used to monitor these populations over the long term.
	Concern that other fish species may not be able to access their spawning habitat in the Roop area under lower water conditions.	During field investigations, EDI has always observed a stream channel that connects the Roop Lakes area to Mayo Lake.
Public Consultation	During the June 2011 public open house, it was suggested that there was a need for better advertising of public events and that key methods of contact were not effective.	Yukon Energy has tried to address this concern for its open house held in the fall of 2011 and the fall of 2014 by working more closely with the MDRRC.
Recreational Activities (hunting, fishing)	Several local resources noted that Mayo Lake was experiencing an increase in harvesting activities. Ethel Lake has suffered from the effects of over-harvesting and resources users would not like to see the same happen to Mayo Lake. All lakes in the area are currently being over hunted. In the past, MDRRC have put restrictions on particular lakes to reduce hunting activity.	Yukon Energy is not responsible for managing harvesting activities. However, the assessment acknowledges the importance of understanding and monitoring fishing pressure and harvest and YEC is proposing to work with the MDRRC and the community of Mayo in this regard. The Project's monitoring plan includes a fish harvest study one year Pre-Project and then every 5 years post-Project. This harvest study will provide a measure of fishing pressure and harvest which will be used as supplementary data when analyzing changes in adult lake trout abundance over time.
Regional Economy	If Yukon Energy wants to lower water levels then power rates should be lowered as well for residents of Mayo.	Yukon Energy does not set rates based on increasing or decreasing water levels; rather on loads on the overall system. All rates are regulated by the Yukon Utilities Board.

Issue/Topic	Interest/Concern Raised	Response
Roop Lakes	Interest in KGS study on backwater effects.	KGS prepared a study on backwater effects in the Roop wetlands. A one-dimensional backwater model was developed along the reach of Roop Creek from Mayo Lake to approximately 7 km upstream to understand the backwater effects caused by Mayo Lake levels on the Roop lakes and creek in the wetlands area. A sonar survey, along with cross-sections of Roop and Edwards creeks and a water profile of Roop Creek were undertaken. Also, a variety of Mayo Lake water levels and Roop Creek flows were analyzed. It was determined that when water levels in Mayo Lake are high, there is a backwater effect on Roop Lakes which is more pronounced closer to Mayo Lake. When water levels in Mayo Lake are lower, there is no backwater effect and water levels in Roop Lakes act independently from Mayo Lake. With lower water levels anticipated as a result of the Project, Roop Lakes will be backwatered less frequently which will be more similar to pre-impoundment conditions. A copy of this study can be found in Appendix 5A.
Sharing of Information/ Project Communication		To address community concerns identified by NND and the MDRRC, Yukon Energy will designate a Project Liaison Contact person if this Project proceeds.
Trapping	Is Yukon Energy considering compensation for trappers?	Access to trapping activities at Mayo Lake will not materially change with the Project.

4.7 FUTURE STEPS IN PUBLIC CONSULTATION

Yukon Energy will make efforts to continue communication with stakeholders about the filing of its submission to YESAB through the Mayo Lake Enhanced Storage Project tab on its website. Opportunities for public engagement are also provided for during YESAB's review of the Project proposal.

CHAPTER 5
ENVIRONMENTAL AND SOCIO-ECONOMIC SCAN

TABLE OF CONTENTS

5.0 ENVIRONMENTAL AND SOCIO-ECONOMIC SCAN 5-1
5.1 OVERVIEW 5-1
5.2 EXISTING ENVIRONMENTAL SETTING 5-2
5.2.1 General Physiography, Surficial Geology/Soil Conditions and Climate 5-2
5.2.2 Water Resources and Aquatic Species in the Region 5-4
5.2.3 Vegetation and Wildlife Common to the Region 5-7
5.3 EXISTING SOCIO-ECONOMIC CONDITIONS 5-10
5.3.1 Population 5-10
5.3.2 Local and Regional Economy 5-11
5.3.3 Resource Use 5-11
5.3.4 The Social and Cultural Context 5-13
5.4 EXISTING AND PLANNED DEVELOPMENTS 5-14
5.4.1 The Existing Mayo Hydro Generation and Mayo Hydro Enhancement Facilities and Loads 5-14
5.4.2 Other Existing and Planned Development 5-15

LIST OF TABLES

Table 5-1: First Nation of Na-Cho Nyak Dun Chief and Council 5-11

LIST OF FIGURES

Figure 5-1: Mayo Lake Control Structure 5-1
Figure 5-2: Erosion Conditions along the Mayo Lake Shoreline 5-4
Figure 5-3: December 2014 Mayo Population Distribution 5-10

APPENDICES

Appendix 5A: Aquatic Environment
Appendix 5B: Mayo Lake Erosion Assessment
Appendix 5C: Existing Projects and Activities Considered in the Cumulative Effects Assessment
Appendix 5D: Heritage Assessment Reports

5.0 ENVIRONMENTAL AND SOCIO-ECONOMIC SCAN

This chapter provides a high-level environmental and socio-economic scan of relevant conditions in the vicinity of the Project, as required to address items set out in the Proponent's Guide Section 6.0, Description of the Existing Environment and Socio-economic Conditions. It is comprised of a summary of existing and known evolving conditions in respect of the following:

- Overview;
- Environmental Conditions;
- Socio-Economic Conditions; and
- Existing and Planned Developments.

5.1 OVERVIEW

The Mayo Lake Enhanced Storage Project is proposed to occur within an existing environmental and socio-economic setting that has seen considerable development and activity over a sustained period of time. Of particular note, a dominant feature of the existing conditions arises from the presence and operation of the existing Mayo Lake control structure. This facility was constructed in the early 1950s, retrofitted in 1988/89 and is currently owned and operated by Yukon Energy. It has been in operation for over 60 years (see Figure 5-1).

Figure 5-1: Mayo Lake Control Structure

The existing conditions provide key inputs for the selection of valued components, for the baseline analysis of each valued component (VC), for determining relevant projects to be considered in the cumulative effects assessment, and for the assessment of Project effects, cumulative effects and mitigation, which are detailed in Chapter 7.

Chapter 3 of this Project Proposal sets out the key geographic areas of focus for the assessment work.

Further detail in respect to the existing conditions is provided in the reports contained in appendices associated with Chapter 5 as follows:

- Aquatic Existing Conditions – Appendix 5A;
- Terrestrial Existing Conditions – Appendix 5B;
- Socio-Economic – Appendix 5C; and
- Heritage Resources – Appendix 5D.

5.2 EXISTING ENVIRONMENTAL SETTING

The Mayo region is situated within the Boreal Cordillera ecozone and is bordered to the north by the Wernecke Mountains and by the Stewart Plateau to the south. To the west of the Stewart Plateau is the Tintina Trench, a linear, geological fault and large valley. The topography around Mayo is characterized by tablelands and rolling uplands with wide u-shaped valleys (Smith et al 2004).

Vegetation and wildlife habitat around Mayo are influenced by elevation, slope, aspect, precipitation, fire cycles and permafrost. The following sections describe the general physiography, surficial geology, soil conditions, and climate of the Mayo region, as well as vegetation, fish and wildlife, and water resources in the area.

5.2.1 General Physiography, Surficial Geology/Soil Conditions and Climate

Mayo sits in the Selwyn Basin, a geological region characterized by chert, shale, and schist, which transects the Yukon, parallel to the Tintina Trench (Roots 2006). The Selwyn Basin has several granite masses with nearby gold-tipped veins rich in silver, lead, zinc and quartz. The mountains in the area are sedimentary and metamorphic rock, underlain and case-hardened by granite (Roots 2006).

In the Quaternary ice age, parts of central and western Yukon were uncovered by ice, and formed a cold, dry habitat corridor known as Beringia. Fossil evidence from Beringian flora and fauna are found around Mayo and present-day descendants of plants and animals from Beringia exist in the region (Burn 2006a). More recent glaciations which left deposits of sediment and moraine in the Mayo area were the McConnell glaciation and the Reid glaciation (Burn 2006b).

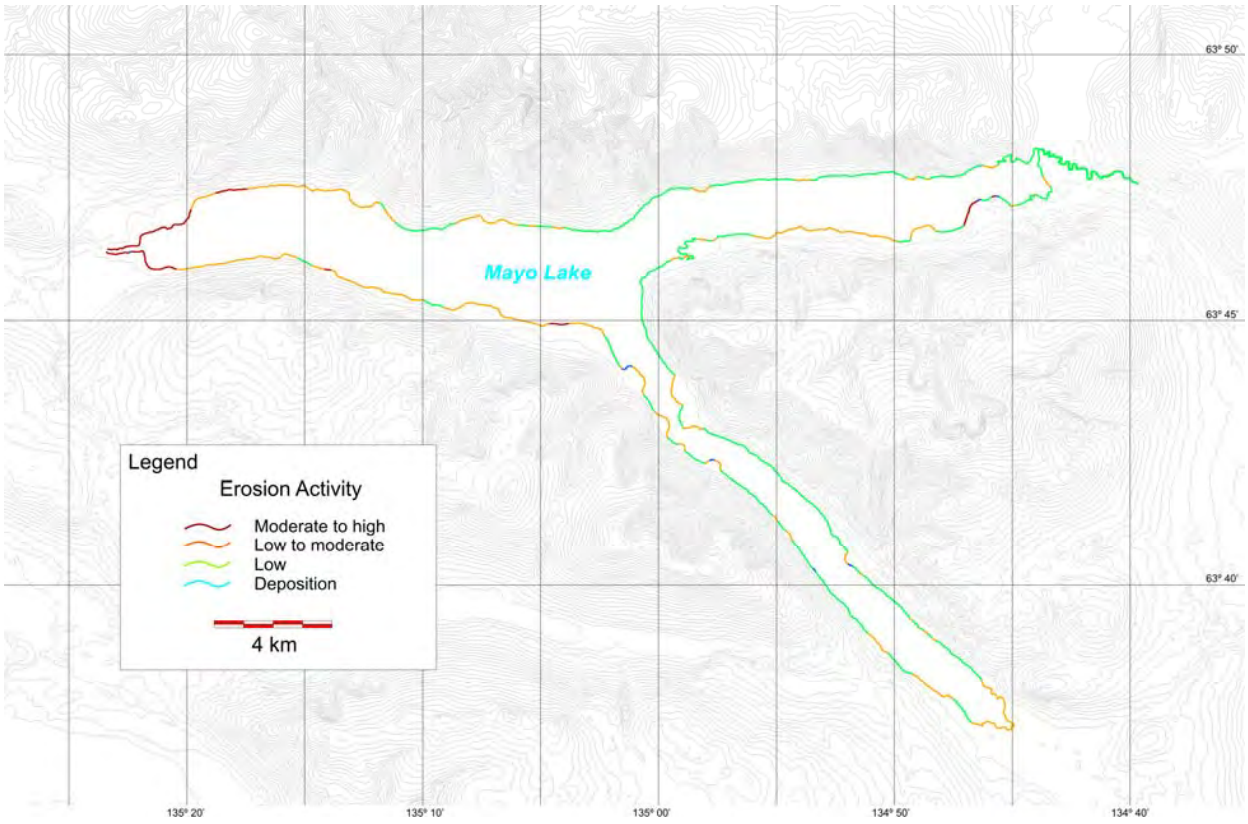
The Mayo region is underlain by discontinuous permafrost, which covers 50% to 90% of the ground below the active layer. The permafrost layer can thaw and cause sinking or slumping of the active layer (Burn 2006c).

The Mayo area is relatively dry and experiences extreme temperature variations and temperature inversions, where the higher elevations can be warmer than low lying valleys. There is relatively little

wind, save at higher altitudes. Average monthly temperatures measured in Mayo between 1904 and 2001 are -25.8°C for January and 15.4°C for July. About 42% of the precipitation in Mayo is snowfall, which begins sporadically in the late fall and leaves about 40cm on the ground by March. The melt period occurs primarily in May, and lakes and rivers in the valley bottoms flood in May and June. The summer is generally a season of higher precipitation than the spring, due to evaporation from lakes and transpiration from vegetation. April has an average monthly precipitation of 11.0mm, while the average for August is 47.1mm (Burn 2006d).

Mayo Lake was raised approximately 5 m (or 16.5 feet) when the original Mayo Lake control structure was built and began operation in 1952, flooding the adjacent shoreline and the lower portion of the Roop Lakes wetland complex. The flooding changed the habitat in areas flooded as well as the shallow littoral habitat within the lake (i.e., fish spawning and shallow rearing areas). Trees were not removed prior to inundation and standing dead trees remain in some sheltered areas of the lake. Flooding of the lake likely increased shoreline erosion and destabilization for a period of time. New shorelines that were more stable would have developed over much of the lake as a result of these erosion processes. Preliminary analysis of existing erosion conditions on Mayo Lake using topographic maps, photos and video evidence of the lake's shoreline areas indicates that the majority of the shoreline is characterized by relatively low bluffs that experience relatively low rates of erosion. About 26% of the shoreline has hard surfaces such as bedrock, which experience very slow rates of erosion (Refer to Appendix 5B). The remainder of the shoreline consists of varying types of sediment materials that are more susceptible to erosion, depending on water level and wave conditions. There is a wide range of materials in this remaining shoreline, including coarser sediments that are less susceptible to erosion, and fine-grained materials that are highly susceptible to erosion. The shoreline areas most susceptible to erosion on Mayo Lake are the bluffs at the west end of Mayo Lake. See Figure 5-2 for locations of shoreline areas most susceptible to erosion. Appendix 5B provides a more detailed analysis of existing shoreline conditions.

Figure 5-2: Erosion Conditions along the Mayo Lake Shoreline



Produced by J.D. Mollard and Associates Limited, 2008.

5.2.2 Water Resources and Aquatic Species in the Region

5.2.2.1 Water Resources

Hydrology

The Mayo River is located in the Stewart River basin that drains into the upper Yukon River. The headwaters of the Stewart River originate in the Wernecke and Hess Mountains. In the Project Regional Study Area, the Mayo River drains Mayo Lake, before flowing into the Stewart River just southwest of the Village of Mayo. Mayo Lake itself is fed by numerous creeks and tributaries, the largest of which are Roop and Nelson creeks, which flow into each respective arm (i.e., Roop and Nelson arms). Roop Creek has a large wetland area (Roop Lakes Wetland) just to the north of Roop Arm. Edwards Creek, another major tributary, flows into Roop Creek immediately upstream of Mayo Lake. Other smaller tributaries include Anderson, Granite (tributary to Roop Creek), Ledge, Cascade, Ping Pong, Steep and Owl creeks.

The peak discharge of water into the Stewart River drainage system occurs in May and June from snowmelt. Inflows slow considerably in July and August (depending on the year). There is relatively little natural lake storage in this region during the peak discharge. After the ground freezes in late fall and the surface is covered with snow, deep groundwater is the only ongoing source of water. Mayo Lake is typically ice covered by late November or early December and the lake is not completely ice free until

early or mid-June. The areas near the ends of Roop and Nelson arms, the narrows on Nelson Arm and the lake outlet begin opening up in early to mid-May.

Water levels on the Stewart River tend to peak between May 17th and June 25th, at times resulting in floods of low lying areas in the river's floodplain. Sediment loads in rivers are lowest in winter and highest during the spring runoff season. Freeze-up begins in October and is usually complete in December (Burn 2006e).

Flows in the Mayo River downstream of Mayo Lake are partially regulated by Yukon Energy for the purposes of power generation. Water levels on Mayo Lake are modified by the permitted operation of Mayo Lake as a storage reservoir, and releases are regulated by Yukon Energy except when the lake is at or above the licenced Controlled Maximum Level. Up to one-third of the Mayo River inflows to Wareham Lake come from uncontrolled local inflows downstream of Mayo Lake with natural unmodified seasonal flows. As a result, the lower Mayo River is still influenced by a notable spring freshet particularly due to inflows from two larger tributary streams (Duncan and Davidson creeks) located between Mayo and Wareham lakes.

Groundwater

The Project Regional Study Area currently experiences an active water table that results in groundwater exchange with surface water sources such as the Mayo River and Mayo Lake, and causes groundwater upwelling into back channels in many areas surrounding the Mayo River. During spring, summer and fall, groundwater can provide a cooling influence on surface water sources. In the winter, groundwater provides a warming influence that can keep areas of river environment from freezing. As a result, winter open water occurs in places on the local rivers, including the Mayo River. This groundwater effect can be seen by winter open water occurring in areas where the current is not otherwise fast enough to prevent ice from forming.

The lower portion of Edwards Creek, which empties into Roop Creek near Mayo Lake, does not freeze completely and as such, the stream can be difficult to cross during the winter months. The rest of the Roop Lakes area experiences extensive ice coverage, although small areas of groundwater discharge have been observed throughout the wetland complex. Open water was also noted in Granite Creek near its outlet to Roop Lakes, which may be an indication of groundwater inputs (EDI 2009).

Aerial monitoring of winter snow cover across the Project Regional Study Area during 2008 showed many areas in the main river channel and in back and side channels where groundwater had melted surface snow and ice, indicating the possible presence of groundwater influences in the specific location. Other areas with indications of groundwater influence are seen in the lower Mayo River (downstream of the Wareham Dam), as well as a high level of open water occurring near the outlet of Edwards Creek and a few small areas at Roop Lakes (EDI 2009).

See Appendix 5A for a more detailed discussion of groundwater in the Project Region.

Water Chemistry

Lakes in the Mayo region tend to have a neutral pH, buffered by calcium carbonate, which originates from local bedrock. Mayo Lake pH and nutrient levels in lakes in the region are generally low and overall

productivity is limited by lake size and depth (i.e., the amount of wetlands and shallow littoral area). Nitrogen levels are low and phosphorous levels are low to moderate in Mayo Lake making it less productive thus less capable of supporting zooplankton and phytoplankton (oligotrophic). These measures are within the range of other Yukon lakes in terms of productivity (Shortbreed and Stocker 1983).

5.2.2.2 Aquatic Species

The water bodies around Mayo are habitat for Chinook salmon, which are anadromous (i.e., they spawn and spend the first year of their lifecycle in freshwater before migrating to the ocean) as well as resident fish species, which complete their entire lifecycle in freshwater. Chinook salmon migrate up the Yukon River from the ocean and reach the Stewart and Mayo Rivers by mid-July/August. They spawn in tributary clear streams to the Stewart on gravelly river bottoms. The alevins hatch in the late winter/early spring and survive on their nutrient-rich yolk sacks for weeks until spring breakup and warming streams become more productive. Fry (yolk sack used up) can move into tributaries and smaller creeks and clearer larger streams to feed in the spring and summer. They rear in freshwater for a year before migrating down the Yukon River to the ocean. In four to seven years, Chinook salmon return as adults to the same rivers and creeks to spawn, and die shortly afterwards. The McQuesten River and the lower Mayo River (below Wareham Dam) are prominent spawning locations in the Stewart River Watershed. Historically, Chinook utilized all of the Mayo River (not just the lower portion). Access to the Upper Mayo River and Mayo Lake has been blocked by the Wareham Dam. Some Chinook reach the headwaters of the Stewart River upstream of Mayo, however, many do not get farther than Fraser Falls, about 60 km upstream of the village (O'Donoghue 2006a).

Lake trout, a non-anadromous char, live in the deepest, coolest lakes of the Mayo Region, including Mayo Lake, Janet Lake, Williamson, Minto, Ethel, Big Kalzas and Little Kalzas. They generally spawn in September on steep, wind exposed rocky shoal lake bottoms and hatch in the spring. Juveniles grow slowly and do not reach sexual maturity until they are between 10 and 12 years old. They can weigh over 25 kg, and are piscivorous, in that they mainly feed on fish including whitefish. Lake trout do not die after spawning and have a long lifespan of 30 – 40 years of age and may spawn 10 to 20 times or more in their life. Because Lake trout have high longevity and survival rates they often do not spawn every year, which allows them to divert energy resources into growth. In some lakes, the adults feed on aquatic invertebrates and remain smaller in size, and develop a reddish flesh (O'Donoghue 2006a). Lake trout are considered a sport fish and are often the primary target by anglers in Yukon.

There are six species of non-anadromous fish in the whitefish family around Mayo, including lake whitefish and round whitefish, which live in most lakes, larger rivers and creeks in the region. Least cisco are a smaller whitefish species that is found in some lakes and rivers. The inconnu is the largest whitefish in the region, and tends to live in rivers and is found in the Stewart and Pelly rivers, but is not very abundant anywhere. Broad whitefish are widely distributed in the Yukon River watershed including the Stewart and Pelly Rivers, but are not abundant anywhere. They are known to migrate relatively far to spawn, and to over-winter in larger water bodies (O'Donoghue 2006a). Pygmy whitefish are a small species of whitefish typically found in deep-water habitats of large lakes. Lake, round and pygmy whitefish are the only whitefish species currently present in Mayo Lake. Historic reports of 'lake herring' in Mayo Lake have lead to speculation of a historic occurrence of cisco in Mayo Lake (de Graff pers comm 2011).

Arctic grayling are also common in the watercourses around Mayo, especially in clear water streams. They spawn shortly after ice out during the spring in areas of moderate current and gravel/cobble substrates (McPhail 2007). While they are found in lakes (including Mayo), they are most prominent in clear water streams including tributary streams to Mayo Lake such as Roop, Edwards and Nelson creeks.

Northern pike are common in the Mayo area, especially in lakes and slower moving streams. They prefer shallow, warm weedy bays and areas, and lake shoals. They are mainly piscivorous, but can eat small mammals and waterfowl, and even other pike. Longnose sucker and burbot are also widely distributed in the area and in the Yukon, as is slimy sculpin, which is the fish with one of the most extensive geographical distributions in the Yukon and in the Mayo area, as they are found in virtually all creeks, rivers and lakes (O'Donoghue 2006a). Along with whitefish, slimy sculpin are also a common dietary item for lake trout in Mayo Lake (EDI 2011).

The construction of the Wareham Dam and the Mayo Lake control structure in the 1950s resulted in habitat fragmentation, impeding upstream movements of fish into the middle portion of the Mayo River and Mayo Lake. These dams blocked upstream fish migrations on the Mayo River including a known Chinook salmon spawning area near the outlet of Mayo Lake (Buchan 1993). There are some accounts of salmon being observed as far upstream as Roop Lakes prior to the construction of these dams (Buchan 1993).

Recent lake trout and whitefish spawning studies have indicated that adaptations have occurred in the years following the installation of the Mayo Lake Control Structure which raised water levels in the lake by about 5m. For example, lake trout are now primarily spawning in areas with clean rock and cobble substrates that would have been above the pre-impoundment lake level. Lake whitefish spawning have been documented in several areas including in tributary streams to Mayo Lake. Significant spawning outside of the lake may have been a response to the changes that have occurred to the lake in the past. Lake whitefish spawning has been documented elsewhere in Yukon lakes near river outlets, as well as in rivers and creeks (Bryan and Kato 1975).

5.2.3 Vegetation and Wildlife Common to the Region

5.2.3.1 Vegetation

Typical northern boreal forest within the Yukon Plateau-North ecoregion is present at elevations up to approximately 1,500 m with shrubs and lichen dominating in alpine areas (Smith et al. 2004). Extensive shrub lands are present at mid elevations and in valley bottoms due to cold air drainage. The most common forest type is comprised of open black spruce with a moist feathermoss understory or a drier understory comprised of lichens. On warmer and better drained sites, white spruce and occasionally aspen or lodgepole pine are present. Throughout the region, paper birch is found scattered throughout and is usually found in cooler locations. Due in part to the high frequency of thunderstorms within the region, forest fires are frequent and result in mixed canopy forests. The high incidence of fires often results in extensive stands of lodgepole pine and occasionally aspen. Steep, south facing slopes along the large rivers (including the Stewart River) within the ecoregion are inhabited by grassland communities which are remnants of the last glacial period.

The forests at lower elevations tend to include stands of balsam popular growing among white spruce, with an understory of willow, rose, Labrador tea, northern comandra, bluebells, and lowbush cranberry.

At mid-elevations, white and black spruce are populous, with the typical understory being willow, Labrador-tea and rose. Lodgepole pine grows in recently burned areas and in drier, sandier soils. Sub-alpine fir and black spruce are found in the lower reaches of north-facing slopes and paper birch also prefers ridges where the temperature is lower. Aspen can be found on warmer, south-facing slopes. Crowberry, blueberry and bearberry are also common boreal plants found in the area (O'Donoghue 2006b).

In the area along the Mayo River within the Project Regional Study Area, there are two wetland complexes north of Wareham Lake. The extensive Roop Lakes wetland complex on the north eastern Roop Arm of Mayo Lake, fed by the Roop and Granite creeks and the wetland at the south end of the Nelson Arm of Mayo Lake. While neither the Roop Lakes wetland nor the wetland at the southern end of Nelson Arm has a specific designation by Yukon Environment, wetlands are recognized as very important components in both aquatic and terrestrial ecosystems in the Yukon.

Larger wetland complexes in the Mayo area outside of the Mayo Lake and Mayo River areas are located along the Stewart River at Horseshoe Slough and at U-Slough. McQuesten Lake is also the site of a large wetland complex. Larger wetland complexes in the region tend to be a mixture of different wetland types. Horseshoe Slough has been designated a Habitat Protection Area under the Yukon Wildlife Act and is described in the Na-Cho Nyak Dun Final Agreement. The *Community Based Fish and Wildlife Management Plan*, *Na-Cho Nyak Dun Traditional Territory* (NND and Wildlife Planning Team 2008) identifies Devil's Elbow along the Stewart River as an important moose calving and waterfowl nesting site.

5.2.3.2 Birds

The Tintina Trench, west of the Mayo region, is an important migratory flyway for many bird species. Many migratory birds also nest in the area including numerous species of waterfowl, waterbirds, raptors, shorebirds and passerines. The assemblage of breeding birds in the Mayo area is typical of the Boreal Cordillera ecozone with a moderate level of diversity as compared to other areas of the Yukon. The majority of species in the area are migratory. Spring migration occurs from mid-April to early June and fall migration from late July until early October. Areas free of ice early in the season (such as the inlets and outlet of Mayo Lake) are important areas for staging waterfowl, waterbirds and shorebirds. Year round resident birds in the area are limited and include, grouse, owls, woodpeckers and some species of passerines.

Bird species of conservation concern (Committee on the Status of Endangered Wildlife in Canada) known or likely to occur within the Mayo region include the following: Horned Grebe (special concern), Peregrine Falcon (special concern), Short-eared Owl (special concern), Common Nighthawk (threatened), Olive-sided Flycatcher (threatened), Barn Swallow (threatened) and Rusty Blackbird (special concern).

The Yukon Government's Wildlife Key Areas (WKA) Database identifies only two key wildlife areas within the Project Regional Study Area:

- WKA ID 2726 for "unspecified raptors" – along the Mayo River from the Stewart River to 6km upstream of Wareham Lake;
- WKA ID 2734 for Bald Eagle – summer nesting at Roop Lakes, lower Edwards Creek and the eastern end of Roop Arm in Mayo Lake; and

- WKA ID 2727 for Golden Eagle along the Stewart River upstream of Mayo.

Bald Eagle, Golden Eagle, Northern Goshawk and Gyrfalcon are raptors living year round in the area, while Osprey, Red-tailed Hawk, Northern Harrier, Sharp-shinned Hawk, American Kestrel, Merlin and Peregrine Falcon are all summer residents (O'Donoghue 2006c). Peregrine falcon nest on cliffs, usually near water and may be expected to be found within the Project Regional Study Area along the lower Mayo River. A cliff nesting raptor survey completed within the Project Regional Study Area during July 2008 did not locate any cliff nests or evidence of nesting activity.

5.2.3.3 Mammals

Nineteen rodent species are resident in the Mayo region. Red squirrels are found in spruce or pine stands, and northern flying squirrels are found in dense, low elevation forests. Least chipmunks tend to live near waterbodies. Arctic ground squirrels and hoary marmots are often in the alpine tundra. Beavers are found in watercourses throughout most of the area, from lowland marshes to subalpine creeks. Muskrats are also found in creeks, rivers, streams and particular at wetlands. A number of smaller rodents, voles and shrews are also present (O'Donoghue 2006d).

Snowshoe hares tend to be found in dense shrub thickets near wetlands and shorelines, and in areas with regenerating vegetation in burns less than 30 years old. Porcupines are also found in the area. Red fox, wolf and coyote are abundant in the area. Coyotes moved into the area from the south around the turn of the twentieth century (O'Donoghue 2006d).

Least weasels and ermine live in the Mayo region, hunt small rodents, and tend to fluctuate in population. Marten are larger and live in old forests; while mink live near watercourses and wetlands. River otters are an aquatic member of the weasel family, common to the large creeks and rivers in the Mayo area. Wolverines are rarely seen residents. Lynx, another seldom-seen, local animal, stalk snowshoe hares in wet places where willows grow and in burned out forests. Lynx populations follow the snowshoe hare cycle (O'Donoghue 2006d).

Black bears and grizzly bears are resident, and are often sighted at the junction of the Mayo and Stewart Rivers. Black bears hibernate in forested areas, where they stay most of the year. Grizzlies hibernate on south-facing slopes at higher elevations, and tend to spend the summer and fall in the subalpine. The bears feed primarily on berries, plant shoots and roots, turning to fish and other animals, particularly when berries are scarce (O'Donoghue 2006d). Black bear scat and tracks were observed in the northern and western portions of the Project Regional Study Area.

Moose are widely dispersed in the Mayo area, with an estimated 200 animals per 1000km2. Calving occurs in late May in densely forested shoreline habitat, and the summer is spent feeding on plants and shoots in wetlands and along streams and creeks, or in recently burned patches. They mate in mid-September and then move to higher altitude willow thickets, where they form feeding groups, descending back into dense spruce forests along the larger rivers by mid-winter (O'Donoghue 2006d).

Caribou used to be more abundant within the broader Mayo region. The Ethel Lake and Clear Creek woodland caribou herds are the closest herds; however, neither frequent the Project Regional Study Area. Mule deer are often sighted along the Silver Trail highway between Wareham Lake and Stewart Crossing (O'Donoghue 2006d).

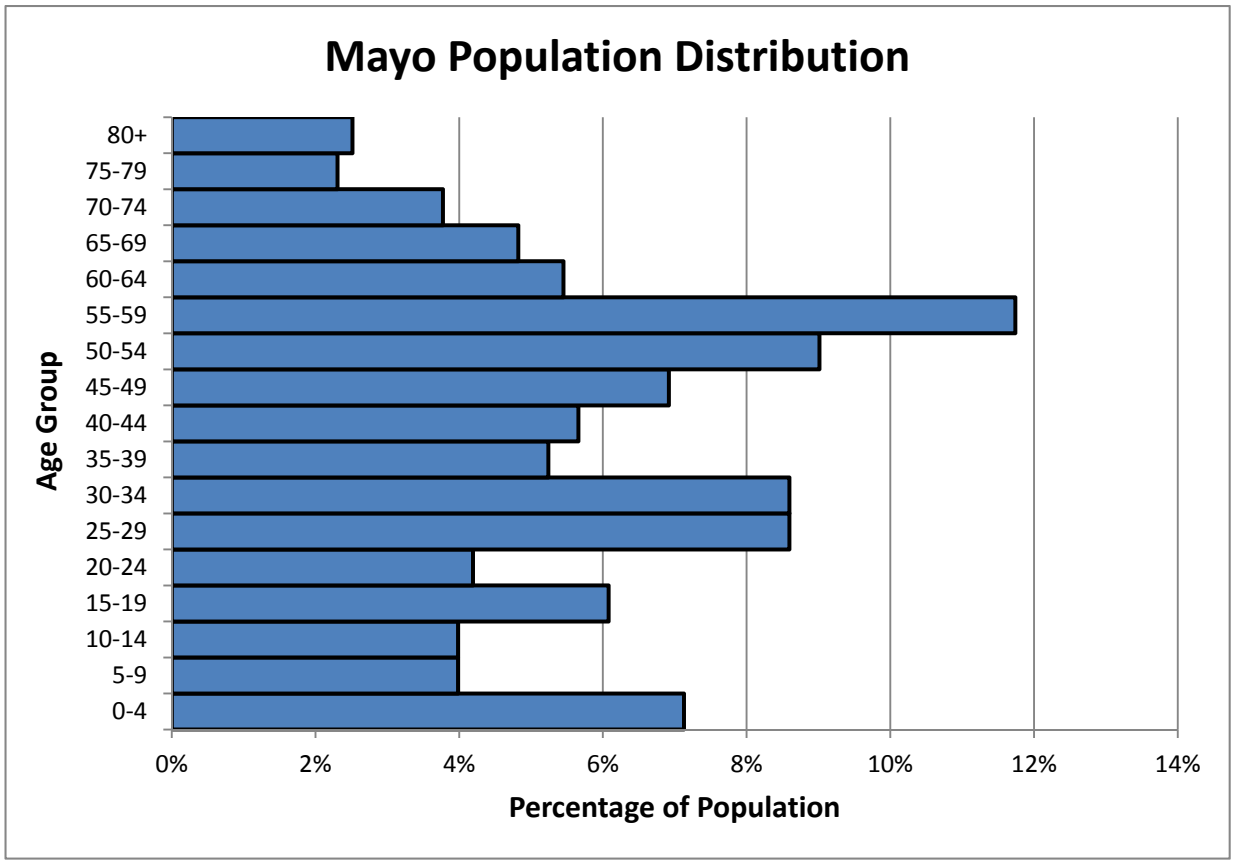
5.3 EXISTING SOCIO-ECONOMIC CONDITIONS

The dominant socio-economic conditions in the Project Regional Study Area relate to the Village of Mayo and the First Nation of Na-Cho Nyak Dun, as well as various resource-related developments. The following provides a high-level scan.

5.3.1 Population

As of December 2014, the population of Mayo was estimated at 477 residents (Yukon Bureau of Statistics 2014). Figure 5-3 provides a population breakdown by age group for the Village of Mayo.

Figure 5-3: December 2014 Mayo Population Distribution



Source: Yukon Bureau of Statistics, Population Report December 2014

The First Nation of Na-Cho Nyak Dun (NND) has a registered population of 547 members as of April 2015 (AANDC 2015), although many of the community members live outside of Mayo, including communities such as Stewart Crossing and Whitehorse. NND is governed by an elected Chief and Council who work under the First Nation Assembly of Na-Cho Nyak Dun, the body which has overall responsibility for First Nation government powers and responsibilities. The Assembly and the Chief and Council govern primarily by consensus. The Council is elected to a three-year term by a majority vote of NND citizens. The current Chief and Council are shown in Table 5-1.

Table 5-1: First Nation of Na-Cho Nyak Dun Chief and Council

Title	Surname	Given Name	Appointment Date	Expiry Date
Chief	Mervyn Sr.	Simon	03/19/2015	03/20/2018
Councillor	Hummel	Kalie-Ann	03/19/2015	03/20/2018
Councillor	Hutton	Melody	03/19/2015	03/20/2018
Councillor	Johnny	Irene	03/19/2015	03/20/2018
Councillor	Kottnitz	Mable	03/19/2015	03/20/2018
Councillor	Peter	Ronald	03/19/2015	03/20/2018
Councillor	Peter	Sharon	03/19/2015	03/20/2018
Deputy Chief	Olsen	Millie	03/19/2015	03/20/2018

Source: AANDC 2015 (First Nation Profiles).

5.3.2 Local and Regional Economy

Although NND have lived throughout the Mayo area for generations, the community of Mayo began to establish itself with the arrival of gold seekers in the late 1800s. The Village of Mayo was officially established in 1903 as a river settlement and port that served the transportation requirements of the mining industry in the Keno mining district. The 1950s marked one of the most active periods of silver mining in the region (Mayo Historical Society 1990) "Year round employment opportunities created by the expansion of the silver mines and the supporting businesses and government offices that sprang into service the mines, as well as jobs with highways and public works, road maintenance camps, and employment with the Northern Canada Power Commission all resulted in Mayo's steady growth as a community" (Bleiler 2006).

Though an important component, today Mayo is no longer a primarily mineral-based economy. The community has recognized that diversification is necessary, and is promoting options such as tourism to strengthen local activity. Accommodation, food services, guiding and outfitting, and retail services provide work for local residents. Government services, including First Nation, territorial, and municipal administration provide over a third of jobs in the community. Placer mining and mineral exploration continue to be part of the local economy.

5.3.3 Resource Use

The Project Regional Study Area is characterized by relatively moderate use of the local natural resources for domestic, traditional and commercial purposes.

5.3.3.1 Traditional and Domestic Resource Use

Hunting, trapping and fishing remain important to the community of Mayo and to NND for both traditional (socio-cultural) and domestic/subsistence purposes. The Mayo River and Mayo Lake are used both directly in terms of resource use, as well as indirectly by providing access to resource use areas.

Hunting and/or trapping for species such as moose, beaver and muskrat is common in the Project Regional Study Area; the Mayo River, Mayo Lake and Roop Lakes Wetlands offer varying degrees of access to hunting areas. Moose are a species of particular importance to the community and the 2008-2013 Community-Based Fish and Wildlife Work Plan (NND and Wildlife Planning Team 2008) indicated

that the 2006 moose survey "showed that the proportion of bulls is low (about 42 bulls/100 cows), reflecting the relatively high harvest (known harvest 3-4%) in the area" (NND and Wildlife Planning Team 2008).

Concern voiced through the public consultation program for the 2008-2013 Community-Based Fish and Wildlife Work Plan identified increased pressure on moose hunting within the broad Mayo region, including the Project Regional Study Area, primarily due to the voluntary closure of McQuesten Lake to moose hunting. While this closure is not being respected by everyone, it is forcing others to relocate and harvest at other sites (creating harvest issues at other lakes); as well as hunters not following "traditional laws" by harvesting more than what was needed (NND and Wildlife Planning Team 2008).

Fishing occurs at various locations along the Mayo River, as well as on Mayo Lake. Common species in the Study Region (particularly Mayo Lake) include lake trout, lake whitefish, northern pike, Arctic grayling, round whitefish and burbot (EDI 2011). Mayo Lake previously had commercial fishing, but this was closed prior to the 1990s. Prior to the closure, the annual commercial quota for Mayo Lake was 3,600 kg for all species combined and 1,800 kg species quota for lake trout. Prior to the 1990s, harvest records from 1974 to 1984 suggest two commercial licenses and up to 11 domestic licenses were issued annually. Lake trout were the primary target species with the maximum recorded yearly harvest of 160 kg in 1979-80. A more intensive fishery may have existed coincident with the mining activity at Elsa and Keno during the 1950s and 1960s. There is little recorded information with respect to harvests of freshwater fish from Mayo Lake by the First Nation subsistence or domestic fisheries. There is however, anecdotal information that suggests harvests were substantial (de Graff 2011). In addition, the outlet of Mayo Lake was the site of an important First Nation subsistence fishery for Chinook salmon prior to the construction of the Wareham Dam and Mayo Lake control structure (in the 1950s). Today, Mayo Lake remains an important fishing location for some members of NND and the community of Mayo. However, some officials with the NND government believe that fish populations in Mayo Lake are less robust and the outlet area can no longer support the former traditional uses (de Graff 2011).

Trapping within the area provides economic and sustenance benefits for trappers. The Project Regional Study Area in the vicinity of Mayo Lake and the Mayo River includes portions of registered trapping concessions ("RTC"s) #74, #84, # 85, #86, #89, and #407; the latter being a community trapping concession. Local stakeholders identified marten, lynx, mink, beaver and muskrat as species of importance for trapping. However, according to the 2008-2013 Community-based Fish and Wildlife Work Plan, there is a concern with trapping sustainability as fewer people are trapping (NND and Wildlife Planning Team 2008). Collection of berries along with other medicinal plants occurs throughout the Project Regional Study Area, including along the Mayo Lake access road and inland from the shores of Mayo Lake.

5.3.3.2 Other Resource Use

Although Mayo Lake is not heavily used by local residents (i.e., compared to other locations such as Ethel Lake), outfitting and outdoor recreation activities such as camping occur in Mayo Lake and in downstream Mayo River areas. The Project is located in Rogue River Outfitters' hunting concession.

5.3.3.3 Mining and other Private/Commercial Land Use

Historically, mining has played a major role in the Mayo area and continues to be active on numerous tributaries of Mayo Lake and Mayo River.

Placer mining typically begins with the spring thaw, and continues over the summer until the freeze-up in fall (approximately 120 days).The mouth of Mayo Lake is the site of leased properties where miners with claims along Mayo Lake launch their barges and boats. For a complete table of mining activity within the Mayo Lake and relevant Mayo River areas and for maps showing placer claims see Appendix 2 (2A, 2C and 2D).

Prior to 2014, there were two to three fairly active placer miners at Mayo Lake who accessed their claims during the summer by boat and barge; and if necessary, by snowmobile or truck in the winter (generally considered more expensive than using a barge). More recently, placer mining activity around the lake has diminished but there is at least one who continues to be active. The main season for placer mining activity is late May/early June up until late October – depending on ice and water levels. The water needs to have risen with the spring freshet to a point where the barges can float, and access at their placer claims is close enough to enable off-loading of equipment.

Special measures and restrictions for placer mining on Mayo Lake were developed in 2009 for the protection of fish stocks and fish habitat on the lake. These measures and standards are part of the placer management system and are implemented through fish habitat authorization under the Fisheries Act (Canada).

5.3.4 The Social and Cultural Context

Traditionally, NND "are known to have used many traditional camps, lookout sites, hunting areas, berry patches and trails in the larger project area with extensive use of rivers" (Ecofor 2010).

In 2008, a shoreline inspection of Mayo Lake revealed several prehistoric artifacts including items largely associated with traditional camps. First Nations people adapted to the dramatic changes that followed the early arrival of early explorers, traders, and later prospectors. Today, NND have taken elements of both First Nation and non-First Nation culture. While people are more often educated and employed in the mainstream system, they continue to practice their culture and traditional pursuits through the traditional teachings of their "families, Elders and the community" (Peter and Hogan 2006).

Today, the Chief and Council of NND often work in close cooperation with the Village of Mayo Mayor and Council. The two governments hold joint council meetings on a regular basis to "discuss issues of mutual importance" (Cooper and Lecki 2006). The two councils collaborated to establish a local youth centre, which is among the many services that the two communities share. In addition, provisions under the NND Umbrella Final Agreement have resulted in the establishment of the Mayo District Renewable Resources Council whereby members of NND and the Mayo community make recommendations on fish and wildlife management within the Mayo District.

5.4 EXISTING AND PLANNED DEVELOPMENTS

The Project Regional Study Area in the vicinity of Mayo Lake and the Mayo River contains a relatively extensive list of developments, including the existing Mayo Hydro Generation Facilities – Mayo A (including the control structure at Mayo Lake) and Mayo B ("Existing Facilities"). In addition, there are many small developments and projects that are either licenced to occur, or are in the process of being reviewed for licencing. As noted in Section 3.2 of Chapter 3, the assessment approach considers other projects and activities which may potentially act cumulatively with effects of the Project and affect selected Valued Components (VCs). The cumulative effects assessment, inherent in the effects assessment in Chapter 7, identified all inputs from other projects that could act in concert with effects of the principal Project and influence the VCs identified, including:

- Past, present and likely future projects and activities in the area that may affect identified VCs; and
- Other existing or anticipated pressures (direct or indirect) on identified VCs.

The Mayo Lake Enhanced Storage Project is proposed to occur within this context of existing and planned developments, and as such their presence is relevant to the assessment of effects from the Proposed Project. Section 5.4.1 below describes the existing Mayo facility and Section 5.4.2 reviews other existing and planned developments.

5.4.1 The Existing Mayo Hydro Generation and Mayo Hydro Enhancement Facilities and Loads

The Existing Facilities consists of the Mayo Hydro Generation Facility ("Mayo A"), Mayo Hydro Enhancement Facility ("Mayo B") and the existing Mayo Lake Control structure. It has a combined installed capacity of approximately 15.4 megawatts and consists of several different structures. A copy of amended water licence HY10-056 is provided in Appendix 2F. The Existing Facilities consist of the following components (see Appendix 6A for further details):

- Mayo Lake Control Structure: The Mayo Lake control structure is a six meter high rock-filled wooden structure complete with a control valve building that allows Yukon Energy to control the level of Mayo Lake within a licensed operating range of 2.59 metres.
- Mayo B: A new 10 MW powerhouse downstream from the existing Mayo A plant. Water is transported from Wareham Lake to the new powerhouse by way of a new tunnel and underground pipe (penstock) system. The Mayo A and B facilities are licenced under Water Licence HY10-056, a Type A Class 3 licence that expires December 31, 2025.
- Mayo A: Consists of two 2.7 megawatt turbines and the Wareham spillway, which is a 32 metre-high earthen dam that controls Wareham Lake levels.

Further information on existing facilities can be found in the 2009 Mayo Hydro Enhanced Project (Mayo B) YESAB submission.

5.4.1.1 Existing Facility Water Levels and Flows

Details on existing facility water levels and flows are described in Chapter 6 – Appendix 6A and 6B.

5.4.2 Other Existing and Planned Development

Outside of Yukon Energy's Existing Facilities, a variety of past and current projects and activities comprise the existing and evolving built environment. A list of past and current projects and activities can be found in Appendix 5C.

CHAPTER 6
PROJECT DESCRIPTION

TABLE OF CONTENTS

6.0 PROJECT DESCRIPTION 6-1
6.1 PROJECT IDENTIFICATION/SCOPE OF PROJECT 6-1
6.1.1 Overview and Background 6-1
6.1.2 Identification of Key Project Aspects 6-2
6.2 PROJECT TIMELINE AND LIFESPAN 6-5
6.3 ALTERNATIVES 6-6
6.3.1 Alternatives to the Project 6-6
6.3.2 Alternative Ways of Undertaking the Project 6-7
6.4 OPERATION PHASE – WATER MANAGEMENT 6-9
6.4.1 Mayo Lake Water Levels 6-11

LIST OF TABLES

Table 6-1: Simulated Weekly Average Water Levels and use of Additional Storage (metre) 6-11

LIST OF FIGURES

Figure 6-1: Mayo Lake Benefits at 442 GW.h/year Load 6-8
Figure 6-2: Mayo Lake Benefits at 545 GW.h/year Load 6-8
Figure 6-3: Average Water Levels by Month Derived from Water Modeling (1981-2008) (assuming grid load of 442 GW.h/year) 6-13
Figure 6-4: Average Water Levels by Month Derived from Water Modeling (1981-2008) (assuming grid load of 545 GW.h/year) 6-14
Figure 6-5: Modeled Mayo Lake Water Levels at 442 GW.h/Year, by Water Year 1981 to 2008 6-15
Figure 6-6: Modeled Mayo Lake Water Levels at 545 GW.h/Year, by Water Year 1981 to 2008 6-16

APPENDICES

Appendix 6A: Existing Facilities and Water Management
Appendix 6B: Modeled Mayo Lake Outflows

6.0 PROJECT DESCRIPTION

6.1 PROJECT IDENTIFICATION/SCOPE OF PROJECT

6.1.1 Overview and Background

The proposed Project revises the existing licensed range within which Yukon Energy is permitted to operate Mayo Lake as a storage reservoir for the Mayo hydro system to store spring and summer flows to support generation of power during the fall and winter. The proposed Project provides increased bottom storage in the lake by lowering the allowed Low Supply Level by up to 1 m, thereby enabling increased water capture and storage in years when extra water is available.

Water management in terms of altering water levels at Mayo Lake as a result of the proposed Project will be subject to the Adaptive Management Plan (AMP) and the Monitoring Plan that provides the supporting data inputs for the AMP, each of which will be part of the proposed licence and not discretionary. The overall purpose of the AMP is to ensure a fully functioning, healthy and sustainable aquatic ecosystem at Mayo Lake based primarily on healthy and sustainable lake trout and lake whitefish populations. The AMP is intended as a primary instrument for managing water levels and water use for hydroelectric generation at Mayo Lake and establishing ecologically relevant water management constraints within the overall operating range. The AMP is a tool for implementing timely changes in water management to address ecological conditions, while providing the flexibility to obtain the most benefit of water storage for power generation. Under the AMP, water management for the Project responds to ongoing monitoring and can be readily adjusted as required or completely reversed if necessary.

For the first three years of the Project operation, the lake will be operated with an additional 0.5 m storage range (i.e., between the existing Full Supply Level of 665.84 m to a revised Low Supply Level of 662.75 m which is 0.5 m below the current Low Supply Level of 663.25 m)[1]. After the first three years, the results of monitoring and the AMP will be used to determine if and how to proceed with up to a full metre extra storage (lowering the Low Supply Level to 3.59 m below the Full Supply Level [LSL] of 665.84 metres) or if the storage range should be reduced to less than 3.09 m.

The Mayo Lake Enhanced Storage Project is proposed to enhance the renewable power generation capability of the existing hydro generating units installed on the Mayo River (see Appendix 6A for a description of existing facilities and modeled water management levels) to displace thermal generation that would otherwise be required during winter/spring to meet the overall power loads throughout the Integrated Yukon grid.

Prior to 1980, winter water levels at Mayo Lake frequently approached the current maximum licensed lower limit of 2.59 m below Full Supply Level because of the energy needs associated with the communities of Elsa, Keno and Mayo (including the mine load requirements at Elsa); however, from 1980

[1] The current controlled range reflects that under certain water conditions, it is possible for the water level of Mayo Lake to be outside of the stated range due to drought or flood conditions. Under those circumstances, Yukon Energy would be required to operate its facilities at the lake so as to not further exacerbate the elevation conditions. In particular, clause 25 of the Mayo Water Licence requires that when the lake elevation exceeds the licensed maximum range, Yukon Energy is required to have all of the gates open; a similar practice would be exercised in the event the licensed minimum range was exceeded, consistent with minimum downstream flow requirements.

to 2010, winter drawdown in Mayo Lake averaged only approximately 1.3 m, in part because the hydro generation plant was not run at full capacity in most years and more so after the 1988/89 closure of the United Keno Hill Mines operation. With interconnection of the Mayo/Dawson and Whitehorse-Aishihik-Faro grids during the spring of 2011 and the added hydropower generation capacity on the Mayo River through construction of the Mayo B project in 2010/11, additional water storage options in Mayo Lake are currently being sought.

The increased storage provided by the Project will enhance the ability to sustain water flows downstream to the Mayo hydro generating units during the winter/spring pre-freshet period, thereby enhancing thermal generation displacement on the Integrated Yukon grid. The Project maintains the existing maximum controlled elevation for Mayo Lake (the Full Supply Level) and requires no physical works for water storage beyond the Mayo Lake Control Dam facilities already in-service for the existing Mayo generation. The existing Water Board licence that governs water management is currently in effect and will be subject to review/renewal in 2025.

Implementation of the proposed Mayo Lake Project will not proceed until resolution of the lower Mayo River winter flow issue is satisfactorily resolved. Yukon Energy continues to work with Yukon Government and the Village of Mayo to address this issue.

Yukon Energy is also involved in a separate process related to dredging of the Mayo Lake outlet channel due to the build-up of sediment deposits. Recent investigation has confirmed that, over the 60 years of operation to date, sediment deposits have aggregated in the outlet channel to a level that is currently reducing long-term average hydro generation capability at Mayo A and B. A separate process to develop a project description and environmental and socio-economic assessment for regulatory review to remove these sediment deposits is now required (with or without the Mayo Lake Project), and is within Yukon Energy's planning process to restore full hydro generation capability under the existing licence. Removal of these sediment deposits will be required in order to utilize additional storage at Mayo Lake as provided for in the proposed Project.

The proposed Project is consistent with Yukon Government policy, as set out in the *Energy Strategy for Yukon* (2009), which includes the goal of increasing renewable energy supply by 20% by 2020. It also is in alignment with Yukon Government's *2009 Climate Change Action Plan*, which includes the reduction of carbon emissions.

6.1.2 Identification of Key Project Aspects

The proposed Project involves increasing the water level operating range on Mayo Lake by lowering the Low Supply Level (LSL) up to 1 m, increasing the current controlled operating range from 2.59 m (from 663.25 to 665.84 metres[2]) to 3.59 m (i.e., adding bottom storage). For the first three years of the Project operation, the storage range would be 3.09 m (lowering the LSL by 0.5 m) after which the results of monitoring and the AMP would be used to determine if and how to proceed with up to a full metre extra storage (lowering the LSL to 3.59 m below the Full Supply Level of 665.84 metres) or if the storage range should be reduced to less than 3.09 m.

[2] The licence is stated in imperial units, using an older datum, as 2,203.0 feet to 2,211.5 feet.

The proposed change to regulation of Mayo Lake is to the bottom part of the operating range and does not constitute any raising of maximum lake levels (i.e., 665.84 metres would remain the regulated Full Supply Level of Mayo Lake).

The available inflows to Mayo Lake do not allow for the full 3.09 metre or 3.59 metre range to be used every year. However, the increased storage range will result in lower average water levels at Mayo Lake.

Yukon Energy's general operational approach for Mayo Lake will be to store late spring and summer flows to support generation requirements between fall and early spring. Lake levels will usually peak in the fall, and slowly decrease until they reach a minimum just before freshet in the spring. The lake will be operated in conformance with the following water management principles and requirements:

1. The overall water management concept and objectives for the Mayo system will not change: Yukon Energy's use of water storage will remain focused on ensuring that peak spring/summer flows are used to fill Mayo Lake within the bounds of the licence and other operational constraints, and that water stored at Mayo Lake is generally released during winter/spring periods (pre-freshet) to provide for required downstream flows and the maximum generation that can be used to serve firm power loads and, where possible, secondary power loads. This general concept for future operation with the Project is the same as the situation today or in the future with or without the Mayo Lake Project[3].
2. Implementation of an environmental protection reservoir management rule to ensure that winter drawdowns (September 15th elevation to the minimum elevation the following spring) are not more than 2.59 metres more than 2 years in a row (the one-in-three "rest rule"). The effect of this rule is that for at least one year in every three, the winter drawdown shall not exceed 2.59 metres.
3. Adoption of the Adaptive Management Plan (AMP) with specific ecological thresholds, as overviewed below and as set out in detail in Appendix 8B, provides for specific mitigation management responses (including limitations on the operating range in certain circumstances) as appropriate when specific environmental conditions are observed through the comprehensive ecological monitoring program proposed as part of the Project.

Both the proposed operational regime changes and the AMP consider the Precautionary Principle and the elements of risk for serious and irreversible harm.

The proposed Project begins with a cautionary approach, utilizing half of the proposed additional 1 m water level range, and relying on the AMP to guide decisions about future increases or decreases from the starting point. Throughout the operation of the proposed Project, the AMP will continue to apply, leading to implementation of appropriate responses if ecological conditions reach action thresholds.

The AMP provides technically and economically feasible approaches for dealing with predicted and any observed impacts. Specifically, the AMP addresses both short term annual monitoring of reproductive success/recruitment (in terms of an early warning/indication of adverse impacts) and long term

[3] The Mayo hydropower facilities (including the Project) will operate in future to help reduce fossil fuel generation otherwise required to supply energy on the Integrated Yukon Grid, i.e., the Project will not change or impact the load requirements on the Yukon grid.

monitoring of adult abundance. Where thresholds for adverse effects are identified either in the short and long term monitoring programs, mitigation measures and changes to water management identified in the plan will be implemented as part of the AMP. It is expected that these programs and operational requirements will be entrenched in the Project authorizations (e.g., water use licence amendment).

As outlined in Appendix 8B, the objectives of the AMP are intended:

- To identify how the proposed Mayo Lake Project may affect the aquatic ecosystem focusing on the effects on lake trout and lake whitefish.
- To establish appropriate indicators of a fully functioning, healthy and sustainable aquatic ecosystem.
- To define a monitoring program that is appropriately sensitive and can measure and report, in a timely way, changes in identified indicators.
- To establish thresholds that define acceptable and unacceptable conditions or changes in identified indicators.
- To describe responses that will be undertaken if indicators and thresholds identify unacceptable conditions or trends.
- To establish a framework for interpretation of monitoring results, and decision-making about adaptive management responses.

The specific Project proposed serves to increase the long-term average hydro generation potential to displace fossil fuel generation on the Yukon system by approximately 2 to 4 GW.h/year[4] (the specific yearly benefit will depend on the overall load level on the Yukon grid, flow conditions throughout Yukon, the Mayo Lake LSL then allowed under the AMP, and the extent of future new renewable generation on the grid).

The proposed Project requires no new physical works. It will utilize the Mayo Lake Control Structure facilities already in-service for the existing Mayo hydro generation, and ongoing maintenance activities of the structure and associated infrastructure from Mayo Lake to the Mayo Lake Control Dam[5]. Hydro power generation will occur at the existing Yukon Energy facilities at Mayo A and B.

Most Yukon Energy operations at Mayo Lake or on the Mayo River are related to and required by the existing projects, and are not expected to be significantly affected by the Mayo Lake Project. There are no "accessory activities".

[4] By way of example, at loads ranging from of 437 to 454 GW.h/year, additional long-term average fossil fuel displacement due to the Project's enhancement of long-term average hydro generation ranges from 1.9 to 2.8 GW.h/year with 0.5 m enhanced Mayo Lake storage and from 3.4 to 4.2 GW.h/year with 1.0 m enhanced Mayo Lake storage. Within the load range of about 460 to 480 GW.h/year, fossil fuel generation displacement benefits with 0.5 m enhanced Mayo Lake storage range between 2.9 and 3.2 GW.h/year.

[5] Maintenance activities noted here refer to any ongoing works required to keep the control structure operational. As reviewed in Section 6.1.1, a separate process to develop a project description and environmental and socio-economic assessment for regulatory review to remove sediment deposits within the outlet channel is now required (with or without the Mayo Lake Project), and is within Yukon Energy's planning process to restore full hydro generation capability under the existing licence.

6.2 PROJECT TIMELINE AND LIFESPAN

Yukon Energy is working to secure fossil fuel displacement benefits from the Project by 2017. To achieve this target and be able to reduce Mayo Lake below its current LSL in spring 2017, the Project approval and licensing process (including the YESAB and Yukon Water Board processes) needs to be concluded no later than during 2016.

As stated above, in order to sustain generation benefits under the current licence regime and gain the estimated benefits of the Project, resolution of the lower Mayo River winter flow issue and outlet channel dredging will also require resolution. These activities are being addressed under separate processes by Yukon Energy. Implementation of the Mayo Project (i.e., changing the water management regime of Mayo Lake) will not occur until these issues are resolved.

Subject to resolution of the lower Mayo River winter flow issues and outlet channel dredging that (as reviewed above) are being addressed under separate processes by Yukon Energy, operation of the Project will begin with the receipt of all final approvals from the required regulatory agencies. The actual use of the additional storage range will primarily occur in late winter/spring although in some years, the lower portion of the proposed storage range will be used over a greater portion of the year. Actual use will be affected by required loads on the Yukon grid, natural inflows, licence conditions including minimum downstream flows and by the ongoing AMP requirements.

There are no added maintenance works required by the Project as compared to maintenance required of the existing works (e.g., travel to the lake to make flow modifications as required, occasional maintenance of the dam structure, and periodic removal of woody debris). The only additional ongoing activity anticipated as a result of the Project is enhanced monitoring of the environmental conditions of the lake, as compared to the status quo operation over the last 50 years, and the related AMP activities.

The Project's proposed amendment to Yukon Energy's existing Class A Water Use Licence HY99-012 for the Mayo hydroelectric facility will be subject to further regulatory review when this licence is renewed. Yukon Energy's current licence expires on December 21, 2025. It is anticipated that any renewed licence would be subject to further review at least once every 25 years.

The extensive fisheries and aquatic monitoring that has been done since 2009 and that will continue to be carried out through to relicensing under the Adaptive Management Plan focused on operational issues will provide a very significant long term data base that will greatly benefit assessment and relicensing in 2025.

There is currently no timetable or plan for final disposition or decommissioning of the main Mayo generating facilities, or of the requirement for water storage to service these facilities. As reviewed in the recent Mayo B licensing, it will be 50 to 100 years before the main generating facilities will require substantial refurbishment. This is far into the future such that it is not feasible today, based on the available information and agreements, to provide meaningful assessment of likely plans or their effects for reclaiming the components of the Mayo generating facilities or the water storage at Mayo Lake. When such plans need to be developed, Yukon Energy will submit these plans as then required for assessment and regulatory review and approval prior to implementation. Accordingly, as was done for the Mayo B application, this Project proposal does not provide any further assessment of final disposition.

6.3 ALTERNATIVES

6.3.1 Alternatives to the Project

The main alternative to the Project is continued reliance on existing fossil fuel generation (using natural gas supplied by LNG and/or diesel fuel) to supply the energy that the Project would otherwise enable.

As noted in Section 6.1, the prime purpose of the Project is to enhance the renewable power generation capability of the existing hydro generating units installed on the Mayo River to displace fossil fuel generation that would otherwise be required during winter/spring (pre-freshet) to meet the overall power loads throughout the Integrated Yukon grid under long-term average hydro generation conditions.[6]

The Project is being pursued by Yukon Energy concurrent with all other identified potential enhancements to existing renewable generation (ongoing feasibility studies related to Whitehorse and Aishihik), as well as a broad Demand Side Management (DSM) energy conservation and efficiency program. Based on Yukon Energy's recent review of near-term resource supply options[7] and updated grid load forecast scenarios[8], there is no alternative near-term renewable energy project or any DSM option currently under study by Yukon Energy that is expected to displace the short and medium-term forecasted default fossil fuel energy generation on the Yukon grid that the Project would displace. This reflects the fact that the Project's annual fossil fuel displacement impact is relatively small (i.e., it tends to offset only one to two year growth on the grid in new default fossil fuel generation requirements absent new renewable generation), and the fact that new greenfield renewable generation typically requires material additional sustained long term loads to justify the required capital costs.

In summary, as Yukon Energy is a regulated utility with an obligation to supply firm power customer loads, the implications of not proceeding with this Project are as follows:

- As an alternative, Yukon Energy would be required to use fossil fuel generation to provide incremental power requirements that cannot be provided through the proposed Project.
- Long-term power costs in Yukon would be higher under an alternative of fossil fuel generation than with the proposed Project, affecting all Yukon ratepayers.
- Ongoing greenhouse gas emissions (GHG) would be higher under an alternative of fossil fuel generation than with the Project.
- Economic development benefits arising to the NNDFN from participation in the proposed Project's economic benefits will not be realized under the alternative of fossil fuel generation.

[6] In the recent Board Order 2013-01, the Yukon Utilities Board approved the amortization of permitting and licencing costs then forecast for the Project over the term of the Mayo generation facility water use licence, and supported the Project as a renewable project.

[7] See Chapters 6 and 8, Yukon Energy Corporation, *Overview of 20-Year Resource Plan: 2011-2030*, July 2012.

[8] See Appendix C: Updated Near-Term Grid Load Scenarios, in Yukon Energy Application for an Energy Project Certificate and an Energy Operation Certificate for the Proposed Whitehorse Diesel-Natural Gas Conversion Project, December 9, 2013 [this project was designated by OIC 2013/200 as a "regulated project" under Part 3 of the *Public Utilities Act*.]

6.3.2 Alternative Ways of Undertaking the Project

Yukon Energy's concept studies for Mayo B[9] reviewed the potential benefits from enhancements to the operating range of Mayo Lake from a "no change" scenario, up to a scenario with 2 metres of additional water level fluctuation.

The 2 metre scenario incorporated up to 1 metre of added top storage (i.e., raising the controlled maximum licensed lake elevation, or FSL) combined with up to 1 metre of added bottom storage (i.e., lowering the minimum licensed lake elevation, of LSL). The 2 metre increase to the storage range (i.e., 1 metre increase and 1 metre decrease) was excluded from further consideration because there was rarely enough inflow to permit this full range at Mayo Lake to be used (i.e., modeling indicated that there was little power generation advantage to increasing the current storage range at Mayo Lake by the full 2 metres as compared to 1 metre); and initial investigations indicated potential concerns with a new higher controlled elevation, including material changes needed to the control structure and potential adverse effects (flooding) on land rights, heritage resources, and erosion of lands adjacent to the lake.

Within the remaining range of up to 1 metre of additional bottom storage, Yukon Energy worked with NNDFN to examine the potential impacts of alternative LSL changes and reservoir management options. As Figure 6-1 and Figure 6-2 illustrate, there is material value or benefit to increased generating potential between the existing licence storage and 0.5m of increased storage; however, between 0.5 m and the full 1 m additional storage, the generating potential improves, but not as much as for the initial half meter of storage.

[9] Concept studies that explored alternatives to the proposed 1 metre drawdown of the Mayo Lake Project were done as a part of the Mayo B Project concept studies. For an in-depth discussion, refer to Yukon Energy's Mayo B YESAB Project Proposal, February 27, 2009.

Figure 6-1: Mayo Lake Benefits at 442 GW.h/year Load

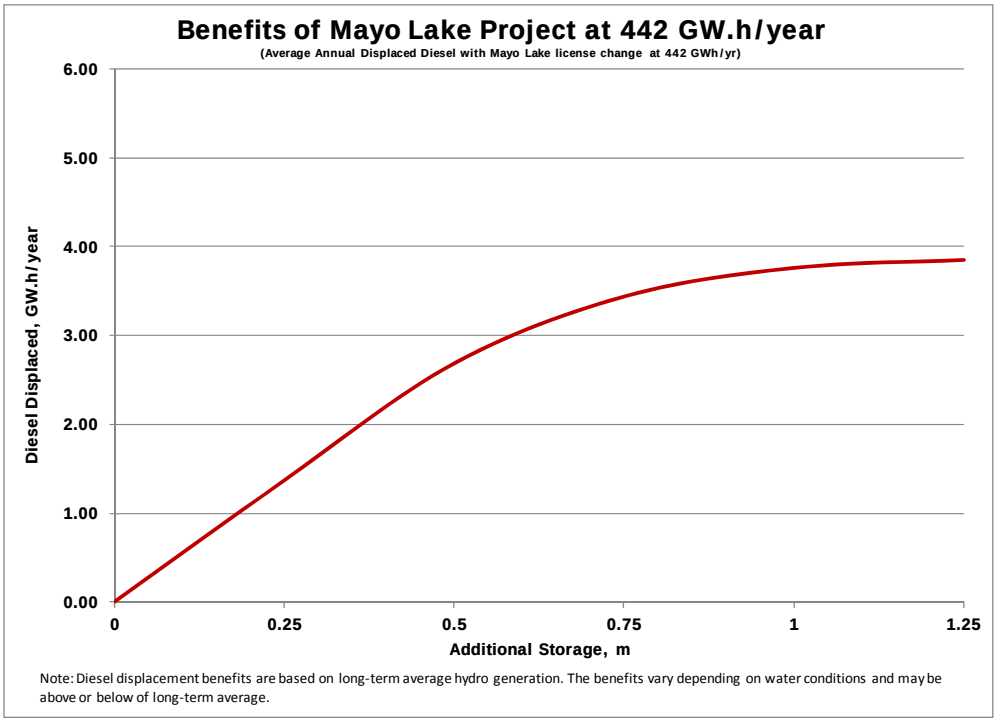
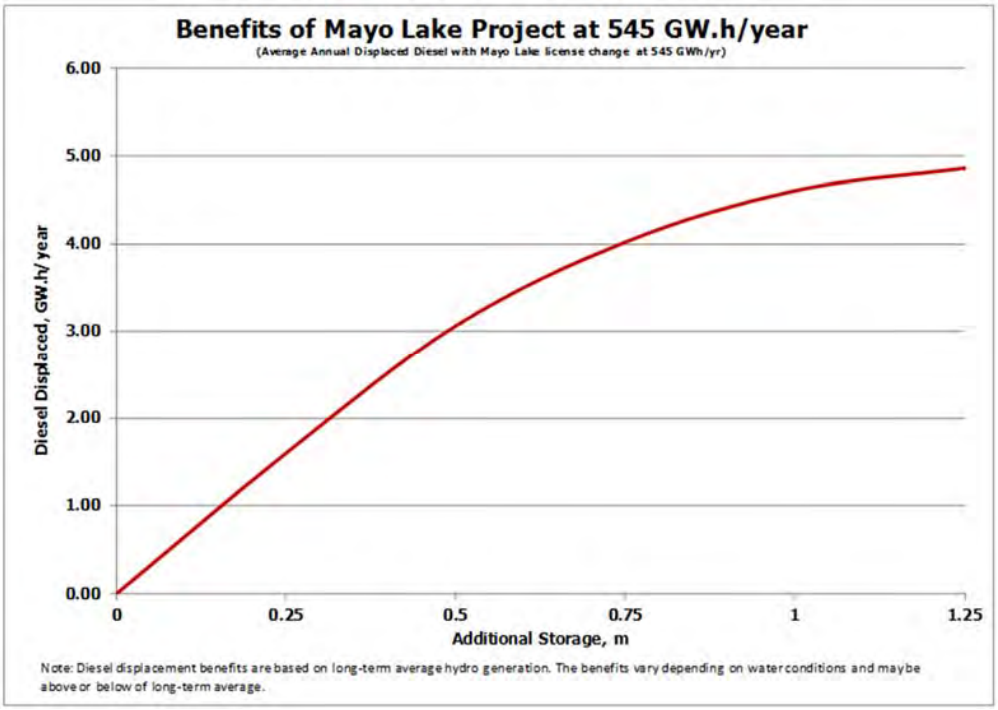


Figure 6-2: Mayo Lake Benefits at 545 GW.h/year Load



As part of this work, the NND/YEC Technical Working Group (TWG) hired an independent fisheries expert to assist the TWG in understanding the options; and to seek the expert's advice on the suitability of the monitoring plan and AMP as a means of addressing and managing uncertainties with respect to potential lake trout and lake whitefish responses to the Project (see Appendix 8C for a copy of the independent expert's final report).

Based on the work of the TWG, Yukon Energy has adopted the approach set out in this Project Proposal, including the proposal during the first three years of the Project operation for the storage range to be 3.09 m (lowering the LSL by 0.5 m) after which the results of monitoring and the AMP would be used to determine if and how to proceed with up to a metre of extra storage (lowering the LSL to 3.59 m below the Full Supply Level of 665.84 metres) or if the storage range should be reduced to less than 3.09 m.

As stated earlier, there is sufficient benefit from this renewable resource Project over the initial 0.5 m storage range to justify the costs of implementing the Project (i.e., regulatory review and on-going monitoring costs). This approach reflects the following considerations as regards environmental impact management:

1. **Monitoring Plan and AMP are integral to the proposal**: Both plans provide for a continual and robust complement of observations, with specific ecologically-based thresholds and prescribed response mechanisms and ongoing assessment by all interests including the proponent, NNDFN, Mayo RRC, regulators and stakeholders that are expected to be effective in early detection of, and response to, any unanticipated and potentially important adverse effects.
2. **The proposed approach is low risk**: The species of interest on the lake are presently in a self-sustaining condition comparable to other similar natural Yukon Lakes, and there is a high degree of resilience to a possible perturbation. Moreover, the predominant mechanisms for potential adverse effects to occur on the lake would require multiple years of repeated occurrence to be considered to have caused significant harm as both lake trout and lake whitefish are long-lived species. Implementing the proposed Project at the initial 0.5 metre level, combined with the sensitive Monitoring and AMP Programs, will consequently not cause serious irreversible harm and thus is considered reasonably precautionary in nature (as discussed in Chapter 7).
3. **The proposed approach provides better opportunity for cause – effect observation than a more gradual incremental phase-in approach (e.g., 0.25 m phase-in stages):** The species of interest on the lake are subject to a high degree of natural variability in such factors as their population levels, spawning success, and growth rates. It was determined that discerning any effects of the proposed Project as compared to natural variability would be extremely difficult if not impossible in the event a smaller perturbation (via a 0.25 m or other smaller incremental phase-in approach) were adopted.

6.4 OPERATION PHASE – WATER MANAGEMENT

The proposed Project will result in a different water regime on Mayo Lake than the situation in future without the Project[10]. In general, the lake will operate on average at a lower elevation with the proposed

[10] Lake elevations have been modeled for the future scenarios both with and without the proposed Project, using Yukon Energy's integrated grid supply (power benefits) model. This model considers the overall operation of the system (all hydro plants, plus

Project than without the proposed Project, with the size of this change varying somewhat by season and by year, as well in response to the overall load on the integrated grid and the LSL allowed at any time under the conditions of the AMP.

The proposed initial 0.5 m extra bottom storage in Mayo Lake, with the ability to increase that to 1 m in the future subject to the conditions of the AMP, retains characteristics of an annual storage system (where the inflows are stored for release the following winter), rather than a multi-year system (where a large range is provided that may take many years to oscillate between the lower reaches and upper reaches of the range). As a largely annual storage system, the proposed Project can be conceptually understood as providing something akin to a new "flood reserve" rather than a "drought reserve", such that the bulk of summer inflows will be released the following winter of each year, to permit storage room to capture the subsequent year's freshet and summer flows. The larger storage range allowed by the Project increases the amount of summer flows that can be stored, and this increased storage will be maximized during very wet years. During average and dry years, the inflows would be insufficient to fill the lake to the current FSL.

Given that inflows to Mayo Lake vary each year, lake storage utilization (i.e., the range and rate of drawdown each winter, and the scheduled releases) depends on the quantity of inflows during each year as well as power system loads. Consistent with existing practice on each reservoir, Yukon Energy will determine the optimum range of Mayo Lake drawdown possible for each week of each year by using a "rule curve," which enables water stored within the licensed range to carry the system from winter until the following spring freshet without violating lake water level and river minimum flow requirements set out in Yukon Energy's water use licence.

Modeling of this water regime is important to understanding both the feasibility of the Project (as it relates to power production) and the environmental and socio-economic implications.

Yukon Energy has completed modeling of the above water management parameters on the basis of a detailed integrated power/water flow model operating on a weekly time step, using a period of historic inflows (1981-2008) and consolidated power system loads of 442 GW.h/year and 545 GW.h/year as a representative range of flow and load conditions that could potentially occur during the first 10 years of the operation phase of the Project[11]. During the operation phase of the Project, with the adoption of the above water management parameters, the water levels and flows on the system from time to time are forecast to assess how these are likely to vary from what would have been the case had the storage

thermal generating units) to meet all required loads, including operation of each of the hydro reservoirs including Mayo Lake. The model operates on a weekly time step over a multi-year horizon. The model incorporates actual hydrological data from 1981 through 2008 inclusive and represents "what would have happened" had a given load level and a given complement of generation been present on the system in the hydrological year in question. This modeling approach reflects the industry standard for multi plant hydro based systems.

[11] These grid loads reflect a range of potential conditions as indicated in Yukon Energy's December 2013 Application for an Energy Project Certificate and an Energy Operation Certificate for the Whitehorse Diesel-Natural Gas Conversion Project (Appendix C: Updated Near Term Grid Load Scenarios): 442 GW.h/yr. reflects the 2015 forecast load for the Base Case with Alexco's Bellekeno mine and the 2017 forecast load for the Base Case with no Alexco (Base Case includes Capstone's Minto mine as well as wholesale and retail Yukon grid loads as then forecast); 545 GW.h/year reflects peak loads forecast (in 2021) under Scenario A2 (Base Case with Alexco and Carmacks Copper mine). The model includes all assumed loads and load profiles, operating characteristics of each system power facility (e.g., unit efficiencies), and licensed parameters for each plant as approved or proposed.

range remained unchanged from the current licence (for detailed information on modeled Mayo Lake levels and outflows please see Appendix 6B).

The following subsection includes the results of the representative modeled water levels and flows, under the two assumed grid loads (442 and 545 GW.h/year) comparing the conditions without the Project (i.e., the "baseline", or Mayo A and Mayo B operating parameters without the proposed Mayo Lake additional drawdown), and the expected operational conditions under the proposed Project (i.e., the baseline conditions with the proposed Mayo Lake initial half metre drawdown and the full 1 metre drawdown that may ultimately occur under the proposed licence amendments).

6.4.1 Mayo Lake Water Levels

Figure 6-3 and Figure 6-4 below show the average baseline, and proposed Mayo Lake water levels with and without the Project over the course of a single calendar year at the representative grid loads of 442 GW.h/year and 545 GW.h/year, respectively. The diagrams show that under both load scenarios, winter drawdown of Mayo Lake typically begins in mid-September/early October and continues to approach the LSL until mid-April/early May when the spring freshet begins. At that point, Mayo Lake refills based on natural inflow, and the lake level will be raised toward the licensed FSL.

The diagrams demonstrate that the general water management strategy and operation of Mayo Lake under the baseline and proposed conditions remain the same. The key difference is that, under the proposed conditions of the Mayo Lake Project, the range in drawdown will be increased to provide Yukon Energy with increased storage capacity each spring – i.e., to allow for additional space in the lake to store larger inflows if the spring and summer runoff are bountiful and to otherwise avoid this extra water from having to be spilled at the Mayo Lake Control Structure over the course of the summer and early fall due to constraints imposed by the FSL.

Table 6-1 below shows weekly average water levels with and without the Project (both 0.5 m and 1 m additional storage options) for the relevant weeks[12]. Averages are calculated from the outputs of a 28-year model assuming inflows are the same as the period from 1981 to 2008.

Table 6-1:
Simulated Weekly Average Water Levels and use of Additional Storage (metre)

		Mid-May		Mid-June		Mid-September		Mid-November		Annual
At 442 GW.h		Week 19	Week 20	Week 24	Week 25	Week 37	Week 38	Week 45	Week 46	Average
No Additional Storage	A	663.64	663.90	665.18	665.33	665.70	665.72	665.45	665.36	664.79
With 1 m Additional Storage	B	663.14	663.40	664.70	664.86	665.47	665.51	665.28	665.19	664.50
With 0.5 m Additional Storage	C	663.29	663.55	664.85	665.01	665.55	665.59	665.34	665.25	664.60
Difference between no Additional Storage and 1 m Additional Storage	D=A-B	0.50	0.50	0.48	0.46	0.23	0.22	0.17	0.17	0.29
Difference between no Additional Storage and 0.5 m Additional Storage	E=A-C	0.35	0.35	0.33	0.32	0.15	0.14	0.11	0.11	0.19

[12] Relevant weeks from a biological perspective are in mid-May (Lake Whitefish habitat availability), mid-June (ice-off) and mid-September (Lake Trout spawning). Mid-November has been added to show the minimum range between water levels. The highest difference in weekly average water levels occurs in weeks 18-19.

At 545 GW.h		Mid-May		Mid-June		Mid-September		Mid-November		Annual Average
		Week 19	Week 20	Week 24	Week 25	Week 37	Week 38	Week 45	Week 46	
No Additional Storage	A	663.63	663.89	665.13	665.23	665.17	665.17	664.79	664.71	664.48
With 1 m Additional Storage	B	662.82	663.08	664.34	664.47	664.67	664.67	664.31	664.23	663.87
With 0.5 m Additional Storage	C	663.16	663.42	664.68	664.80	664.91	664.91	664.53	664.46	664.14
Difference between no Additional Storage and 1 m Additional Storage	D=A-B	0.81	0.80	0.79	0.76	0.50	0.50	0.47	0.48	0.61
Difference between no Additional Storage and 0.5 m Additional Storage	E=A-C	0.47	0.47	0.45	0.43	0.26	0.26	0.25	0.25	0.33

On average, the Project will result in the following lower operating levels of lake operation based on the modeling assessments shown in Figure 6-3 and Figure 6-4, as well as Table 6-1 (the ranges shown are for 0.5 m and 1.0 m LSL):

- At 442 GW.h/year grid load level, the average Mayo Lake operation with additional 0.5 m storage for the year compared to the existing licence conditions will be 0.19 metres lower, and 0.29 metres lower under 1 m storage. At the higher load of 545 GW.h/year these values would be 0.33 metres and 0.61 metres respectively.

- At the 442 GW.h/yr. load level, the modeling results show that depending on water conditions, the difference in lake elevation as compared to the baseline (no additional storage) will vary over the year ranging from 0.11 m to 0.35 m under the 0.5 m additional storage range; and ranging from 0.17 to 0.50 m under the 1 m additional storage range.

- At the 545 GW.h/yr. load level, the modeling results show that depending on water conditions, the difference in lake elevation as compared to the baseline (no additional storage) will vary over the year ranging from 0.25 m to 0.47 m under the 0.5 m additional storage option; and between 0.47 m and 0.81 m for the 1 m additional storage option.

Figure 6-3:
Average Water Levels by Month Derived from Water Modeling (1981-2008)
(assuming grid load of 442 GW.h/year)

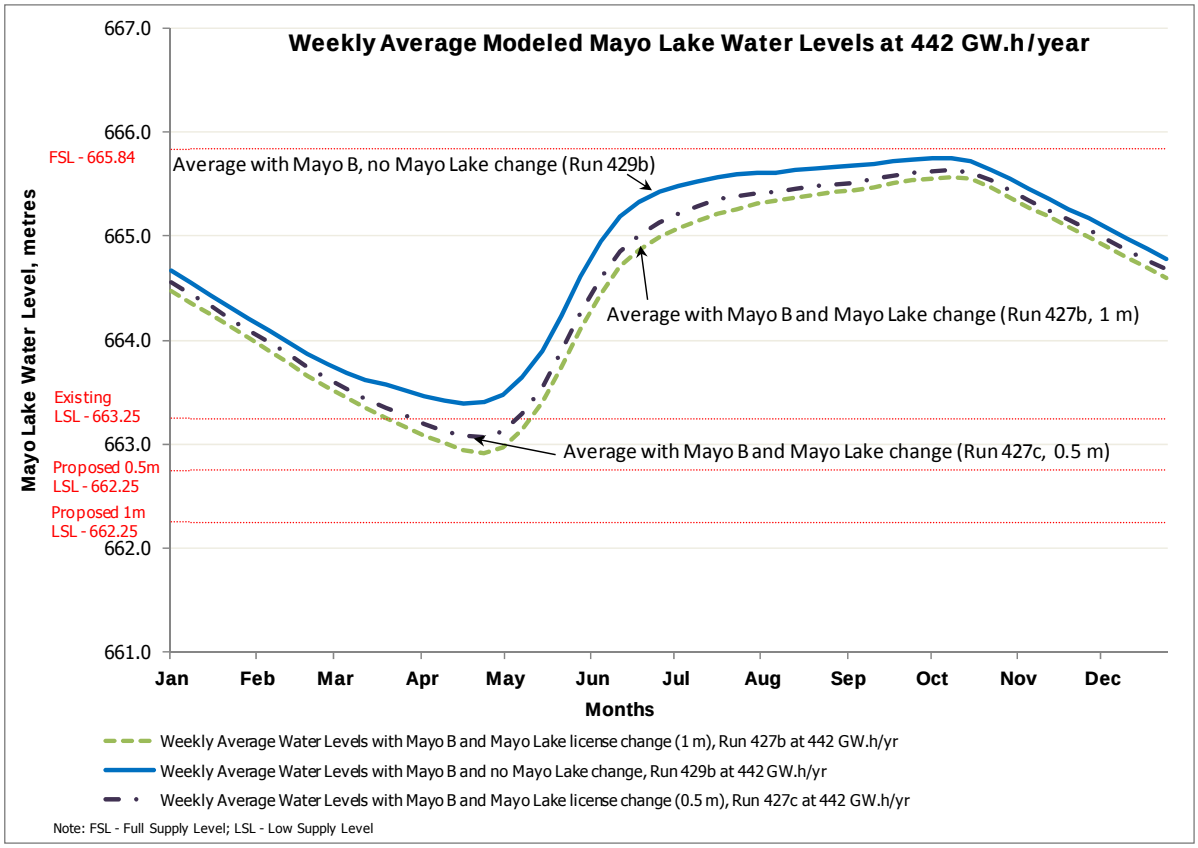
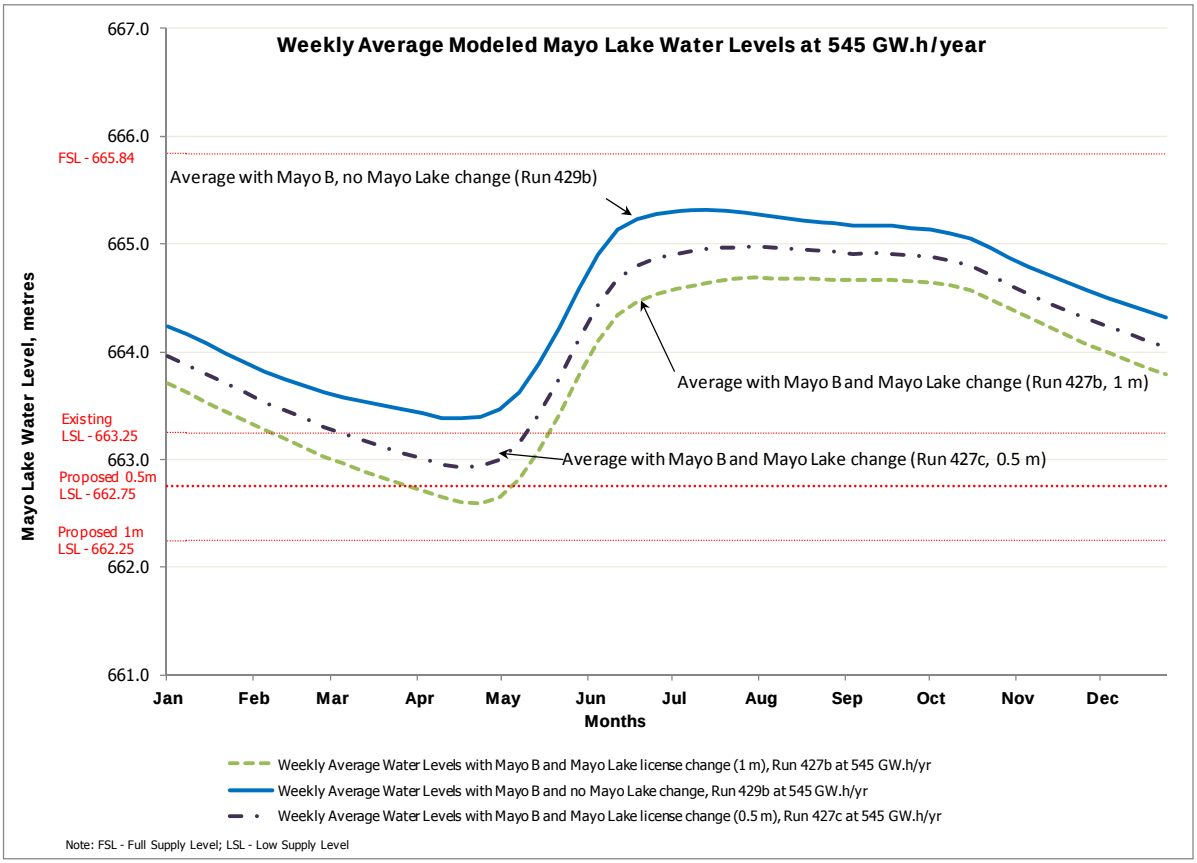


Figure 6-4:
Average Water Levels by Month Derived from Water Modeling (1981-2008)
(assuming grid load of 545 GW.h/year)



Additional power generation benefits will not be realized every year. In low inflow years, there could be little to no incremental benefits; however, in high inflow years (i.e., flood years), benefits of having a larger storage reservoir could be substantial. In that regard, the average changes to lake levels throughout the year do not fully demonstrate the economic value of the Project, as it arises in the different water conditions that can be experienced over several years. On an annual basis, the variations in water levels are shown in Figure 6-5 and Figure 6-6 for the range of representative grid loads. The water elevations shown in these figures are derived from the outputs of modeling the respective water inflows from each year shown on the horizontal axis – from 1981 to 2008. These figures demonstrate the flood reserve nature of the Project, particularly in years with large refills, such as 1988; in that year the lower elevation permitted with the proposed Project allows a large spring freshet to be stored, as the lake is raised back up to the full supply level by summer. Absent the proposed Project, this water condition would lead to major spillage starting in early summer.

Figure 6-5:
Modeled Mayo Lake Water Levels at 442 GW.h/Year, by Water Year 1981 to 2008

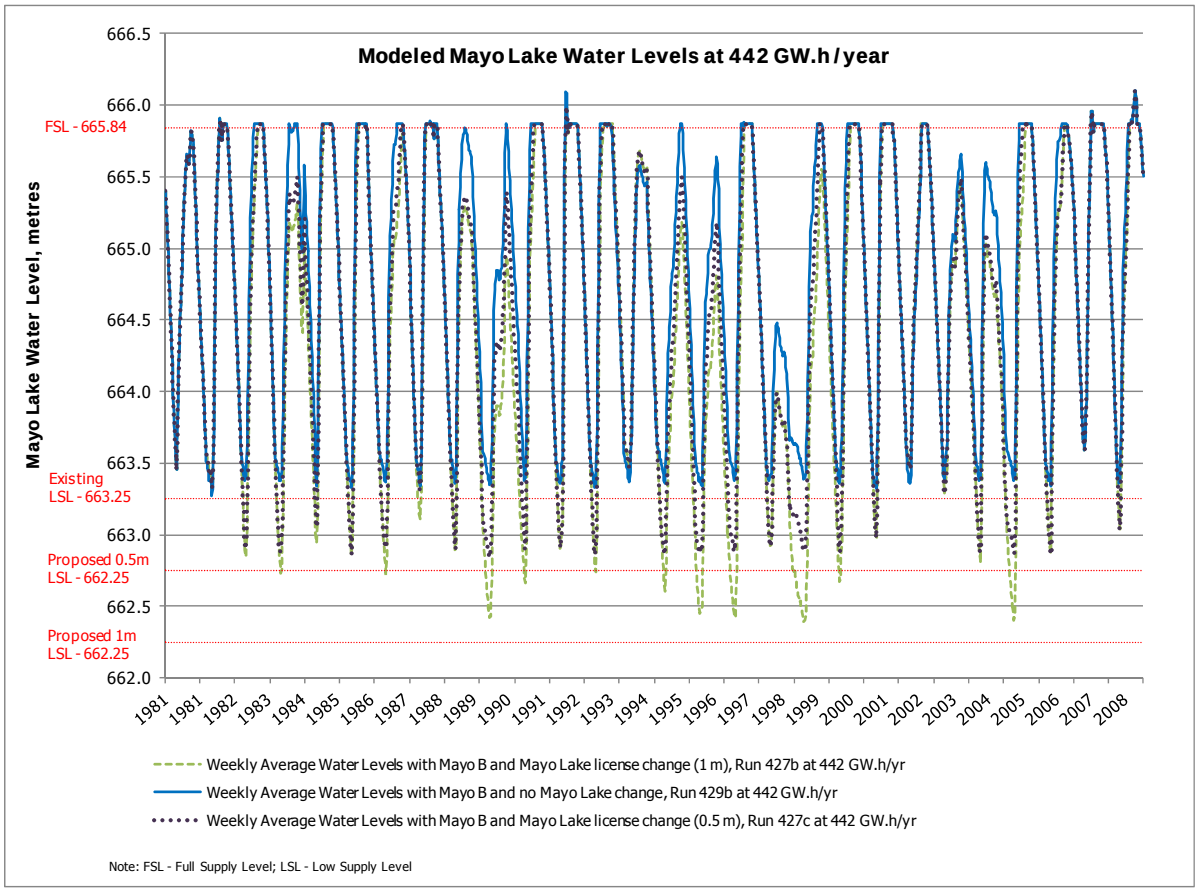
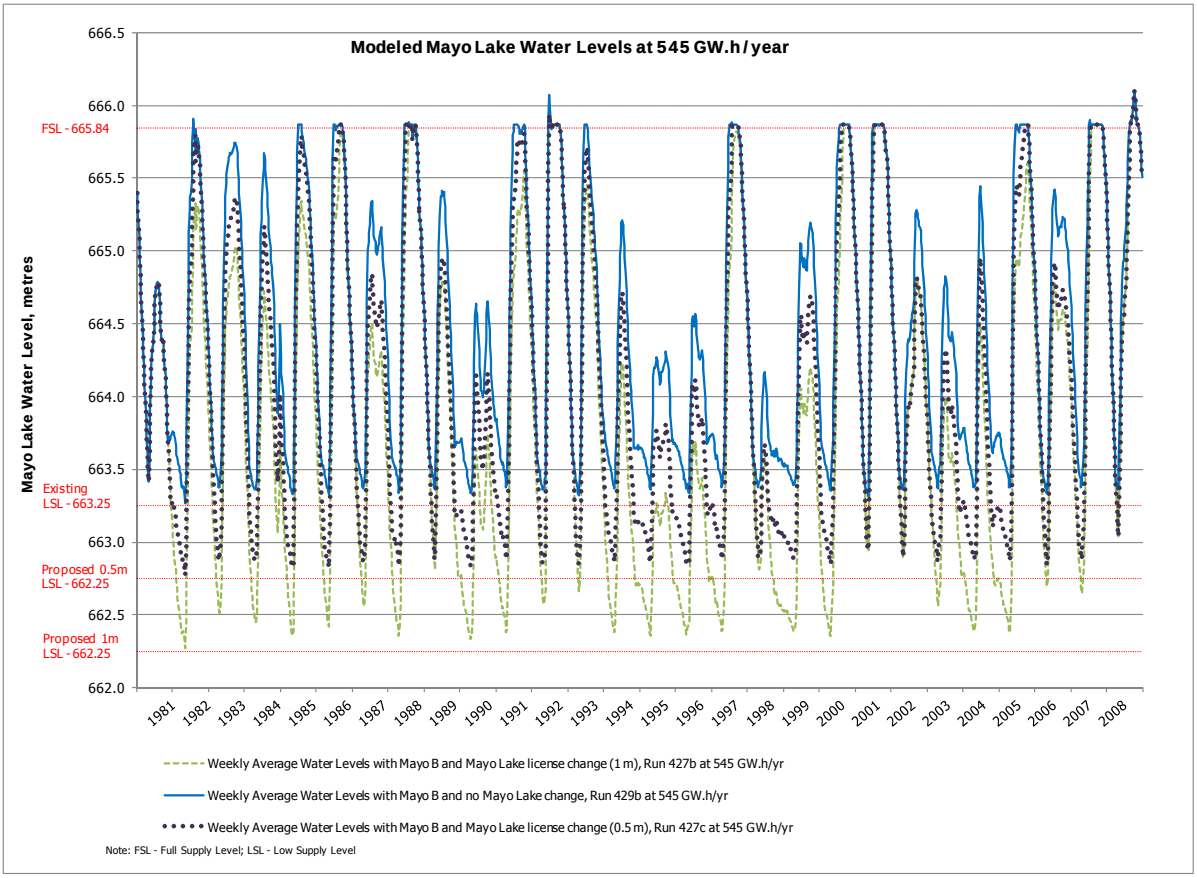


Figure 6-6:
Modeled Mayo Lake Water Levels at 545 GW.h/Year, by Water Year 1981 to 2008



In summary, the following conclusions are provided based on the above figures the range of expected grid load conditions:

- With the proposed Project, the new lower range will be expected to be used to some degree in each year to ensure the ability to capture the extra water when it may come. The degree of use will be reduced for lower grid loads versus higher grid loads within the range examined in the above figures.
- The typical maximum water elevation (summer peak level) will be lower than with the baseline conditions.
- As provided in Figure 6-3 and Figure 6-4 above, based on long-term average hydro generation with the Mayo Lake Project, cycling within a year would be similar to the baseline conditions but at a lower average elevation.

The Project includes a comprehensive Monitoring and Adaptive Management program (Appendix 8A and B), which in some instances can lead to progressive revisions to the water management parameters, most notably the lower supply level. In the event these provisions are triggered, the water management objectives for Mayo Lake would remain the same. Specifically, with a slightly increased LSL, Yukon Energy would continue to attempt to maximize the potential provided by the enhanced range as flood

reserve by making maximum use of the water storage resource through the winter season, and permitting spring freshet refill to be stored to the extent permitted by the then-governing range.

CHAPTER 7
ENVIRONMENTAL AND SOCIO-ECONOMIC EFFECTS ASSESSMENT

TABLE OF CONTENTS

7.0 ENVIRONMENTAL AND SOCIO-ECONOMIC EFFECTS ASSESSMENT 7-1
7.1 OVERVIEW OF APPROACH 7-1
7.2 IDENTIFICATION OF VALUED COMPONENTS 7-2
7.2.1 Environmental Valued Components 7-4
7.2.2 Socio-Economic Valued Components 7-6
7.3 ASSESSMENT OF EFFECTS 7-7
7.3.1 Assessment of Effects on Environmental Valued Components 7-7
7.3.2 Assessment of Effects on Socio-Economic Valued Components 7-33
7.3.3 OTHER POTENTIAL EFFECTS 7-46

LIST OF TABLES

Table 7-1: Environment Valued Components Considered for the Assessment of the Mayo Lake Enhanced Storage Project 7-4
Table 7-2: Socio-Economic Valued Components Considered for the Assessment of the Mayo Lake Enhanced Storage Project 7-6
Table 7-3: Environmental Effects Assessment 7-9
Table 7-4: Comparison of Spring Stopover Habitat Availability for Migratory Birds During Weeks 18 – 22 (average); 442 GWh Load Scenario 7-29
Table 7-5: Socio-Economic Effects Assessment 7-35
Table 7-6: Modelled Mayo Lake Outflows 7-39
Table 7-7: Mid-September Water Levels at 442 GW.h/yr. Load Scenario 7-39

LIST OF FIGURES

Figure 7-1: Lake Trout Egg Collector 7-13
Figure 7-2: Collecting Lake Trout Eggs 7-14
Figure 7-3: Lake Trout Egg Incubators Deployed in the Lake Bed 7-14
Figure 7-4: Lake Trout 7-15
Figure 7-5: Deepwater Lake Trout Spawning Habitat Before Rehabilitation 7-17
Figure 7-6: Deepwater Lake Trout Spawning After Rehabilitation 7-17
Figure 7-7: Lake Whitefish Spawning Area in a Tributary to Mayo Lake (Upper Roop Creek) 7-19
Figure 7-8: Early Spring Lake Whitefish Rearing Habitat in Nelson Arm 7-20
Figure 7-9: Lake Whitefish Fry 7-20
Figure 7-10: Beach Seining for Juvenile Lake Whitefish 7-21
Figure 7-11: Roop Lakes Wetland Complex 7-23
Figure 7-12: Shallow Water Littoral Area of Mayo Lake (Roop Arm) 7-25

Figure 7-13: Bird Species Frequently Observed at Mayo Lake/Roop Lakes during Migration. From Left to Right: Bald Eagle, Trumpeter Swan, Northern Pintail and Pectoral Sandpiper 7-27
Figure 7-14: Aerial View of WKA 2734 at the East End of Roop Arm 7-28
Figure 7-15: Active Beaver Lodge and Food Cache in Mayo Lake (Nelson Arm) During 2014 7-31
Figure 7-16: Cow Moose at Roop Lakes 7-32
Figure 7-17: Lower Roop Creek 7-38
Figure 7-18: Mayo Lake Boat Launch 7-40
Figure 7-19: Lake Trout 7-41
Figure 7-20: Barge Transporting Heavy Equipment on Mayo Lake 7-43

7.0 ENVIRONMENTAL AND SOCIO-ECONOMIC EFFECTS ASSESSMENT

Chapter 7 provides an assessment of the effect of the Project, focusing on the following:

- Overview of Approach;
- Identification of Valued components (VCs);
- Assessment of Environmental and Socio-Economic Effects; and
- Other Potential Effects.

7.1 OVERVIEW OF APPROACH

This chapter provides an assessment of the environmental and socio-economic effects of the Project to determine whether, after the implementation of mitigation measures, the Project is likely to result in significant adverse residual effects (including significant adverse cumulative effects) on identified VCs. The effects assessment builds on the framework established in earlier chapters, including:

- The assessment approach as reviewed in Chapter 3;
- The public consultation as described in Chapter 4;
- The results of an environmental and socio-economic scan provided in Chapter 5;
- The Project Description as discussed in Chapter 6; and
- The proposed monitoring and adaptive management plans in Chapter 8.

There are two main pathways for effects from the Project on VCs:

- **Project-related direct and indirect changes to the aquatic and terrestrial environment:** Changes to the aquatic and terrestrial VCs (including associated wildlife and aquatic life) as a result of a change in the water management regime. Environmental changes can also be linked indirectly to subsequent socio-economic effects such as resource use (as noted under next bullet).
- **Project-related direct and indirect socio-economic effects:** Supply of lower cost grid electricity to displace thermal generation during Project operation resulting in saving benefits to ratepayers, benefits flowing to NND and a decrease in greenhouse gas emissions. Changes to access for users and resource harvesters on Mayo Lake as a result of a change in the water management regime. As noted above, environmental changes to the biophysical environment can be linked indirectly to socio-economic effects.

Both beneficial and adverse environmental and socio-economic effects are explored, where appropriate, along with the potential effects of the environment on the Project (i.e., climate change).

The assessment focuses on effects of the Project that are considered "likely" to occur. Based on the approach set out in Chapter 3, the expected effects of Project activities are assessed for each

environmental and socio-economic VC, focusing on the effect attributes, or criteria, described in Chapter 3 (See Chapter 3 for details on each):

- Direction or nature of the effect;
- Magnitude of the effect;
- Geographic or socio-economic extent of the effect;
- Duration of the effect;
- Frequency of the effect;
- Reversibility of the effect;
- Ecological or socio-economic context; and
- Likelihood of effect being significant.

Significance for the Project's effects on any VC is determined using the approach and criteria set out in Chapter 3 based on scientific analysis of ecosystem effects including Traditional Knowledge and local knowledge, socio-economic research and professional judgment. Noted uncertainties in the information base about potential effects on VCs, but where the risk of serious irreversible effects is negligible, are addressed further in Chapter 8 Monitoring and Adaptive Management Plans.

7.2 IDENTIFICATION OF VALUED COMPONENTS

As discussed in Chapter 3, a VC based approach is intended to ensure that potential significant adverse effects to important environmental and social components will be detected and mitigated through the assessment process. Consistent with environmental assessment best practice, VCs for this assessment were identified based on the following considerations:

- Focal species and habitat (i.e., defining landscape attributes required to meet the needs of biota, and also the management regimes that should be applied to them);
- Representation (i.e., seeking to maintain an appropriate representation of ecosystem networks and populations on the landscape over time, while recognizing and managing for natural temporal fluctuations in composition that occur);
- Special elements (for example rare or under-represented ecosystems, rare and/or threatened flora or fauna species, important harvested species, and unique landforms);
- Socio-economic context (i.e., a socio-economic component recognized as being important because of its integral connection to, or reflection of, the socio-economic system; its commercial or economic value; and/or its role in maintaining quality of life in a community);
- Ecological processes (processes of social or environmental importance); and
- First Nation/Resident/Community values or concerns.

The selection of VCs helped to focus the assessment on components deemed to be of particular importance or of special interest to residents/users or to the ecosystem. The VC selection process also helped to define and describe effects pathways, and to identify temporal and spatial boundaries for the assessment of Project effects.

In this assessment, the analysis focuses on those environmental and socio-economic components that may potentially be affected by the Project. As such, the VCs selected for this assessment must be valued in environmental or socio-economic terms, and have some connection to or overlap with the Project that could create a pathway for effects to occur. VCs were identified through:

- Consultation with interested parties (as described in Chapter 4);
- Consideration of the environmental and socio-economic setting (as discussed in Chapter 5 and appendices). This includes field studies undertaken within the aquatic and terrestrial environments; heritage resources field studies; socio-economic data collection; a consideration of Traditional Knowledge and local knowledge and plans and policies applicable to the Project; and
- Consideration of the Project Description (as described in Chapter 6) and likely pathways of effect on the environmental and socio-economic setting.

During the consultation process, certain issues were identified that are of social or environmental importance related to the existing environment, but that do not have pathways of effect flowing from the Project (e.g., raptors, caribou, climate change, changes to existing fish passage); these topics are discussed in Chapter 4. The proposed Project is not anticipated to have effects related to these existing environmental concerns and as such no VCs have been defined related to these concerns for the current assessment.

Consistent with Environment Canada's *Environmental Assessment Best Practice Guide for Wildlife at Risk in Canada* (Lynch Stewart, 2004), all species at risk (that are either listed federally under the Species at Risk Act, or by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC)) that may be present in the proposed Project Regional Study Area were initially considered in the environmental VC scoping. As described in Chapter 5, bird species of conservation concern (Committee on the Status of Endangered Wildlife in Canada) known or likely to occur within the Mayo region include the following: Horned Grebe (special concern), Peregrine Falcon (special concern), Short-eared Owl (special concern), Common Nighthawk (threatened), Olive-sided Flycatcher (threatened), Barn Swallow (threatened) and Rusty Blackbird (special concern).

Nesting of Peregrine Falcons in the regional study area is unlikely and even if nesting did occur, effects of the Project on Peregrine Falcons or their habitat are extremely unlikely. As such Peregrine Falcon, which is a species at risk, is not considered as a VC for the purposes of this assessment. Similarly, although the environmental surveys included a survey of raptor nests to determine their relative abundance and distribution in the Project Regional Study Area, nest trees were located above the waterline in taller trees that are not expected to be affected by the Project. Therefore raptors are not considered a VC for this assessment.

Finally, well-chosen VCs can provide a representative measure of the Project's effects on the non-selected environmental and socio-economic components. Further, measures designed to mitigate adverse effects

on VCs also serve to minimize the likelihood of adverse impacts on other environmental and social components. For example, in this assessment two key aquatic environmental VCs were identified: lake trout and lake whitefish. While there are other aquatic fish species that may potentially be affected by the Project, the assessment related to these two VCs substantially addresses potential pathways of effect of the Project on other fish species. The Mayo Lake population of lake trout and lake whitefish were selected as VCs as they represent the dominant predator and prey species in Mayo Lake and are thus major components of the aquatic ecosystem and they appear to be more sensitive to water level changes due to general life history and spawning/rearing habitat requirements. Measures to protect or evaluate impacts for these species would also likely cover other shallow lake spawning and rearing by other fish species. It is anticipated that mitigation measures adopted relative to potential effects on these VCs will also be effective for other aquatic species.

The following sections summarize and characterize the VCs considered in this assessment.

7.2.1 Environmental Valued Components

This section provides a description of the environmental VCs considered in the effects assessment. Environmental VCs include both aquatic environment VCs and terrestrial environment VCs that are of particular concern in the Local Study Area and that may potentially be affected by the Project. Table 7-1 summarizes the Environmental VCs, the characterization of potential effects on the VC and the parties who identified the VC as a potential concern.

Table 7-1: Environment Valued Components Considered for the Assessment of the Mayo Lake Enhanced Storage Project

Key Interests	Valued Component	Identified by[1]:	Pathway of Potential Effect
Freshwater Fish and Habitat	Lake Trout Population	NND, OP, OG	Increase in winter drawdown range of Mayo Lake may result in potential increased dewatering and duration of dewatering of lake trout spawning areas, resulting in decreased egg survival during incubation.
	Lake Whitefish Population	NND, OG, OP	Increased operating range and reduction of the LSL of Mayo Lake may result in a change of the amount of shallow littoral rearing habitat quantity and fry growth and survival in early spring; and potential effects on spawning success for fish that may spawn in the lake not influenced by streamflow.

[1] NND = Government and Citizens of the First Nation of Nacho Nyak Dun; OP = Other Interested Persons; and OG = Federal, Territorial, or Municipal, Government.

Key Interests	Valued Component	Identified by[1]:	Pathway of Potential Effect
	Fish community productivity	OG	Increase in winter drawdown and reduced LSL of Mayo Lake water levels may affect the fish community productivity and species composition, Such changes may arise due to reduction in juvenile lake trout/lake whitefish abundance and/or changes in invertebrate/aquatic macrophyte communities. Over the longer term, ongoing small effects in terms of reduced growth and survival of sub adult and adult year classes of lake trout and lake whitefish could result in lower productivity and sustainable harvest potential and result in increased vulnerability to overharvest.
Wetland Type Habitat	Roop Lakes	NND, OP	Increase in winter drawdown range of Mayo Lake may alter wetland habitat quality in the Roop Lakes area.
	Shallow Water Littoral Areas at the ends of Roop and Nelson Arms	NND, OP, OG	Increased use of lowered LSL storage may potentially affect quality and quantity of shallow water littoral area in Roop Arm and Nelson Arm. This includes potential changes in aquatic macrophyte and in vertebrate communities and productivity.
	Ducks, Geese and Migratory Birds	NND, OP, OG	Increased winter drawdown and water level management range with reduced LSL may potentially affect waterfowl breeding and staging areas in the wetland areas at the end of Roop Arm and Nelson Arm.
Aquatic Mammals	Aquatic Furbearers – Beaver/Muskrat	NND, OG	Increased winter drawdown and water management range and reduced LSL of Mayo Lake may directly affect lake shoreline habitat resulting in challenges exiting and entering lodges; likely will lead to effects on beaver & muskrat (access to food caches; increased predation) in the lake proper only during the winter months. Adjacent systems such as the Roop Lakes area will not be affected.
Mammals	Moose	NND, OG	Mayo Lake water level fluctuations may affect littoral and wetland moose habitat. Potential changes to forage distribution, quality and/or quantity.

7.2.2 Socio-Economic Valued Components

This section provides a description of the Socio-economic VCs considered in the effects assessment. Socio-economic VCs include components related to traditional and domestic resource use (including commercial trapping); other resource use (including placer mining, tourism, outfitting, outdoor recreation, and private & commercial land use); and regional economy. Table 7-2 summarizes the socio-economic VCs, the characterization of potential effects on the VC and the parties who identified the VC as a potential concern.

Table 7-2: Socio-Economic Valued Components Considered for the Assessment of the Mayo Lake Enhanced Storage Project

Key Interests	Valued Component	Identified by[2]:	Pathway of Potential Effect
Traditional and Domestic Resource Use	Hunting - Access	NND, OP	Mayo Lake water level fluctuations may potentially affect access for hunting in some years in the spring (i.e., boat access to Roop Lakes Complex).
	Fishing - Access	NND, OP	Lower water levels in spring may affect access for a short time period in late May/early June.
	Fishing – Harvest Success	NND	Mayo Lake water level fluctuations may indirectly affect fish harvest success.
	Trapping - Access	NND, OP	Access to trapping activities at Mayo Lake will not be adversely affected.
	Trapping - Success	NND, OP	Trapping success for beaver may be affected due to less beaver along the Mayo Lake shoreline (including the ends of Roop and Nelson arms).
Other Resource Use	Placer Mining - Access	OP	Short-term effects in late May/early June (after ice-off) may affect placer miners using the barge access in the outlet channel and shoreline access to claims.
	Tourism, Outfitting and Outdoor Recreation	NND, OP	Increased winter flows may affect snowmobiling and access to trails along the Mayo River Zone 4 if suspended ice occurs in late winter/early spring. Lower early spring water levels on Mayo Lake may affect timing and ability to use beach and boat launch at west end of Mayo Lake.

[2] NND = Government and Citizens of the First Nation of Nacho Nyak Dun; OP = Other Interested Persons; and OG = Federal, Territorial, or Municipal, Government.

Key Interests	Valued Component	Identified by[2]:	Pathway of Potential Effect
	Private & Commercial Land Use	OP, OG	Lower early spring water levels on Mayo Lake may affect water access to commercial and private lease-holders (including placer miners) and property owners at Mayo Lake. Increased winter flows from Mayo Lake to Wareham Lake – there is no expectation of an adverse effect on private lease-holders and property holders between Mayo Lake and Wareham Lake.
Regional Economy	Government Fiscal Flows	NND	Yukon Energy and NND have reached an investment agreement; NND has the opportunity to accrue benefits in the form of financial returns commensurate with their investment.
	Utility Ratepayers	NND, OP, OG	Improved system capability and reliability through new renewable power generation at stable costs, and reduced fossil fuel generation costs to service future load growth. Reduced reliance on fossil fuel generation to meet the growing demand will reduce greenhouse gas emissions as per Yukon Government policy.

7.3 ASSESSMENT OF EFFECTS

As reviewed in Chapter 3 (Section 3.2), for the purpose of assessing environmental and socio-economic effects of the Project, current conditions in areas potentially affected by the Project and the projected evolution of these conditions without the Project are considered. Project effects on existing conditions are predicted for each environmental and socio-economic VC by comparing (a) "what would be expected in the future without the Project" and (b) "what would be expected in the future with the Project".

7.3.1 Assessment of Effects on Environmental Valued Components

Section 7.3.1 provides assessment of Project effects and mitigation measures with regard to the following environmental VCs:

- Lake trout population;
- Lake whitefish population;
- Fish community productivity;
- Roop Lakes;
- Shallow water littoral habitat at the ends of Roop and Nelson arms;
- Ducks, geese and migratory birds;
- Aquatic furbearing mammals – Beaver; and
- Moose.

With respect to cumulative effects, the effects assessment considers several existing environment activities, including fishing and recreation, and sediment releases and transport related to various existing activities in the Project Regional Study Area. No specific future changes to these existing conditions are identified based on other projects known to be occurring in the future; therefore, current conditions are expected to continue.

Table 7-3 summarizes the effects assessment for each of the environmental VCs. More detail on certain specific effects on environmental VCs is provided below.

Table 7-3: Environmental Effects Assessment

ID #	Description/Nature of Potential Project Effect	Mitigation	Cumulative Effects Assessment	Residual Effects after Mitigation	Effect Attribute Ratings & Determination of Significance	Monitoring/Follow-up
Lake Trout Population						
1	Increase in winter drawdown range of Mayo Lake may result in potential increased dewatering of lake trout spawning areas, resulting in decreased egg survival during incubation.	• 1 in 3 year rest rule. • Experimental deepwater spawning habitat enhancement and/or use of temporary covers to direct choice of spawning habitat. • Progressive water management responses as specified in the AMP. • Reduce dewatering period by delaying the timing of drawdown if necessary and/or faster early spring refilling by reducing outflows (within operational and licensing constraints).	• Potential increased harvest pressure especially by anglers who select for large spawning size fish; this would reduce resilience of the population.	• Potential short-term adverse effects on lake trout spawning and incubation success. • No long-term adverse effects on lake trout at the population level.	• Direction: Adverse • Magnitude: Moderate • Geog. Extent: Low • Duration: Short-term • Frequency: Moderate • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	• Comprehensive field monitoring program with annual reporting and review of results. • Adaptive management with defined thresholds and rules. • Annual meeting with Mayo RRC and local residents to review field monitoring results and collect local and TK observations (see details in Monitoring and AMP).
Lake Whitefish Population						
2	Increased operating range and reduction of LSL of Mayo Lake may result in some potential short-term decrease in shallow littoral rearing habitat quantity and fry growth and survival in early spring, especially in the end of Nelson Arm; and potential effects on lake spawning success.	• 1 in 3 year rest rule. • Progressive water management responses as specified in the AMP. • Faster early spring refilling by reduction of outflows if necessary (within operational and licencing constraints).	• Potential increased harvest pressures by subsistence gillnet fishers in the future.	• Potential short term adverse effects on lake whitefish rearing, growth and survival of fry. • No long-term adverse effects on Lake whitefish populations.	• Direction: Adverse • Magnitude: Small to Moderate • Geog. Extent: Low to Moderate • Duration: Short-term • Frequency: High • Reversibility: Reversible • Ecological/SE Context: Moderate No significant adverse effect.	• Comprehensive field monitoring program with annual reporting and review of results. • Adaptive management with defined thresholds and rules. • Annual meeting with Mayo RRC and local residents to review field monitoring results and collect local and TK observations.

ID #	Description/Nature of Potential Project Effect	Mitigation	Cumulative Effects Assessment	Residual Effects after Mitigation	Effect Attribute Ratings & Determination of Significance	Monitoring/Follow-up
Fish Community Productivity						
3	Increase in winter drawdown and reduced LSL of Mayo Lake water levels may affect the fish community productivity in terms of reduced survival and growth, especially in terms of Lake trout incubation success and juvenile lake whitefish rearing in shallow littoral habitat, at the ends of Roop and Nelson arms. Over the longer term, ongoing small effects in terms of reduced growth and survival of sub adult and adult year classes could result in lower productivity and sustainable harvest potential and result in increased vulnerability to overharvest.	• 1 in 3 rest rule. • Progressive water management responses as specified in the AMP. • Ongoing evaluation of monitoring data to determine if long term small changes (i.e., chronic effects) are occurring. • Periodic harvest monitoring to allow for timely changes to harvest management if necessary.	Increased harvest pressure by anglers on adult lake trout spawners could result in fish community changes including an increase in abundance of other prey fish species.	• No likely short to medium effects but over long term fish community could change in terms of reduction in lake trout and lake whitefish populations and increased abundance of other species especially with increased harvest pressure.	• Direction: Adverse • Magnitude: Moderate • Geog. Extent: Moderate • Duration: Medium Term • Frequency: Moderate • Reversibility: Reversible • Ecological/SE Context: Moderate No significant adverse effect.	• Comprehensive long term monitoring program involving hydro acoustic surveys and SPIN netting and other interim sub-adult and adult monitoring. • Adaptive management with defined thresholds and rules including changes in year class strength of Lake trout and Whitefish; long term overall combined abundance as the major predator/prey species that remains within the range of natural variability for healthy Yukon populations. • Annual meeting with Mayo RRC and local residents to review field monitoring results and collect local and TK observations.
Roop Lakes						
4	Increase in winter drawdown range of Mayo Lake may alter wetland habitat quality in the Roop Lakes area.	None required (see Monitoring and Follow-up).	None identified.	• None.	• Direction: Positive • Magnitude: Moderate • Geog. Extent: Moderate • Duration: Long-term • Frequency: Moderate • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	• A follow-up wetland health assessment in 5-10 years post Project to compare the Pre-Project assessment of 2010. • Monitoring of water elevations in Roop Lakes to confirm independency from Mayo Lake at lower water levels. • Monitoring of water levels in Roop Lakes in response to changes in water level management of Mayo Lake.

ID #	Description/Nature of Potential Project Effect	Mitigation	Cumulative Effects Assessment	Residual Effects after Mitigation	Effect Attribute Ratings & Determination of Significance	Monitoring/Follow-up
Shallow Water Littoral Areas at the ends of Roop and Nelson arms						
5	Increased use of lowered LSL storage may potentially affect quality and quantity of shallow water littoral area in Roop Arm and Nelson Arm. This includes potential changes in aquatic macrophyte communities and invertebrate productivity.	• Progressive water management responses as specified in the AMP.	None identified.	• Potential shifts in aquatic macrophyte community and invertebrates.	• Direction: Positive and/or Adverse • Magnitude: Moderate • Geog. Extent: Low • Duration: Medium to Long-term • Frequency: High • Reversibility: Reversible • Ecological/SE Context: Moderate No significant adverse effect.	• Comprehensive field monitoring program (focus on fish use of these habitats) with annual reporting and review of results. • Periodic sampling of aquatic macrophytes. • Annual meeting with Mayo RRC and local residents to review field monitoring results and collect local and TK observations.
Ducks, Geese and Migratory Birds						
6	Increased winter drawdown and water level management range with reduced LSL may potentially affect waterfowl breeding and staging areas in the wetland areas at the end of Roop Arm and Nelson Arm.	None required.	None identified.	• Potential shifts in locations for waterfowl breeding and staging areas within the Mayo Lake watershed.	• Direction: Neutral No significant adverse effect.	• Incidental collection of Post Project bird observations. • Annual meeting with Mayo RRC and local residents to collect local and TK observations.
Aquatic Furbearing Mammals						
7	Increased winter drawdown and water management range and reduced LSL of Mayo Lake may directly affect lake shoreline habitat, resulting in challenges exiting and entering lodges; likely will lead to effects on beaver & muskrat (access to food caches; increased predation) in the lake proper only. Adjacent systems such as the Roop Lakes area will not be affected.	None required.	None identified.	• Potential for adverse effects on aquatic furbearers due to reduced water levels in winter and reduced overwintering habitat.	• Direction: Adverse • Magnitude: Low • Geog. Extent: Low • Duration: Long term • Frequency: High • Reversibility: Reversible (at project decommissioning or if storage range reduced) • Ecological/SE Context: Low No significant adverse effect.	• Post Project observation of use of lake lodges through technical, local and traditional knowledge.

ID #	Description/Nature of Potential Project Effect	Mitigation	Cumulative Effects Assessment	Residual Effects after Mitigation	Effect Attribute Ratings & Determination of Significance	Monitoring/Follow-up
Moose						
8	Mayo Lake water level fluctuations may affect littoral and wetland moose habitat. Potential changes to forage distribution, quality, and/or quantity.	• None required.	None identified.	• None.	• Direction: Adverse • Magnitude: Low • Geog. Extent: Low • Duration: Long term • Frequency: High • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	• Incidental collection of Post Project moose observations. • Annual meeting with Mayo RRC and local residents to collect local and TK observations.

7.3.1.1 Lake Trout Population

Lake trout are the most abundant and dominant predatory fish in Mayo Lake and therefore perform important ecological functions in terms of fish community stability and balance. Lake trout are also most sought after for recreational and subsistence fisheries. Lake trout are a cold water fish species well adapted to large lakes and are found in numerous lakes throughout much of the Yukon.

As determined by 6 years of baseline data collection, the peak spawning activity for lake trout occurs during the last week of September. Lake trout are broadcast spawners and eggs are deposited over loosely sorted cobble/boulder areas in a number of areas of Mayo Lake; Gull Island is the primary spawning site with secondary spawning sites in the Main Arm and western portion of Roop Arm. Eggs incubate within the substrate over the winter months, hatch during the spring and emerge as a fry when the lake becomes free of ice in early June.

Determining the water depth of egg deposition was a key component of aquatic baseline studies conducted from 2009 to 2014. This was accomplished through the use of egg collector bins which allow for a density of eggs to be measured across a range of depths (Figure 7-1). When data from all years are combined, eggs have been captured at full supply depths of 1.4 to 4.2 m with peak deposition in the 2.5 to 3.5 m range. As the lake is not always at the full supply level during spawning, it is also possible to view the egg collector data in terms of spawning water depths[3] where eggs were captured at depths ranging from 1.0 to 3.9 m with the peak deposition in the 2.0 to 3.0 m range. Refer to aquatic baseline reports 2009 - 2014 in Appendix 5A for additional information on egg collector results.

Figure 7-1: Lake Trout Egg Collector

Lake trout egg incubation studies were done in combination with the egg collector studies to determine how lake trout egg survival is influenced by water level management during the incubation period (Figure 7-2; Figure 7-3; Figure 7-4). Conducted for 4 years, these studies involved the collection of a small number of spawning adults, the onsite fertilization of eggs, placement of eggs into incubators and deployment into the lake across a range of depths. When retrieved the following spring, it is possible to determine how winter drawdown influenced survival of eggs exposed to differing amounts and duration of dewatering. The results of these studies indicate that lake trout eggs are resilient and are able to

[3] Spawning water depths refer to the depth of water at the time of spawning (last week of September) whereas full supply depths refer to the depth of water when the lake is at the full supply level.

survive despite being dewatered during the winter months provided that they are rewatering prior to ice off (emergence period) of the lake and ice cover/snow is maintained through the dewatering and rewatering period. The level of survival of dewatered eggs is dependent on dewatering duration. For example, egg survival for incubators dewatered up to 8 weeks was within the range of variation of non-dewatered incubators. When dewatering increased to 9 weeks or greater, there was a notable trend of decreased survival with an increased duration of dewatering. The ability for salmonid eggs to survive in dewatered conditions has been documented in published literature on the subject. Refer to aquatic baseline reports 2009-2014 and Attachment 5A-7 in Appendix 5A for additional information on egg incubation studies and the ability for eggs to survive dewatered conditions.

Figure 7-2: Collecting Lake Trout Eggs

Figure 7-3: Lake Trout Egg Incubators Deployed in the Lake Bed

The proposed reduction in LSL and increased overwinter drawdown may result in potential increased dewatering of lake trout spawning areas and increased duration of dewatering, resulting in decreased egg survival during incubation. In order to predict how the change in water management may influence lake trout egg survival, egg collector and egg incubation data was used to develop a model which combined modelled lake elevation data with existing egg deposition and survival data. The results of this

model (Appendix 5A, Attachment 5A-7 – Lake Trout Egg Survival technical memo) indicate that there may be a decrease in egg survival during some years; however, there are also a number of years where egg survival is very high and similar to Pre-Project levels. The modelling exercise also indicated the importance of spring water levels on egg survival, in particular the magnitude of spring water level increases prior to complete ice off on the lake during early June. A rapid increase in water levels during the month of May provides the potential to rewater eggs that were dewatered during the winter months and thus allow for increased survival of these eggs. Reducing the duration of dewatering and/or modifying the timing of water level fluctuations has the potential to result in higher egg survival.

Since baseline data collection activities specific to Mayo Lake began in 2009, lake trout eggs have been captured at full supply depths[4] of 1.4 to 4.2 metres at the main Gull Island spawning area, the primary spawning site in the lake. Despite predicted reductions in egg survival during some years, lake trout are long-lived species, which may spawn for 10-20 years and as such are somewhat resilient to variable year-to-year spawning success. They are also known for their adaptability to changing conditions[5]. Existing sources of data (historic and baseline) for Mayo Lake indicate that there are normal distributions of age and size ranges of lake trout despite the lake being used as a reservoir since the 1950s. For example, 2010 index netting data for the period of time when more of the existing storage range was used (1980s) indicate that successful lake trout recruitment was occurring every year, and there do not appear to be relationships between age class strength and magnitude of winter drawdown/minimum winter elevation.

Potential increased harvest pressure, especially from anglers who select for large spawning size fish, could act cumulatively in the future, thus reducing the resilience of the population to the effects of water level management.

Figure 7-4: Lake Trout

Mitigation and Monitoring

The primary mitigation for the Project includes the application of monitoring results to a well-designed Adaptive Management Plan (AMP; Appendix 8A) with well-defined thresholds and responses. An adaptive

[4] Full supply depths refers to the water depths measurements based on the water level being at the full supply level (665.87 m); Spawning water depths are depths based at the peak time of lake trout spawning for a particular year (last two weeks of September).

[5] Refer to Aquatic Baseline reports in Appendix 5A.

management approach is acceptable given the Project and project effects are reversible and lake trout are a long lived species that may spawn multiple (10-20) times during their lifespan. The extensive baseline studies and lake trout egg survival modelling help to predict Project effects on lake trout. The AMP will ensure that effects are detected and addressed in a timely fashion to ensure that long term effects to lake trout do not occur.

The AMP is driven by an extensive monitoring plan for the Project. The monitoring plan includes a number of components which focus on lake trout and will include the following (see Chapter 8 and Appendix 8A Monitoring Plan for details). The collection of monitoring data for several life stages from egg to juvenile and adult is intended to ensure that any potential effects of the Project are detected and addressed in a timely fashion without causing long term harm to the lake trout population.

- Lake trout spawning and incubation through egg collectors and incubators to monitor changes in spawning and incubation success at the primary spawning site;
- Beach seining of juvenile lake trout to provide an index of young-of-the-year (YOY) abundance and monitor spawning, incubation and rearing success;
- Hydroacoustic surveys to provide an index of sub-adult lake trout to monitor overall recruitment of a number of year classes and support the results of the YOY monitoring (i.e., beach seining); and
- Summer Profundal Index Netting (SPIN) of large sub-adult and adult lake trout is proposed to monitor long-term change to large juvenile and adult Lake trout populations and year class abundance and variability.

As originally proposed in the Mayo B YESAA Proposal, Yukon Energy will implement a one year-in-three rest rule, which states that in the event that winter drawdown exceeds 2.59 metres for two years in a row, the third year's drawdown will be equal to or less than 2.59 metres. Maintaining the existing maximum water level drawdown of 2.59m (as described in Chapter 6) in at least one out of any three year period, at a minimum, should provide a safeguard to allow successful spawning and incubation in these years.

Experimental lake trout spawning habitat rehabilitation of potential deepwater spawning areas at key spawning locations (i.e., Gull Island) has been initiated and will be continued and expanded in accordance with the AMP (see the Monitoring Plan in Appendix 8A) (Figure 7-5; Figure 7-6). The frequency of additional cleaning will depend on the rate of sedimentation as observed during the monitoring, as well as overall level of usage by spawning lake trout. A description of the deep substrate cleaning trials and results are provided in Appendix 5A – 2013 and 2014 Baseline Studies Report. Additionally or alternatively, the use of temporary covers to direct choice of spawning habitat may also be employed as an experimental mitigation measure (it has been done successfully in other southern lakes) to potentially increase lake trout egg survival by limiting access to shallow water areas subjected to longer periods of winter dewatering and thus decreased egg survival.

Figure 7-5: Deepwater Lake Trout Spawning Habitat Before Rehabilitation

Figure 7-6: Deepwater Lake Trout Spawning After Rehabilitation

An alternative method of increasing lake trout egg survival may be to reduce the duration of dewatering of eggs by delaying the timing of drawdown if necessary, and/or faster early spring refilling by reducing outflows during the month of May (if feasible and within operational and licensing constraints for the upper and lower Mayo River).

Monitoring data will be reviewed on an annual basis by the Mayo Lake Project Management Committee (MLPMC), a joint committee comprised of YEC and NND representatives and an advisory group comprised of members from the Mayo District RRC and regulators (Yukon Environment). The data will be reviewed in a timely manner each year to allow for AMP responses and/or mitigation measures to be applied during the following year. This will ensure that in the event that the identified thresholds are breached, the appropriate AMP response is made in a timely fashion.

To summarize, lake trout monitoring will include the following (see Chapter 8 and Appendix 8A Monitoring Plan for details):

- Immediate Indicator: Lake trout spawning and incubation through egg collectors and incubators to monitor changes in spawning and incubation success;
- Immediate Indicator: Beach seining of juvenile Lake trout to monitor spawning, incubation and rearing success;
- Near to Medium Term Indicator: Hydroacoustic surveys of sub-adult Lake trout to monitor sub-adult recruitment to support the results of the early year class monitoring (i.e., beach seining); and
- Long-Term Indicator: Summer Profundal Index Netting of adult Lake trout to monitor long-term change to large juvenile and adult Lake trout populations.

The independent expert hired by the Technical Working Group, Dr. Drew Bodaly, reviewed the monitoring plan and the AMP and concluded that risk of irreversible, long-term harm to lake trout populations was low given the implementation of these plans (see Appendix 8C for further details on Dr. Bodaly's report).

Determination of Significance

In summary, residual adverse effects on lake trout are expected to be moderate in magnitude (may be small if in the range of natural variability and harvest pressures remain low), short-term in duration, low in geographic extent, of moderate frequency, reversible, and ranks low in ecological context. Overall, Project effects are deemed **not significant**.

7.3.1.2 Lake Whitefish Population

Lake whitefish are the dominant and most abundant prey fish species found in Mayo Lake and are the primary food source for predatory fish in the lake including lake trout, northern pike and burbot. Lake whitefish are found throughout a wide range of habitats in the Yukon including large deep lakes and shallower more productive waterbodies. Tagging studies and juvenile fish sampling conducted during the baseline studies have indicated that the majority of lake whitefish spawning in the Mayo Lake system occurs in large tributary streams to the lake and in areas where these streams flow into the lake; spawning was confirmed in Edwards, Roop, Granite and Nelson creeks (Figure 7-7). It is possible that lake whitefish have adapted to spawn in or adjacent to tributary streams since the impoundment of the lake in the 1950s although stream spawning has been documented in other areas of the Yukon for this species. The timing of spawning is somewhat variable and is determined by water temperatures with stream spawning occurring earliest (late September), followed by stream mouth areas in mid-October and lake spawning after mid-November.

Figure 7-7: Lake Whitefish Spawning Area in a Tributary to Mayo Lake (Upper Roop Creek)

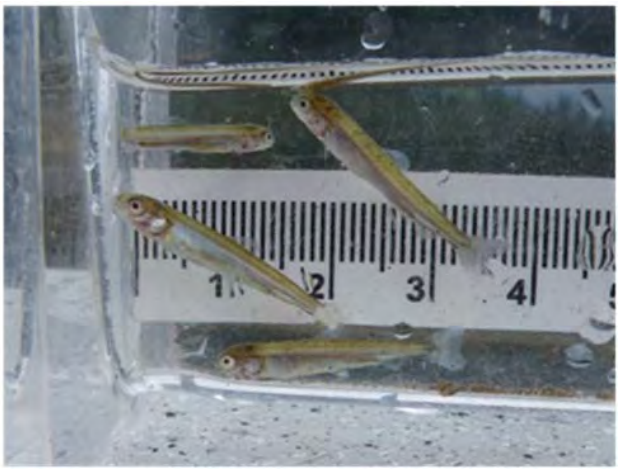
Lake whitefish have a reproductive strategy that involves large numbers of small eggs and fry with minimal yolk sacs and less swimming ability compared to other salmonids such as lake trout. They spawn in areas where early spring river and wind lake currents will deposit the fry in warm shallow waters that are productive in terms of planktonic food when the main part of the lake is still frozen. Thus shallow littoral and wetland areas such as the ends of Roop and Nelson arms that become ice free and warm up weeks before ice off are critical to survival of lake whitefish fry (Figure 7-8; Figure 7-9) (see Appendix 5A – Mayo Lake Aquatic Baseline Studies 2010 for additional information on ice off conditions). It is important to note that Roop Lakes constitute an important early rearing habitat for lake whitefish and a number of tagged lake whitefish from Mayo Lake were found to migrate to Roop Creek upstream of the lakes for spawning.

The proposed reduction in LSL and lower spring water levels may result in changes to the amount of shallow water littoral habitat in Mayo Lake for lake whitefish fry during the spring (mid-May). A reduction is predicted (see Appendix 5A, Attachment 5A-8 Lake Whitefish Early Spring Rearing Habitat technical memo) at the end of Nelson Arm where lower water levels result in less shallow water habitat due to the bathymetry of the lake bed in this area. The bathymetry at the end of Roop Arms differs from Nelson Arm in that lower water levels will result in an increased amount of shallow water habitat available in this area.

It is possible that a reduction in shallow water habitat quantity during the important spring rearing period may have a potential effect on fry growth and survival in Nelson Arm. There is also potential for water level changes to have minor effects on egg survival in lake spawning areas; however, these are not expected to be considerable due to the presence of flowing water in the vicinity of these areas.

Figure 7-8: Early Spring Lake Whitefish Rearing Habitat in Nelson Arm

Figure 7-9: Lake Whitefish Fry



Despite predicted reductions in spring rearing habitat during some years, lake whitefish are long-lived species that may spawn for 10 years or more and as such are somewhat resilient to variable year-to-year spawning success. In populations not affected by water management, periodic reductions in juvenile recruitment have not resulted in long term reductions in adult abundance. This is supported by population status data from other large Yukon lakes that show considerable variation in age class strength (see Appendix 5A – Mayo Lake Aquatic Baseline Studies 2010). Existing sources of data (historic and baseline) for Mayo Lake indicate that there are normal distributions of age and size ranges of lake whitefish despite the lake being used as a reservoir since the 1950s.

Potential increased harvest pressures by subsistence gillnet fishers in the future could act cumulatively, reducing overall numbers of lake whitefish in Mayo Lake and thus reducing the resiliency of the population to respond to changes in water management.

Mitigation and Monitoring

The primary mitigation for the Project includes the application of monitoring results to a well-designed Adaptive Management Plan (AMP; Appendix 8B) with well-defined thresholds and responses. An adaptive management approach is acceptable given the Project and its potential effects do not pose the risk of

serious irreversible harm and also that lake whitefish are a long lived species that spawn multiple times during their lifespan. The extensive baseline studies and lake whitefish rearing habitat area analysis help to predict Project effects on lake whitefish. The AMP will ensure that effects are detected and addressed in a timely fashion to ensure that long term effects to lake whitefish do not occur.

The AMP is driven by an extensive monitoring plan for the Project. The collection of monitoring data for numerous life stages is intended to ensure that any potential effects of the Project are detected early and are addressed without any long term harm accruing to the lake whitefish population. The monitoring plan includes a number of components which focus on lake whitefish and will include the following (see Chapter 8 and Appendix 8A Monitoring Plan for details):

- Immediate Indicator: Beach seining of juvenile lake whitefish to provide an index of young-of-the-year (YOY) abundance and monitor early changes (i.e., in the year they occur) due to spawning, incubation and rearing success (Figure 7-10);
- Near to Medium Term Indicator: Hydroacoustic surveys to provide an index of sub-adult lake whitefish (along with lake trout) to monitor overall recruitment of a number of year classes and support the results of the YOY monitoring (i.e., beach seining); Shallow water small mesh netting to monitor changes in relative age class strength of sub-adult lake whitefish; and
- Long-Term Indicator: Index netting and/or SPIN surveys to monitor long-term changes in age class strength of adult lake whitefish and overall species composition in the lake.

Figure 7-10: Beach Seining for Juvenile Lake Whitefish

As described above, the one in three rest rule will maintain the existing maximum water level drawdown of 2.59 m in at least one out of a three year period (at a minimum), which may reduce effects on lake spawning in these years and result in an increased amount of spring rearing habitat availability in shallow water littoral areas at the ends of Roop and Nelson arms due to higher spring water levels with the reduced overwinter drawdown.

An alternative method of increasing early season juvenile lake whitefish survival may be to allow for faster early spring refilling by reducing outflows during the month of May (if feasible and within operational and licensing constraints for the upper and lower Mayo River). This would result in increased shallow water littoral habitat availability at the ends of Roop and Nelson arms.

The independent expert hired by the Technical Working Group, Dr. Drew Bodaly, reviewed the monitoring plan and the AMP and concluded that risk of irreversible, long-term harm to lake whitefish populations was low given the implementation of these plans (see Appendix 8C for details on Dr. Bodaly's report).

Determination of Significance

In summary, residual adverse effects on the lake whitefish population are expected to be small to moderate in magnitude, short-term in duration, low to moderate geographic extent, high frequency, reversible, and ranks moderate in ecological context. Overall, Project effects are deemed **not significant**.

7.3.1.3 Fish Community Productivity

The proposed increased storage range of Mayo Lake may potentially affect fish community productivity as a result of many factors that may include a reduction in juvenile lake trout and lake whitefish abundance, changes in plant or invertebrate communities and productivity and/or increase in harvest pressure. A reduction in the proportion of lake trout and lake whitefish in the lake may lead to shifts in overall species composition within the lake. For example, some Yukon lakes that have historically had high lake trout harvest pressure have experienced a shift in species composition with more adaptable and prey species such as burbot, longnose sucker and round whitefish becoming more common than lake trout and lake whitefish (inferred from index netting results – Mayo Lake Aquatic Baseline Studies 2010).

Mitigation and Monitoring

Mitigation measures include the one in three rest rule described above, progressive water management responses specified in the AMP, and periodic harvest monitoring to allow for timely changes to harvest management if necessary.

Monitoring related to fish community productivity includes the following (see Chapter 8 and Appendix 8A Monitoring Plan for further details):

- Hydroacoustic surveys to provide an index of lake whitefish to monitor overall recruitment of a number of year classes and support the results of the YOY monitoring (i.e., beach seining);
- SPIN surveys to monitor long-term changes in lake trout abundance with incidental information on age class strength;
- Index netting and small mesh netting surveys to monitor long-term changes in age class strength of lake whitefish and determine overall species composition in the lake; and
- Harvest monitoring every five years Post-Project to provide a measure of fishing pressure and harvest.

Determination of Significance

In summary, residual adverse effects on the lake whitefish population are expected to be moderate in magnitude, medium-term in duration, moderate geographic extent, moderate frequency, reversible, and rank moderate in ecological context. Overall, Project effects are deemed **not significant**.

7.3.1.4 Roop Lakes

The Roop Lakes wetland is a wetland complex located to the northeast of Mayo Lake (Figure 7-11). The wetland covers an area of approximately 12 km^2 (de Graff 2010) and is a complex network of lakes, ponds and interconnected channels. The wetland is drained by Roop Creek, which includes one major tributary (Granite Creek), and flows into Mayo Lake at the eastern end of Roop Arm. Edwards Creek, an important spawning area for lake whitefish enters Roop Creek immediately upstream of Mayo Lake.

An increase in storage range of Mayo Lake, which will involve somewhat lower average summer water levels, increased winter drawdown and lower spring water levels on Mayo Lake may alter wetland habitat quality in the Roop Lakes area. NND and Can-nic-a-nick Environmental Sciences undertook a Roop Lakes Wetland Health Assessment in 2009/10 (see Appendix 5A, Attachment 5A-14 for details) and concluded the following:

- The pond closest to Mayo Lake (Pond 1) had diminished biological diversity and richness, increased presence of decaying organic matter, low abundance of sensitive species and high abundance of a single invertebrate group compared to Ponds 2 and 3, which are further upstream from Mayo Lake;
- There was diminished evidence of impact as one moved upstream into the Roop Lakes system (towards Ponds 2 and 3);
- There was no evidence of impact from water management of Mayo Lake on upper most water body sampled (Pond 3); and
- The Roop Lakes wetland is important habitat for flora, fauna and rearing and spawning habitat for some species of fish.

Figure 7-11: Roop Lakes Wetland Complex

In addition to the Roop Lakes Wetland Health Assessment, KGS Group undertook a backwater study in 2008 to understand the effects of Mayo Lake water levels on the hydraulic conditions of Roop Creek and Roop Lakes (see Appendix 5, Attachments 5A-16 and 17).

In general, the extent of backwater effects and the threshold water levels at which these occur vary with higher or lower flow levels coming out of Roop Creek. When flows in Roop Creek are low, the Roop Lakes

complex is more susceptible to backwater effects from Mayo Lake. The Mayo Lake elevations that result in backwater effects on Roop Lake include the following:

- In the lowermost portion of the wetland (closest to Mayo Lake), the minimum Mayo Lake water elevation (El.) that causes backwater effects ranges from El. 664.0 m at low Roop Creek flows (1 m^3/s or less) to El. 664.8 m at high Roop Creek flows (25 m^3/s or more).
- In the uppermost portion of the wetland (furthest from Mayo Lake), the minimum Mayo Lake elevation that causes backwater effects ranges from El. 664.3 m at low Roop Creek flows (1 m^3/s or less) to El. 665.0 m at high Roop Creek flows(25 m^3/s or more).

The results of the wetland health assessment and the backwater effects study are consistent and indicate that the portion of Roop Lakes immediately upstream of Mayo Lake is frequently watered and rewatered as a result of backwater effects from the lake and this is reflected by more lake like characteristics rather than wetland characteristics conditions in this area. With the proposed changes in water management on Mayo Lake, water levels will be lower on average and Roop Lakes will be backwatered less frequently as a result. This should be considered a positive or neutral effect. Less frequent backwatering of the wetlands closer to Mayo Lake will be more similar to the pre-impoundment condition of this area and may allow for the area to stabilize.

Mitigation and Monitoring

Based on the results of the studies described above and in Appendix 5A, it is not anticipated that mitigation will be required.

It is expected that the Project will have a positive or neutral effect on lower pond inundation with shallow water levels and more exposed shoreline that may result in stabilization of this wetland. There are no anticipated effects on the upper Roop wetlands. The Monitoring Plan includes a follow-up wetland health assessment in 5-10 years and 3 years of Post-Project water level monitoring in Roop Lakes at varying distances from Mayo Lake. The results of this monitoring will be compared to Pre-Project data to determine if there are any discernible effects due to the Project.

Determination of Significance

In summary, Project effects on wetlands are expected to be positive and long-term in duration. No further assessment is presented.

7.3.1.5 Shallow Water Littoral Areas at the ends of Roop and Nelson Arms

Baseline studies conducted from 2008 to 2010 identified that the primary lake whitefish spawning areas were located in tributaries to the lake (i.e., Roop, Granite, Edwards and Nelson creeks) and near the outlet of Nelson Creek. In early spring, larval lake whitefish originating in the spawning tributaries emerge and are transported downstream into the shallow water areas within the Roop Lakes wetlands and at the ends of Roop and Nelson arms in Mayo Lake (Figure 7-12). The Roop Lakes wetlands provide a relatively large area of productive shallow water habitat that is not subjected to water level management conditions on Mayo Lake. A larval whitefish drift sampling program conducted during the spring of 2010 documented the downstream movement of larval lake whitefish in the spawning streams from late April until early June, with the highest numbers captured in mid-May. Beach seining conducted

in June and July throughout the lake from 2009 to 2014 has identified the shallow water areas at the ends of the arms as the most important lake whitefish rearing areas in the lake.

Figure 7-12: Shallow Water Littoral Area of Mayo Lake (Roop Arm)

Wetland and shallow littoral areas at the ends of the lake arms become ice free up to a month prior to other areas of the lake due to the inflow of warmer water from tributaries and the presence of shallow water that warms quickly during the spring. These rapidly warming waters provide productive early spring rearing habitat and feeding areas for newly hatched lake whitefish fry.

As noted in Chapter 6, Project Description, the Project will result in increased use of the lower portion of the storage range and lower spring water levels, which may potentially affect the quality and quantity of shallow water littoral area in Roop and Nelson arms. This includes potential changes in aquatic macrophyte and invertebrate communities and productivity.

The presence of aquatic macrophytes in shallow water littoral areas at the ends of Roop and Nelson arms are a distinguishing characteristic of these areas. Aquatic macrophyte surveys conducted during 2010 and 2013 (see Appendix 5A – Mayo Lake Aquatic Baseline Studies) indicate that a variety of aquatic macrophyte species can be found in this area including tall erect plants (ex - *Potamogeton richardsonii*), short plants (*ex - Callitriche hermaphroditica)* and mat forming species (charaphytes). Aquatic macrophytes provide a variety of important ecological processes in shallow water littoral areas of Mayo Lake including water oxygenation, nutrient cycling, provision of shelter for fish and habitat for plankton and invertebrates that are eaten by fish.

With the proposed changes in water management on Mayo Lake, changes in the distribution and relative abundance of the three different plant types are likely to occur. Increasing the magnitude of water level fluctuations may result in a shift towards a higher relative abundance of short and mat forming species such as *Chara* sp., *Callitriche* sp. and *Eloecharis* sp. at the expense of tall, erect species such as *Potamogeton* sp. (Wilcox and Meeker 1990; Hellsten 2002).

In addition to aquatic plants, it is possible that larger water fluctuations may result in changes to the invertebrate communities in these areas, which are the primary food source of lake whitefish in Mayo Lake. With larger water level fluctuations, adaptable invertebrates such as the chironimids are likely to increase (Hunt and Jones 1972) due to a rapid life cycle and strong dispersal abilities. Other invertebrates that have been found to increase with larger fluctuations include amphipods, copepods and oligocheates (McEwen and Butler 2010, Furey et al. 2006, Hunt and Jones 1972). Overall diversity typically decreases in reservoirs with greater diversity often found directly below the maximum extent of drawdown (Fillion 1967). However, the presence of cover features (woody debris) were found to shelter dewatered macro invertebrates (Fillion 1967). Mayo Lake has extensive amounts of woody debris within the current and proposed drawdown zone due to impoundment of the lake and this material may help to offset the effects of winter drawdown on macro invertebrate abundance.

Groups of invertebrates known to decrease in abundance as a result of drawdown conditions include megoptera, plecoptera (Fillion 1967), coleoptera, odonata, ephemeroptera (Hunt and Jones 1972) and mollusca (Fillion 1967, Hunt and Jones 1972). The decline in abundance of these species has been attributed to association between these taxa and aquatic macrophytes, which are sometimes less abundant with larger drawdowns. The ability for some macro invertebrates such molluscs (and presumably gastropods) to survive periods of dewatering has been suggested to be linked to the presence of unfrozen lake bed substrates during drawdown. Late winter investigations in the shallow littoral areas of Mayo Lake have documented the presence of unfrozen substrates despite being dewatered and contacted by ice (Appendix 5A, Mayo Lake Aquatic Baseline Studies 2013). Some researchers have also proposed that increased winter drawdown can result in a larger zone of photosynthetic activity due to greater light penetration as a result of lower water levels (Palomaki 1994). If this were to occur in Mayo Lake, it is likely that the littoral area at the end of Roop Arm would benefit as average spring depths post project are predicted to decrease (see Appendix 5A, Attachment 5A-8 Lake Whitefish Early Spring Rearing Habitat technical memo).

Despite the potential for shifts in aquatic macrophyte and invertebrate communities, the effects on overall fish productivity are expected to be balanced by the positive and negative effects. For example, average lower lake levels may influence the plants and invertebrates in shallow areas, increased light penetration and photosynthesis will increase plants and invertebrate diversity in slightly deeper areas. The effects of the proposed changes in water management on the productivity of these areas will be monitored through an intensive monitoring program aimed at various life stages of fish[6]. In particular, it is anticipated that a decrease in the productivity of these habitats will be detected as changes in the abundance of juvenile/sub-adult lake whitefish, which will be monitored through a variety of methods including beach seining, small mesh netting and hydroacoustic surveys.

[6] Fish have been chosen to be the main method to monitor aquatic productivity as they are an important VC and productively effects will be reflected in the fish data. While aquatic macrophytes will be monitored Post Project, it is considered supplemental information that can be used to explain trends in fish data. Information on changes to plants or invertebrates does not provide clear answers on the overall productivity of a system. Changes to plant and invertebrate communities could be a positive or negative influence the important fish species identified as VCs and as such by focusing the monitoring on the fish, changes in productivity can be put in the context of impacts to VC's that are most important from an ecological and socio-economic perspective.

Mitigation and Monitoring

Mitigation focuses on progressive water management responses as specified in the AMP. The Monitoring Plan contains a comprehensive field monitoring program including Post Project monitoring of aquatic macrophytes and various sampling methods (beach seining, small mesh netting) for fish which use the shallow water littoral areas of Mayo Lake These methods are intended to provide an indirect but important index measure of habitat productivity of shallow littoral areas of the lake including aquatic macrophytes and invertebrates. An annual meeting with the Mayo RRC and local residents to review the field monitoring results and to collect local and Traditional Knowledge observations will also occur.

Determination of Significance

It is uncertain whether the potential project effects will be positive or negative. In the circumstance where the effects are considered adverse, the effects on shallow water littoral areas at the ends of Roop and Nelson arms would be moderate in magnitude, low in geographic extent (i.e., localized to the ends of the arms), medium to long-term in duration, high in frequency, reversible, and rank moderate in ecological context. Overall, Project effects are deemed **not significant**.

7.3.1.6 Ducks, Geese and Migratory Birds

No potential Project effects on nesting songbirds, including species at risk such as the Rusty Blackbird have been identified.

Various species of migratory birds commonly use the Roop Lakes wetland area as well as the shallow water littoral areas at the ends of Roop and Nelson arms (Figure 7-13) (see the Terrestrial Studies Report filed in Appendix 7 of the Mayo B Hydro Enhancement Project). These areas are used for both summer nesting and as stopover habitat during spring and fall migration. Mossop and Sinott (1998a) rated the Roop Lakes wetlands of high importance to waterbirds and other wetland species based on results of an air reconnaissance survey of several wetlands in the central Yukon. NND and Can-nic-a-nick's Wetland Health Assessment report of 2009-2010 identifies a list of species observed during their survey (see Appendix 5A, Attachment 5A-14; Table 11). This report also noted the ends of the Roop Arm and the Roop Lakes areas as important habitat for ducks, geese and waterfowl.

Figure 7-13: Bird Species Frequently Observed at Mayo Lake / Roop Lakes during Migration. From Left to Right: Bald Eagle, Trumpeter Swan, Northern Pintail and Pectoral Sandpiper

Yukon Government's Wildlife Key Areas Database identifies one key wildlife area in the vicinity of Mayo Lake:

- WKA ID 2734 (Figure 7-14) is a summer nesting area for the Bald Eagle and is located at the eastern end of Roop Arm of Mayo Lake and extending into the Roop Lakes system. Note that there is an active Bald Eagle nest where Roop Creek flows in Mayo Lake.

Figure 7-14: Aerial View of WKA 2734 at the East End of Roop Arm

Increasing the storage range of Mayo Lake by reducing the LSL may potentially affect waterfowl breeding and staging areas in the shallow water areas at the ends of Roop Arm and Nelson Arm. The most likely effect on migratory birds is anticipated during the spring migration period when open water areas provide key stopover habitats for these species. During this time of year (late April through late May), much of the landscape remains snow covered and most waterbodies in the region remain frozen until late in May or early June. For this reason, areas that become free of ice early in the year provide important stopover habitat for many bird species. This is the case for the shallow water areas at the ends of Roop Arm and Nelson Arm.

Effects during the summer breeding season and fall staging are not anticipated as water levels during these times of year will on average be lower but more comparable to the baseline. During the summer and fall, birds within the region are much more spread across the landscape due to the considerable increase in available habitat and it is for this reason that the spring migration period, when stopover habitats are limited, is the focus of this effects assessment.

With the increased storage range on Mayo Lake, water levels during May will on average, be lower than the current water level regime by 0.3 m (0.5 m additional storage) to 0.8 m (1.0 m additional storage). This may result in changes in the quantity of different habitat types used as spring stopover habitat. Stopover habitat can be separated into four general types, described below.

- Type I - Shrubs and other terrestrial vegetation - used as spring stopover habitat by numerous species of passerines. Examples of species expected include ruby-crowned kinglet, yellow warbler, yellow-rumped warbler, Wilson's warbler, white-crowned sparrow, dark-eyed junco and rusty blackbird.

- Type II - Mudflats (exposed bare ground and mud) - used as spring stopover habitat by shorebirds and some species of passerines. Examples of species expected include semi-palmated plover, lesser yellowlegs, pectoral sandpiper, American robin, American pipit and Lapland longspur.
- Type III - Shallow water (less than 2.0 m) - used as spring stopover habitat by swans, geese and dabbling ducks. Examples of species expected include Canada goose, trumpeter swan, American wigeon, mallard and northern pintail.
- Type IV - Deep water (greater than 2.0 m) – used as spring stopover habitat by loons, grebes and diving ducks. Examples of species expected include common loon, red-necked grebe, ring-necked duck, lesser scaup and goldeneye.

Based upon existing bathymetric data (see Appendix 5A, Mayo Lake Aquatic Baseline Studies 2009), it is possible to make predictions about how lower spring water levels will influence the availability of each broad habitat type in the shallow littoral areas at the ends of Roop and Nelson arms. In both Roop Arm and Nelson Arm, changes in the availability of Type I Habitat as stopover habitat are not anticipated. Under the current regime and proposed regime, these areas are above the influence of water levels during the spring and will continue to be in the future despite the reduced LSL.

In the Nelson Arm littoral area, lower water levels during May would result in a reduced amount of Type III habitat, which will result in more area of Type II habitat (Table 7-4). In the Roop Arm littoral area, the amount of Type II and III habitat increases Post-Project due to lower water levels (Table 7-4).

The reduction of Type III habitat in Nelson Arm is offset by a larger increase of this habitat in Roop Arm and birds are capable of moving between the two areas. Type II habitat will increase in both arms due to lower water levels. The extent of Type IV habitat cannot be modelled; however, it is not expected to change. Deeper areas become ice free shortly after shallow water areas at the ends of the arms. Notable amounts of this type of habitat typically become available as Nelson and Roop arms become ice free beginning in early May (see Appendix 5A, Mayo Lake Aquatic Baseline Studies 2010 for information on relative time of ice melt).

Table 7-4: Comparison of Spring Stopover Habitat Availability for Migratory Birds During Weeks 18 – 22 (average); 442 GWh Load Scenario

Habitat Type	Storage Range	Habitat Area (ha)[1]		
		Nelson Arm	Roop Arm	Total
Type II - Mudflats (exposed ground[2])	3.59 m	77.46	51.93	129.39
	3.09 m	72.75	44.68	117.44
	2.59 m	58.02	31.50	89.52
	Historical	44.76	19.04	63.80
Type III - Shallow Water (less than 2 m)	3.59 m	28.47	132.48	160.95
	3.09 m	32.07	133.39	165.47
	2.59 m	41.46	125.27	166.73
	Historical	52.84	101.5	154.34

1. The same calculations were done for the 545 GWh scenario which showed a similar pattern to the data shown here.
2. The area between the Full-supply level and the water level.

Despite changes in the relative amount of habitat types available in the two areas during spring migration, it is anticipated that there will be sufficient stopover habitat for all bird species, despite the lower water levels. Given that birds are highly mobile, they are also able to use other wetlands in the region, such as Roop Lakes, a regionally important wetland, which would be relatively unaffected by lower spring water levels in Mayo Lake and would continue to provide a diversity of spring stopover habitat for migratory birds. Incidental observations of Roop Lakes and the ends of Roop and Nelson arms during May of 2010 indicate that Roop Lakes is currently used more extensively by migratory birds than Mayo Lake during spring migration.

Mitigation and Monitoring

No mitigation is required as effects are considered neutral. There is sufficient habitat within the overall Mayo Lake area for shifts in locations of waterfowl breeding and staging areas to occur and not affect the species' populations. As part of the Project's Monitoring Plan, incidental collection of Post-Project observations of migratory birds will occur; as well as annual review with the Mayo District RRC and local residents to collect local and Traditional Knowledge observations.

Determination of Significance

Project effects from a species or regional perspective are expected to be positive and medium term in duration. No further assessment is presented.

7.3.1.7 Aquatic Furbearing Mammals

Aquatic mammals, in particular beaver, activity was observed throughout the aquatic portions of the Project Regional Study Area. Beaver food caches were observed on Mayo Lake, and beaver activity was visible along most of the Mayo River between Mayo Lake and Wareham Lake, including dams on several tributary streams and back channels flowing into that portion of the river.

NND and Can-nic-a-nick's Wetland Health Assessment Report also noted beaver lodges along the Mayo Lake shoreline and in the Roop Lakes wetland area. In addition to beaver, the Report also noted mink and river otters as using the Roop Lakes area.

Beaver lodge occupation surveys during the fall of 2011 and 2014 indicated a low number of active lodges in the main body of Mayo Lake (2 in 2011, 1 in 2014) and 12 inactive lodges (Figure 7-15) (see Appendix 5A, Attachment 5A-12 Current Status of Beaver and Potential Project Effects). Incidental observations from 2008 to 2010 indicated that there may have been up to 4 active lodges in Mayo Lake at this time. Annually since 2009, a combination of incidental observations and survey data indicate that active beaver lodges are located throughout Roop Lakes and also in Nelson Creek immediately upstream of Mayo Lake. A local trapper at Mayo Lake also indicates that beaver appear to be colonizing new habitats in tributaries to Mayo Lake, including Ping Pong Creek (see Appendix 5A, Attachment 5A-12 Current Status of Beaver and Potential Project Effects).

Figure 7-15: Active Beaver Lodge and Food Cache in Mayo Lake (Nelson Arm) During 2014

Increasing the storage range on Mayo Lake by reducing the LSL, and the increased winter drawdown may directly affect beaver overwintering habitat, resulting in challenges exiting and entering lodges, interfering with access to food caches and resulting in an increased risk of predation to beavers exiting their lodges in search of food during the late winter. This effect is limited to the shoreline of Mayo Lake where beavers are currently uncommon. Beavers in the nearby Roop Lakes area and other tributaries to Mayo Lake will not be affected by the increased storage range on Mayo Lake. Effects to beavers in the upper Mayo River are not anticipated as flows in the Mayo River will only change slightly in magnitude and duration with the project.

Observations of other aquatic furbearers such as muskrats, otters and mink have been very infrequent in the main body of Mayo Lake. Incidental observations of these species are primarily limited to the Roop Lakes area and other tributary streams to Mayo Lake, such as Edwards Creek. This is expected as these areas provide more suitable habitat for these species. Seeing as these habitats are not affected by the current water fluctuations or proposed Project, effects to aquatic furbearers other than beaver are not anticipated in the Project area.

It is important to note that tributary streams as well as the Roop Lakes wetland area and the Nelson Creek area will continue to provide suitable overwintering habitat for beavers and other aquatic mammals, thereby providing a source of furbearers for harvest by local trappers and subsistence hunters. Beavers are not likely to re-colonize Mayo Lake under the current or proposed management regime; however, the effect is highly reversible since beaver populations will continue to thrive in Roop Lakes and adjacent tributary systems and they may be able to recolonize the lake in the future if there are changes to the water level management regime that are more conducive to their preferred ecological needs.

Mitigation and Monitoring

Although no mitigation is required, Post-Project monitoring through observation of lake lodges will occur through technical and local knowledge observations. An annual meeting with the Mayo District RRC and local residents to review the field monitoring results and to collect local and Traditional Knowledge observations will also occur.

Determination of Significance

It is expected that adverse effects on aquatic furbearing mammals will be low in magnitude and geographic extent, long-term in duration, high frequency, reversible, and low in ecological context. Although effects on local aquatic furbearers in the Project Local Study Area may remain, there are substantial populations and habitat for aquatic furbearers throughout the Mayo River/Lake and Stewart River watersheds such that the effects from a species or regional perspective will **not be significant**.

7.3.1.8 Moose

Within the Project Regional Study Area, most observations of moose and quality moose habitat occurred within the upper Mayo River, between Wareham Lake and Mayo Lake and in the Roop Lakes wetland area[7] (Figure 7-16). The Terrestrial Studies Report noted frequent observation of bulls and cows with calves along the Mayo River, particularly in the upper Mayo River. Moose trails were also observed during winter overflights, travelling in all directions on the upper Mayo River, with habitat use in high elevation habitats east of the upper Mayo River.

Figure 7-16: Cow Moose at Roop Lakes

According to the NND and Can-nic-a-nick Wetland Health Assessment report, the Roop Lakes area is a popular moose hunting area. The Wetland Health Assessment report indicated sightings of cows and calves in the wetland area during their September 2009 survey. Moose have been observed incidentally on numerous occasions at all times of the year in the Roop Lakes area. Observations from other areas of Mayo Lake have been infrequent.

The above information related to moose is consistent with resource use data collected both during the Mayo B Hydro Enhancement Project and this (Mayo Lake) Project.

Mayo Lake water level fluctuations may potentially affect littoral and wetland moose habitat at the end of Roop Arm and Nelson Arm, with potential changes to forage distribution, quality and/or quantity particularly during late winter/early spring. In particular, the lower average summer water levels and

[7] Refer to Terrestrial Studies Report filed in Appendix 7 with the 2009 Mayo B Hydro Enhancement Project.

reduced LSL and lower spring water levels may result in a shift in aquatic plants that are a major portion of the summer diet of moose, to more shorter 'mat-forming' species of plants that are less desirable forage for moose. These effects are expected to be localized (to Mayo Lake proper) and will not have any predictable effect on the use of the area by moose. Given the large home range of moose, the extensive amount of moose habitat for all life cycles through the Project Regional Study Area, as well as the Local Study Area, effects on moose are not expected to be significant.

Mitigation and Monitoring

Although no mitigation is required, Post-Project monitoring through observation will occur through technical, local and Traditional Knowledge observations. An annual meeting with the Mayo District RRC and local residents to review the field monitoring results and to collect local and traditional knowledge observations will also occur.

Determination of Significance

The likelihood of adverse effects on Moose is uncertain, but in the circumstance where the effects were considered to be adverse they would be low in magnitude and geographic extent, long-term in duration, high in frequency, reversible, and low in ecological context. Overall, potential Project effects are deemed **not significant**.

7.3.2 Assessment of Effects on Socio-Economic Valued Components

This section generally focuses on those VCs of the socio-economic environment that are of particular concern in the Project Regional Study Area and that may be potentially affected by the Project based on the above noted pathways. For the majority of socio-economic components, potential Project effects of operation remain relatively close to the Project Regional Study Area. However, there are some effects of the Project that can extend beyond the Project Regional Study Area (e.g., utility ratepayer effects) to affect the overall Yukon economy in particular.

Section 7.3.2 provides an assessment of Project effects and mitigation measures with regard to the following socio-economic VCs:

- Hunting - Access;
- Fishing - Access;
- Fishing – Harvest Success;
- Trapping - Access;
- Trapping – Success;
- Placer mining - Access;
- Tourism, Outfitting and Outdoor Recreation;
- Private & Commercial Land Use;
- Government Fiscal Flows; and
- Utility Ratepayers.

Table 7-5 summarizes the effects assessment for each of the socio-economic VCs. More detail on certain specific effects on socio-economic VCs is provided below.

Table 7-5: Socio-Economic Effects Assessment

ID #	Description/Nature of Project Effect	Mitigation	Cumulative Effects Assessment	Residual Effects after Mitigation	Effect Attribute Ratings & Determination of Significance	Monitoring/Follow-up
Traditional and Domestic Resource Use						
Hunting - Access						
9	Mayo Lake water level fluctuations may potentially affect access for hunting in some years (i.e., boat access to Roop Lakes Complex).	• Water management to optimize rapid spring refill when feasible.	None identified.	• None; access in fall/winter is when water levels are higher.	• Direction: Adverse • Magnitude: Moderate • Geog. Extent: Low • Duration: Short term • Frequency: Low to Moderate • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	• Annual meeting with Mayo RRC and local residents to collect local and TK observations.
Fishing - Access						
10	Lower water levels in spring may affect access for short time period in late May/early June.	• Improvement of boat ramp/access [also applies to hunting].	None identified.	• Access in early June may be affected in some years.	• Direction: Positive No significant adverse effect.	• Annual meeting with Mayo RRC and local residents to collect local and TK observations.
Fishing - Harvest Success						
11	Mayo Lake water level fluctuations may indirectly affect fish harvest success.	• 1 in 3 year rest rule. • Experimental deepwater spawning habitat enhancement and/or use of temporary covers to direct choice of spawning habitat. • Progressive water management responses as specified in the AMP. • Reduce dewatering period by delaying the timing of drawdown if necessary and/or faster early spring refilling by reducing outflows (within operational and licensing constraints).	None identified.	• None.	• Direction: Neutral to Adverse • Magnitude: Low • Geog. Extent: Low • Duration: Short term • Frequency: Moderate • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	Angler Harvest survey as specified in Monitoring Plan. • Annual meeting with Mayo RRC and local residents to collect local and TK observations.
Trapping - Access						
12	Access to trapping activities at Mayo Lake will not be adversely affected.	• None required.	None identified.	• None.	No affect – determination of significance is not required.	• Annual meeting with Mayo RRC and local residents to collect local and TK observations.

ID #	Description/Nature of Project Effect	Mitigation	Cumulative Effects Assessment	Residual Effects after Mitigation	Effect Attribute Ratings & Determination of Significance	Monitoring/Follow-up
Trapping - Success						
13	Habitat changes along the lake shoreline will result in fewer beaver along the lake proper. No expected effects on trapper success along the tributaries and creeks that feed into the lake, as well as the Roop Lakes system.	• None required.	None identified.	• None.	• Direction: Adverse • Magnitude: Low • Geog. Extent: Low • Duration: Short term • Frequency: Moderate • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	• Annual meeting with Mayo RRC and local residents to collect local and TK observations.
Other Resource Use						
Placer Mining						
14	Short-term effects in late May/early June (after ice-off) will affect placer miners using the barge access in the outlet channel – delayed by approximately 2 weeks.	• The separate project of dredging noted in Chapter 6 will assist with access in the outlet channel.	None identified.	• None.	• Direction: Positive • Magnitude: Moderate • Geog. Extent: Low • Duration: Long term • Frequency: High • Reversibility: N/A • Ecological/SE Context: Low No significant adverse effect.	Occasional follow-up with barge landing users to ascertain effectiveness of access improvement.
Tourism, Outfitting and Outdoor Recreation						
15	Increased winter flows may affect snowmobiling and access to trails along the Mayo River Zone 4 (between Mayo Lake and Wareham Lake) if suspended ice occurs in late winter/early spring. Increased drawdown of Mayo Lake may affect timing and ability to use beach and boat launch at west end of Mayo Lake.	• Improvement of boat ramp/access.	None identified.	• Changes in winter flows may affect snowmobiling and access to trails along Zone 4.	• Direction: Adverse • Magnitude: Low • Geog. Extent: Low • Duration: Short term • Frequency: High • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	Post-license observation through local and traditional knowledge.
Private & Commercial Land Use						
16	Increasing the bottom storage range of Mayo Lake may affect water access to commercial and private lease-holders (including placer miners) and property owners along Mayo Lake (effects likely to occur prior to freshet and will be short-lived).	• Improvement of boat ramp/access.	None identified.	• None.	• Direction: Adverse • Magnitude: Low • Geog. Extent: Low • Duration: Short term • Frequency: High • Reversibility: Reversible • Ecological/SE Context: Low No significant adverse effect.	Yukon Energy to facilitate discussions with regulators to enable land owners access if issues emerge post-project.

ID #	Description / Nature of Project Effect	Mitigation	Cumulative Effects Assessment	Residual Effects after Mitigation	Effect Attribute Ratings & Determination of Significance	Monitoring / Follow-up
17	Increased winter flows from Mayo Lake to Wareham Lake – there is no expectation of an adverse effect on the property owners between Mayo and Wareham lakes.	• None required.	None identified.	• None.	No effect – determination of significance is not required.	Monitoring of water levels at Wareham Lake and Minto Bridge as part of normal operations.
Regional Economy						
Government Fiscal Flows						
18	YEC and NND have reached an investment agreement; NND has the opportunity to accrue benefits in the form of financial returns commensurate with their investment.	None required.	None identified.	• Potential participation in the Project by NND including financial returns commensurate with their investment.	• Direction: Positive • Duration: Long term • Frequency: High No significant adverse effect.	N/A.
Utility Ratepayers						
19	Improved system capability and reliability through new renewable power generation at stable costs and reduced diesel fuel generation costs to service future load growth. Reduced reliance on diesel generation to meet the growing demand will reduce greenhouse gas emissions as per YG policy.	None required.	None identified.	• Lower cost (relative to alternative sources of supply), renewable energy and enhanced system reliability. • Displaced diesel generation resulting in reduced GHG emissions.	• Direction: Positive • Duration: Long term No significant adverse effect.	N/A.

7.3.2.1 Traditional and Domestic Resource Use

Hunting – Access

Hunting is an important activity within the Project Regional Study Area. The majority of moose hunting occurs along the Mayo River between Mayo Lake and Wareham Lake, as well as the area around Mayo Lake, including the Roop Lakes system (Figure 7-17). The Mayo Lake access road is a key area for hunting and access to Mayo Lake and the upper Mayo River areas. Some community members generally launch their boats downstream of the Mayo Lake control structure and float downstream to the Minto Bridge area. The Roop Lakes area is accessible by traversing the length of Mayo Lake by boat and following Roop Creek upstream into the wetland complex.

Figure 7-17: Lower Roop Creek

Mayo Lake water level fluctuations may potentially affect access for hunting in some years. However, most moose hunting occurs in the fall when water levels are at the highest levels. As the LSL will result in the lake being operated at overall lower water levels than in the past, access within the lowest reach of Roop Creek (immediately upstream of Mayo Lake) will experience the most effect.

Flows in the upper Mayo River during hunting season (September) are expected to be similar to the baseline scenario. For example, historical flows (1981-2008) during weeks 37 through 39 (September 10 – 30) have averaged 15.7 cms. Depending on the load scenario and amount of additional Mayo Lake drawdown, modelled outflows from Mayo Lake range from 12.8 to 18.7 cms during this time period (Table 7-6). It is important to note that these flows only represent reaches 11 and 12 (upstream of the Davidson Creek Bridge) as uncontrolled inputs from Davidson and Duncan creeks are not included in this analysis. Flows from these tributaries would be expected to buffer the minor effects to flows on the upper Mayo River during weeks 37 through 39.

Table 7-6: Modelled Mayo Lake Outflows

Load Scenario	Storage Range	Week 37-39 Average Mayo Lake Outflow
442	2.59	18.7 cms
	3.09	18.4 cms
	3.59	17.8 cms
545	2.59	14.6 cms
	3.09	12.8 cms
	3.59	12.8 cms
Historical	2.59	15.7 cms

Boat access to Roop Lakes can be more challenging when water levels in Mayo Lake are low. The very lower portion of Roop Creek does include a deepwater channel that allows for boat access across a wide range of Mayo Lake levels. However, the lower portion of the Roop Lakes wetland complex contains a number of shallow water areas that may become challenging to pass with larger boats when water levels in Mayo Lake are greater than 1.7 m below FSL. This value is based upon field experience by EDI field crews who have accessed the upper portion of the wetland complex when water levels were 1.65 m below FSL. Also of note are the Mayo Lake elevations described by the KGS backwater effect model. This model predicts that the lower portion of Roop Lakes is backwatered when Mayo Lake elevations are between 664.0 and 664.8 m (1.87 and 1.07 m below FSL, respectively. Collectively, this information indicates that a lack of backwater effect on lower Roop Lakes may make boat access to this area more challenging, especially for larger boats (propeller driven boats that have a notable draft). In some years more effort may be required to navigate past shallow areas in the lower portion of the channel nearest Mayo Lake (e.g., lining the boat may be required for short sections).

A comparison of historical and modelled future mid-September water levels (at the 442 GWh load) indicates that with the Project, there may be an increased frequency of years where boat access to Roop Lake may be more challenging (Table 7-7). Lower water levels associated with the 545 GWh load scenario indicate a higher number of years where Roop Lakes access may be more challenging (ex – 8 out of 28 years with 0.5 m of additional storage).

Table 7-7: Mid-September Water Levels at 442 GW.h/yr. Load Scenario

Load Scenario	Storage Range	# of Years with mid-September Water Levels		Average Elevation below FSL
		< 1.7 m below FSL	> 1.7 m below FSL	
442	2.59	28	0	0.17
	3.09	27	1	0.32
	3.59	27	1	0.40
Historical	2.59	28	0	0.53

Mitigation and Monitoring

Operating within technical and licence constraints, Yukon Energy will aim to optimize rapid spring refill when feasible. The one in three rest rule will ensure that in one out of three years, the lake will be

operated with a drawdown of 2.59 m which would allow for greater refilling and subsequently higher mid-September water levels in the following year. Yukon Energy will also be improving the boat launch ramp/access at the west end of Mayo Lake during future outlet channel maintenance activities. Yukon Energy will meet on an annual basis with the Mayo District RRC and local residents to collect local knowledge observations related to a variety of topics including hunting access and can work to resolve issues associated with access, where practical.

Determination of Significance

Project effects on hunting access will be adverse, of moderate magnitude, low geographic extent, short-term in duration, of low to moderate frequency, reversible and low in socio-economic context;. Overall, Project effects are deemed **not significant**.

Fishing – Access

There is a moderate level of fishing activity within the Project Regional Study Area, with lake trout being the primary species of interest. Fishing effort is not as high as compared to other lakes in the Project Regional Study Area due to a number of factors. These factors include the distance from major centers (i.e., Whitehorse) and the unpredictable weather conditions on the large body of Mayo Lake. Ethel Lake is also used more extensively by residents of the Village of Mayo for fishing.

Subsistence fishing occurs on Mayo Lake; specifically local First Nation members have set nets to capture whitefish and this may increase in the future due to harvest restrictions on other important food fisheries (Chinook salmon).

Lower water levels in the spring, especially immediately after ice-off, may potentially affect boat access for a short time period in early June (Figure 7-18).

Figure 7-18: Mayo Lake Boat Launch

Mitigation and Monitoring

Future maintenance to the lake outlet channel will provide the opportunity to improve access to the lake over the current condition. Yukon Energy will meet on an annual basis with the Mayo District RRC and local residents to collect observations and information related to a variety of topics, including fishing access.

Determination of Significance

With mitigation the effects of the Project are considered positive. No further assessment is presented.

Fishing – Harvest Success

Fishing success is mainly dependant on the number of target fish species in the lake. Most fishers target lake trout and the monitoring and adaptive management plans ensure that key thresholds for lake trout at various life stages are maintained (Figure 7-19). There are also key thresholds and adaptive management for the lake trout's primary food source, lake whitefish. Over the short term, there may be some effects to year classes of lake trout and/or lake whitefish; however, the AMP will outline corrective actions if thresholds are reached. Occasional poor age classes are not thought to represent a major effect on the adult population (i.e., the catchable fish). Recruitment into the adult population is typically density dependant, as such the age classes before and after poor years are likely to have higher survival rates (i.e., from less intra-specific competition; North South Consultants 2008).

Figure 7-19: Lake Trout

Mitigation and Monitoring

Mitigation is addressed indirectly by the AMP components that focus on fish; as such, no specific mitigation is required. The Project's Monitoring Plan includes a fish harvest study to be undertaken every five years Post-Project to provide a measure of fishing pressure and harvest success levels. In addition,

Yukon Energy will meet on an annual basis with the Mayo District RRC and local residents to collect local and Traditional Knowledge observations related to a variety of topics, including fishing success.

Determination of Significance

Project effects on fishing success are predicted to be neutral to adverse. In the case of the latter outcome, the effects would be small in magnitude and low geographic extent, short-term in duration, of moderate frequency, reversible and low in socio-economic context. Overall, Project effects are deemed **not significant**.

Trapping – Access

There is limited trapping activity within the Project Local and Regional Study areas although some domestic trapping does continue in the vicinity of Mayo Lake and the upper Mayo River. Due to economic factors (lower prices for pelts and increased cost of being on the land), trapping is not as prevalent in the Local and Regional Study areas as it likely once was.

Access to the land and water for trapping activities will not be adversely affected by the Project. Snowmobile trails on land and across the frozen lake will be comparable to existing conditions.

Mitigation and Monitoring

No mitigation is required as there is no adverse effect. Yukon Energy will meet on an annual basis with the Mayo District RRC and local residents to collect observations and other information related to a variety of topics including trapping access to address any concerns.

Determination of Significance

No significant effects are predicted.

Trapping – Success

As stated above, trapping activity within the Local and Regional Study areas is relatively low. However, as noted in the aquatic furbearing section, Project effects on beaver and muskrat include habitat changes along the lake shoreline (due to increased winter drawdowns and a lower overall LSL) that will result in fewer beaver along the lake proper. There are not expected to be any effects to beaver habitat along tributaries and creeks that feed into the lake, as well as the Roop Lakes system. Taking this into consideration, there is considerable habitat available for the beaver within the Regional Study Area, thus enabling long-term trapping availability for local resource users.

Mitigation and Monitoring

No mitigation is proposed.

Determination of Significance

Project effects on trapping success will be adverse, of small magnitude and low geographic extent, short-term in duration, of moderate frequency, reversible and low in socio-economic context;. Overall, Project effects are deemed **not significant**.

7.3.2.2 Other Resource Use

Placer Mining - Access

As described in Chapters 2 and 5, placer mining activity occurs at Mayo Lake and in the upper-most reaches of the Upper Mayo River (Duncan and Davidson Creeks) within the Local Study Area. Over recent years (i.e., since the Mayo B YESAB submission), the number of active operators around Mayo Lake have declined; however, claim staking in the surrounding land around Mayo Lake has increased.

Operation and management of Mayo Lake water levels pursuant to the revised water management regime will result in a short-term effect in late May/early June (after ice-off) on those placer miners along the lake that require access by barge (Figure 7-20). There will be no effect on placer mining access downstream of the control structure (i.e., Duncan and Davidson creeks).

Figure 7-20: Barge Transporting Heavy Equipment on Mayo Lake

The barges are used to haul heavy equipment, fuel drums and supplies out to placer claims, leaving from the west end of the lake. Mayo Lake must refill sufficiently to enable the barges to float off the mud-flats and subsequently get close enough to the placer claim property to off-load the equipment and supplies on site. Under the proposed management regime, the lowest lake levels will occur at the end of winter/early spring, after the lake has been drawn down to meet winter energy demands. This will

typically occur in late April/early May, just prior to spring freshet in May/June, and prior to the normal ice free season on the lake.

Operating the lake at a lower LSL may potentially result in access issues for some placer claims at the site of operation (each site is unique and does not experience the same access issues). Dredging of the outlet channel is a required activity for the operation of the Mayo Lake Control Structure and will also assist the existing active placer mining operator travel through the channel. Currently, there are few other placer miners operating on the lake; those that remain are aware that the lake is very active, with shifting shoreline conditions due to high wind and wave action.

Mitigation and Monitoring

As noted in Chapter 6, Yukon Energy needs to undertake outlet channel maintenance dredging to remove a build-up of sediment and a cofferdam remnant that is currently affecting their ability to take full advantage of the existing Mayo Lake storage capability. The dredging will assist in removing sediment build-up in the area of the channel next to the barge landing and will ultimately assist placer miners' access to their claims. If issues emerge post-Project, Yukon Energy will facilitate discussion with regulators to address the issue of access to the barge landing and/or placer claims on Mayo Lake.

Yukon Energy will post water levels on their website for easy access by lake users prior to accessing the lake. Occasional follow-up with placer miners and users of the barge landing to ascertain effectiveness of access improvement will be undertaken.

Determination of Significance

Project effects on placer mining are expected to be positive and long-term in duration. No further assessment is presented.

Tourism, Outfitting and Outdoor Recreation

Tourism activities are focused on the vicinity of the Village of Mayo and will not be affected by the Project. Outfitting activities occur beyond the Project Regional Study Area and will not be affected by the Project. Mayo Lake is used for a variety of outdoor recreation purposes (e.g., boating, fishing, camping); and the Upper and Lower Mayo River has some boating/canoeing use although it is not considered "high Use" as other areas in the vicinity of the Village are used more frequently (e.g., Ethel Lake, Five Mile Lake). The Upper and Lower Mayo River will remain available for recreational canoeing and boating for community residents, if so desired.

In years where a part or all of the licenced additional storage is used, there may be some increased winter flows that may affect crossings of the Upper Mayo River if suspended ice occurs in late winter/early spring when flows have to be reduced to meet licence requirements for minimum lake levels. This is expected to be an uncommon occurrence. The area adjacent to and surrounding the Upper Mayo River and Mayo Lake access road provide abundant and suitable areas for snowmobiling, without concerns for late winter/early spring ice conditions.

As noted above, an increased draw-down of Mayo Lake and operation of the lake at a lower supply level may affect timing and ability to use the beach and boat launch at the west end of Mayo Lake. The lowest

lake levels are anticipated to occur in April or early May, just prior to spring freshet in May/June, which generally results in an increase in the lake elevation over a short time period. The potential effect on timing and ability to use the beach and the boat launch is expected to be short in duration.

Mitigation and Monitoring

Yukon Energy will improve the boat launch ramp/access upstream of the Mayo Lake control structure during outlet channel maintenance activities in advance of utilizing the increased storage range. Yukon Energy will meet on an annual basis with the Mayo District RRC and local residents to collect observations and other information related to a variety of topics, including outdoor recreation and access.

Determination of Significance

The residual Project effects on outdoor recreational activities are expected to be adverse, low in magnitude and geographic extent, short-term in duration, of high frequency, reversible and low socio-economic context. Overall, Project effects are deemed **not significant**.

Private and Commercial Land Use

It is unlikely that there will be any discernible Project effects on private or commercial land use within the Project Regional Study Area. There is no expectation of an adverse effect on the property owner near the Minto Bridge from the slight increase in winter flow magnitude and/or duration between Mayo and Wareham lakes.

An increase in the bottom storage range of Mayo Lake may potentially affect water access to commercial and private leaseholders (including placer miners), as well as property owners along the shoreline. However, the timing of affected access will at most be a short window in early June. The majority of property owners and leaseholders are at the west end near the mouth of Mayo Lake, and have existing road access. The Project will potentially provide a positive effect on the issue of erosion, as lower average lake levels will slow down the erosion process.

Mitigation and Monitoring

Yukon Energy is committed to improving the boat launch ramp/access upstream of the Mayo Lake control structure and is currently planning maintenance to the outlet channel that will improve access to the lake over the current condition. Yukon Energy will meet on an annual basis with the Mayo District RRC and local residents to collect observations and information related to a variety of topics, including potential effects on private and commercial land use. If issues emerge post-Project, Yukon Energy will facilitate discussion with regulators to address the issue. Monitoring of water levels and flows downstream of Mayo Lake will continue post-Project.

Determination of Significance

The residual Project effects on private and commercial land use are expected to be adverse, low in magnitude, low in geographic extent, short-term in duration, of high frequency, reversible and low socio-economic context. Overall, Project effects are deemed **not significant**.

7.3.2.3 Regional Economy

The Project is expected to provide regional economic benefits within the Project Regional Study Area and the broader Yukon region.

Government Fiscal Flows

Yukon Energy and the First Nation of Na-Cho Nyak Dun reached a Project agreement in 2010 and an Investment Agreement in 2013 whereby NND has the opportunity to accrue benefits in the form of financial returns commensurate with their investment in the Project. The two Agreements cover both the Mayo B Hydro Enhancement Project and the Mayo Lake Enhanced Storage Project. No mitigation or monitoring is required.

Determination of Significance

Project effects on government fiscal flows are expected to be positive and long-term; no further assessment is presented.

Utility Ratepayers

As discussed in Chapter 6, benefits are expected to be realized by all Yukon utility ratepayers when new industrial loads and on-going domestic load growth can be serviced through additional renewable generation capacity on the system. The Project will result in long-term benefits of providing lower cost (relative to fossil fuel generation) renewable energy and improved system capability and reliability. The Project will also result in reduced reliance on diesel generation, which will reduce greenhouse gas emissions[8].

The Project is consistent with Yukon Government policy, as set out in the *Energy Strategy for Yukon* (2009), which includes the goal of increasing renewable energy supply by 20% by 2020. It also is in alignment with Yukon Government's *2009 Climate Change Action Plan*, which includes the reduction of carbon emissions.

No mitigation or monitoring is required.

Determination of Significance

Project effects on utility ratepayers are expected to be positive and long-term; no further assessment is presented.

7.3.3 OTHER POTENTIAL EFFECTS

In environmental assessment practice, the effects that the environment can have on the project is considered as part of the environmental assessment and appropriate measures are applied to ensure that

[8] By way of example, at the representative range of grid loads (442 GW.h/year to 545 GW.h/year) that potentially could occur during the first 10 years of Project operation, the Project would reduce thermal generation at long-term average hydro generation water conditions by 2.4 to 3.1 GW.h/year with 0.5m reduced LSL and by 3.3 to 4.5 GW.h/year with 1.0 m reduced LSL.

there will be no significant adverse effects in this regard. During the operational phase of the Project, for example, potential effects of the environment could occur as a result of climate change.

Climate Change

The Yukon Government *Climate Change Action Plan*, released in February, 2009 and the Energy Strategy for Yukon, released in January, 2009 both note that increases in renewable generation support government objectives. The plan and strategy, which were developed to complement one another, set reduction of greenhouse gas emissions as a priority. The Yukon Government Climate Change Action Plan identifies renewable resource development, including hydro, as a mitigation strategy that will help reduce or delay global warming (Yukon Government 2009b). The *Energy Strategy for Yukon* sets out the goal of increasing renewable energy supply, including hydro, in the Yukon by 20% by the year 2020. Furthermore, the Energy Strategy seeks to "…optimize the efficiency and reliability of electricity generation and distribution" (Yukon Government 2009a) and recognizes the importance of investing in electricity infrastructure to meet future needs and leverage economic development in the Territory. "Investments in additional renewable energy infrastructure will be required in order to enhance the kinds of long term legacy benefits that are currently enjoyed with the existing hydro system. These investments will also buffer Yukon's energy sector from volatile fossil fuel prices and help to minimize greenhouse gas emissions from diesel generated electricity" (Yukon Government 2009a).

As stated in Yukon Government's *Climate Change Action Plan – 2012 Progress Report*, "Yukon's temperature, wind and precipitation patterns have experienced significant changes. Since 1948, Yukon's annual average temperature has increased by 2.2°C and the average winter temperature by 5.5°C (Environment Canada, Trends and Variations, 2011)" (Yukon Government 2012). The 2012 Progress Report reported on Goal # 2: Adapting to Climate Change, with a specific initiative focused on preparing community adaptation plans. Mayo was part of this initiative with the Yukon Government and the Northern Climate Exchange to complete the Mayo community adaptation plan – these plans are to evaluate vulnerabilities and identify plans to adapt to climate change challenges or opportunities (Yukon Government 2012).

The Mayo Region Climate Change Adaptation Plan indicates that temperature and precipitation trends since 1947 have experienced change, particularly in the years since the 1960s where temperatures warmed in both summer and winter; and precipitation increased in summer and decreased slightly in winter (with high variability).

The Mayo Region Climate Change Adaptation Plan (Hennessey, Stuart, Duerden, 2012) indicates that projections for temperature and precipitation in the region (including the Project Regional Study Area) show an increase between now and 2050 as follows:

- An annual temperature increase of 2.5°C by 2050 under a modest climate change scenario and a 3.6°C increase under a medium-high scenario (with the greatest temperature increase occurring in the winter or spring months); and
- An annual precipitation increase of 10% by 2050 under a modest climate change scenario and a 14% increase under a medium-high scenario (with the greatest precipitation occurring in spring – typically the driest time of year).

Yukon Energy monitors changes in the regional climate in the Project Regional Study Area as necessary using climate information including measurements of temperature, precipitation, and wind speed provided by the Meteorological Service of Canada.

Using climate change predictions for the Mayo region, it is possible to make general predictions in terms of how water levels and the flow regime in Mayo Lake may change. Specifically the following scenarios could occur:

- The predicted increase in air temperature could potentially reduce the period of ice coverage on Mayo Lake and could increase water temperatures in the lake.
- An increase in precipitation within the watershed could translate to overall higher average water levels in the lake.
- In the event of increased snowpack accumulation, this could result in a more rapid increase in water levels during freshet (May). Freshet may also occur earlier in the spring.

On average, the climate change predictions appear to result in a positive effect to fish within Mayo Lake. Increased air temperatures would translate into a slight increase in surface water temperatures in the lake which could increase the overall productivity of the lake. In terms of lake trout, this increase in water temperature could result in a longer growing season which in turn may result in an increased growth rate of juveniles and adults. Lake trout is a cold water species and an increase in water temperatures can be detrimental to populations in small and/or shallow lakes; however, Mayo Lake is a relatively cold and deep lake and even a considerable increase in water temperature would not be expected to negatively affect the species. A reduced period of ice coverage combined with a more rapid increase in water levels during the spring (May), could reduce the potential for egg loss due to dewatering. This may result in increased egg to fry survival which may increase the recruitment success of lake trout over the future water level management scenarios modelled (REF egg survival memo here).

Lake whitefish could also benefit from the climate change predictions due to a potential overall increase in juvenile and adult productivity due to a longer growing season. An increase in air temperatures and precipitation could result in increased winter flows which could in turn positively affect lake whitefish egg survival in the primary spawning areas (tributaries and tributary inlets). An earlier timing of ice off on the lake could also increase early survival of lake whitefish fry by providing warmer water temperatures during the critical spring rearing period. A more rapid freshet would result in an increase in water levels during the month of May and an increased availability of shallow water habitat in the ends of the arms. If this occurred the water levels may be on average higher than the modelled water level management scenarios (REF LW habitat area memo here).

Yukon Energy expects to continue to monitor the capability of major Global Climate models and Regional Climate models to accurately represent climate change variables. As these models are calibrated to predict climate regimes with confidence they potentially may be able to predict the frequency and magnitude of extreme events in the Project Regional Study Area (e.g., severe storms, wind events, flooding). In the event such technological developments are successful, it is anticipated that the results of such models would form a component of Yukon Energy's future planning.

CHAPTER 8
ADAPTIVE MANAGEMENT AND MONITORING

8.0 ADAPTIVE MANAGEMENT AND MONITORING

8.1 INTRODUCTION

Environmental and socio-economic monitoring and adaptive management can be undertaken for the following reasons:

- To ensure the implementation and success of any mitigation measures identified as required or preferred during the assessment process.
- To confirm the accuracy of baseline information or any assumptions made with regard to the Project during the assessment process.
- To test the accuracy of predictions made during the assessment process and ensure that effects are consistent with conclusions in the assessment and any conditions of the approvals provided by the regulator. Adaptive management practices will be applied to ensure effects are consistent with the findings of the assessment and/or to provide adjustments to project operation under the guidance of regulators, the NND First Nation, the Mayo RRC, and technical and traditional knowledge experts to ensure protection of identified valued components.
- To detect any unanticipated project effects and implement mitigative or corrective measures as necessary to ensure that no significant adverse effects result from long term operation of the project under licence conditions and criteria.

This chapter outlines the monitoring and adaptive management plans for the Mayo Lake Project. As stated in Chapter 6, water management in terms of altering water levels at Mayo Lake as a result of the proposed Project will be subject to the Adaptive Management Plan (AMP) and the Monitoring Plan that provides the supporting data inputs to the AMP, each of which will be part of the proposed licence and are non-discretionary.

8.2 MONITORING PLAN

The Monitoring Plan (see Appendix 8A) provides added detail to the methods, types, location and timing of programs identified for Project monitoring. The monitoring components outlined in Section 1.1 of the Monitoring Plan are meant to collect additional baseline data and provide supporting data to be used when interpreting other components of the monitoring plan (e.g., fish sampling). These components do not feed directly into the AMP. These programs include (see Appendix 8A for details):

- Review of lake elevation and climate data;
- Water temperature and turbidity monitoring;
- Late winter ice thickness and water quality monitoring;
- Aquatic macrophyte surveys; and
- Fish harvest (creel) surveys.

The components outlined in Section 1.2 of the Monitoring Plan provide the data to feed into the AMP and depending on the outcome of the monitoring, may require adaptive management responses. These programs include:

- Fisheries studies in Mayo Lake:
    - Annual Lake trout spawning and incubation monitoring using egg collectors and incubators;
    - Annual Juvenile lake trout and lake whitefish monitoring by beach seining in known important index rearing and spawning areas and in new spawning areas ;
    - Periodic medium term Sub-adult lake whitefish/lake trout and monitoring using hydroacoustic surveys and shallow water small mesh gillnetting; and,
    - Periodic medium to long term Adult lake trout and lake whitefish monitoring using SPIN surveys and potentially, lethal index netting.
- Roop Lakes water level and wetland health monitoring; and
- Upper Mayo River geomorphology monitoring.

8.3 ADAPTIVE MANAGEMENT PLAN

The overall purpose of the AMP is to ensure a fully functioning, healthy and sustainable aquatic ecosystem at Mayo Lake based primarily on healthy and sustainable lake trout and lake whitefish populations. Lake trout and lake whitefish are highly sensitive to water management and are the dominant predator and prey species in the lake and thus critical indicator species for the ecosystem. The AMP is intended as a primary instrument for managing water levels and water use for hydroelectric generation at Mayo Lake and establishing ecologically relevant water management criteria and constraints within the overall operating range.

The following objectives for the plan are intended to achieve the overall purpose stated above:

- To identify how the proposed Mayo Lake Project may affect the aquatic ecosystem focusing on the effects on lake trout and lake whitefish as key indicator species;
- To establish appropriate key indicators of a fully functioning, healthy and sustainable aquatic ecosystem;
- To define a monitoring program that is appropriately sensitive and can measure and report, in a timely way, changes in identified key indicators;
- To establish thresholds that defines acceptable and unacceptable conditions or changes in identified key indicators;
- To describe responses that will be undertaken if indicators and thresholds identify unacceptable conditions or trends; and

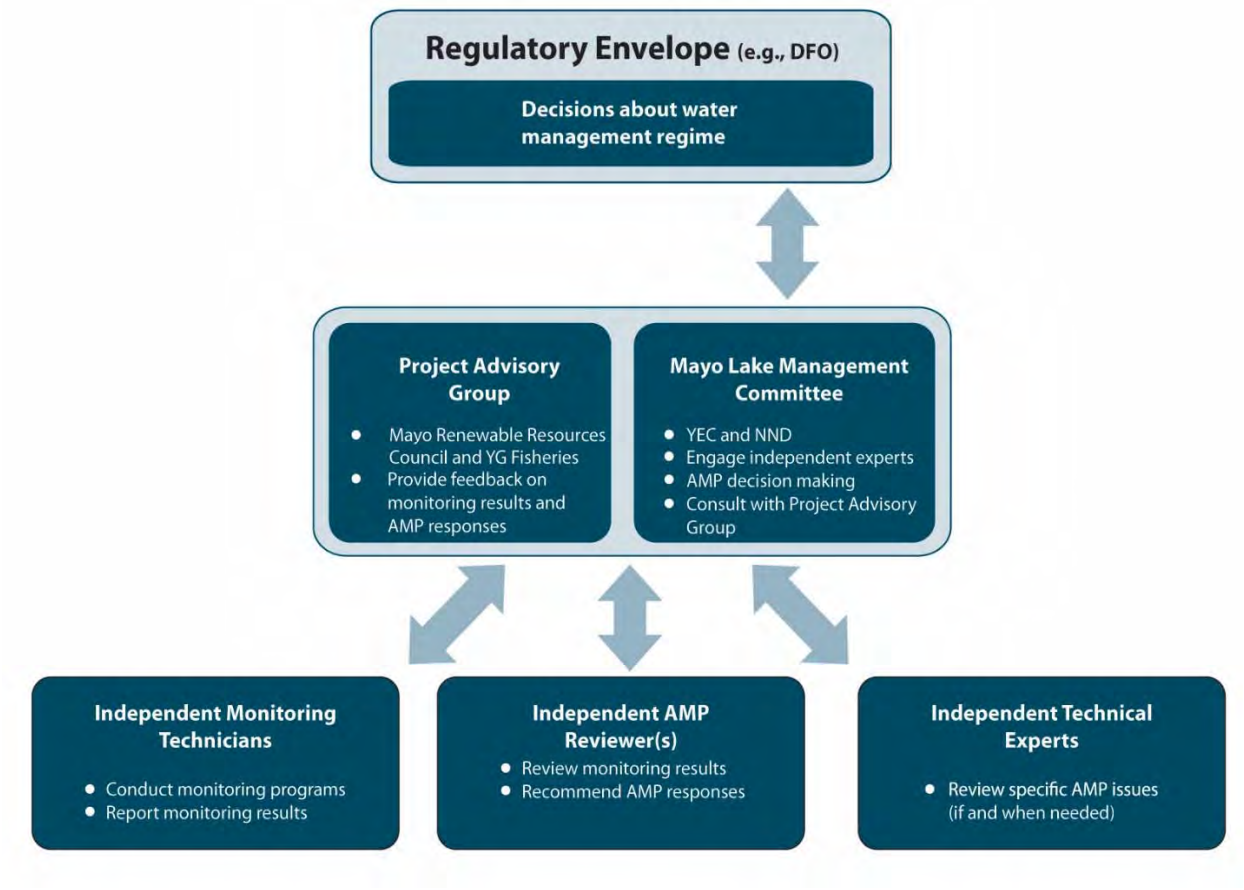
- To establish an inclusive framework involving regulators, NNDFN, Mayo RRC, technical and traditional knowledge experts as well as local users for interpretation of monitoring results, and decision-making about adaptive management responses.

The AMP provides technically and logistically feasible approaches for modifying water level management parameters based on observed impacts and prescribed thresholds and water management responses. Specifically, the AMP addresses both short term annual monitoring of reproductive success/recruitment (in terms of an early warning/indication of adverse impacts) and long term monitoring of sub-adult and adult abundance. Where thresholds for adverse effects are identified either in the short and long term monitoring programs, mitigation measures and changes to water management identified in the AMP will be implemented. It is expected that these programs and operational requirements will be entrenched in the Project authorizations (e.g., water use licence amendment).

The project begins with a cautionary approach, utilizing half of the proposed additional water level range of 1.0 m as a starting point, and relying on the AMP to guide decisions about future increases or decreases from the original storage range increase of 0.5 m. Throughout the operation of the project, the AMP will continue to apply, leading to implementation of appropriate responses if ecological conditions reach action thresholds. Please see Appendix 8B for details on the AMP.

It should be noted that the AMP outlines a framework for evaluation of monitoring results and AMP decision-making – this is described in Section 2 of the AMP. The framework is illustrated in Figure 1 below. Details on each component (e.g., Project Advisory Group, Mayo Lake Management Committee etc.) are described in Appendix 8B.

Figure 1: AMP Evaluation Framework



8.4 EXTERNAL TECHNICAL EXPERT REVIEW PROCESS

Working together as a Technical Working Group, Yukon Energy and NND hired an external independent advisor and technical expert and in 2012 to provide expert and scientific advice on the following:

- The potential risks of long-term harm to the lake trout and lake whitefish populations in Mayo Lake of an increased drawdown range;
- The suitability of the Monitoring and Adaptive Management plans as a means of addressing and managing uncertainties with respect to potential lake trout and lake whitefish responses to the Project; and
- The ability of the Monitoring and Adaptive Management plans to detect unacceptable biological impacts within the context of the AMP of incremental changes over several years in contrast to larger changes over a short period of time.

Process

A scope of work and specific questions were developed by the TWG and provided to the independent advisor Dr. Bodaly who is a highly qualified scientist with significant working experience and expertise on Yukon fish populations. The TWG held two workshops with Dr. Bodaly:

- November 2012: to discuss the Project and the process and expectations of him in his review and provision of expert advice; and
- February 2013: a discussion and review of this draft report. At the same time, YEC's team presented a proposal for changes to the monitoring program to address concerns raised by Dr. Bodaly in his draft report. These changes included proposals for interim monitoring of sub-adult and adult fish in addition to the young-of-the-year and long term adult monitoring included in the original monitoring plan.

Conference calls and email correspondence with Dr. Bodaly also occurred in a transparent manner (i.e., all members of the TWG received information concurrently).Yukon Energy's team as well as NND's team provided comments on the final draft report prior to Dr. Bodaly's submission of the Final Report in mid-March 2013.

Results

The results of the independent review process (see Appendix 8C for the final report) indicated that:

- Risk of irreversible, long-term harm to lake trout and lake whitefish populations is low under either drawdown scenario (i.e., 0.5 m vs 1.0 m additional storage), with the implementation of the comprehensive monitoring and adaptive management plans as proposed; and
- The revised monitoring plan (including hydroacoustic monitoring) and adaptive management plan are deemed "effective at detecting, addressing, and managing any impacts that might result from increased drawdown".
    - The ability to detect adverse impacts through monitoring and adaptive management is acceptable regardless of which drawdown scenario is implemented.

The independent reviewer did note that from purely a scientific biological perspective (and not including economic and social factors), his preference was incremental changes over several years as this would have less uncertainty and risk. However, Yukon Energy must consider and balance a variety of factors when putting forward a Project proposal, including the views and inputs of the project partner NNDFN and costs and benefits of a Project and impacts to ratepayers. When all factors are considered, Yukon Energy has chosen to propose the initial 0.5 m of additional storage, with the ability to increase this storage range up to 1.0 m subject to the conditions in the AMP. This approach maintains a low environmental risk while potentially gaining the largest renewable power and economic benefits over time.

9.0 GLOSSARY AND REFERENCES

9.1 GLOSSARY OF ACRONYMS AND TERMS

9.1.1 List of Acronyms

AMP	Adaptive Management Plan
C	Celcius
CEA	Cumulative Effects Assessment
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
CPUE	Catch per Unit Effort
DFO	Department of Fisheries and Oceans
DO	Designated Office
DSM	Demand Side Management
FSL	Full Supply Level
GHG	Greenhouse gas
GW.h	Gigawatt Hours
ID	Identification
LNG	Liquefied Natural Gas
LSA	Local Study Area
LSL	Low Supply Level
LT	Lake Trout
LW	Lake Whitefish
m	Metre
MDRRC	Mayo District Renewable Resources Council (also RRC)
NND	Na-cho Nyak Dun First Nation (also NNDFN)
OG	Other Government (Federal, territorial or municipal)
OP	Other Public
RRC	Renewable Resource Council (also MDRRC)
RSA	Regional Study Area
SPIN	Summer Profundal Index Netting
TK	Traditional Knowledge
TWG	Technical Working Group
VC	Valued Component
WKA	Wildlife Key Area
YECL	Yukon Electrical Company Limited
YESAA	Yukon Environmental and Socio-Economic Assessment Act
YESAB	Yukon Environmental and Socio-Economic Assessment Board

9.1.2 List of Terms

Aboriginal community: A community where most of the residents are Aboriginal (i.e., Indian, Métis, Inuit or other Aboriginal Peoples) and that has a separate form of government; provides some level of service to its residents; and has clear community boundaries.

Adaptive management: Involves the implementation of new or modified mitigation measures over the life of a project to address unanticipated environmental effects. The need for the implementation of adaptive management measures may be determined through and effective follow-up program.

Adverse effects: Negative effects on the environment and people that may result from a proposed project.

Alevin: A young fish; a newly hatched salmon when still attached to the yolk sac.

Anadromous: Fish that migrate from the sea into fresh water to spawn; or one which stay entirely in fresh water and migrate upstream to spawn.

Assessment: An evaluation by a designated office, a screening by the executive committee or a review by a panel of the Yukon Environmental and Socio-Economic Assessment Board established by Section 8 of YESAA.

Authorization: A licence, permit or other form of approval that is issued or given by: (a) the Governor in Council, a government agency, an independent regulatory agency or a municipal government, or (b) a First Nation under its final agreement or a First Nation law, but does not include an access order issued under the Yukon Surface Rights Board Act or a consent given by a First Nation for access to settlement land in circumstances where an access order could be issued under that Act.

Baseline: Past and current conditions in which a Valued Component is or has existed.

Bathymetry: The study or underwater depth and the mapping of underwater environments using contour lines.

Berm: Structures, generally made of earth, used to control erosion and sedimentation by reducing the rate of surface runoff. The berms either reduce the velocity of the water or direct water to areas that are not susceptible to erosion, thereby reducing the adverse effects of running water on exposed top soil.

Biodiversity: The existence of a wide range of different species in a given area or during a specific period of time.

Board: The Yukon Environmental and Socio-economic Board established by Section 8 of the Yukon Environmental and Socio-Economic Assessment Act.

Compliance monitoring: A broad term for a type of monitoring conducted to verify whether a practice of procedure meets the applicable requirements prescribed by legislation, internal policies, accepted industry standards or specified terms and conditions (e.g., in an agreement, lease, permit, licence or authorization). Mitigation monitoring is one type of compliance monitoring.

Conservation: Any various efforts to preserve the earth's natural resources, including such measures as: the protection of wildlife; the maintenance of natural prairie grasses, wetlands of wilderness areas; the control of air and water pollution; and the prudent use of farmland, mineral deposits and energy supplies.

Cumulative effects: The likely effects of the project in combination with the likely effects of other past, existing and future projects and activities. To be considered a cumulative effect, the other past, existing and future projects being considered in the assessment must affect a VC that is also being affected by the principal project; in this way the projects act cumulatively upon a valued component.

Decision document: A decision document issued by a decision body under section 75, 76 or 77 of YESAA.

Demographic: Information pertaining to human population dynamics, including the size, structure and distribution of populations and how populations change over time due to births, deaths, migration and ageing. Demographic analysis can relate to whole societies or to groups defined by criteria such as education, nationality, religion and ethnicity.

Designated Office: An office maintained under subsection 22(1) of YESAA.

Determination of significance: Taking into account the implementation of appropriate mitigation measures, a conclusion about whether adverse environmental effects are likely to be significant The significance of adverse environmental effects is determined by a combination of scientific data, regulated thresholds, standards, social values and professional judgment. For example, the ecological context of a project may be a determinant of whether likely adverse effects are significant.

Drawdown: The difference between the highest level a lake reaches in one summer and the lowest level a lake reaches during the following winter. For hydro reservoirs, drawdown indicates the amount of water required to satisfy the electrical loads placed in it and its water use licence commitments.

Duration of the effect: How long the effect would last. Effects may be considered low, moderate or high. Low effects are short term, lasting less than one year or not materially beyond the duration of the construction phase or the decommissioning phase of the Project. Moderate effects are medium term, lasting from 1 to 10 years or no more than one-generation span of the species affected. High effects are long term, lasting more than 10 years or more than one generation of the species affected or lasting throughout a major portion of the operations phase of the Project.

Ecological or socio-economic context: The sensitivity to environmental or socio-economic disturbance, capacity to adapt to change. This may be ranked as low, moderation or high; where ranked low, the VC is resilient to imposed change, where ranked moderate the VC has some capacity to adapt to imposed change and where ranked high the VC is fragile and has low resilience to imposed change.

Effects monitoring: The monitoring of environmental and socio-economic effects, or of the effectiveness of mitigative measures.

Environmental component: Fundamental element of the physical, biological or socio-economic environment, including the air, water, soil, terrain, vegetation, wildlife, fish, birds and land use that may be affected by a proposed project, and may be individually assessed in the environmental assessment.

Environmental monitoring: Periodic or continuous surveillance or testing, according to a predetermined schedule, of one or more environmental components. Monitoring is usually conducted to determine the level of compliance with stated requirements, or to observe the status and trends of a particular environmental component over time.

Erosion: Physical and chemical breaking down and transportation of geologic material.

Fee simple settlement land: Land that is, or is to be treated as, fee simple settlement land, as referred to in the definition "settlement land". Settlement Land owned under the same form of fee simple title as is commonly held by individuals who own land. For example, buying an individual lot in a subdivision will normally be held in fee simple title.

First Nation: A Yukon First Nation, within the meaning of the Umbrella Final Agreement.

Fish habitat: Spawning, nursery, rearing, food supply and migration areas upon which fish depend.

Fish ladder: A structure on or around artificial barriers to facilitate fishes' natural migration.

Flow: Motion characteristic of fluids (liquids or gases); any uninterrupted stream or discharge.

Frequency of the effect: Refers to how often an impact would occur, and may be ranked as low, moderate or high. Low frequency means the effects would never occur, occur once or seldom occur. Moderate frequency means the effect would occur occasionally. High frequency means the effect would occur continuously, on a regular basis or at regular intervals.

Fry: the young of fish.

Furbearer/ furbearing mammals: Referring to those mammal species that are trapped for the useful or economic value of their fur.

Gigawatt: A Gigawatt is the unit of electrical power equivalent to one billion watts or one million kilowatts.

Government agency: A federal agency or a territorial agency.

Greenhouse gas (GHG): Gaseous components of the atmosphere that contribute to the "greenhouse effect". Some greenhouse gases occur naturally in the atmosphere, while others result from human activities. Naturally occurring greenhouse gases include water vapor, carbon dioxide, methane, nitrous oxide, and ozone. Certain human activities, however, add to the levels of most of these naturally occurring gases.

Groundwater: The portion of sub-surface water that is below the water table, in the zone of saturation.

Habitat: The area or environment where an organism or ecological community normally lives or occurs. It is the space uniquely suited to required functions (e.g., breeding) through the arrangement of food, water, shelter, and cover.

Hectare (ha): A metric unit of square measure equal to 10,000 square metres or 2.471 acres.

Heritage resource: (a) a moveable work or assembly of works of people or of nature, other than a record only, that is of scientific or cultural value for its archaeological, palaeontological, ethnological, prehistoric, historic or aesthetic features; (b) a record, regardless of its physical form or characteristics, that is of scientific or cultural value for its archaeological, palaeontological, ethnological, prehistoric, historic or aesthetic features; or (c) an area of land that contains a work or assembly of works referred to in paragraph (a) or an area that is of aesthetic or cultural value, including a human burial site outside a recognized cemetery.

Heritage site: A heritage site is a location where a landmark of natural or cultural importance is legally protected. Heritage resources in the Yukon are protected under the Historic Resources Act and are defined as (i) historic sites, (ii) historic objects, and (iii) any work or assembly of works of nature or human endeavour that is of value for it archaeological, palaeontological, pre-historic, historic, scientific, or aesthetic features.

Hydroelectric power: Hydroelectric power is electricity harnessed from the energy of moving or falling water. Most hydroelectric power comes from the potential energy of dammed water driving a water turbine and generator.

Hydrology: The science dealing with the properties, distribution and circulation of water.

Hydrograph: Hydro (meaning water) and graph (meaning chart) refers to a record of discharge (flow) in a stream or river through time.

Impact: A positive or negative effect of a disturbance on the environment or a component of the environment.

Interested publics/ other publics: Any person or body having an interest in the outcome of an assessment, for a purpose that is not frivolous or vexatious, and includes: (a) the Fish and Wildlife Management Board established under the Umbrella Final Agreement, in relation to a project that is likely to affect the management and conservation of fish or wildlife or their habitat; (b) the salmon subcommittee of the Fish and Wildlife Management Board, in relation to a project that is likely to affect the management and conservation of salmon or their habitat; and (c) a renewable resource council established under a first nation's final agreement, in relation to a project that is likely to affect the management and conservation of fish or wildlife or their habitat within the traditional territory of that first nation.

Kilowatt (kW): The unit of power equivalent to 1,000 watts.

Kilowatt Hour (kWh): The unit measure of electrical power equivalent to use of 1,000 watts for a period of one hour (e.g., ten 100-watt light bulbs switched on for one hour would use one kWh [or 1,000 watts for one hour]).

Land Use Permit: A Land Use Permit allows a specific activity over a specified period of time. It does not give any exclusive rights or tenure to the land.

Littoral area: On or near a shore or the shallow area of a lake. This is an area where there is vegetation growth, providing primary habitat and eco-system food sources.

Local knowledge: Information held by community members, such as farmers, hunters, fishers and naturalists, who are familiar with the environment in a specific geographic area. Community knowledge may be used in the environmental assessment of a proposed project. For example, fish harvesters in a specific area may know where the best "fishing spots" are, and therefore may contribute to identifying potential fish habitat.

Megawatt (MW): A watt is the unit used to measure electric power. A megawatt (MW) is 1,000,000 watts.

Mitigation (mitigative measures): measures for the elimination, reduction, or control of adverse environmental or socio-economic effects, which include: (a) Avoiding effects altogether by not taking a certain action or parts of an action. (b) Minimizing effects by limiting the degree of magnitude of the action and its implementation. (c) Rectifying the effects by repairing, rehabilitating, or restoring the affected environment. (d) Reducing or eliminating the effects over time by preservation and maintenance operations during the life of the action. (e) Compensating for effects by replacing or providing substitute resources or environments.

Monitoring: Any ongoing process or program for measuring the actual effects of constructing or operating a development.

Northern Tutchone Land Use Planning Region: One of eight planning regions in the Yukon.

Operating regime: The pattern of use applied to the operations of a hydro facility, including any constraints placed on it by its water use license or other legislation and the strategy developed to maximize the electricity that can be produced within those constraints.

Physiography: A description of the natural features of the surface of the earth.

Phytoplankton: Microscopic organisms that live in watery environments, both salty and fresh.

Piscivorous: Habitually feeding on fish; fish-feeding.

Placer: Deposit of river sand or gravel containing particles of gold or another valuable mineral.

Probability: The chance or possibility that a specific event will occur.

Project: An activity that is subject to assessment under section 47 or 48 and is not exempt from assessment under section 49 of YESAA. For the purposes of this submission document it is the Mayo Lake Enhanced Storage Project.

Project Study Region: An area extending beyond the Construction Footprint Area identified to examine potential environmental and socio-economic effects of a project. For the Mayo Lake Enhanced Storage Project, this includes adjacent aquatic and terrestrial regions within a 5km buffer along the Mayo River, from the Village of Mayo to and around Mayo Lake.

Proponent: Proponent, in relation to a project or other activity, means a person or body that proposes to undertake it, or a government agency, independent regulatory agency, municipal government or first

nation that proposes to require — under a federal or territorial law, a municipal by-law or a First Nation law — that it be undertaken.

Ratepayer: A person who pays a regular charge for the use of a public utility, as gas or electricity, usually based on the quantity consumed.

Registered Trapping Concession (RTC): A parcel of land on which the holder is given exclusive rights to harvest furbearing animals.

Regulatory: Relating to a regulation or pertaining to legal requirements.

Renewable Resources Council (RRC): The Yukon First Nation Final Agreement provided for the establishment of Renewable Resources Councils (RRC's) in each of First Nation's Traditional territories. Acting as independent public interest advisory bodies, the RRC's may make recommendations on any matter related to fish and wildlife conservation, the establishment of Special Management Areas and to forest resources management.

Reservoir: A large natural or artificial lake used for collecting and storing water for human use.

Residual effects: Effects of a project that are expected to remain after mitigation measures have been implemented.

Scoping: The iterative process of identifying issues of concern related to the project, including the selection of Valued Components (VCs), identification potential pathways of effects along with the spatial and temporal boundaries for assessing effects of the project.

Settlement land: Land that is category A settlement land, category B settlement land or fee simple settlement land under a final agreement or under section 63 of the Yukon Surface Rights Board Act, or land that is to be treated as such by virtue of a self-government agreement, and includes Tetlit Gwich'in Yukon land, but does not include water or mines and minerals defined to be non-settlement land.

Shoreline: The narrow strip of land in immediate contact with the sea, lake or river.

Significance: A measure of the residual effects after the application of mitigation measures. Effects may be considered significant (high residual effect), potentially significant (moderate residual effect), not significant/ insignificant (low residual effect) or not significant/ negligible (no definable effects).

Socio-economic effects: Includes effects on economies, health, culture, traditions, lifestyles and heritage resources.

Species: A group of inter-breeding organisms that can produce fertile offspring.

Staging: Resting and gathering of waterfowl such as geese and ducks on a water body prior to, or during fall migration.

Subsistence economy: An economy in which a group obtains the necessities of life through self-provisioning. In such a system wealth is not measured in any form of currency, but rather exists in the form of natural resources.

Terrestrial: Living on or in the ground, or related to the ground.

Territory: (a) in relation to a first nation for which a final agreement is in effect, that first nation's traditional territory and any of its settlement lands within Yukon that are not part of that traditional territory; (b) in relation to the first nation known as the Tetlit Gwich'in, the areas described in Annex A of Appendix C to the Gwich'in Agreement; and (c) in relation to any other first nation, the geographic area within Yukon identified on the map provided by that first nation under the Umbrella Final Agreement for the purpose of delineating the first nation's traditional territory.

Threshold: A limit of acceptable change. Threshold measurements enable both project proponents and regulators to evaluate the acceptability of a project-related effects on a specific component of the environment by comparing the effects of the project against a pre-determine limit of acceptable change. Thresholds may be refined over time, as understandings of populations and ecological interactions evolve.

Traditional economy: A traditional economy is an economic system in which decisions such as the who, how, what, and for whom questions are all made on the basis of customs, beliefs, religion, habit, etc.

Traditional knowledge: The accumulated body of knowledge, observations and understandings about the environment, and about the relationship of living beings with one another and the environment, that is rooted in the traditional way of life of first nations. Note: Often referred to as Aboriginal Traditional Knowledge (ATK), which is knowledge held by, and unique to Aboriginal peoples. It is a living body of knowledge that is cumulative and dynamic and adapted over time to reflect changes in the social, economic, environmental, spiritual and political spheres of the Aboriginal knowledge holders. Sometimes used interchangeably with Traditional Ecological Knowledge (TEK), however TEK is generally considered to be a subset of ATK and is primarily concerned about knowledge about the environment.

Traditional lifestyle: Activities which have been followed by communities and people for long periods, often for generations.

Traditional resource use: Hunting, trapping, fishing and food gathering by Aboriginal peoples whether for subsistence purposes or otherwise.

Traditional territory: Lands designated under the Umbrella Final Agreement that provide rights for subsistence hunting and fishing activities; allocation of 70 percent of traplines; representation on land use planning bodies; membership on the Yukon Water Board, Development Assessment Board, Surface Rights Board, Fish and Wildlife Management Board and the Renewable Resources Councils.

Tributary: A stream or river that flows into another river or other body of water.

Uncertainty: The possible error or range of error which may exist within assumptions.

Valued Component (VC): Described in YESAB guides as an element of a project area that is valued for environmental, scientific, social, aesthetic, or cultural reasons. For the Project, VCs were identified in the process of scoping the Project and through the Public Involvement Program (PIP).

Waterfowl: Ducks, geese and swans (game birds that frequent water).

Water regime: A description of water body (i.e., lake or river) with respect to elevation, flow rate, velocity, daily fluctuations, seasonal variations, etc.

Watershed: The area within which all water drains to collect in common channel or lake.

Wetlands: Those lands where the water table is at, near or above surface or where land has been saturated for a long enough period to produce such features as wet-altered soils and water-tolerant vegetation.

Wildlife habitat: Any area providing food, shelter, cover, air and space, or any one of the aforementioned, to wildlife such as mammals, birds, reptiles, amphibians and/or invertebrates.

Wildlife Key Areas (WKA): Any area that is critical to wildlife during at least a portion of the year. This importance may be due to vegetative characteristics such as residual nesting cover, or behavioral aspects of the animals such as lambing areas. Key areas include: winter ranges, lambing/fawning/calving areas, dancing/strutting grounds, nesting areas, breeding grounds, riparian and woody drainages, and roosting areas.

Yukon Environmental and Socio-Economic Assessment Act (YESAA): An Act to establish a process for assessing the environmental and socio-economic effects of certain activities in Yukon.

Zooplankton: A freshwater community of floating or weakly swimming non-photosynthetic, mostly microscopic organisms such as rotifers and copepods.

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Appendix 5.5
Aishihik Turbines Uprate Study
(KGS 2016)

YUKON ENERGY

AISHIHIK TURBINES UPRATE STUDY

FINAL – REV 1

KGS Group 14-1404-004
February 2016

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ATTENTION: Mr. Ron Gee
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RE: Aishihik Turbines Uprate Study RFP #2014-053 – Final Report, Rev 1

Dear Mr. Gee:

KGS Group is pleased to submit two hard copies and a digital copy of this revised report for the Aishihik Turbines Upgrade Study. Table 1 of the report was revised to clarify the information.

Please contact the undersigned if you have any questions on the report.

We thank you for the opportunity to providing Yukon Energy Corporation with engineering services for this project.

Yours truly,

J. Lambert, P.Eng.
Senior Mechanical Engineer

DB/gr
Enclosure

EXECUTIVE SUMMARY

The Aishihik Generating Station ("AGS") was built in the mid-1970's. It originally consisted of two vertical Francis turbines, AH1 and AH2, manufactured by Dominion Engineering Works and coupled to General Electric generators. A third horizontal Francis unit, AH3, manufactured by Kossler/Voith was added in 2011. Both the AH1 and AH2 stators were eventually re-wound with varying amounts of additional generator capacity in 2003 and 2006 respectively; AH2 generator has more capacity than AH1 generator.

Due to their vintage, AH1 and AH2 are not as efficient as modern turbines. Combined with the fact that their associated generators having additional capacity, this provides an opportunity to increase energy production by uprating and refurbishing them with modern runners. The study examines two options: firstly, uprating only AH2 and secondly, uprating both AH1 and AH2.

The Aishihik Generating Station unit AH2 could be uprated at a cost of $3.0M with a discounted payback of 6 years. The major components to be uprated include the runner, the generator air coolers, the excitation system, and the cables from the generator to the circuit breaker and from the outdoor switchgear to the transformers. YEC could, at its discretion, add opportunity work on the balance of turbine/generator components and on the AGS balance of plant.

Alternatively, AH1 and AH2 can both be uprated with new runners for a cost of $4.7 M and a discounted payback of 8 years. The incremental amount of work to add the uprate AH1 to the scope of work is limited to the new runner and optional opportunity work since it will not require new cabling or a new excitation system.

The uprated units would provide an increase in plant capacity, which would displace diesel generation, and would increase Yukon Energy Corporation's annual energy generation.

TABLE OF CONTENTS

PAGE

EXECUTIVE SUMMARY i

1.0 BACKGROUND 1

2.0 PRESSURE SHAFT AND TAILRACE TUNNEL HYDRAULIC STUDY 2
2.1 HYDRAULIC REVIEW 2
2.2 TRANSIENT PRESSURE FLUCTUATIONS 2

3.0 TURBINE UPRATE REVIEW 3
3.1 TYPICAL OPERATION AND OPTIMIZATION OF NEW RUNNERS 3
3.2 ANALYSIS OF RUNNER UPRATE OPTIONS 3

4.0 ENERGY AND CAPACITY BENEFITS ANALYSIS 5
4.1 ENERGY 5
4.2 CAPACITY 7
4.3 VALUE OF CAPACITY AND ENERGY 8

5.0 ELEC**TRICAL** EQUIPMENT ASSESSMENT 9
5.1 IN**TRODUCT**ION 9
5.2 EXISTING ELECTRICAL ARRANGEMENT 9
5.3 ELECTRICAL EQUIPMENT UNDER STUDY 10
5.4 GENERATING STATION POWER OUTPUT 10
5.4.1 Electrical Components Associated to AH2 Only 10
5.4.2 Electrical Components Common to All Units 11
5.5 ELECTRICAL EQUIPMENT RATING 11
5.5.1 AH2 Generator Stator Winding 11
5.5.2 AH2 Excitation System 11
5.5.3 AH2 MV Power Cables to Generator Breaker Switchgear 12
5.5.4 AH2 Generator Breaker 13
5.5.5 Generator Breaker Switchgear 13
5.5.6 F1 and F2 MV Power Cables 13
5.5.7 S167 Switchgear 15
5.5.8 MV Power Cables to T1 and T3 Transformers 16
5.5.9 T1 and T3 Transformers 18
5.6 ELECTRICAL CONCLUSION 18

6.0 MECHANICAL EQUIPMENT ASSESSMENT 20
6.1 SURFACE AIR COOLING SYSTEM 20
6.2 OPPORTUNITY WORK 20

7.0 ECONOMIC ANALYSIS 24
7.1 COSTS ASSOCIATED WITH RERUNNERING 24
7.2 CAPACITY AND ENERGY BENEFITS 26
7.3 PAYBACK PERIOD 28

8.0 CONCLUSION 30

9.0 STATEMENT OF LIMITATIONS AND CONDITIONS 31
9.1 THIRD PARTY USE OF REPORT 31
9.2 CAPITAL COST ESTIMATE STATEMENT OF LIMITATIONS 31

TABLES

1. Aishihik Turbine Budgetary Propsals
2. Energy Benefits
3. Plant Capacity
4. Summary of Assessment Results
5. Budget Estimate to Upreate Units
6. Financial Benefits
7. Payback Periods
8. Sensitivity Analysis

LIST OF APPENDICES

A. Hydraulic Capacity Review
B. Turbine Vendor Budgetary Proposals:
    B-1 Runner Upgrade RFI
    B-1 Alstom Proposal
    B-2 Norcan Proposal
C. Energy Benefit Analysis
D. Excitation System Assessment
E. Business Case Calculations

1.0 BACKGROUND

The two original vertical Francis turbine generating units (AH1 & AH2) at the Aishihik Hydro facility were manufactured by Dominion Engineering Works Limited in 1974 and placed into service in 1975. They are 15 blade runners rated at 20,500 HP (15.3MW) at 592 feet of head. These turbines were coupled to Canadian General Electric generators rated at 15.6MVA / 14.0MW.

In 2003, the AH1 generator was rewound by General Electric, increasing its stator capacity to 17MVA / 15.3MW. The generator's capacity now matches the turbine's output of 15.3MW.

In 2006, the AH2 generator was rewound by Voith, increasing its stator capacity to 19.2MVA / 17.2MW. The generator's capacity now exceeds the turbine's output of 15.3MW.

The newer horizontal Francis turbine generating unit AH3, manufactured by Kossler/Voith, was placed into service in 2011. It produces 9,625 HP (7.180 MW) turbine at 592 feet of head and it is connected to an 8.25MVA TDPS-India generator. This unit is not considered for uprating.

Although uprating AH2 offers the greater opportunity for a single unit uprate, the benefits of fitting AH1 with a higher efficiency runner were also reviewed.

Only the components related to turbine, generator and power train capacity and efficiency uprate are examined in this report. These uprate elements are justified and costed out. A project payback is then calculated using a calculation spreadsheet provided by YEC. Opportunity work normally performed during runner and generator uprates are identified, but are not costed out, since they do not have capacity or energy benefits and payback. Similarly, project indirect costs such as camp facilities and internal YEC engineering costs are not considered.

KGS Group used an integrated multi-disciplinary team of experienced engineers to carry out the Aishihik Turbine Uprate Study. They conducted engineering reviews, sent vendors requests for information (RFI's) and compiled capital cost estimates for two options for YEC's consideration. KGS Group also performed computations of payback based on KGS calculations of energy benefits.

2.0 PRESSURE SHAFT AND TAILRACE TUNNEL HYDRAULIC STUDY

The initial task in the turbine uprate study was to conduct a high level hydraulic review of the conveyance system in order to determine the maximum flow that can be conveyed before affecting functionality and safety of the system.

2.1 HYDRAULIC REVIEW

KGS Group reviewed the existing documentation and developed a one dimensional computer model to confirm the conveyance system hydraulics. It was determined that the limiting factors for increasing plant flow capacity are the requirements to maintain the emergency evacuation path in the tailrace tunnel and to maintain the tunnel operating at less than full flow.

The current plant capacity provides 1.06 m of emergency freeboard throughout the tunnel during normal downstream river conditions. During flood conditions, no data is available about water levels in the West Aishihik River. These river water levels have the potential to limit the available emergency freeboard at the downstream end of the tailrace tunnel. Until further information about flood stages in the West Aishihik River is obtained and analyzed, no increase in plant flow is recommended.

Should the tunnel transition from partially full to full flow, there is a possibility of backwater effects such as a significant rise in tailwater level at the plant and possibly pressure transient issues. The magnitudes of these effects have not been determined. KGS Group recommends that the Turbine Rerate Specification includes a section on limiting water flow through the new runner, or runners, such that the total plant flow limit is respected under all operating conditions.

KGS Group's hydraulic review is provided in Appendix A.

2.2 TRANSIENT PRESSURE FLUCTUATIONS

A high level assessment of transient pressure fluctuations in the pressure tunnel during unit start-ups and shut-downs was not required since the maximum plant flow conditions will not change as a result of runner uprates.

3.0 TURBINE UPRATE REVIEW

KGS Group issued a Request for Information (RFI) for budget pricing, as well as technical information on a new runner for Unit 2, and other required turbine modifications or new components that may be beneficial to the efficiency or power output of the turbine. Two proposals were received, one from Alstom Power and one from Norcan Hydraulic Turbine Inc., hereafter called Alstom and Norcan. The vendor responses are presented in Appendix B.

3.1 TYPICAL OPERATION AND OPTIMIZATION OF NEW RUNNERS

The Vendors were informed that in order to provide a “spinning reserve” to accept sudden load increases on Yukon Energy Corporation’s electrical grid, the AH1 and AH2 units are typically operated at approximately 80% of their maximum power output. They may, however, be operated at relatively low power levels during periods of low demand and at maximum output during periods of high demand.

Because of the above-mentioned operation strategy, the proposed new runners should be optimized to provide, in order of importance:

1. The highest efficiency at approximately 80% gate opening.
2. The highest maximum output at full gate opening.
3. The highest efficiency at gate openings lower than 80%.

3.2 ANALYSIS OF RUNNER UPRATE OPTIONS

Based on the above criteria, Alstom and Norcan focused on obtaining higher efficiencies by taking advantage of modern design and manufacturing techniques. Both vendors offered runners that would fit within the existing runner chamber. The principal elements of the turbine that were targeted were the runner blade shapes and labyrinth seal design. Alstom also foresees potential extra improvements by changing wicket gate profiles. The future RFP to vendors should prompt them to explore these and other areas of potential efficiency gains.

Alstom and Norcan picked runners from their stock of prior designs as reference runners for Aishihik. They provided expected curves of turbine power and efficiency for a net head of 180.4 m. A summary of the budgetary proposals follow in Table 1.

TABLE 1
AISHIHIK TURBINE BUDGETARY PROPOSALS

ITEM	NORCAN	ALSTOM
Budgetary cost (not adjusted)	$497,273	$743,000
Description of new runner	40” Francis Cast CA6NM or Forged A182F6NM	40” Francis Forged martensitic steel
Fabrication method	Runner will be forged and machined.	Runner will be fabricated. Crown and band will be cast or forged and pre machined.
Proposed scope of the upgrades, beyond the provision of new runners	none	Refurbish Wicket Gates. Different runner bolting pattern. Redesign labyrinth.
Number of runner blades proposed	15	15
Performance at 180.4 m net head: • Max Power at rated flow 9.72 cms • Best efficiency • Flow at best efficiency point	 16.1 MW 93.83% 9.32 cms	 16.1 MW 93.5% 8.4 cms
Maximum runaway speed	Not given	185%
Delivery time for major equipment after placement of order	11-12 months	9-10 months
Time required for installation in the field	6-8 weeks	Not given

4.0 ENERGY AND CAPACITY BENEFITS ANALYSIS

4.1 ENERGY

The energy benefit analysis for the potential upgrades of Aishihik Generating Station (AGS) were conducted using the long term energy model YECSIM developed by KGS Group for Yukon Energy Corporation (YEC). The options for potential upgrades of AGS could include the upgrades of either AH1 or AH2 or both.

The software YECSIM is a detailed integrated power / water flow model operating on a weekly time step. It can be used for analysis of the operation and future expansion of the YEC electrical generating capacity. This model includes all assumed loads and load profiles, operating characteristics of each system power facility (e.g. unit efficiencies), licensed parameters for each plant as approved or proposed, and desired operating parameters for the system (such as reducing line losses or voltage stability), as well as the hydrological conditions. More information about the model can be found in the YECSIM User's Manual.

As required by the YECSIM model, the 3-tier systems for specification of efficiency were developed for the the existing conditions based on the original turbine and generator efficiency curve and the potential upgrade options based on the turbine and generator efficiency curves provided by vendors. The plant maximum flow was limited at the 23.7 m^3/s. The two energy demand levels for the WAF/MD integrated system, including the low energy demand level (468.1 GWh/year) and the high energy demand level (575.1 GWh/year), were used in the YECSIM model simulations.Those two energy loads could reasonably be expected to occur or be surpassed within the future 20 to 30 years starting from 2009, as described in the report for the proposed Mayo Hydro Enhancement Project prepared by YEC (Ref. 2). More information related to the YECSIM model setup is provided in Appendix C.

The hydro energy generation from the WAF/MD system for the existing conditions and the potential upgrade options were forecasted using the YECSIM model. The detailed description of the energy benefit analysis is provided in Appendix C. Table 2 below shows the modeled net hydro energy contributions to the WAF/MD integrated system for the potential upgrade options.

The model results show:

- For the upgrades of AH1 only, using Alstom turbine would generate energy benefit from 2.19 GWh/year to 2.26 GWh/year to the system, while using Norcan turbine would generate energy benefit from 0.96 GWh/year to 1.27 GWh/year to the system.
- For the upgrades of AH2 only, using Alstom turbine would generate energy benefit from 2.25 GWh/year to 2.35 GWh/year to the system, while using Norcan turbine would generate energy benefit from 1.14 GWh/year to 1.40 GWh/year to the system. The energy benefit for the upgrades of AH2 only is slightly higher than the one for the upgrade of AH1 only.
- For the upgrades of both AH1 and AH2, using Alstom turbines would generate energy benefit from 2.74 GWh/year to 3.04 GWh/year to the system, while using Norcan turbine would generate energy benefit from 1.81 GWh/year to 2.37 GWh/year to the system. The energy benefit for the upgrades of both AH1 and AH2 are higher than the one for the upgrades of either AH1 or AH2.

TABLE 2
ENERGY BENEFITS

Unit Upgrade Option	Net Energy Contribution due to the Upgrades using Alstom Turbine (GWh/year)		Net Energy Contribution due to the Upgrades using Norcan Turbine (GWh/year)	
	Low Energy* Demand	High Energy** Demand	Low Energy* Demand	High Energy** Demand
Upgrade of AH1 Only	2.26	2.19	0.96	1.27
Upgrade of AH2 Only	2.35	2.25	1.14	1.40
Upgrade of AH1 and AH2	2.74	3.04	1.81	2.37

*: Low energy demand (468.1 GWh/year)

**: High energy demand (575.1 GWh/year)

Going forward in this report, only the Alstom proposal will be analyzed for economic benefits. This proposal has the higher initial cost and the higher net energy contribution to the WAF/MD System.

4.2 CAPACITY

Incremental capacity represents an important benefit to the proposed turbine upgrade project. Although the proposed turbine capacity may exceed the existing turbine capacity, hydraulic conditions limit the effectiveness of this additional capacity. According to YEC, Aishihik GS is typically run at around 80% plant flow, so any excess turbine capacity requiring additional plant flow may not be realized. Therefore, the evaluation was based on plant capacity at 80% plant flow instead of the individual turbine capacity.

Plant capacity was estimated for each configuration based on the typical plant flow of 19 m^3/s. The estimated plant capacities for each proposed plant configuration are shown in Table 3.

TABLE 3
PLANT CAPACITY

SIMULATION SCENARIO	PLANT EFFICIENCY (%)	PLANT CAPACITY (MW)	INCREMENTAL PLANT CAPACITY (MW)
Existing Condition	87.8	29.8	-
New AH1 - Alstom	89.9	30.5	0.7
New AH1- Norcan	89.7	30.5	0.6
New AH2 - Alstom	89.9	30.5	0.7
New AH2 - Norcan	89.7	30.5	0.6
New AH1 and AH2 - Alstom	91.6	31.1	1.3
New AH1 and AH2 - Norcan	91.3	31.0	1.2

Incremental plant capacity varies depending on how many units are upgraded. Alstom units provide a marginal capacity benefit relative to Norcan units. Upgrading both AH1 and AH2 provides close to double the incremental capacity of upgrading only one unit.

For the purpose of designing electrical components, the plant capacity was evaluated at maximum flow and maximum expected net head using an optimistic estimate of conveyance

system losses. For a plant flow of 23.7 m^3/s and net head of 182.2 m, the existing plant capacity is 37.2 MW. Proposed configurations range in capacity from 37.9 MW for the Norcan AH1 replacement to 38.6 MW for the Alstom 2 unit replacement.

4.3 VALUE OF CAPACITY AND ENERGY

YEC provided the following values for capacity and energy increase:

- Capacity: $2,500,000 per MW based on avoided capital cost of new natural gas generation.
- Energy: $200,000 per GWh per year based on avoided operating (i.e. variable cost) cost of natural gas.

5.0 ELECTRICAL EQUIPMENT ASSESSMENT

5.1 INTRODUCTION

This section summarizes the results of the electrical assessment carried out on the major electrical components associated to AH2 unit, with the purpose of determining if these components are able to support an uprated capacity of 19.2 MVA.

The scope of the assessment includes the generator, excitation system, medium voltage power cables, switchgear and generator step up transformers. This report assumes that as a result of a runner replacement, AH1 unit will not increase its rating beyond 17 MVA. Furthermore, it is assumed that all generators could be expected to operate at 95% of nominal voltage (13.1 kV) while operating at nominal rating.

This study was solely based on equipment ratings as provided by datasheets and nameplates. Results presented on this report have not factored equipment age, condition, or maintenance.

5.2 EXISTING ELECTRICAL ARRANGEMENT

With reference to single line diagrams P130 and S137, the Aishihik Generating Station is composed of three hydro generating units, with the following ratings:

- AH1: 17 MVA, 13.8 kV
- AH2: 19.2 MVA, 13.8 kV
- AH3: 8.25 MVA, 13.8 kV

The combined plant nominal output is 44.45 MVA.

These generators are connected to a common 13.8 kV switchgear with medium voltage (MV) power cables. This switchgear, which is located at the generator level, includes dedicated generator circuit breakers (one for each unit). This switchgear is connected to a second 13.8 kV switchgear, which is part of the substation S167, using two sets of MV power cables (feeders F1

and F2), and run vertically in cable trays. These two cable systems are normally operated in parallel.

The 13.8 kV switchgear part of substation S167 is then connected with medium voltage power cables to two generator step up transformers.

5.3 ELECTRICAL EQUIPMENT UNDER STUDY

Since the scope of the electrical review is to assess the limits of electrical components associated to AH2 unit, the following components have been analyzed:

- AH2 stator winding
- AH2 excitation system
- MV power cables interconnecting AH2 to the generator breaker switchgear
- AH2 generator circuit breaker and associated switchgear
- MV power cables interconnecting the generator breaker switchgear to the S137 switchgear
- S137 switchgear and associated circuit breakers
- MV power cables interconnecting the S137 switchgear to the generator step up transformers
- Generator step up transformers

5.4 GENERATING STATION POWER OUTPUT

In order to assess the capability of the electrical equipment associated to AH2 unit, the expected station output needs to be defined. Based on an uprate of 19.2MVA for unit AH2, the following system ampacity would be required:

5.4.1 Electrical Components Associated to AH2 Only

The electrical components associated only to AH2 need to be able to continuously carry the nominal output of AH2 unit:

- 803 A at nominal (13.8 kV) voltage
- 846 A at 13.1 kV (95% of nominal voltage)

5.4.2 Electrical Components Common to All Units

The electrical components that are associated to all units (i.e. switchgears) need to be able to continuously carry the nominal output of the three units operating in parallel and at nominal capacity:

- 1860 A at 13.8 kV (nominal voltage)
- 1959 A at 13.1 kV (95% of nominal voltage)

5.5 ELECTRICAL EQUIPMENT RATING

5.5.1 AH2 Generator Stator Winding

According to Voith's drawing 4671A49 (AH2 unit nameplate after stator rewind), AH2 stator winding is rated for 19,200 kVA at nominal 13,800 V. Since this information was provided by Voith Siemens, the Company retained by YEC to rewind the unit, KGS Group assumes this information to be accurate, and therefore, no further studies or investigations were undertaken.

5.5.2 AH2 Excitation System

The AH2 generator is equipped with a DC exciter, controlled by SR125E Basler automatic voltage regulator (AVR). As a part of the generator rewind, project the generator rotor field poles were reinsulated, however, the DC exciter was not upgraded.

Based on the documentation provided by YEC and discussions with Voith Siemens, the following conclusions can be made:

- According to the machine data provided by Voith-Siemens, to produce the rated power of 19.2 MVA, the generator rotor field voltage and field current requirement is 75 V and 720A respectively, while the DC exciter is rated at 670 A.

- The DC exciter will operate beyond its design limit to produce the rated voltage at 19.2 MVA, 0.9 power factor.

To operate AH2 unit at the uprate power of 19.2 MVA, the following two alternatives should be investigated:

- The existing exciter could be replaced with a static exciter to match the generator field requirements. The generator field leads and associated slip rings should be checked so that these are properly rated for operation at 19.2 MVA.
- The rotating DC exciter could be upgraded to meet the rewound generator field requirements. The associated AVR would need to be replaced to meet the requirement of the upgraded exciter. The generator field leads and associated slip rings should be checked so that these are properly rated for operation at 19.2 MVA.

5.5.3 AH2 MV Power Cables to Generator Breaker Switchgear

According to the information provided by YEC's drawing O111D4956 "AH2 Cable Tray and Termination Diagram, AH2 unit is connected to its generator circuit breaker with 3 x 1C 750MCM, 15 kV, copper MV power cable. Based on this drawing, these cables run in a steel ladder tray. Assuming these cables are provided with one diameter spacing, the ampacity of this feeder can be obtained from the 2015 edition of the Canadian Electrical Code, Table D17M. Based on this table, and assuming an ambient temperature of 40°C, this feeder is expected to have an ampacity of 706 A.

Since AH2 unit will have an output of 803 A at nominal voltage, the existing feeder will be overloaded. Based on the configuration provided in drawing O111D4956, this feeder will operate at its limit when AH2 operates at the following ratings:

- 16,875 kVA at nominal (13.8 kV) voltage
- 16,019 kVA at 13.1 kV (95% of nominal voltage)

To reach a nominal output of 19.2 MVA, a second, parallel run of similar cables should be installed to ensure equal load distribution. AH2 feeder cables could also be replaced for 6 X 1C 350MCM 15kV copper power cables, installed in cable tray, providing one diameter spacing, assuming an ambient tempearure of 40°C.

5.5.4 AH2 Generator Breaker

Based on the single line diagrams provided by YEC, the AH2 generator circuit breaker (equipment tag P130-52-AH2) has a rating of 1200 A. When the generator supplies its uprate nominal power rating of 19.2 MVA, this generator circuit breaker will be loaded at the following ratings:

- 67% of 1200 A at nominal (13.8 kV) voltage
- 71% of 1200 A at 13.1 kV (95% of nominal voltage)

According to these results, AH2 generator circuit breaker has sufficient rating to support an uprate capacity of 19.2 MVA.

5.5.5 Generator Breaker Switchgear

According to single line diagrams, the generator breaker switchgear, which is installed at the generator level and is common to all units, has a rating of 2000 A. When all generators supply their nominal power rating of 44.45 MVA, the generator breaker switchgear will be loaded at the following ratings:

- 93% of 2000 A at nominal (13.8 kV) voltage
- 98% of 2000 A at 13.1 kV (95% of nominal voltage)

Based on these results, the generator breaker switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

5.5.6 F1 and F2 MV Power Cables

The MV power cable system that connects the generator breaker switchgear to the S167 switchgear is composed of two sets of 15 kV cables run in vertical cable trays, inside the vertical shaft leading to the surface. These cable systems, which normally operate in parallel, have the following characteristics:

- Feeder F1: 9 x 1C 750MCM Okonite Okoguard 15 kV 133%
- Feeder F2: 9 x 1C 750MCM Okonite Okoguard 15 kV 133%

When these cable systems operate in parallel, it is expected that they will equally share the load, as both systems use the same cable type and quantity. When a single cable system is in service, it will be required to carry the entire plant output. This study has assessed both operating conditions.

According to the CEC Rule 28.108 (a) conductors supplying a group of two or more motors (generators) shall have an ampacity not less than 125% of the full load current rating of the motor (generator) having the largest full load current rating, plus the full load current ratings of all the other motors (generators) in the group. For this assessment, it has been assumed that since generator outputs are limited by the water conveyance system and turbines, generators are not able to produce more than their nominal outputs (i.e. 44.45 MVA combined).

The ampacity of each feeder system was calculated based on the following assumptions:

- Cables are run in ventilated cable trays, with approximately 25% diameter spacing between each cable
- Elevator shaft temperature was assumed to be 40°C

The 2015 edition of the CEC, Table D17N, provides cable ampacities for single conductor cables in cable trays, installed in contact or spaced less than one diameter apart. Based on this table, F1 and F2 feeders are expected to have the following ampacity:

- F1 and F2 Feeders: 678 A per 750 MCM conductor (2034 A)

When all generators supply their nominal power rating of 44.45 MVA, and both cable systems are operating in parallel, and assuming equal load sharing, each cable system is expected to be loaded at the following ratings:

- F1 Feeder: 46% of 2034 A at nominal (13.8 kV) voltage

- F2 Feeder: 46% of 2034 A at nominal (13.8 kV) voltage
- F1 Feeder: 48% of 2034 A at 13.1 kV (95% of nominal voltage)
- F2 Feeder: 48% of 2034 A at 13.1 kV (95% of nominal voltage)

Based on these results, F1 and F2 feeders have sufficient excess capacity to support an uprate capacity of 19.2 MVA.

When all generators supply their nominal power rating of 44.45 MVA, and only one feeder is in service, the cable is expected to be loaded at the following rating:

- F1 or F2 Feeder: 91% of 2034 A at nominal (13.8 kV) voltage
- F1 or F2 Feeder: 96% of 2034 A at 13.1 kV (95% of nominal voltage)

According to these results, F1 or F2 feeder would be operating close to their limit when AH2 operates at uprate capacity of 19.2 MVA.

5.5.7 S167 Switchgear

According to single line diagrams, the S167 switchgear is rated 2000 A and is equipped with 2000 A circuit breakers. When all generators supply their nominal power rating of 44.45 MVA, the S167 switchgear will be loaded at the following ratings:

- 93% of 2000 A at nominal (13.8 kV) voltage
- 98% of 2000 A at 13.1 kV (95% of nominal voltage)

Based to these results, the S167 switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

5.5.8 MV Power Cables to T1 and T3 Transformers

According to drawings provided by YEC and site photos, the MV power cable systems that connect the S167 switchgears to T1 annd T3 generator step up transformers have the following characteristics:

- Feeder to T1 Transformer: 9 x 1C 750 MCM 15 kV cable in cable tray
- Feeder to T3 Transformer: 9 x 1C 750 MCM 15 kV buried cables transition to overhead line and to 6 x 1C 750 MCM 15 kV cable in buried conduit.

The 2015 edition of the CEC, Table D17N for outdoor installations, provides cable ampacities for single conductor cables in cable trays, installed in contact or spaced less than one diameter apart. Based on this table, the feeder connected to T1 transformer is expected to have the following ampacity:

- Feeder to T1 Transformer 545 A per 750 MCM conductor (1635 A)

Based on this analysis, the feeder to T1 Transformer could carry the following load:

- 39.1 MVA, equivalent to 88% of the uprate plant capacity (44.45 MVA) at 13.8 kV
- 37.1 MVA, equivalent to 83% of the uprate plant capacity (44.45 MVA) at 13.1 kV

Since the feeder to T3 transformer is composed of three distinctive arrangement (underground duct, overhead line and cable in buried conduit), each arrangement is analyzed individually.

The cable run connecting the S167 switchgear to the overhead line is assumed to be an underground duct bank. For this arrangement, the feeder ampacity was estimated from IEEE Standard 835-1994, Table 342, for 25°C earth temperature, 100 load factor and average ground resitivity. Table 342 provides the following ampacity:

- Feeder to T3 Transformer (underground duct): 444 A per 750 MCM conductor (1332 A)

Based on this analysis, the feeder to T3 Transformer (underground duct) could carry the following load:

- 30.2 MVA, equivalent to 68% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 31.8 MVA, equivalent to 72% of the uprate plant capacity (44.45 MVA) at 13.8 kV

The overhead line connecting to disconnect switch S167-89-LT3 is assumed to be two parallel runs of 266 MCM ACSR (Partridge). The line ampacity was estimated from ACSR cable catalogues for 25°C ambient temperature and wind velocity of 2 ft/sec. ACSR cable catalogues provide the following ampacity:

- Feeder to T3 Transformer (overhead line): 455 A per 266 MCM conductor (910 A)

Based on this analysis, the feeder to T3 Transformer (overhead line) could carry the following load:

- 20.6 MVA, equivalent to 46% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 21.8 MVA, equivalent to 49% of the uprate plant capacity (44.45 MVA) at 13.8 kV

According to site photos, the feeder connecting the disconnect switch S167-89-LT3 to the T3 transformer runs in buried conduit. For this arrangement, the feeder ampacity was estimated from IEEE Standard 835-1994, Table 488, for 25°C earth temperature, 100 load factor and average ground resitivity. Table 488 provides the following ampacity:

- Feeder to T3 Transformer (buried conduit): 521 A per 750 MCM conductor (1042 A)

Based on this analysis, the feeder to T3 Transformer (buried conduit) could carry the following load:

- 23.6 MVA, equivalent to 53% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 24.9 MVA, equivalent to 56% of the uprate plant capacity (44.45 MVA) at 13.8 kV

Since the feeder to T3 Transformer has three different ampacities, the rating of this feeder should be assumed as the lowest of the three ampacities. Therefore, the overall ampacity of the feeder to T3 Transformer would be limited by the overhead line:

- 20.6 MVA, equivalent to 46% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 21.8 MVA, equivalent to 49% of the uprate plant capacity (44.45 MVA) at 13.8 kV

5.5.9 T1 and T3 Transformers

YEC's single line diagrams show that T1 and T3 generator step up transformers (GSU) are oil filled 30/40 MVA (ONAN/ONAF). When both transformers are operating in parallel, and assuming these transformers have similar reactances (equal load sharing), it is expected that each transformer would be loaded to 22.2 MVA or 56% of their ONAF rating.

If a single GSU is assumed in to be in service, that transformer will be loaded to 111% of its ONAF rating. If YEC expects a single GSU to be in service while the three units operate at their nominal rating, KGS Group recommends transformer temperatures be properly monitored. Transformer operation beyond its nameplate rating is normally associated with accelerated loss of service life.

5.6 ELECTRICAL CONCLUSION

From the above information and assumptions, the following conclusions can be made:

- AH2 excitation system: The DC exciter will operate beyond its design limit to produce the rated voltage at 19.2 MVA, 0.9 power factor.
- MV Power cable from AH2 to generator breaker switchgear: This feeder does not have enough ampacity to operate at 19.2 MVA. To reach a nominal output of 19.2 MVA a second, parallel run of similar cables should be installed to ensure equal load distribution. AH2 feeder cables could also be replaced for 6 X 1C 250MCM 15kV copper power cables, installed in cable tray, providing one diameter spacing, assuming an ambient temperature of 40°C.
- Generator breaker: AH2 generator circuit breaker has sufficient rating to support an uprate capacity of 19.2 MVA
- Generator Breaker Switchgear: The generator breaker switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

- F1 and F2 MV power cables: F1 and F2 feeders have sufficient excess capacity to support an uprate capacity of 19.2 MVA when these feeders operate in parallel. However, F1 or F2 feeder would be operating close to their limit when a single feeder system is in service.

- S167 Switchgear: The S167 switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

- MV power cables to T1 Transformer: The feeder can carry up to 37.1 MVA, equivalent to 83% of the uprate plant capacity at 13.1 kV and 39.1 MVA, equivalent to 88% of the uprate plant capacity at 13.8 kV

- MV power cables to T3 Transformer: The feeder is limited by the ampacity of the overhead line to 20.6 MVA, equivalent to 45% of the uprate plant capacity at 13.1 kV or to 21.8 MVA, equivalent to 49% of the uprate plant capacity at 13.8 kV

- T1 and T3 transformers: T1 and T3 transformers have sufficient excess capacity to support an uprate capacity of 19.2 MVA when these transformers operate in parallel. However, if a single transformer is assumed to be in service, that transformer will be loaded to 111% of its ONAF rating.

6.0 MECHANICAL EQUIPMENT ASSESSMENT

The main mechanical system that is affected by the additional power output of an upgraded runner is the generator surface air cooling system.

6.1 SURFACE AIR COOLING SYSTEM

The generator surface air coolers (SACs) are assumed to be the original ones provided by Canadian General Electric in the early circa 1973. There are four SACs per unit. They are fed with river water through a common header and 2" branch lines and they discharge to the tailrace.

Through first principle calculations, we estimate that the heat exchange rate across the SACs could increase by a maximum of 25% if the stator temperature rise increases to 80°C above ambient from its present 60°C. Given the age of the SAC piping and cooling coils, the heat exchangers could possibly be fouled and/or internally corroded. This would reduce their effectiveness in transmitting the heat from the air into the cooling water. As such, the heat exchangers should be considered near the end of their life cycle, making them unsuitable for higher duty usage. The entire SAC piping system and heat exchangers should be changed out with the unit rerate project. The T/G contractor could be asked to provide this service.

6.2 OPPORTUNITY WORK

The rerunnering project offers an opportunity to address work items identified in the 2014 Aishihik Hydro Asset Assessment Report. Table 4 contains data from Table 1: Summary of Assessment Results, in the assessment report. It identifies work items that could be performed, at YEC's discretion, during the unit rerate outage. Although the assessment report focused on AH2, the results can be applied to AH1 in this study. A more detailed assessment of AH1 would have to be conducted if YEC decides to uprate its runner as well.

Opportunity work has no payback. The cost of performing the opportunity work is outside the scope of this report as it is not directly related to unit uprates. A discussion on the opportunity work items is provided in the section below Table 4.

TABLE 4
SUMMARY OF ASSESSMENT RESULTS

PRIORITY #	ENGINEERING DISCIPLINE	COMPONENT	ASSESSMENT RESULTS
26	Mechanical	Turbines	Study and potential replacement of turbine air, oil and water piping.
27	Mechanical	Generator	Study and potential replacement of generator air, oil and water piping.
37	Mechanical	Turbines	Study and potential replacement of addition of greasing points to reduce binding of wicket gate links and levers.
40	Mechanical	Fire Protection	Provide deluge fire suppression systems.
43	Mechanical	Turbines	Provide wicket gate shear pin detection and annunciation.
44	Mechanical	Turbine Inlet Valve (TIV)	Automation of TIVs to allow remote closure. Clean and Paint TIV
47	Electrical	P&C	Vibration Monitoring Review.
76	Civil	TIV	Monitor and potential repairs of TIV and distribution pipe leakage.

ITEM 26, TURBINE PIPING

The air, oil and water pipes and related valves and instrumentation servicing the turbines and generators are almost 40 years old. Their condition should be assessed and the remaining life estimated utilizing NDT (Ultrasonic) inspection techniques. In the event that the above program

cannot be executed in its entirety, focus should be placed on the Piezometer piping and the turbine air admission piping which have visible signs of distress.

ITEM 27, GENERATOR PIPING

The air, oil and water pipes and related valves and instrumentation servicing the turbines and generators are almost 40 years old. Their condition should be assessed and the remaining life estimated utilizing NDT (Ultrasonic) inspection techniques. The generator surface air cooling pipes and heat exchangers are addressed in Subsection 6.1.

ITEM 37, GREASING POINTS

Some areas of the turbine may benefit from adding greasing points or self-lubricated materials to wicket gate levers and arms. We understand that levers and arms have bonded to each other in the past.

ITEM 40, FIRE PROTECTION

There is no fire suppression on the generators in the powerhouse. The former Halon suppression systems have been removed. We recommend providing water deluge fire suppression systems on units AH1 and AH2.

ITEM 43, WICKET GATE SHEAR PIN DETECTION

The units are currently not equipped with wicket gate shear pin breakage sensors. A broken shear pin detection and annunciation system would alert station operators or SCC of the fact that a unit may not stop turning after being shut down. Consideration should be given to adding shear pin breakage monitoring capabilities, complete with annunciation to SCC.

ITEM 44, TIV CLOSURE AUTOMATION

The AH1 and AH2 TIVs can now only be operated locally. Due to the limited access to the powerhouse and the lack of emergency closure capability at the intake, the TIVs should be remotely operable. A loss of unit control (wicket gate operation failure), or a breach in the water passage could not be stopped without sending staff into the powerhouse. This situation would more than likely be unsafe. With no way to stop the water, the plant would be flooded for some

time. As such, remote operation capability should be implemented for the AH1 and AH2 TIVs. At this time, the addition of a counterweight could also be investigated to improve reliability.

ITEM 44 B, RE-PAINT TIV

The Turbine Inlet Valve for Unit AH-2 is showing signs of external surface corrosion. As such, the TIV should be tool cleaned (wire brushed) or sandblasted and re-painted.

ITEM 47, VIBRATION MONITERING REVIEW

Review minor discrepencies on the vibration monitering equipment.

ITEM 76, LEAKAGE IN TIV SUPPORTS

YEC staff have indicated that there is a water leak on unit AH2. Water reportedly leaks from between the spiral case and the concrete. During the AH2 rerunnering outage, further investigations should be carried out to determine the source of the leak. It should be noted that the leak may be from embedded sections of piezometer piping. Selectively pressurizing these tubes, or possibly the use of dyes may assist in finding the source of this leak.

7.0 ECONOMIC ANALYSIS

The economic analysis performed in the following sections utilizes the scope of work and costs described in Sections 3.0, 5.0 and 6.0 above and the capacity and energy values provided by YEC in Section 4.3. The details of the analysis, including runner costs, energy and capacity benefits, related uprate costs and payback, are given in Appendix C.

7.1 COSTS ASSOCIATED WITH RERUNNERING

KGS Group has prepared a Class 4 capital cost estimate and payback calculation for the turbine uprate project based on the value of energy provided by YEC. A Class 4 (-30%/+50%) cost estimate, as defined by AACE International, is used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval.

The Turbine Upgrade pricing in Table 5 below is the one associated with the Alstom budget proposal, since it is the most costly of the two budget prices, and it also offers the most capacity and energy benefits.

Other costs associated with the uprate project were estimated by KGS Group.

No estimates are provided for opportunity work since they do not provide a definable payback. KGS Group could provide a proposal to estimate the opportunity costs if requested to do so.

TABLE 5
BUDGET ESTIMATE TO UPRATE UNITS

ITEM	DESCRIPTION / ASSUMPTIONS	ONE UNIT	TWO UNITS
Turbine Uprate - Alstom			
Turbine field work		$250,000	$500,000
Turbine runner engineering		$106,000	$137,800
Runner and coupling bolts, supply		$343,000	$686,000
Fix labyrinths		$43,000	$86,000
Extra to T/G Vendor scope Work			
Performance / Efficiency Test		$125,000	$125,000
Crane operator and station operator		$48,000	$96,000
Drawings, manuals, etc.		$5,000	$6,500
Generator Surface Air Coolers		$50,000	$100,000
Excitation System Uprate, AH2 only		$750,000	$750,000
Cable from AH2 to Circuit Breaker		$150,000	$150,000
Cables from S167 to T1 & T2		$150,000	$150,000
Contingency No. 1*		$100,000	$200,000
Contingency No. 2*		$50,000	$100,000
Sub-Total A		$2,170,000	$3,087,300
Engineering support	12% of Sub-Total A	$260,400	$370,476
Sub-Total B		$2,430,400	$3,457,776
Goods and Services Sales Tax	5% of Sub-Total B	$121,520	$172,889
Sub-Total C		$2,291,520	$3,630,665
Contingency No.3*	30% of Sub-Total C	$687,456	$1,089,199
Total of Class 4 Estimate (-30% +50%)		**$2,978,976**	**$4,719,864**
Excluded from this estimate:			
Opportunity Work	Other Work:		
Turbine, generator, intake gates,	Camp services		
Turbine inlet valve	YEC engineering		
Distribution Pipe repairs	Project management		
Power cables and switchgear			
Generator Breaker			
Unit step-up transformer			
Controls and Protection			

* Notes:
Contingency No. 1 accounts for unforeseen items that may need to be repaired when unit is dismantled.
Contingency No. 2: T/G vendors identified scaffolding, if required, as Owner's responsibility
Contingency No. 3 accounts for unforeseen scope of work and changing market conditions.

7.2 CAPACITY AND ENERGY BENEFITS

The following economic parameters were provided by YEC for use in the payback calculations.

- One-time benefit of an increase in capacity - $2,500,000 per MW based on avoided capital cost of new natural gas generation.
- Annual benefit of an increase in annual energy - $200,000 per GWh based on avoided operating (i.e. variable cost) cost of natural gas.
- Discount rate of 7.2%.
- For paybacks less than 5 years a simple payback should be used.
- For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant.

KGS Group determined capacity and energy financial benefits from the above economic parameters and the capacity and energy values determined in Section 4.0.

The time schedule of the project is assumed to be as follows:

- Year 1, engineering
- Year 2, fabrication
- Year 3, installation of first unit
- Year 4, installation of second unit.

The benefits summarized in Table 6 incorporate the following simplified cash flow assumptions:

For rerunnering a single unit:

- 10% of project costs are spent in Year 1
- 45% of project costs are spent in Year 2
- 45% of the project costs are spent in Year 3
- 100% of Capacity Benefits are credited in Year 3
- Energy Benefits are credited annually from Year 4 onwards

For rerunnering two units:

- 10% of project costs are spent in Year 1
- 30% of project costs are spent in Year 2
- 30% of the project costs are spent in Year 3
- 30% of the project costs are spent in Year 4
- 50% of Capacity Benefits are credited in Year 3
- 50% of Capacity Benefits are credited in Year 4
- 50% of Energy Benefits are credited in Year 4
- 100% of Energy Benefits are credited annually from Year 5 onwards

TABLE 6
FINANCIAL BENEFITS

BENEFIT OF INCREASED CAPACITY at 80% PLANT FLOW	Increase in Capacity MW	Value of Increase in Capacity $ per MW	One Time Benefit
Upgrade AH2	0.7	$2,500,000	$1,750,000
Upgrade AH1 and AH2	1.3	$2,500,000	$3,250,000

BENEFIT OF INCREASED ENERGY FOR LOW ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.26	$200,000	$452,000
Upgrade AH1 and AH2	2.74	$200,000	$548,000

BENEFIT OF INCREASED ENERGY FOR HIGH ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.15	$200,000	$430,000
Upgrade AH1 and AH2	3.04	$200,000	$608,000

7.3 PAYBACK PERIOD

Payback periods for the following options were calculated using a spreadsheet provided by Yukon Energy Corporation. The spreadsheet is presented in Appendix C.

TABLE 7
PAYBACK PERIODS

PROJECT OPTIONS	ENERGY DEMAND SCENARIO	DISCOUNTED PAYBACK PERIOD (see note)
AH2 uprate	low energy demand	6 years
AH2 uprate	high energy demand	6 years
AH1 and AH2 uprate	low energy demand	7 years
AH1 and AH2 uprate	high energy demand	6 years

Note: Payback period is measured from the start of the uprate project, not from the time the uprated unit(s) is put back into service.

A single unit uprate has a discounted payback of 6 years in both the low energy years and the high energy years. A two unit uprate project also has a discounted payback of 6 or 7 years depending on energy demands.

7.3.1 Sensitivity Analysis

KGS Group conducted a sensitivity analysis on the following:

- Capacity benefits of between $1M (high speed diesel gensets) and $10M (wind or higher cost new hydro).
- Energy benefits going from $100,000 (best possible natural gas operating cost) to $300,000 (diesel operating cost).

The analysis was conducted on the AH2 Uprate – Low Energy Demand scenario only.

TABLE 8
SENSITIVITY ANALYSIS

Base Information

Nominal Capital Cost	$2,978,976
Discount Rate	7.2%
Capacity Increase	0.7 MW
Energy Increase	2.26 GWh/year

Sensitivity to CAPACITY Value (holding energy value constant at $200,000/GWh/yr)					
	TRIAL 1	TRIAL 2	TRIAL 3	TRIAL 4	TRIAL 5
Variable Benefit, $ per MW	$1M	$2.5M	$5M	$7.5M	$10M
Payback Period, years	11	6	2	2	2
Sensitivity to ENERGY value (holding capacity value constant at $2,500,000/MW)					
	TRIAL 6	TRIAL 7	TRIAL 8	TRIAL 9	TRIAL 10
Varialbe Benefit, $/GWh/yr	$100,000	150,000	$200,000	$250,000	$300,000
Payback Period, years	11	7	6	5	5
Worst Case: Capacity Value at $1,000,000/MW and Energy value at $100,000/GWh/yr					
	TRIAL 11				
Payback Period, years	>21				

Notes and Observations on Sensitivity Analysis:

- A 2 year payback means that the project is paid back in the year that the unit is returned to service.
- The lowest Capacity Benefit of $1M per MW has a payback of 11 years.
- Once the Capacity Benefit reaches $5M per MW, the project has a payback on the first year that the unit is returned to service since this benefit exceeds the cost of the project.
- The lowest Energy Benefit of $100,000 per GWh per year has a payback of 11 years.
- The highest Energy Benefit of $300,000 per GWh per year has a payback of 5 years.
- The worst case scenario of lowest capacity and energy benefits has a payback of 24 years. This value is beyond the 21 year limit of YEC spreadsheet.

8.0 CONCLUSION

Aishihik GS Generating Unit AH2 can be uprated by installing a new Francis runner at a cost of $3.0 M resulting in a discounted payback of 6 years (3 years after uprated unit is returned to service), using current capacity and energy benefit values. This cost includes a new excitation system, generator coolers, new cables from the unit to its generator circuit breaker and possibly new cables from the outdoor switchgear to the T1 and T2 transformers.

Alternatively, both AH1 and AH2 units could be uprated with new Francis runners at a cost of $4.7 M. This option would have a discounted payback of 8 years.

The two uprate options would keep plant water discharge within existging maximum flows. Hydraulic stability during unit start-ups and shut-downs would not be affected and the height of water in the discharge tunnel would not change.

The uprate project budgetary costs in the above sections do not include expenses associated with opportunity maintenance work, or other work on the units not directly related to unit uprate objectives. They also do not cover indirect costs, such as camp facilities, and YEC engineering and project management costs.

Given the strong influence of the capacity and energy benefits on the project payback time, we recommend that YEC revisit the payback projection using updated benefit values at project evaluation time.

The payback was calculated with unit capacities at 80% in keeping with, what we undestand to be, current operating practice. The payback periods would be shorter if the calculations were done at 100% of rated output.

9.0 STATEMENT OF LIMITATIONS AND CONDITIONS

9.1 THIRD PARTY USE OF REPORT

This report has been prepared for YEC to whom this report has been addressed and any use a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

9.2 CAPITAL COST ESTIMATE STATEMENT OF LIMITATIONS

The cost estimates included with this report have been prepared by KGS Group using its professional judgment and exercising due care consistent with the level of detail required for the stage of the project for which the estimate has been developed. These estimates represent KGS Group's opinion of the probable costs and are based on factors over which KGS has no control. These factors include, without limitation, site conditions, availability of qualified labor and materials, present workload of the bidders at the time of tendering and overall market conditions. KGS Group does not assume any responsibility to the Client, in contract, tort or otherwise in connection with such estimates and shall not be liable to the Client if such estimates prove to be inaccurate or incorrect.

APPENDIX A

HYDRAULIC CAPACITY REVIEW

KGS GROUP CONSULTING ENGINEERS

MEMORANDUM

TO: **Dave Brown, P. Eng.**
Joel Lambert, P. Eng.

FROM: **Dave White, P. Eng.**
David Hinton, P. Eng.

DATE: **May 25, 2015**

PROJECT NO: **14-1404-004**

RE: **Aishihik Turbine Uprate Study**
Hydraulic Capacity Review

1.0 INTRODUCTION

As part of the Aishihik Generating Station (GS) uprate study, KGS Group performed a high level hydraulic review of the conveyance system for Yukon Energy Corporation (YEC) in order to determine the maximum flow that can be conveyed before affecting functionality and safety of the system. This memorandum describes KGS Group's hydraulic review of the conveyance system, including a review of existing documentation and a confirmation of conveyance system hydraulics.

2.0 EXISTING CONDITIONS

The Aishihik GS was commissioned in 1975 as a two-unit hydroelectric facility located northwest of Whitehorse, Yukon. In 2011, a horizontal Francis turbine (Unit #3) was added to the GS. KGS Group has been tasked with undertaking a feasibility study to upgrade Unit #2, including how much additional flow could safely be carried by the conveyance system.

Figure 1 shows the Aishihik GS general arrangement. Flow enters the underground powerhouse through a 5.6 km long power canal, a 175 m deep intake, and a 915 m long pressure tunnel. A wye diverts water towards Unit #3, followed by two 35 m long penstocks that bifurcate to the original units. The water exits the powerhouse first through a surge chamber, then a 1,460 m long tailrace tunnel and a 900 m long tailrace channel before discharging into the West Aishihik

River. The tailrace tunnel is intended to be operated under open-channel flow conditions and doubles as an emergency exit for plant staff that, in case of an emergency can use a raft to make their way out of the powerhouse through the tunnel. The original plant had a rated flow of 19.4 m^3/s, while the current plant has a rated total flow of 23.7 m^3/s [Ref 1].

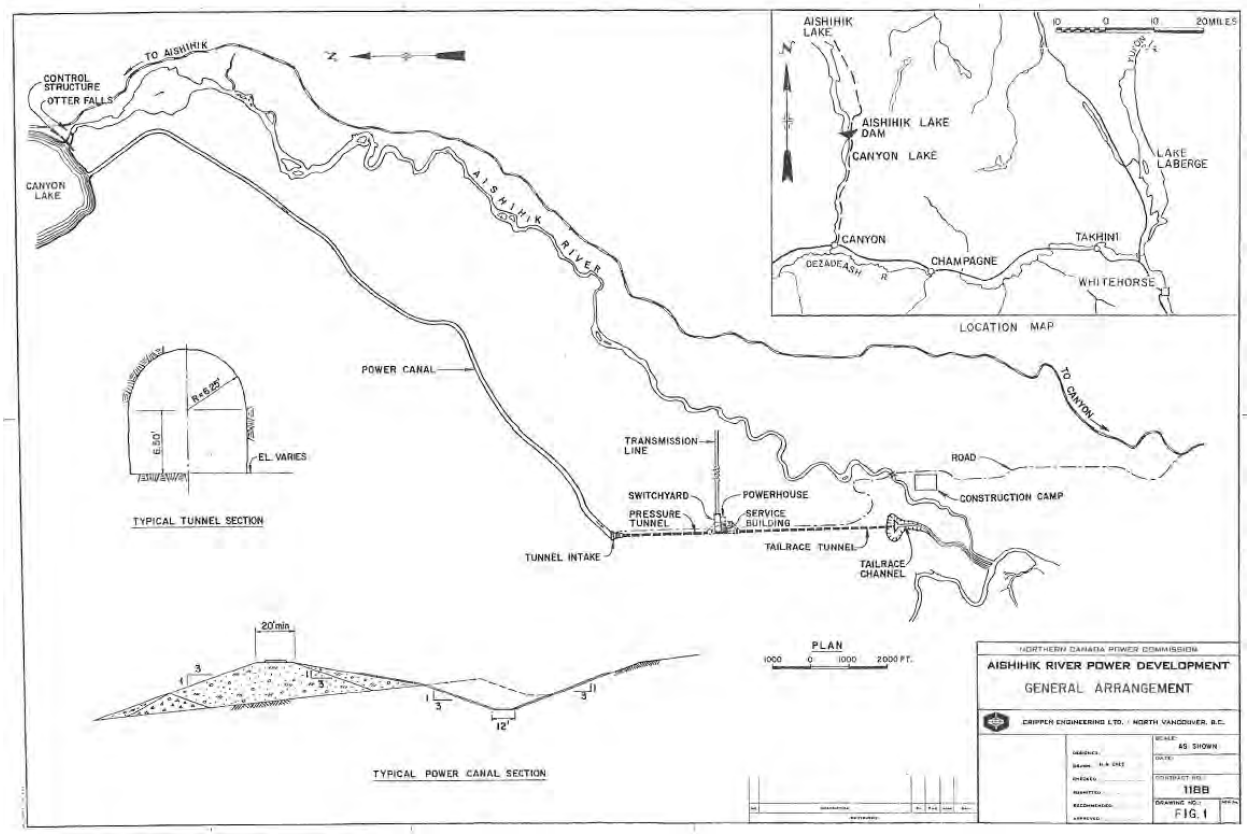

Figure 1: Aishihik GS General Arrangement

Hydraulic concerns raised by YEC of increased plant flow include:

- Reliability of tailrace tunnel as an emergency exit
- Transition of tailrace tunnel from open-channel to full flow
- Back-up of water into the powerhouse from the tailrace tunnel
- Transient pressures in the power and tailrace tunnels

The operational concerns of tailrace tunnel flow will likely limit the safe flow capacity of Aishihik

GS. As such, the tailrace tunnel and channel were the focus of this review.

The tailrace tunnel was constructed by the drill and blast method with approximately 50% of the length lined with shotcrete and 50% left exposed. The shotcrete and exposed rock sections were generally in excellent condition during an August 2008 inspection by Klohn Crippen Berger [Ref 2], however construction rails and ties were left in place, which may have a minor effect on actual tunnel dimensions. As-built tunnel dimensions are unknown, and could have a significant effect on hydraulic conveyance of the tunnel. A survey of the tailrace tunnel dimensions and invert elevations could be performed to confirm the actual tunnel area and confirm hydraulic capacity.

3.0 DEVELOPMENT OF HYDRAULIC MODEL

KGS Group developed a one-dimensional computer model of the downstream conveyance system from the powerhouse to the West Aishihik River using the XP-SWMM Software package. This software allows for accurate modelling of both closed conduit and open channel flows, and solves dynamic wave routing using the St. Venant equations. The model was developed using information obtained from the design drawings as well as the 2008 hydraulics report [Ref 2].

The Manning's n value for surface roughness of the tailrace tunnel and channel were estimated based on results from the 2008 inspection and accompanying photographs such as Photo 1 which shows the tailrace channel material. Tailrace tunnel roughness was estimated as 50% well-trimmed, normal blasted and 50% well-trimmed and shotcreted for a composite Manning's roughness of n = 0.026. Tailrace channel roughness was estimated as a Manning's roughness of n = 0.033, corresponding to a gravel bottom with dry rubble sides. Minor losses were included for the surge tank exit, and the tailrace tunnel junction and exit.

Photo 1: Tailrace Tunnel Outlet and Tailrace Channel

The hydraulic model was verified using two powerhouse tailwater levels measured by YEC and two powerhouse tailwater levels included in the design drawings at specific plant flows. West Aishihik River downstream boundary condition water levels were not measured with the powerhouse tailwater levels, so a sensitivity of river water levels was completed instead.

4.0 ANALYSIS OF RESULTS

The model was simulated for a range of West Aishihik River water levels to determine the relationship between river level and safe plant flow.

Figure 2 shows a water surface profile of the Aishihik GS downstream conveyance system flowing at full plant capacity with normal depth downstream boundary condition. Higher West Aishihik River stages could cause a backwater effect on the downstream end of the tailrace tunnel, reducing the capacity of the tunnel. No data was available for expected water levels in the West Aishihik River so the frequency of such backwater effects is unknown. Further refinement of results would require a rating curve or measured water levels at specific flows in the West Aishihik River.

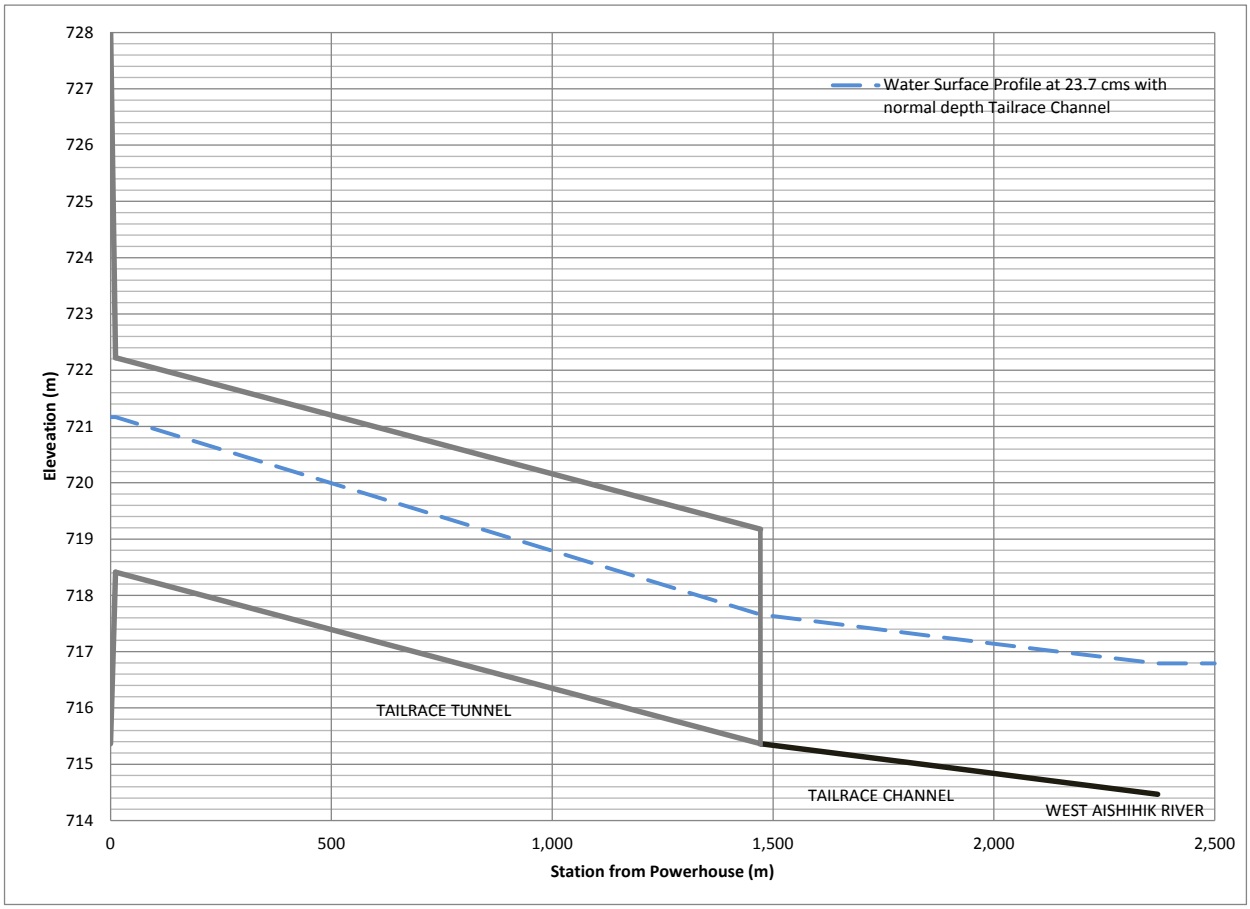

Figure 2: Aishihik GS Downstream Conveyance System Water Surface Profile

Figure 3 shows the maximum flow that can be passed through the tailrace tunnel without pressurized flow for various water levels in the West Aishihik River. Unit #3 is assumed to flow at its full capacity of 4.26 m^3/s for all the scenarios. Figure 3 indicates that as the West Aishihik River stage increases, less flow can be passed through the tailrace tunnel due to backwater effects along the tailrace channel. Depending on the river water level, the tailrace tunnel could pass more flow than the existing 19.43 m^3/s (Unit #1 and #2) with open-channel flow. As long as the tunnel maintains open-channel flow, transient pressures and backup of water into the powerhouse are not expected.

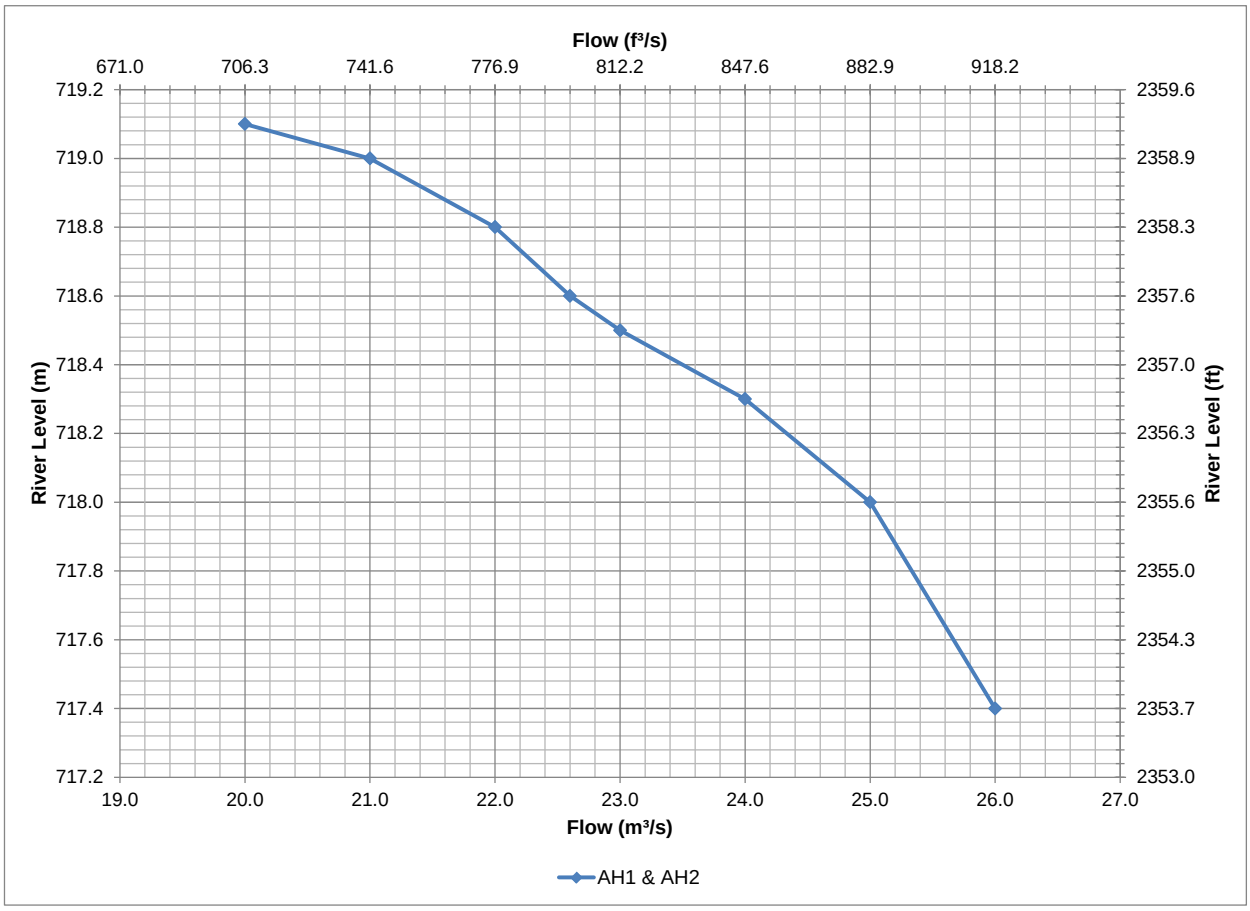

Figure 3: Maximum Flow Through Units 1 and 2 Without Pressurized Tunnel Flow

The other hydraulic concern is ensuring the tailrace tunnel remains open as a safe emergency exit at all times. This is the limiting factor for increasing flow through Unit 2. A reasonable estimate for safe tailrace tunnel flow using the powerhouse tailwater elevation-discharge equation has been compiled by Acres and is described in their February 1999 memo [Ref 3]. This relationship indicates expected powerhouse water levels under normal circumstances and is shown in Figure 4. According to this relationship, water level at the upstream end of the tailrace tunnel (ie. at the powerhouse) would be 721.17 m with current plant flow capacity. This would leave at least 1.06 m of freeboard available for emergency evacuation during normal conditions throughout the tunnel. Using the same equation, a total plant flow of 24.4 m^3/s may be possible while maintaining a 1.00 m freeboard. However, the 1.00 m freeboard may not still be available during extreme conditions if the elevated river levels drown out the tunnel outlet, so increasing plant flow would not be recommended at this point.

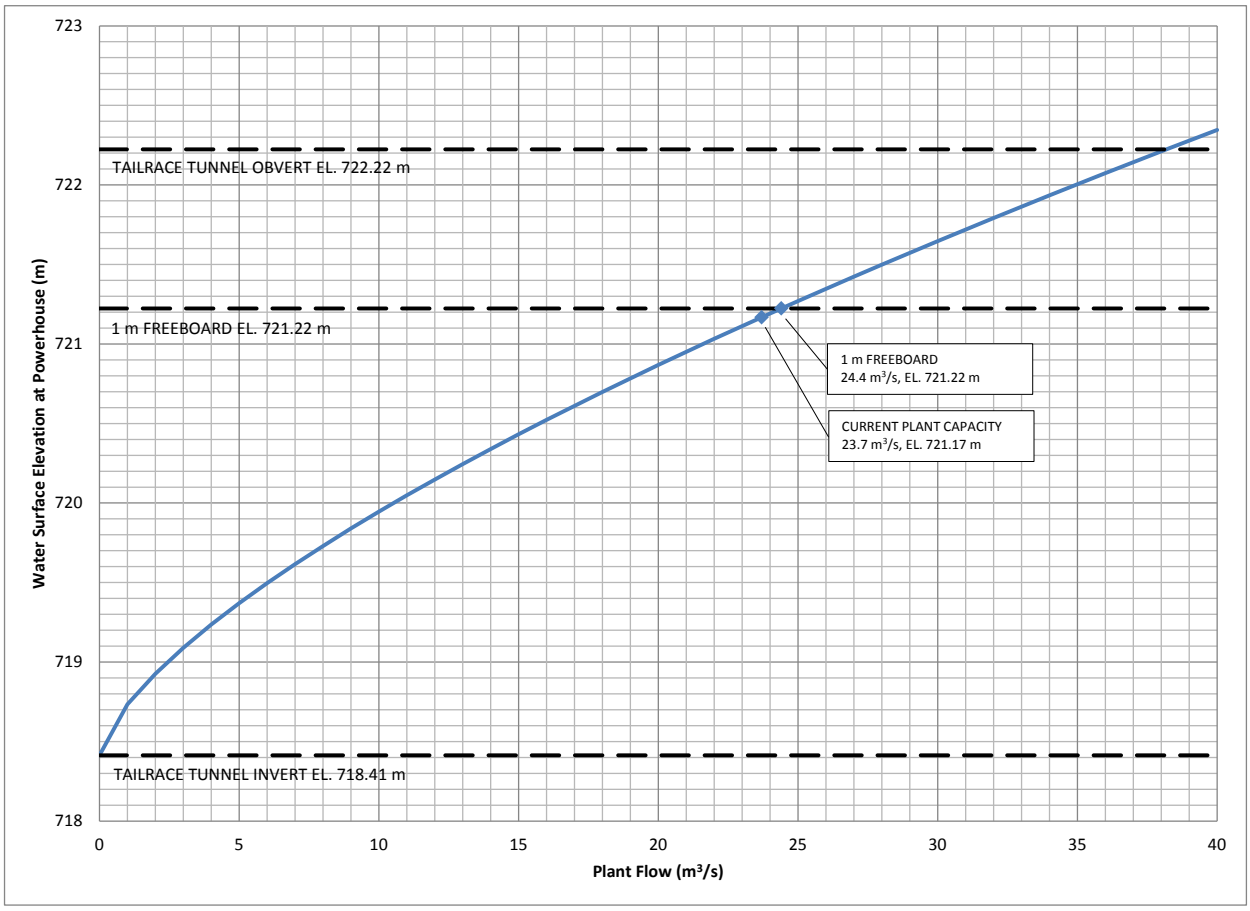

Figure 4: Powerhouse Tailwater Stage-Discharge Relationship

Without further West Aishihik River water level information, it would be impossible to confirm that the tailrace tunnel would be a safe emergency exit at all times. Although there is currently adequate freeboard during normal conditions, the extreme flood conditions of the river are unknown. It is recommended to gather additional information about flood levels in the West Aishihik River to confirm the safety of emergency evacuation under a wider range of conditions. Without further study regarding the West Aishihik River, the discharge through the Aishihik GS should not be increased beyond its current capacity.

5.0 CONCLUSIONS

KGS Group performed a high level hydraulic review of the Aishihik GS conveyance system, including a review of previous documentation and the development of a one-dimensional XP-

SWMM hydraulic model of the tailrace. From this analysis, the following conclusions about the maximum safe plant flow were drawn:

1. The limiting factor for increasing plant flow capacity is the requirement to maintain emergency evacuation access in the tailrace tunnel; however a survey of actual tailrace tunnel dimensions could be conducted to confirm the assumptions adopted in the hydraulic analysis described in this memorandum.
2. The current plant capacity of 23.7 m^3/s provides 1.06 m of emergency freeboard throughout the tailrace tunnel during normal conditions.
3. Flows as high as 24.4 m^3/s could be passed through the tunnel while still maintaining 1.00 m of emergency freeboard throughout the tunnel during normal downstream river levels.
4. During flood conditions, no data is available about expected water levels in the West Aishihik River. The river water levels have the potential to limit the available emergency freeboard at the downstream end of the tailrace tunnel.
5. Further information about flood stages in the West Aishihik River should be gathered. Until such information is obtained and analysed, no increase in plant flow is recommended.

5.0 REFERENCES

1. Hatch, “Aishihik Turbine Performance Test: Performance Test Results”, December 11, 2009.
2. Klohn Crippen Berger, “Aishihik GS Hydraulics Final Report”, November 7, 2008.
3. Acres, memo from Alfred Breland to S. G. Bridgeman. “Tailwater Elevation – Discharge Equations for Aishihik GS”, February 5, 1999.

Prepared By:

David Hinton, P.Eng.
Water Resources Engineer

Reviewed By:

Dave White, P.Eng.
Water Resources Engineer

DPH/nf

APPENDIX B

TURBINE VENDOR BUDGETARY PROPOSALS

APPENDIX B-1

RUNNER UPGRADE RFI

Aishihik Generating Station
Potential Runner Upgrade
Request for Information
DRAFT – Rev A

KGS Group 14-1404-004
February 2015

Prepared By

Joel Lambert, P. Eng.
Senior Mechanical Engineer

Approved By

Mike Markovich, P. Eng.
Senior Mechanical Engineer

KGS Group
Winnipeg, Manitoba

TABLE OF CONTENTS

PAGE

1.0 BACKGROUND....1

2.0 REQUESTED INFORMATION....2

3.0 TYPICAL OPERATION AND OPTIMIZATION OF NEW RUNNERS....4

4.0 REFERENCE FIGURES....5

5.0 EXISTING EQUIPMENT DETAILS....6
- 5.1 TURBINES....6
- 5.2 GENERATORS....6
- 5.3 TAILWATER RATING INFORMATION:....6

6.0 CONSTRAINTS....7
- 6.1 HYDRAULIC....7
- 6.2 MECHANICAL....7
- 6.3 ELECTRICAL....7

7.0 OTHER RELEVANT DATA....8
- 7.1 SEISMIC INFORMATION....8

8.0 BASIS OF BUDGETARY COST ESTIMATE....9
- 8.1 SCOPE OF SUPPLY....9
- 8.2 WARRANTY....9
- 8.3 PERFORMANCE GUARANTEES....9
- 8.4 SITE INSTALLATION....9

9.0 SUBMISSION AND CONTACT INFORMATION....11

LIST OF APPENDICES

A. Reference Drawings
B. Original Generator Nameplates
C. Rewind Generator Nameplates

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1.0 BACKGROUND

The Aishihik Generating Station (AGS) is located northwest of Whitehorse, Yukon. The site is accessible by an all-weather road. From the Whitehorse airport, it is approximately 122 km West on the Alaska Highway and approximately 20 km North on an un-nammed road. The closest community with services is Haines Junction, approximately 60 km away.

The AGS was constructed in 1972 and originally consisted of two 15 MW vertical Francis turbines (AH1 and AH2) with a net head of 180 metres. In 2011, a third 7 MW horizontal Francis turbine (AH3) was added.

The AGS units are located in an underground powerhouse approximately 110 metres below the surface. Water is drawn from Canyon Lake using a 5.6 km long power canal, through a concrete intake structure and a 1.1 km long tunnel. AH1 and AH2 are equipped with spherical valves that allow for isolation of the units for maintenance. Water discharges from the draft tubes, into a 1.4 km long tailrace tunnel and a 900 m tailrace channel before discharging into the West Aishihik River.

In 2003, the AH1 generator was rewound that increased the electrical capacity to 17,000 kVA. In 2006, the AH2 generator was rewound that increased the electrical capacity to 19,200 kVA. AH1 underwent a ten year overhaul in 2012 and the AH2 ten year overhaul was done in 2013.

While the project is not exclusive to the upgrade of the AH2 unit, it is perceived that it offers the greater opportunity for upgrade/uprate. It is the intent to also review the merits of upgrading both the AH1 and AH2 units.

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2.0 REQUESTED INFORMATION

KGS Group has been retained by Yukon Energy Corporation to conduct a study into the potential upgrade of the turbine on Unit #2 at the Aishihik Generating Station. To this end, we are requesting budget pricing, as well as technical information on the runners you may have that are suitable, and other required turbine modifications or new components that may be beneficial to the efficiency or power output of the turbine.

Although currently at the concept study stage, the project, should it proceed, would eventually include the design, supply, manufacture, quality assurance, delivery, installation, testing, commissioning, and warranty for one or two new turbine runner(s) and any other modifications required to achieve the proposed improved performance.

To determine the feasibility of upgrades, the following preliminary information is requested:

- Budgetary cost. Please be sure to include for new coupling bolts
- Description of the proposed new runner, including number of blades, materials, and method of fabrication (single piece casting, welded etc.)
- A description of the proposed scope of the upgrades, beyond the provision of new runners
- Number of runner blades proposed
- Efficiency curves (Hill Chart) for the proposed turbines
- Sigma critical value
- Expected cavitation characteristics based on setting, referenced to limits in Figures A.1 and A.2 in IEC 60609-1-2004
- Any operational constraints, such as maximum number of hours above and below the recommended operation envelope
- Maximum runaway speed
- Expected hydraulic thrust load
- Indicate delivery time for major equipment after placement of order
- Indicate anticipated time required for installation in the field

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Clearly indicate in your budgetary proposal where requested items are excluded or are not in compliance with this document.

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3.0 TYPICAL OPERATION AND OPTIMIZATION OF NEW RUNNERS

In order to provide a “spinning reserve” to accept sudden load increases on Yukon Energy Corporation’s electrical grid, the AH1 and AH2 units are typically operated at approximately 80% of their maximum power output. They may, however, be operated at relatively low power levels during periods of low demand and at maximum output during periods of high demand.

Because of the above-mentioned operation strategy, the proposed new runners should be optimized to provide (in order of importance):

1. The highest efficiency at approximately 80% gate opening
2. The highest maximum output at full gate opening
3. The highest efficiency at gate openings lower than 80%

A preference will be shown for fabricated (welded) runners over one-piece cast runners. Cast runners may be accepted, depending on efficiency, cavitation and equipment guarantees.

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4.0 REFERENCE FIGURES

Refer to the following drawings, in Appendix A, for more detailed information on the site and the existing turbines.

- Fig. 1: General Arrangement
- Fig. 2: Longitudinal Section
- D122: Powerhouse Area – General Arrangement
- M9-D31: Powerhouse Arrangement: Mechanical – Transverse Section
- M9-D34: Powerhouse Arrangement: Mechanical – Longitudinal Section Looking Upstream
- 222 F 30000: 20500 HP Vertical Francis Turbine Sectional Elevation
- 222 F 30001: 20500 Vertical Francis Turbine Plan
- 222 D 30014: Runner
- 222 F 20019: Turbine Shaft
- 292D653AL Large Generator

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5.0 EXISTING EQUIPMENT DETAILS

In this section, elevations are reference to mean sea level.

5.1 TURBINES

Make:	Dominion Engineering Works
Rated net head:	180.4 m
Rated discharge (per unit):	9.72 m^3/s
Power at rated net head and discharge (per unit):	15 MW
Speed:	720 RPM
Number of runner blades:	15
Number of wicket gates:	20
Throat diameter:	1016 mm
Setting elevation (centreline of distributor):	715.52 m

5.2 GENERATORS

Make:	Canadian General Electric
Synchronous Speed:	720 RPM
Maximum runaway speed rating of generators:	1330 RPM
AH1 capacity:	17,000 kVA
AH2 capacity:	19,200 kVA
Power factor:	0.9

Refer to Appendix B and C for pictures of the generator nameplates.

5.3 TAILWATER RATING INFORMATION:

TWL elevation at 8.5 m^3/s:	719.9 m
TWL elevation at 21.25 m^3/s:	721.4 m
TWL elevation at 25 m^3/s:	722.0 m

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6.0 CONSTRAINTS

6.1 HYDRAULIC

The rated flow of the proposed new turbine runners cannot exceed the rating of the existing runners. This is due to a limitation in the tailrace tunnel. The tailrace tunnel is designed to operate at partially filled (i.e. the tunnel has a free water surface for its entire length). Increasing the flow beyond the existing maximum values may cause the tunnel to switch to full flow, resulting in backwater effects and potential dynamic issues that would result if the flow alternated between flowing filled and partially filled.

The tailrace tunnel is also used as an emergency egress route from the underground powerhouse. For this reason, a minimum freeboard is required between the roof of the tunnel and the maximum water level.

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6.2 MECHANICAL

Other than the maximum runaway speed rating of the existing generators, no mechanical limitations that would limit a runner upgrade have been identified.

If any changes to the distributor or wicket gates are recommended by the Supplier, the capacity of the servo and governor oil system would need to be confirmed.

6.3 ELECTRICAL

The switchgear, power conductors and generator step-up transformers have the sufficient capacity to accommodate the increased power generated by the upgraded units.

The excitation system is currently under review, but for the purposes of this RFI, please assume that there is no constraint on the maximum power output based on the excitation system.

7.0 OTHER RELEVANT DATA

7.1 SEISMIC INFORMATION

The design seismic coefficient (PGA) shall be 0.17g.

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8.0 BASIS OF BUDGETARY COST ESTIMATE

For the purposes of the budgetary cost estimate requested, please assume the following.

8.1 SCOPE OF SUPPLY

Allow for:

- Provision of a one new runner
- Provision of new coupling bolts
- Provision of new runner blade templates in accordance with IEC 60193-1999 to measure both blade profile and angle
- Provision of all stationary parts required for the installation of the new runner and of any new turbine components to be replaced to enhance turbine performance
- The submission and review of drawings, design documentation and quality assurance documentation by Owner's Engineer.
- The provision of 3 paper copies and one electronic copy of Operating and Maintenance (O&M) manuals for all equipment supplied.

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8.2 WARRANTY

Warranty work for a period of two years from substantial performance.

8.3 PERFORMANCE GUARANTEES

If the turbine re-runnering project proceeds, it is likely that the Owner will seek performance guarantees for efficiency and power output, supported by liquidated damages. The level of liquidated damages has not been determined at this point.

8.4 SITE INSTALLATION

Please include a cost estimate for complete site installation of the new runner (assuming only one runner is replaced) and any other required modifications.

Provide:

- Duration and person-days of work
- Cost for person-day of work

Indicate whether or not values include living out allowances and accommodation costs.

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9.0 SUBMISSION AND CONTACT INFORMATION

Please direct questions or submit information to:

KGS Group
Attention: Joel Lambert, P.Eng.
3rd Floor, 865 Waverley Street
Winnipeg, MB
R3T 5P4
Email: jlambert@kgsgroup.com
Phone: 204-896-1209
Cell: 204-770-6411

Please provide the requested information by March 10, 2015.

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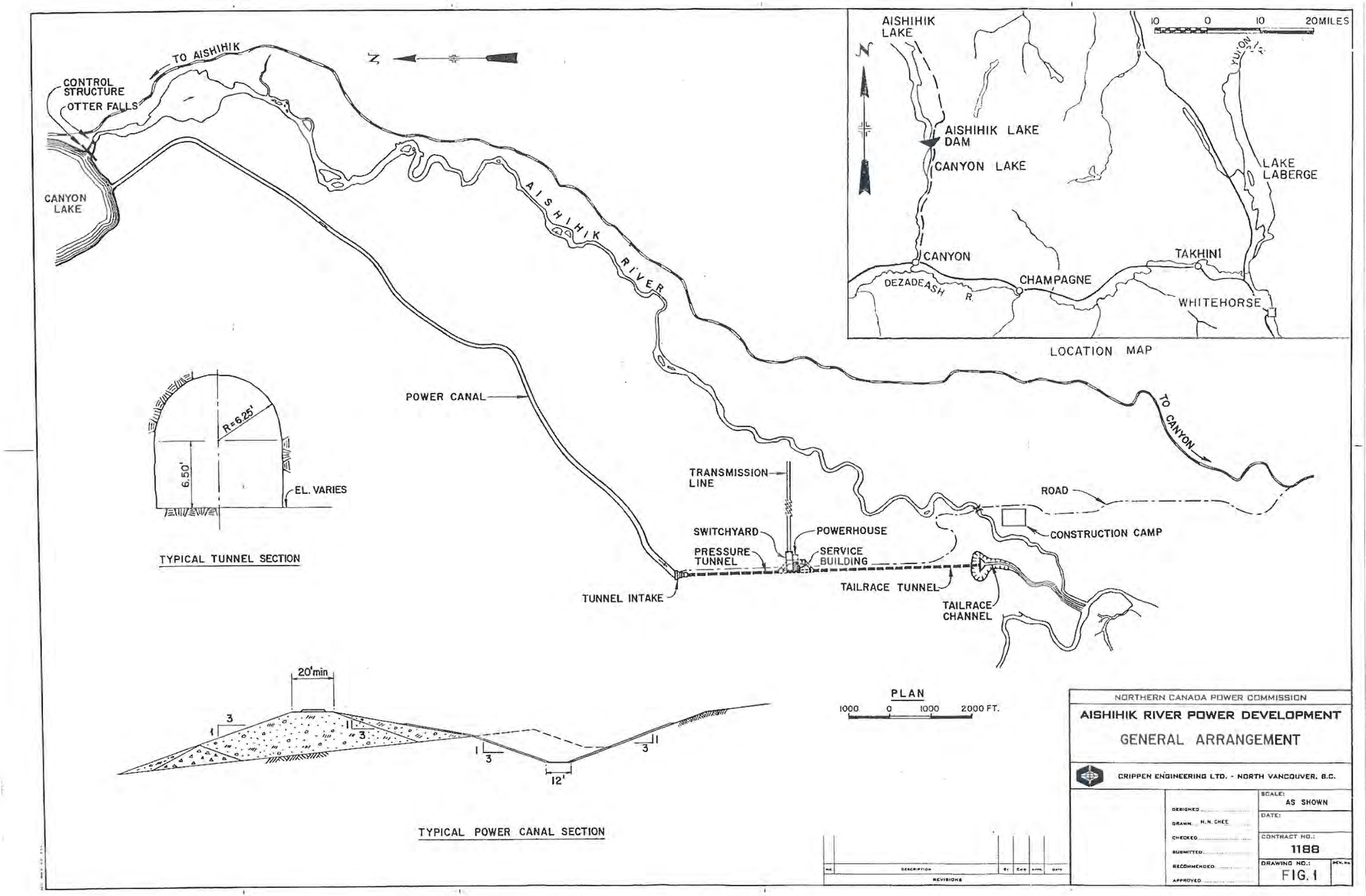
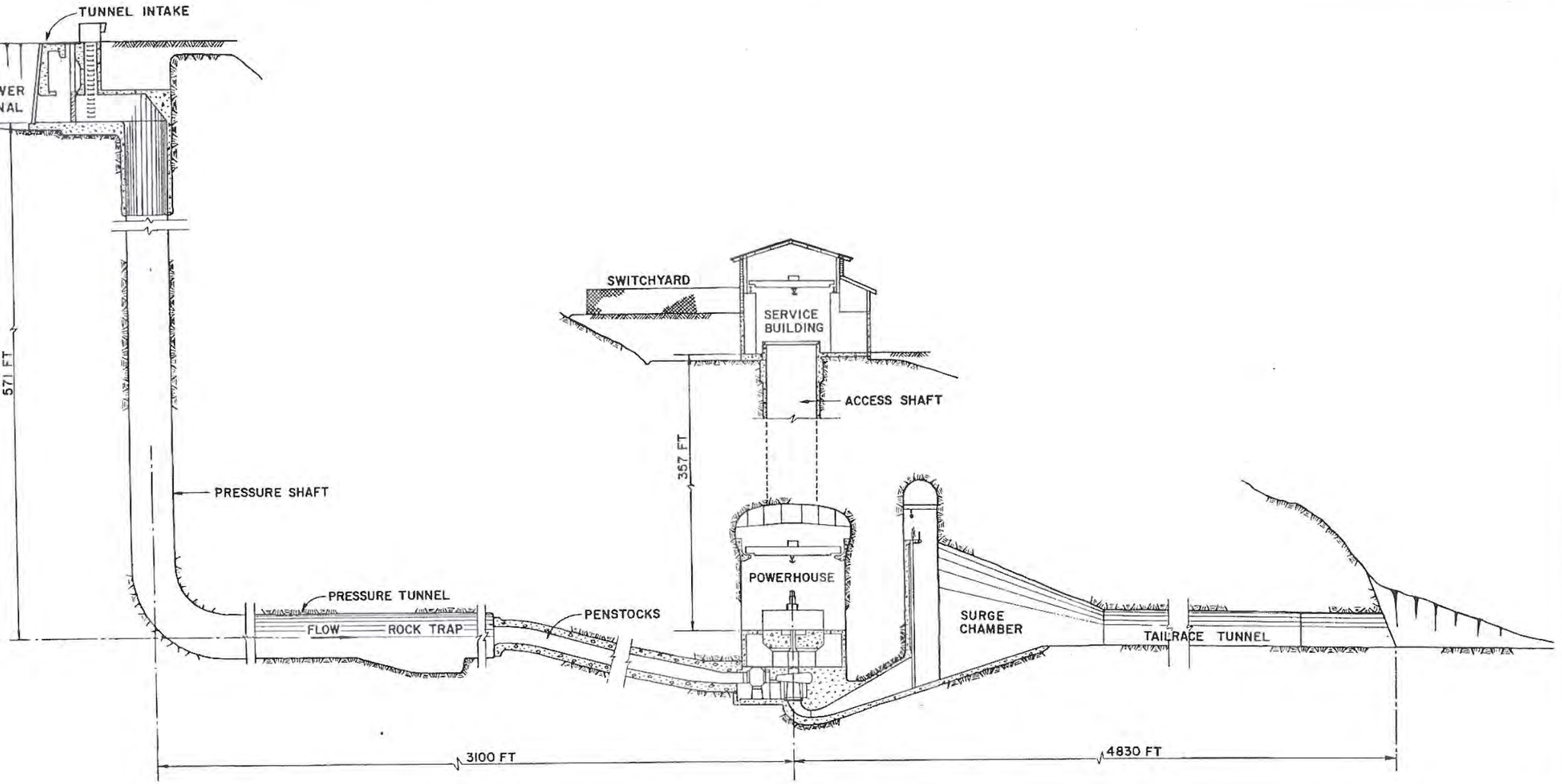
APPENDIX A

REFERENCE DRAWINGS


TO AISHIHIK
CONTROL STRUCTURE
OTTER FALLS
CANYON LAKE
N
AISHIHIK RIVER
POWER CANAL
TO CANYON
TRANSMISSION LINE
ROAD
CONSTRUCTION CAMP
SWITCHYARD
POWERHOUSE
PRESSURE TUNNEL
SERVICE BUILDING
TAILRACE TUNNEL
TUNNEL INTAKE
TAILRACE CHANNEL
PLAN
1000 0 1000 2000 FT.
AISHIHIK LAKE
AISHIHIK LAKE DAM
CANYON LAKE
LAKE LABERGE
YUKON R.
CANYON
DEZADEASH R.
CHAMPAGNE
TAKHINI
WHITEHORSE
10 0 10 20 MILES
LOCATION MAP
R=6.25'
6.50'
EL. VARIES
TYPICAL TUNNEL SECTION
20'min
3
1
1
3
1
3
1
3
12'
TYPICAL POWER CANAL SECTION
NORTHERN CANADA POWER COMMISSION
AISHIHIK RIVER POWER DEVELOPMENT
GENERAL ARRANGEMENT
CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.
DESIGNED
DRAWN H.N. CHEE
CHECKED
SUBMITTED
RECOMMENDED
APPROVED
SCALE: AS SHOWN
DATE:
CONTRACT NO.: 1188
DRAWING NO.: FIG. 1
REV. NO.
NO. DESCRIPTION BY CHD APPD DATE
REVISIONS



NORTHERN CANADA POWER COMMISSION

AISHIHIK RIVER POWER DEVELOPMENT

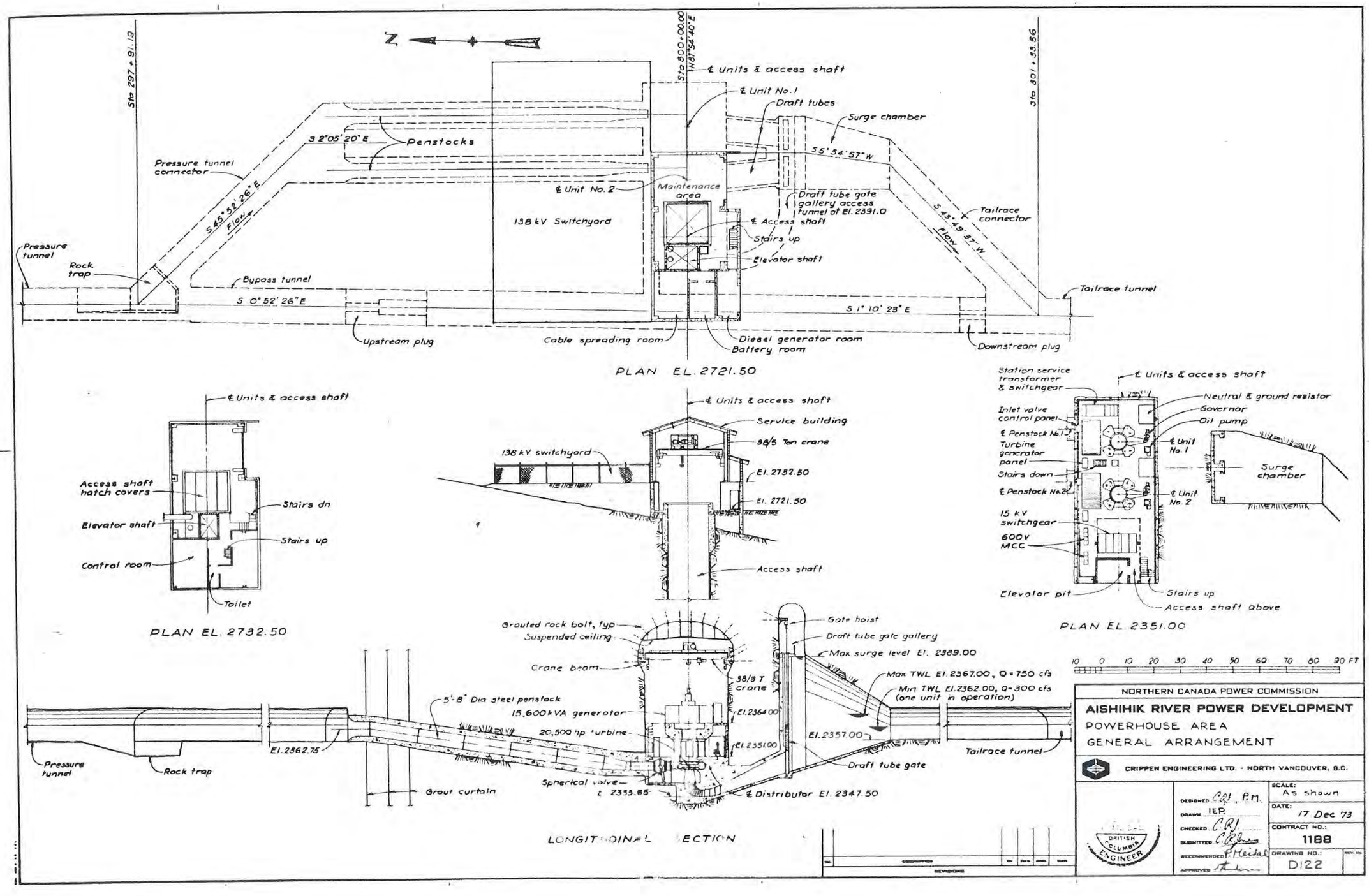
LONGITUDINAL SECTION

CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.

DESIGNED	SCALE: —
DRAWN: H.N. CHEE	DATE:
CHECKED	CONTRACT NO.: 1188
SUBMITTED	DRAWING NO.: FIG. 2
RECOMMENDED	REV. No.
APPROVED	

REVISIONS

No.	DESCRIPTION	BY	CHK	APPD	DATE



NORTHERN CANADA POWER COMMISSION

AISHIHIK RIVER POWER DEVELOPMENT

POWERHOUSE AREA

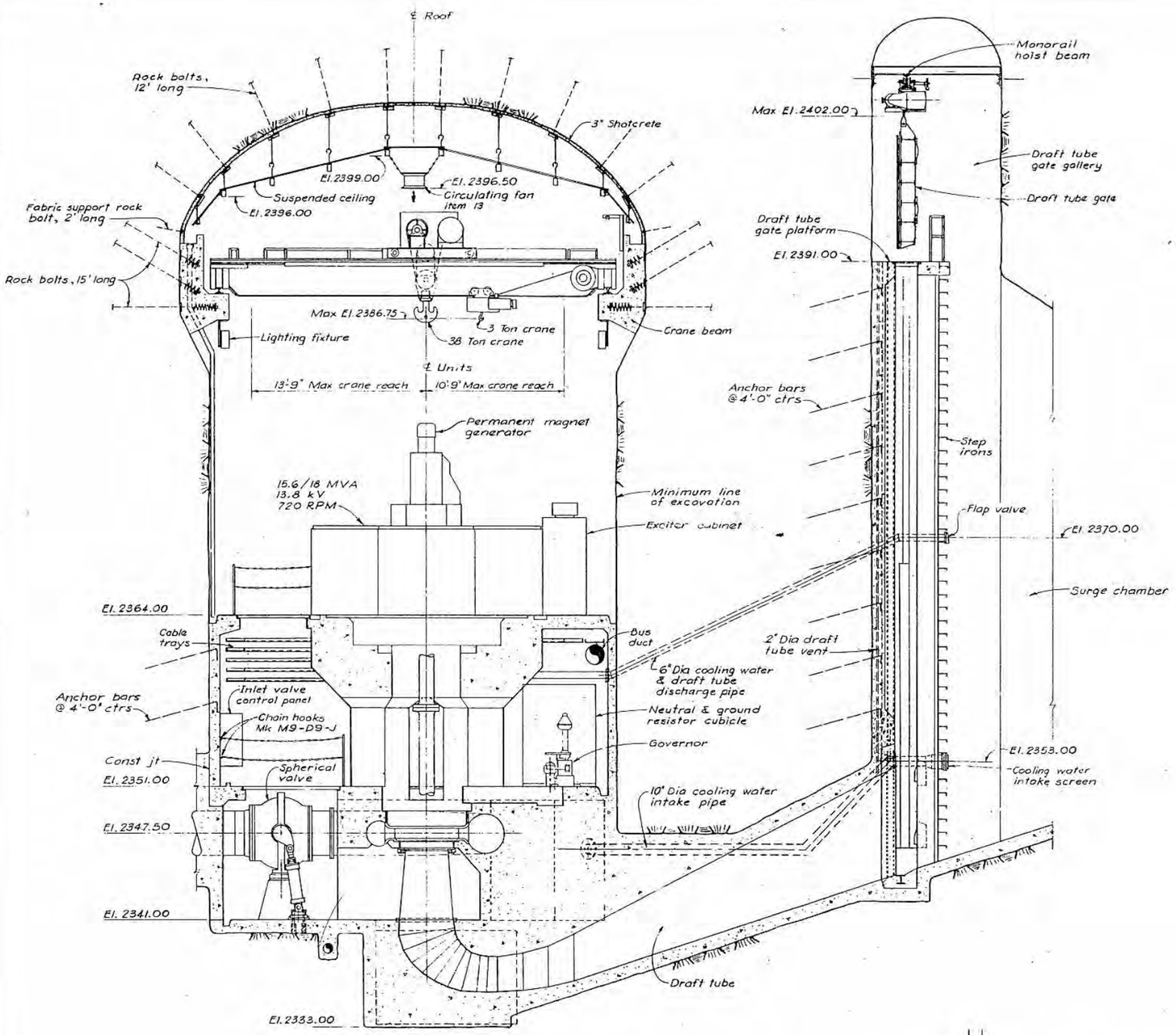
GENERAL ARRANGEMENT

CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.

DESIGNED C.R.J., P.M.	SCALE: As shown
DRAWN I.E.R.	DATE: 17 Dec 73
CHECKED C.R.J.	CONTRACT NO.: 1188
SUBMITTED C.R.J.	
RECOMMENDED P. Meidal	DRAWING NO.: D122
APPROVED	

BRITISH COLUMBIA ENGINEER

REVISIONS



TRANSVERSE SECTION THRU ℄ UNIT NO. 2

NOTE:
1. For list of H & V items and legend see Dwg M10 - D5.

M.G. Benham 30.1.76

NO.	DESCRIPTION	BY	CHK	APPR.	DATE
1	As built.	K.O.S	M.G.B	J.P.D	30-1-76

REVISIONS

NORTHERN CANADA POWER COMMISSION

AISHIHIK RIVER POWER DEVELOPMENT

POWERHOUSE ARRANGEMENT: MECHANICAL
TRANSVERSE SECTION

CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.

J. P. DAVIES — BRITISH COLUMBIA — ENGINEER

DESIGNED	M.G.B
DRAWN	I.E.P. Aug
CHECKED	J.P.D
SUBMITTED	M.G.B
RECOMMENDED	
APPROVED	P. Meisel

SCALE:	1/4" = 1'-0"
DATE:	June 24, 1974
CONTRACT NO.:	1188
DRAWING NO.:	M9-D31
REV. NO.	1

CRIPP M9 D31

El. 2409.25
El. 2400.00
El. 2391.00
El. 2382.00
El. 2373.00
El. 2364.50
El. 2364.00
El. 2351.00
El. 2341.00
El. 2333.25

Access shaft
Circulating fan, item 13
Suspended ceiling, see Dwgs D135 & D136
Minimum line of excavation
38-Ton crane
Top of crane rail El. 2389.00
3 Ton crane
Lighting fixture
22 Ga Galbestos Corrugated
Cross bracing
Cable trays
4" Dia drain
Crane access ladder
Emergency lights
Mk M9-D9-H
Hatch cover
℄ Unit No. 2
℄ Unit No 1
Bypass tunnel
Heating plenum
600V MCC
15 kV switchgear
600V MCC
No. 2 turbine generator panel
No. 2 turbine generator panel
600 V Station service switchgear
Cable trays
Mk M9-D10-A
Step irons

NOTES
1. For list of H & V items and legend see Dwg D139

5 0 5 10 15 20 FT

LONGITUDINAL SECTION THRU ℄ UNITS
LOOKING UPSTREAM

NORTHERN CANADA POWER COMMISSION

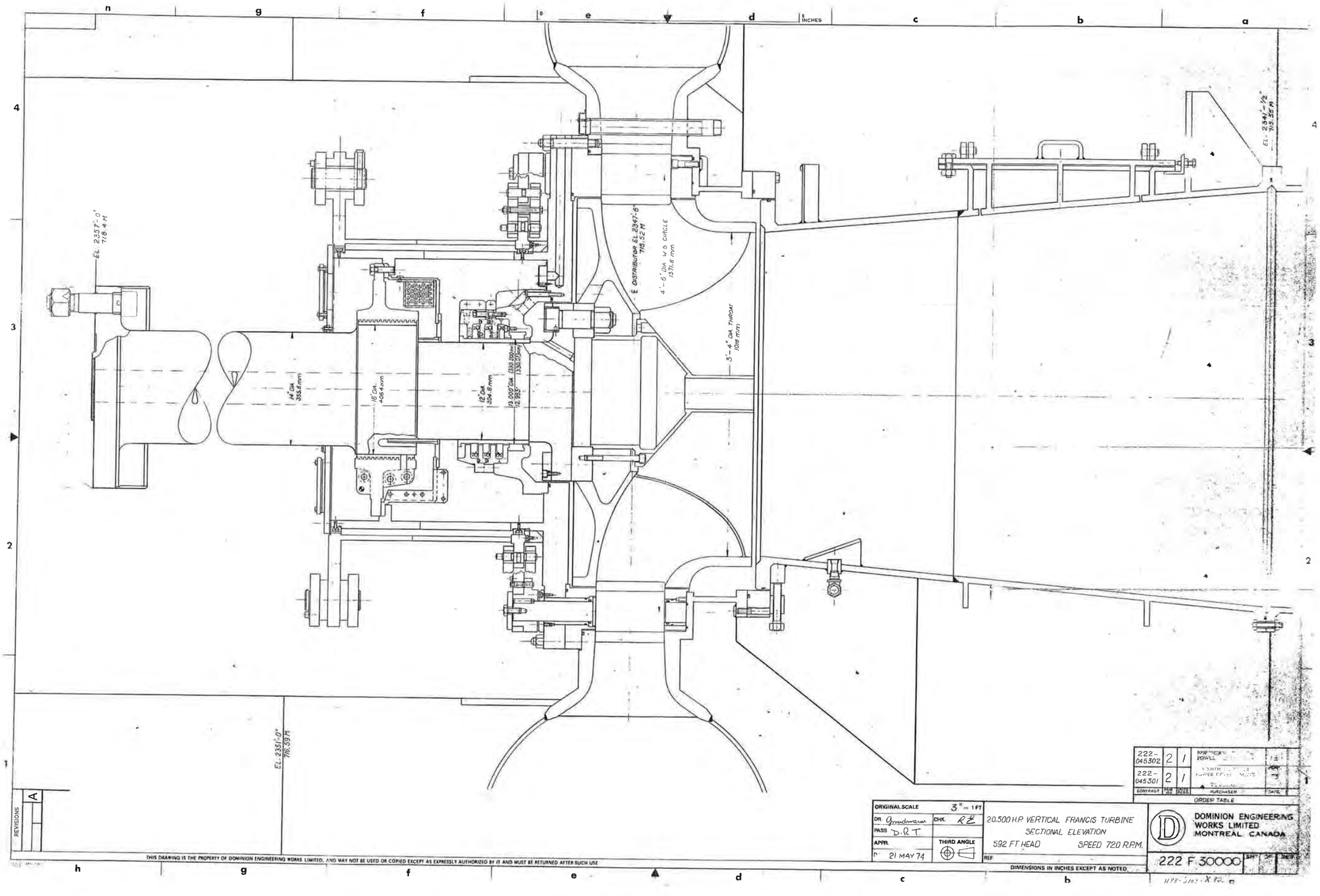
AISHIHIK RIVER POWER DEVELOPMENT
POWERHOUSE ARRANGEMENT-MECHANICAL
LONGITUDINAL SECTION
LOOKING UPSTREAM

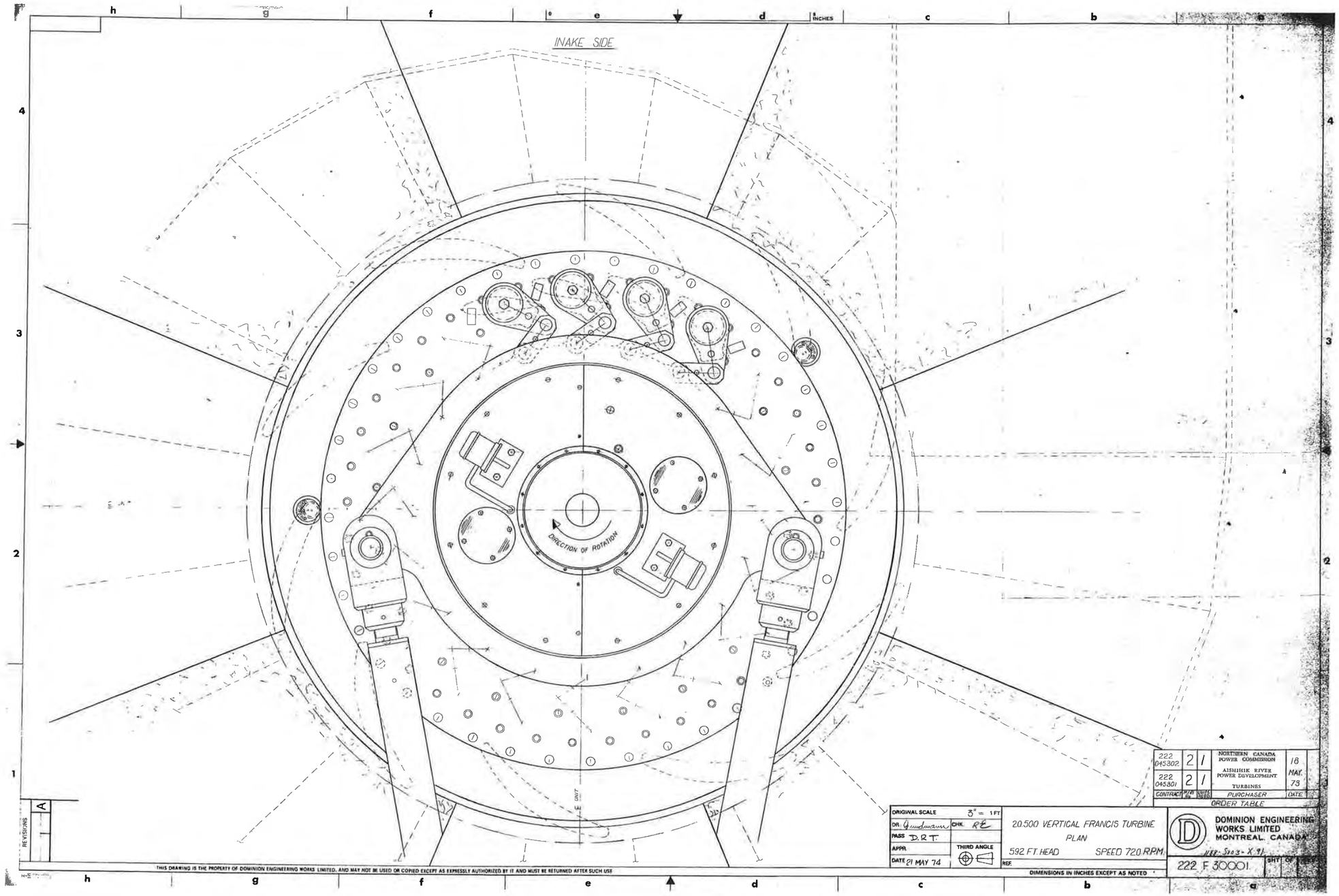
CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.

PROFESSIONAL ENGINEER PAUL BEDAL YUKON TERRITORY

DESIGNED CRJ	SCALE: As shown
DRAWN IEP Barry	DATE: 31 Jan 1974
CHECKED MG Benham	CONTRACT NO.: 1188
SUBMITTED	DRAWING NO.: D 148
RECOMMENDED P Meidal	REV. No.
APPROVED	

REVISIONS


EL 2357'-0"
718.4 M
14" DIA
355.6 mm
16" DIA
406.4 mm
12" DIA
304.8 mm
13.000" DIA (330.200 mm)
12.985" (329.819 mm)
DISTRIBUTOR EL 2347'-6"
715.52 M
4'-6" DIA W.G. CIRCLE
1371.6 mm
3'-4" DIA THROAT
1016 mm
EL 2341'-1/2"
713.32 M
EL 2351'-0"
716.30 M
REVISIONS
A
ORIGINAL SCALE 3" = 1 FT
DR. Grundmann
CHK. RE
PASS D.R.T.
APPR.
DATE 21 MAY 74
THIRD ANGLE
20,500 H.P. VERTICAL FRANCIS TURBINE
SECTIONAL ELEVATION
592 FT HEAD SPEED 720 R.P.M.
REF
DIMENSIONS IN INCHES EXCEPT AS NOTED
DOMINION ENGINEERING WORKS LIMITED
MONTREAL CANADA
222 F 30000
222-045302 2 1
222-045301 2 1
ORDER TABLE
THIS DRAWING IS THE PROPERTY OF DOMINION ENGINEERING WORKS LIMITED, AND MAY NOT BE USED OR COPIED EXCEPT AS EXPRESSLY AUTHORIZED BY IT AND MUST BE RETURNED AFTER SUCH USE


INTAKE SIDE
DIRECTION OF ROTATION
CL UNIT
ORIGINAL SCALE 3" = 1 FT
DR. Grundmann CHK. RE
PASS D.R.T.
APPR.
DATE 21 MAY 74
THIRD ANGLE
20.500 VERTICAL FRANCIS TURBINE
PLAN
592 FT. HEAD SPEED 720 RPM.
REF.
DIMENSIONS IN INCHES EXCEPT AS NOTED
222 045302 2 1
222 045301 2 1
NORTHERN CANADA POWER COMMISSION
AISHIHIK RIVER POWER DEVELOPMENT
TURBINES
18 MAY 73
CONTRACT PURCHASER DATE
ORDER TABLE
DOMINION ENGINEERING WORKS LIMITED MONTREAL, CANADA
222 F 30001
REVISIONS
A
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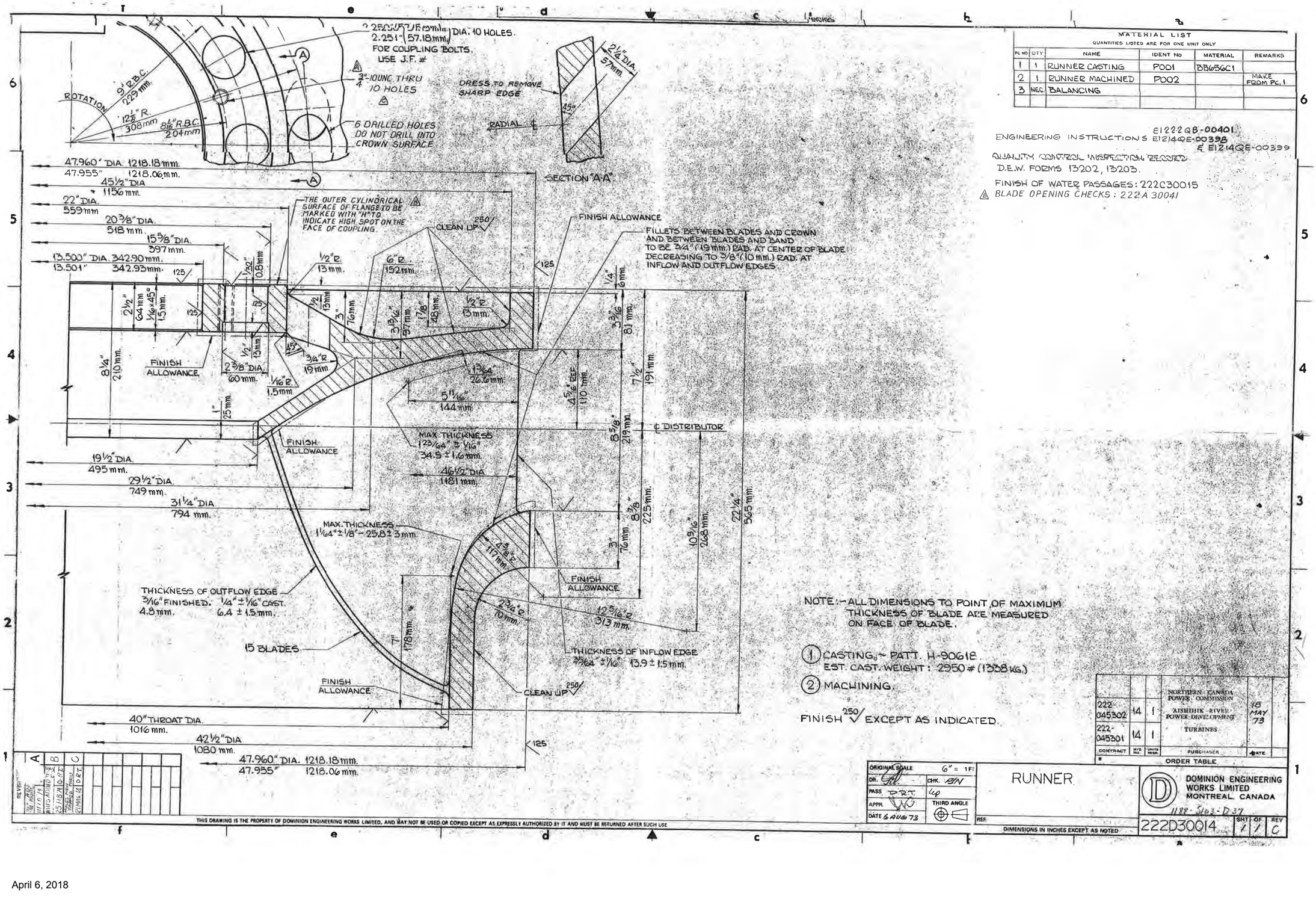

MATERIAL LIST
QUANTITIES LISTED ARE FOR ONE UNIT ONLY

PC NO	QTY.	NAME	IDENT NO	MATERIAL	REMARKS
1	1	RUNNER CASTING	P001	BB656C1	
2	1	RUNNER MACHINED	P002		MAKE FROM PC. 1
3	NEC.	BALANCING			

E1222QB-00401
ENGINEERING INSTRUCTIONS E1214QE-00398 & E1214QE-00399

QUALITY CONTROL INSPECTION RECORD
D.E.W. FORMS 13202, 13203.

FINISH OF WATER PASSAGES: 222C30015

△ BLADE OPENING CHECKS: 222A 30041

NOTE:- ALL DIMENSIONS TO POINT OF MAXIMUM THICKNESS OF BLADE ARE MEASURED ON FACE OF BLADE.

(1) CASTING - PATT. H-90618
EST. CAST. WEIGHT: 2950 # (1338 KG.)

(2) MACHINING.

FINISH 250 EXCEPT AS INDICATED.

CONTRACT	M/D NO.	UNITS REQD.	PURCHASER	DATE
222-045302	14	1	NORTHERN CANADA POWER COMMISSION AISHIHIK RIVER POWER DEVELOPMENT TURBINES	18 MAY 73
222-045301	14	1		

ORDER TABLE

REVISIONS			
	A	B	C
	26 APR 73 W.C.A.	15 MAY 73 W.C.A.	21 MAY 73 D.R.T.

ORIGINAL SCALE	6" = 1F		
DR.	CHK.		
PASS. D.R.T.			
APPR.	THIRD ANGLE		
DATE 6 AUG 73			

RUNNER

REF:

DIMENSIONS IN INCHES EXCEPT AS NOTED

DOMINION ENGINEERING WORKS LIMITED
MONTREAL, CANADA

1188-Sht3-D37

222D30014 | SHT 1 OF 1 | REV C

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222F30019

THE OUTER CYLINDRICAL SURFACE OF FLANGE TO BE MARKED WITH "H" TO INDICATE HIGH SPOT ON THE FACE OF COUPLING AT BOTH ENDS OF SHAFT.

2 13/32" (61 mm) DIA. & C'BORE 12-EQ. SP HOLES HOLES TO BE FINISHED TO 2.500/2.501" (63.50/63.53 mm) DIA. AT SITE WITH GENERATOR SHAFT

OIL SUMP OUTER 222F30022

OIL SUMP INNER 222D30069

OIL SUMP INNER & OUTER TO BE ASSEMBLED FOR TESTING SEE E.S. 200-P-00014

⑤ PAINT THIS AREA WITH A THIN COAT OF RED LEAD PAINT BEFORE ASS'Y OF SHAFT SLEEVE

.500 DIA (12.7 mm) REAM 1-HOLE 2 1/4" (57 mm) DEEP AT ASS'Y WITH PC.7

① P001

MUST NOT BE CONVEX
-.00075" (.019 mm)
⊥ .00075" (.019 mm) A

2.250/2.251" (57.150/57.175 mm) DIA. & C'BORE AS SHOWN 10-EQ. SP HOLES FOR COUPLING BOLTS TO MATCH HOLES IN RUNNER 222D30014 USE JIG J.F.

⌖ .006" (.152 mm) A
◉ .001" (.025 mm) A

DIA. (19 mm) 10 HOLES AS SHOWN
DRESS EDGE OF 3/4" DIA. (19 mm) HOLES TO EQUIVALENT OF 1/16" R. FAR SIDE (1.6 mm)

⚠ 1" - 13 UNC x 1" (17 mm) DEEP 10 HOLES DRILL 1 3/16" (30 mm) ON FAR SIDE

3/4"-10 UNC x 1" (25 mm) DEEP 6 HOLES DRILL 1 3/16" (40 mm) DEEP FAR SIDE

CHIP 1-SLOT 13/32" (10 mm) WIDE AT EACH HOLE

POLISH OVER THIS AREA

LIMIT OF .002" TOLERANCE 0.05 mm

106 1/2" (2705 mm)

107 1/4" (2724 mm) REF.

CHIP 1-SLOT 13/32" (10 mm) DEEP AT EACH HOLE

- DIAMETERS ◉ .002" (.051 mm) A EXCEPT AS NOTED
- F.A.O. 125 EXCEPT AS NOTED

INSTRUCTIONS
ES 200 A.E.-00014
EI 222-P-00405
EI 222-P-00410
Q.C.I.R. 13201 & 13202
DO NOT REMOVE CENTRE PLUGS PC.6 AFTER FINAL MACHINING

MATERIAL LIST
QUANTITIES LISTED ARE FOR ONE UNIT ONLY

PC #	QTY	NAME	IDENT No	MATERIAL	REMARKS
1	1	TURBINE SHAFT	P001	FORGED STEEL A-I.S.I. TYPE 405	FORGING DRWG. 222B30016 ORDER DRWG. 222B30039
2	2	HALF SLEEVE	P002		
3	2	SOFT IRON WIRE	P003	SOFT IRON	S3351P064
4	NEC	WELDING ROD	B50QEL100	AWS/ASTM E-308	
5	NEC	PAINT-RED LEAD	F50QETE		
6	2	CENTRE PLUGS FOR SHAFT MACHINING	SHOP STD.	BC210 H 1/2 B	250-275 B.HN
7	1	PIN	P007	BC152B STN.ST.420T	

① 222F30019

P002 ② P002 ②

③ 1/16" (1.6 mm) DIA. x 8 9/16" (219 mm) LG. SOFT IRON WIRE MAT'L-S3351 P064

④ B50QEL100 (A.I.S.I. TYPE 308 STAINLESS STEEL) AFTER ASSEMBLY TO SHAFT

MACHINE TO THIS DIAMETER BEFORE MACHINING 3/64" GAPS

WELD PREPARATION AT JOINTS BEFORE MACHINING, TACK WELD ONLY

NOTE:- BORE OF HALF SLEEVES MUST BE IN TIGHT CONTACT WITH SHAFT AT ALL POINTS BEFORE WELDING

-FOR FABRICATION DRWG. SEE 222B30039

F.A.O. 250 EXCEPT AS NOTED

② 222F30019

1/4"-20 UNC x 9/16" (14 mm) DEEP DRILL #7 (4.7 mm) THRU

MATCHED FIT .0005" TO .0010" (.0127 mm TO .0254 mm) .501" DIA. TIGHT WITH PC.1 & PC.2

⑦ 222F30019

REVISIONS

A	21 Nov 72	D.C.
B	23 Nov 72	D.C.

CONTRACT	ITEM No.	UNITS REQD.	PURCHASER	DATE
222-045302/19	1		NORTHERN CANADA POWER COMMISSION	
222-045301/19	1		ATHABASKA RIVER POWER DEVELOPMENT	18 MAY 73
			TURBINES	

ORIGINAL SCALE 3", 6", 12", 24" = 1 FT
DR. F.B. CHK. J.M.L.
PASS D.R.T.
APPR.
DATE 23 NOV 73
THIRD ANGLE

TURBINE SHAFT

DOMINION ENGINEERING WORKS LIMITED MONTREAL, CANADA

222F30019 SHT 1 OF 1 REV B

DIMENSIONS IN INCHES EXCEPT AS NOTED

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NORTHERN CANADA POWER COMM.
AISHIHIK RIVER POWER DEVELOPMENT
GENERATORS & ACCESSORIES

CANADIAN GENERAL ELECTRIC Co. 292D653AL

TITLE
GENERATOR OUTLINE

FIRST MADE FOR

MACHINE	TYPE	CLASS	FORM	P.F.	R.P.M.	VOLTS	REQ'N.	E.N.	PT.
GENERATOR	ATI	10-15600	W	·9	720	13800	9280-788	525L439	1
EXCITER	EV	2-57KW	—	—	720	85	9280-788-2	101230	1

TO BE NOTED BY PURCHASER

(1) REFER TO CONTRACT FOR MATERIAL TO BE SUPPLIED BY C.G.E. CO. THE AMOUNT OF SUCH MATERIAL IS NOT INCREASED BY ANYTHING SHOWN ON THIS DRAWING.

(2) GENERATOR HALF OF COUPLING GUARD SUPPLIED BY C.G.E. Co.
TURBINE HALF OF COUPLING GUARD SUPPLIED BY D.E.W.

(3) COUPLING STUDS, REAMER, DRILLING TEMPLATE AND PIN GAUGE FOR SPIGOT SUPPLIED BY TURBINE MANUFACTURER

(4) COMBINED BRAKES & JACKS FOR ROTATING UNIT. SUPPLIED BY CGE CO.

(5) ERECTION & MAINTENANCE MANUAL — PGEI-10154

(6) SHIPPING DIMENSIONS OF MAJOR COMPONENTS — 704C6878AE

(7) LIFTING CLEARANCES, WEIGHTS & DEVICES — 761D201AK

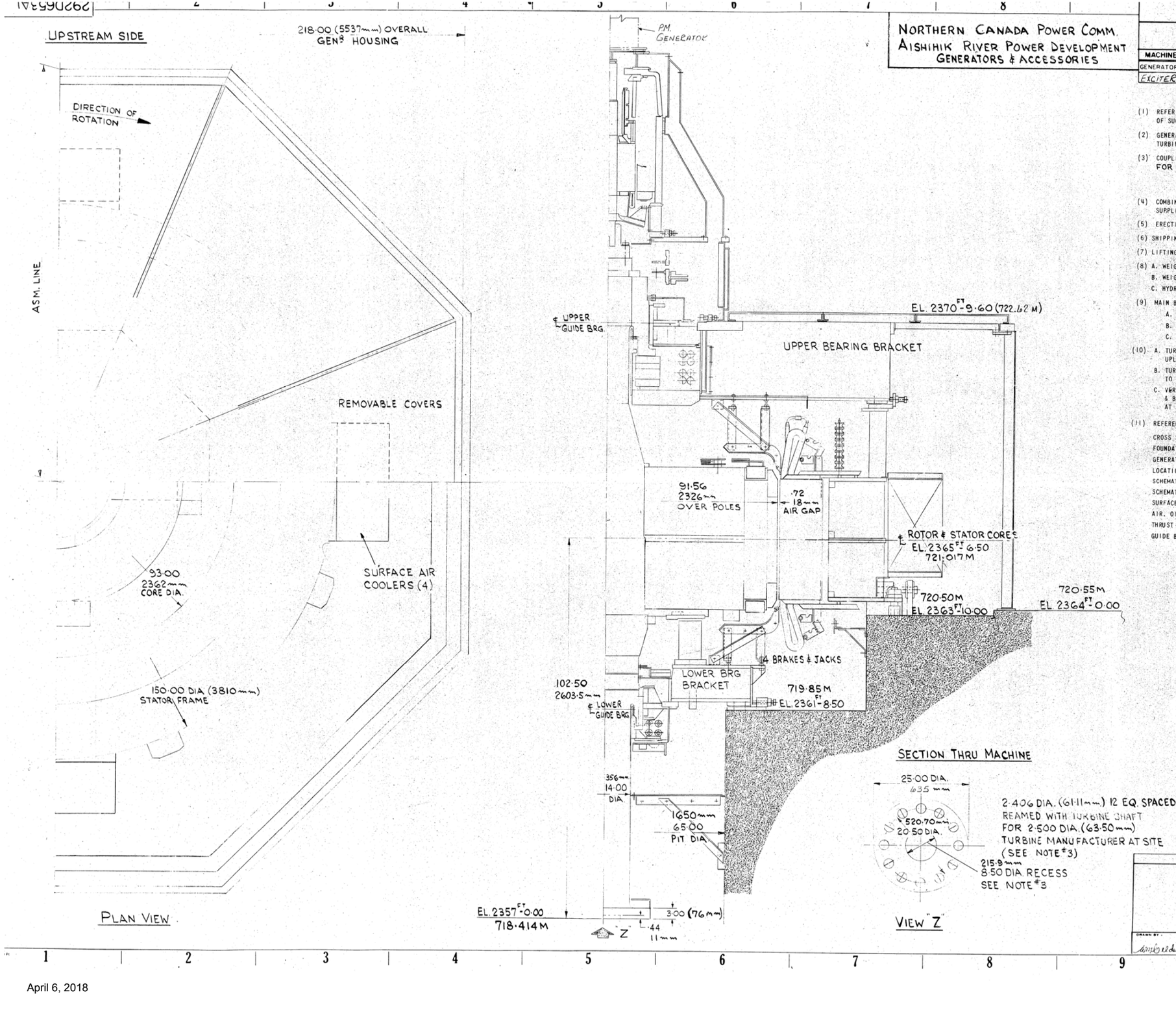
(8) A. WEIGHT OF ROTATING PARTS, GENERATOR, EXCITER — 76,600 LB
B. WEIGHT OF TURBINE SHAFT & RUNNER — 8,100 LB
C. HYDRAULIC THRUST * — 50,000 LB

(9) MAIN BRACKET DEFLECTION DUE TO WEIGHT OF
A. GENERATOR ROTOR — 0·0261 (·66 mm)
B. GENERATOR ROTOR, TURBINE SHAFT & RUNNER — 0·0289 (·73 mm)
C. GENERATOR ROTOR, TURBINE SHAFT & RUNNER, & HYDRAULIC THRUST. — 0·0495 (1·26 mm)

(10) A. TURBINE MANUFACTURER TO ALLOW MINIMUM VERTICAL UPLIFT OF * FOR GENERATOR BEARING SERVICING.
B. TURBINE MANUFACTURER TO LIMIT VERTICAL UPLIFT TO A MAXIMUM OF *
C. VERTICAL CLEARANCES IN GENERATOR BEARINGS, SEALS & BRUSH RIGGING WILL BE * AND WILL BE CHECKED AT ASSEMBLY AND OVERHAULS.
* 0.375 (9.52 mm)

(11) REFERENCE DRAWINGS - GENERAL

CROSS SECTION ASSEMBLY	591E106HM
FOUNDATION PLAN	292D620CR
GENERATOR HOUSING ASSEMBLY	292D611BK
LOCATION OF LEADS	912D600AN
SCHEMATIC DIAGRAM OF MACHINE WIRING	761D205CA
SCHEMATIC DIAGRAM OF CABINET WIRING	761D230AB
SURFACE AIR COOLER PIPING	292D660FL
AIR, OIL, WATER & FIRE PROTECTION PIPING.	292D660FM
THRUST & GUIDE BEARING ASSEMBLY	591E128AR
GUIDE BEARING ASSEMBLY	591E128AS



REVISIONS	PRINTS
Work Completed RK	24
	REF.

DRAWN BY: [illegible] CHECKED BY: [illegible]

LARGE GENERATOR
PETERBOROUGH, CANADA WORKS

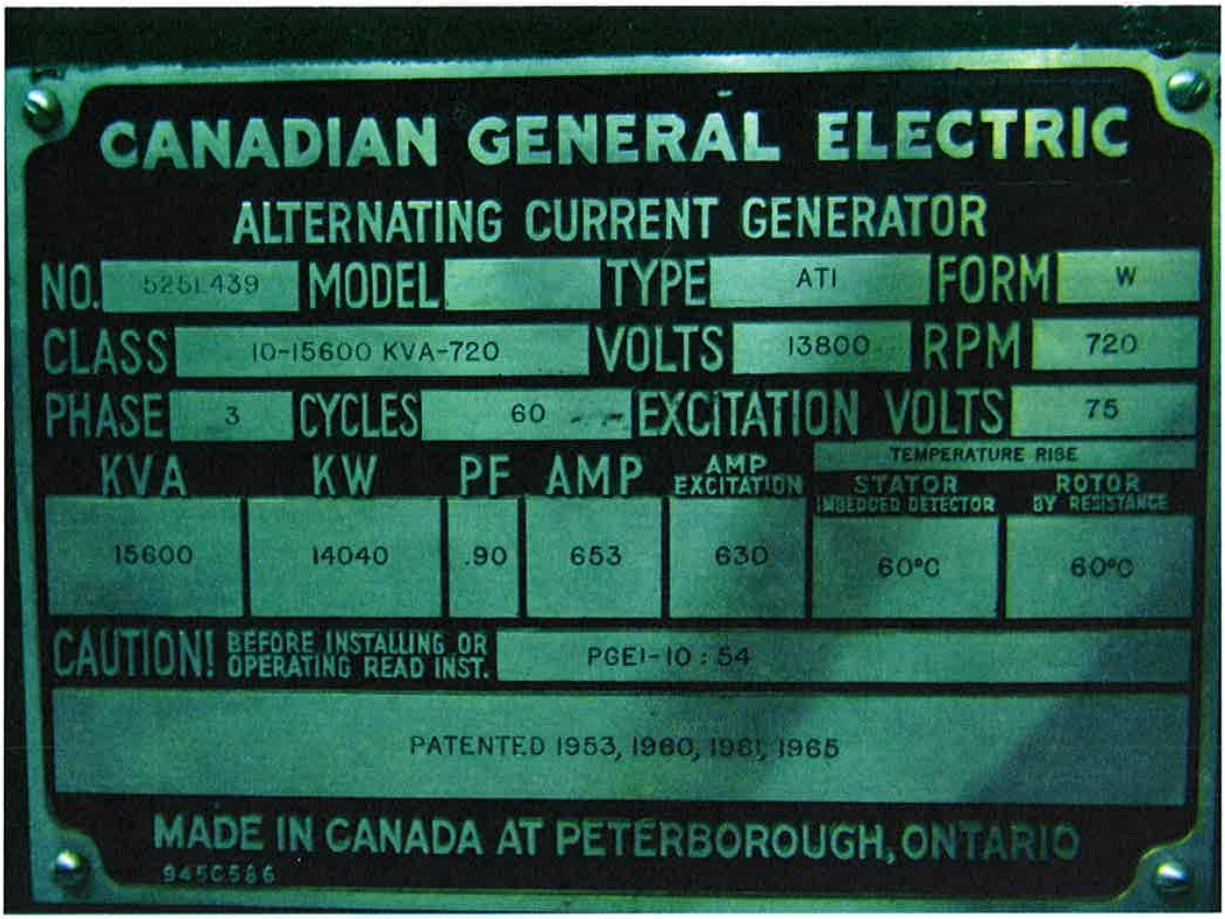
292D653AL

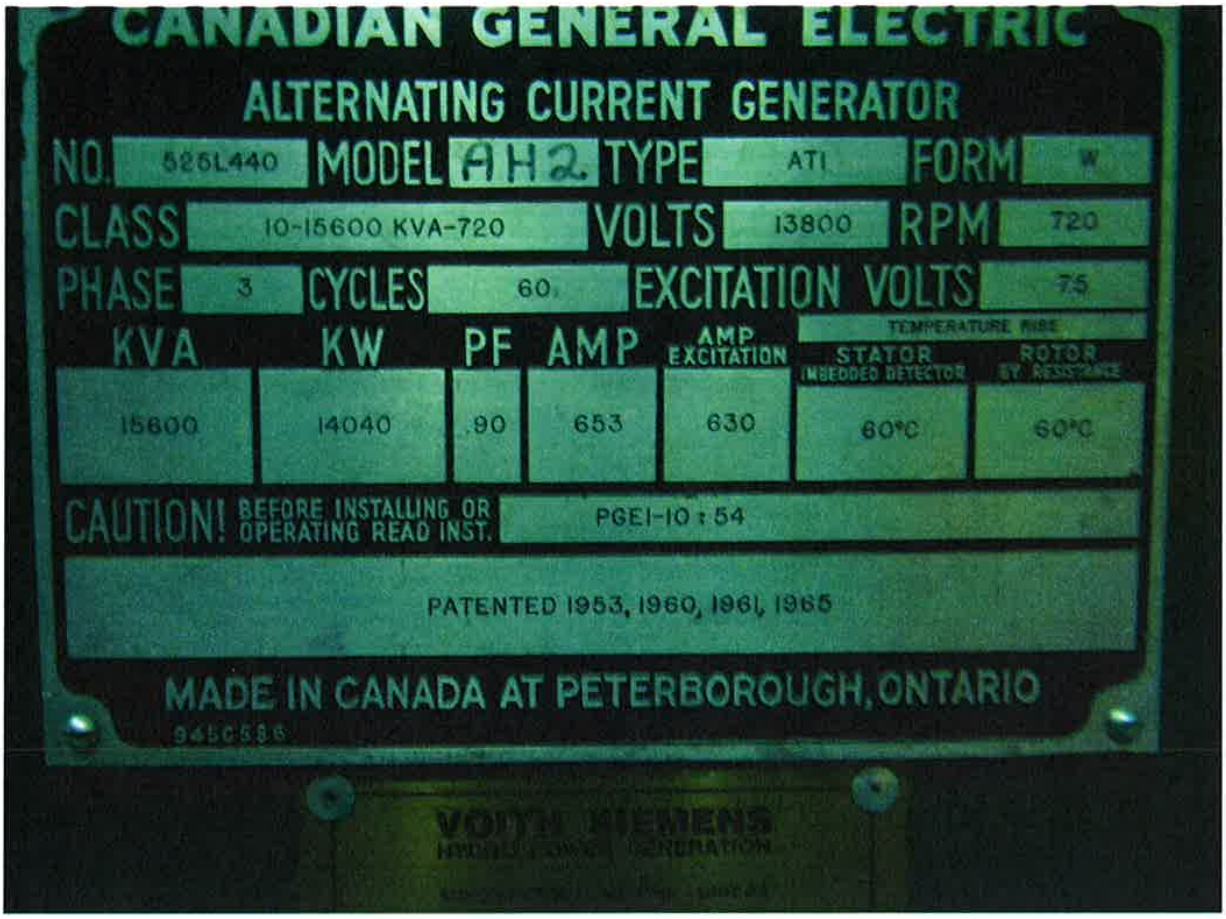
1188-5106-D6F

DRAFT

APPENDIX B

ORIGINAL GENERATOR NAMEPLATES

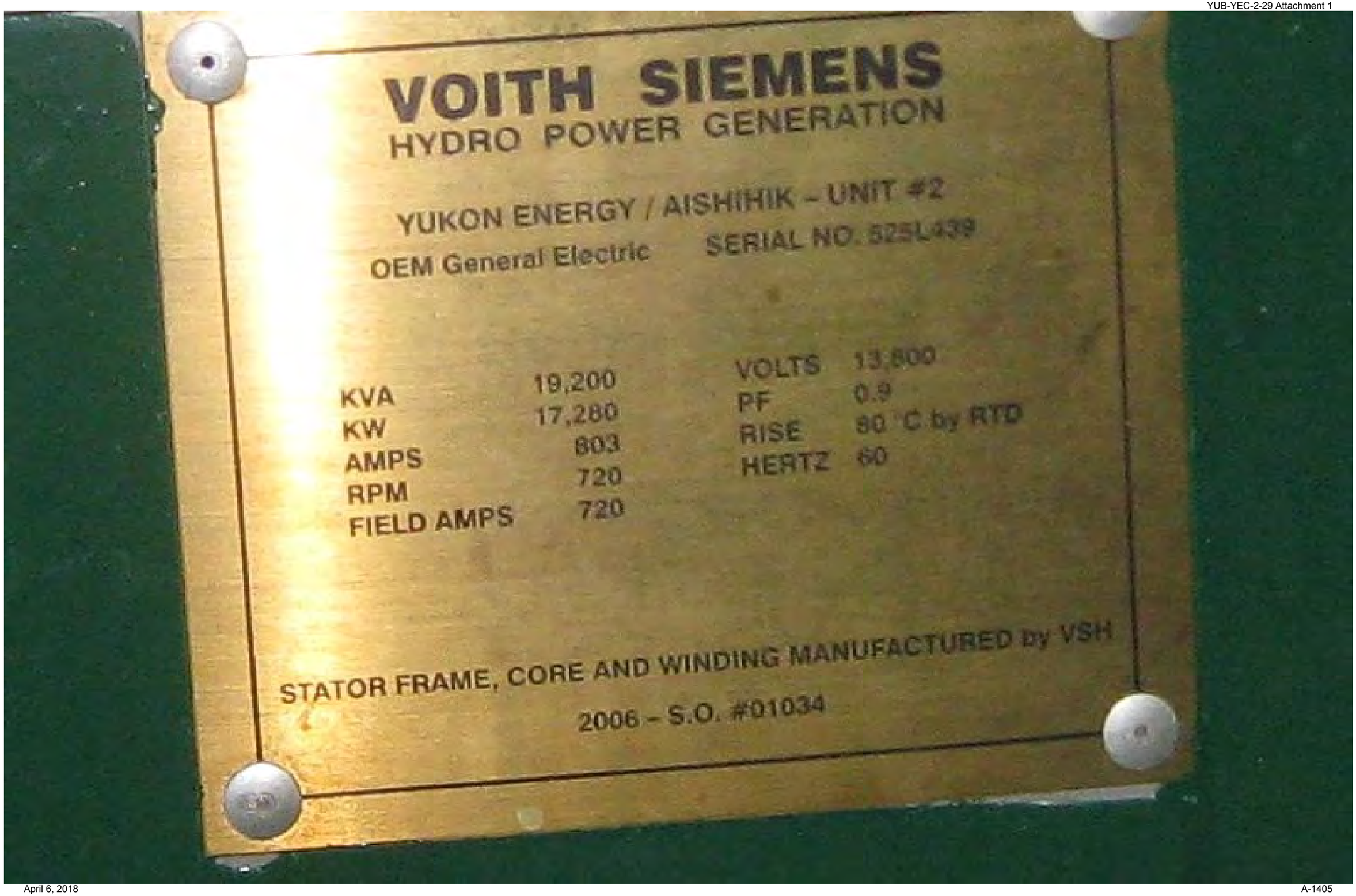

CANADIAN GENERAL ELECTRIC
ALTERNATING CURRENT GENERATOR
NO. 5251439
MODEL
TYPE ATI
FORM W
CLASS 10-15600 KVA-720
VOLTS 13800
RPM 720
PHASE 3
CYCLES 60
EXCITATION VOLTS 75
KVA
KW
PF
AMP
AMP EXCITATION
TEMPERATURE RISE
STATOR IMBEDDED DETECTOR
ROTOR BY RESISTANCE
15600
14040
.90
653
630
60°C
60°C
CAUTION! BEFORE INSTALLING OR OPERATING READ INST.
PGEI-10:54
PATENTED 1953, 1960, 1961, 1965
MADE IN CANADA AT PETERBOROUGH, ONTARIO
945C586

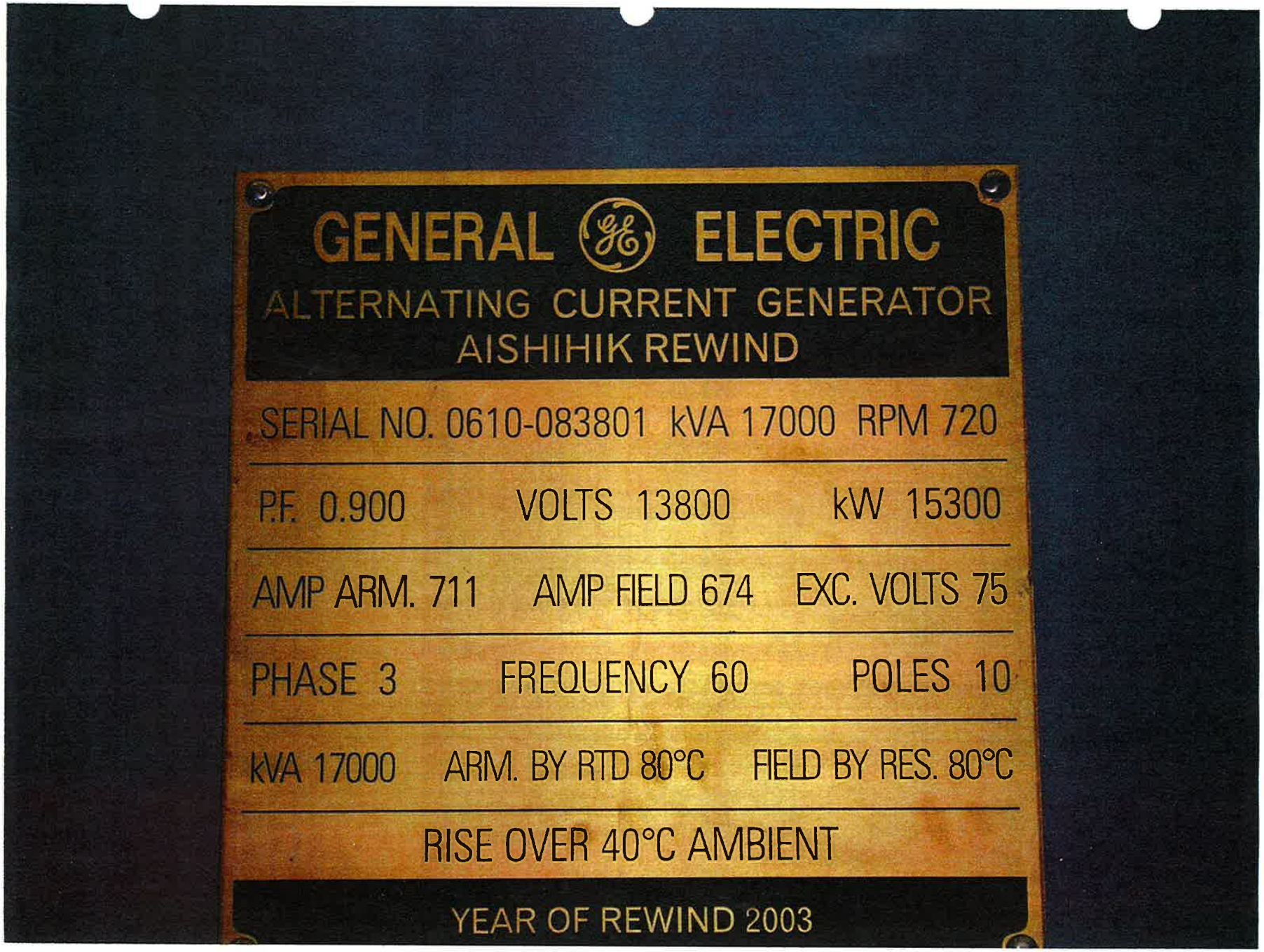

CANADIAN GENERAL ELECTRIC
ALTERNATING CURRENT GENERATOR
NO. 526L440 MODEL AH2 TYPE ATI FORM W
CLASS 10-15600 KVA-720 VOLTS 13800 RPM 720
PHASE 3 CYCLES 60 EXCITATION VOLTS 75
KVA KW PF AMP AMP EXCITATION
TEMPERATURE RISE
STATOR (EMBEDDED DETECTOR) ROTOR (BY RESISTANCE)
15600 14040 .90 653 630 60°C 60°C
CAUTION! BEFORE INSTALLING OR OPERATING READ INST. PGEI-10 : 54
PATENTED 1953, 1960, 1961, 1965
MADE IN CANADA AT PETERBOROUGH, ONTARIO
945C586

DRAFT

APPENDIX C

REWIND GENERATOR NAMEPLATES


VOITH SIEMENS
HYDRO POWER GENERATION
YUKON ENERGY / AISHIHIK – UNIT #2
OEM General Electric
SERIAL NO. 525L439
KVA 19,200
KW 17,280
AMPS 803
RPM 720
FIELD AMPS 720
VOLTS 13,800
PF 0.9
RISE 80 °C by RTD
HERTZ 60
STATOR FRAME, CORE AND WINDING MANUFACTURED by VSH
2006 – S.O. #01034


GENERAL ELECTRIC
ALTERNATING CURRENT GENERATOR
AISHIHIK REWIND
SERIAL NO. 0610-083801 kVA 17000 RPM 720
P.F. 0.900 VOLTS 13800 kW 15300
AMP ARM. 711 AMP FIELD 674 EXC. VOLTS 75
PHASE 3 FREQUENCY 60 POLES 10
kVA 17000 ARM. BY RTD 80°C FIELD BY RES. 80°C
RISE OVER 40°C AMBIENT
YEAR OF REWIND 2003

APPENDIX B-2

ALSTOM PROPOSAL

1079, rue Daigneault Granby (Québec) J2J 2S4
Téléphone: 450-372-0755 Télécopie: 450-372-1316
24/7 Emergency service line : 1 855 522-0755
service.canada.smallhydro@alstom.com

March 10th , 2015

Client :
KGS Group , Yukon Energy
Joel Lambert P.Eng.
3rd floor
865 Waverley Street
Winnipeg, Manitoba,
R3T 5P4, Canada

Site address:
Aishihik Generating Station
Yukon Territories, Canada

Telephone : 204-896-1209

E-Mail : jlambert@kgsgroup.com

Project description: Potential Runner Upgrade Request For Information 14-1404-004

Our reference: OB-Yukon Energy Aishihik Generating Station

We are pleased to submit our budgetary proposal for the supplies and works for Aishihik Generating Station runner upgrade.

At this stage, this budgetary proposal gives a preliminary indication of the conditions under which we could perform the works and DOES NOT CONSTITUTE A BINDING OFFER. Alstom reserves the right to alter any aspect of this budgetary proposal, including the pricing information.

Nevertheless we trust the information provided is sufficiently detailed to enable you to assess the benefits which you can obtain from Alstom and we confirm our keen interest in working with you.

We remain at your disposal to further discuss the contents of our budgetary proposal and to offer you a firm proposal with definitive prices, price escalation details, as well as full terms and conditions in the event that this project goes forward.

Best regards

Alex Viens 450-372-0755 ext 289

Alstom is please to respond to "*Aishihik Generating Station Potential Runner Upgrade, Request for Information, Draft revA*" 14-1404-004 to estimate the turbine performances with a new runner.

Based on the information provided by KGS for Yukon Energy, Alstom understand that the power plant has currently 3 units having the following characteristics:

Unit 1	15 MW vertical Francis runner (1972), net head= 180 m, generator rewound in 2003 to 17 000 kVA
Unit 2	15 MW vertical Francis runner (1972), net head= 180 m, generator rewound in 2006 to 19200 kVA
Unit 3	7 MW horizontal Francis runner (2011)

KGS is asked in the RFI to investigate the refurbishment of unit 2. The hydraulic characteristics of unit 2 are the following:

Original Equipment Manufacturer	Dominion Engineering Works
Rated net head:	180.4 m
Rated discharge (per unit):	9.72 m3/s *
Synchronous Speed	720 RPM
Runaway speed	1330 RPM
Nb of stay vanes	10
Nb of wicket gates	20
Nb of runner blades	15
Runner exit diameter	1016 mm
Distributor height (estimated)	218 mm
Distributor centerline elevation	715.52 m
Tailwater level (normal)	721.4 m

*The new runner cannot use more flow than 9.72 m^3/s as there is an evacuation tunnel in which the water is flowing and this tunnel cannot be more filled than now.

Alstom has studied the replacement of the runner of unit 2 and provides in this document expected performances for the rated net head of 180.4 m. Alstom has more than 100 years in hydroelectric runner design with a huge selection of projects realized worldwide. Francis, Kaplan, Pelton and Bulbs hydroelectric turbines are designed and manufactured every day 24h/day by Alstom employees all around the Globe. Vertical Francis runners represent an important part of Alstom Hydro.

Alstom takes advantage of its past experiences for the design of new runners. Indeed, the design process is based on the selection of an existing reference from which adaptations/changes are applied to reflect the situation of the turbine to refurbish. All parts of the turbines are studied, from the spiral case inlet up to the draft tube outlet. Calculations of the fluid flow with the use of computers (CFD) are part of the normal design process. For the present budgetary proposal, the expected performances were estimated using the reference Alstom runner shown on the image in Figure 1. Adaptations and changes to the chosen Alstom reference to fit Aishihik's configuration were done relying on analytic relations and experience.

Alstom has selected a reference which has a very good cavitation behavior, a high efficiency, a runaway speed close to 1330 RPM and acceptable mechanical static stresses at synchronous speed. As seen in the figure, the distributor height of the reference (in blue) is higher than Aishihik's distributor height. Alstom proposes for Aishihik a runner with the same distributor height as the current distributor height and the shift in performance induced by this change of height is already taken into account. The main characteristics of the proposed runner are given in Table 1 below.

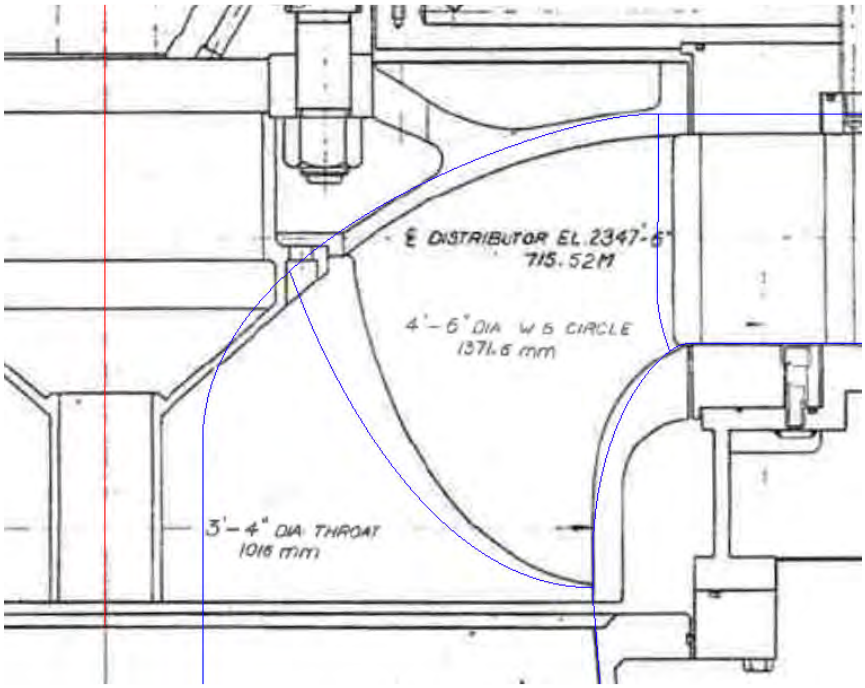


Figure 1 : Alstom reference (in blue), Aishihik in black

Table 1: Main characteristics of the proposed runner

Nb of blades	15
Distributor height	218 mm
Exit diameter	1016 mm

The proposed runner would be made from a forged martensitic stainless steel ingot. After removal of steel by machining, the final shape would be obtained. As the runner is not obtained from a casting, the numerous metal defects generally obtained from cast parts would not be found. Moreover, the mechanical solidity of the runner would be further enhanced as no welds would be done, resulting a high quality runner. Runners could be delivered within 9-10 months with this industrial scheme.

Alstom is currently manufacturing runners for Soo River G.S, a project similar to Aishihik . Dimensions of both runners are very close to each other, Figure 2 allows a better comparison of both runners. On this figure, the Soo River runner is pictured at the outlet diameter of the Aishihik runner. The outlet diameter of Soo River is 1100 mm, which is very close to the outlet diameter of the Aishihik runner. As it is seen, dimensions and overall shape are quite close to each other.

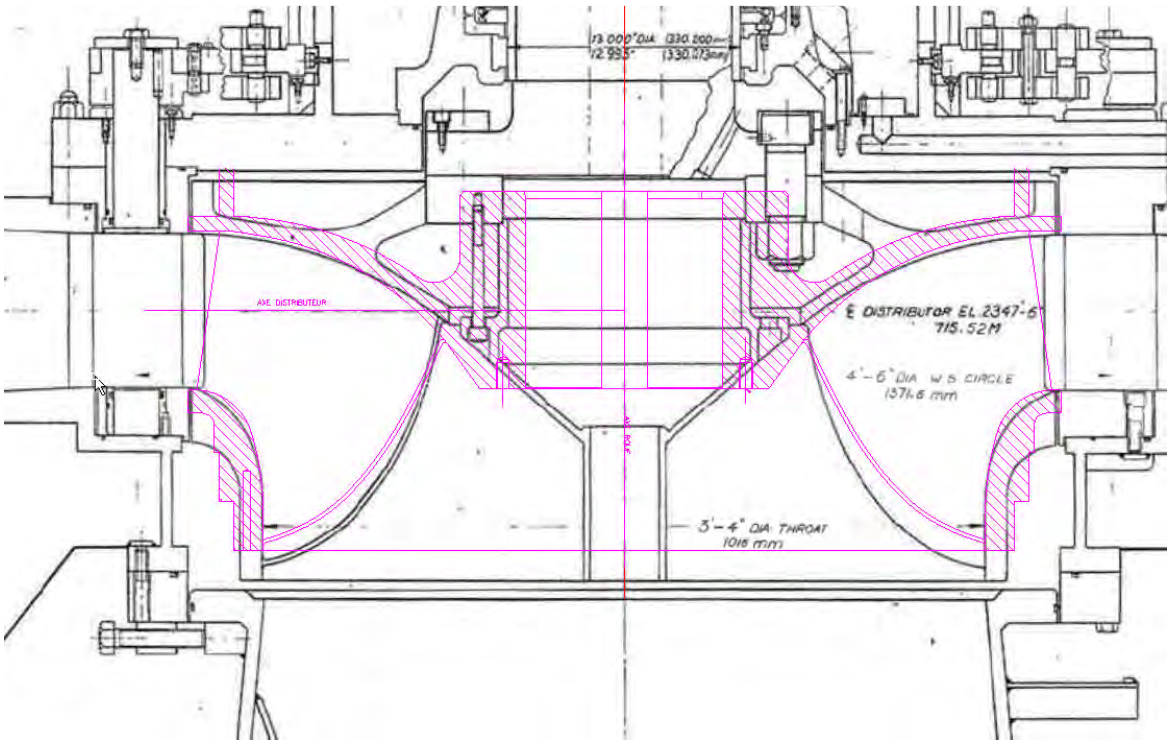


Figure 2: Comparison of Aishihik runner with Soo River runner (Soo river in purple, Aishihik in black)

Estimation of the expected performances at Hnet=180.4 m is presented below in Figure 3. The green curve is the expected efficiency whereas the blue curve is the expected turbine power. A tailwater level of 721.4 m is assumed at this point. As mentioned earlier, the discharge cannot exceed 9.72 m^3/s. This is represented by the vertical red line. At this maximum discharge, the expected power is 16.1 MW and the efficiency is 93.5%. The peak efficiency at this head is expected to be obtained at roughly 85% of the maximum discharge, i.e. at 8.4 m^3/s.

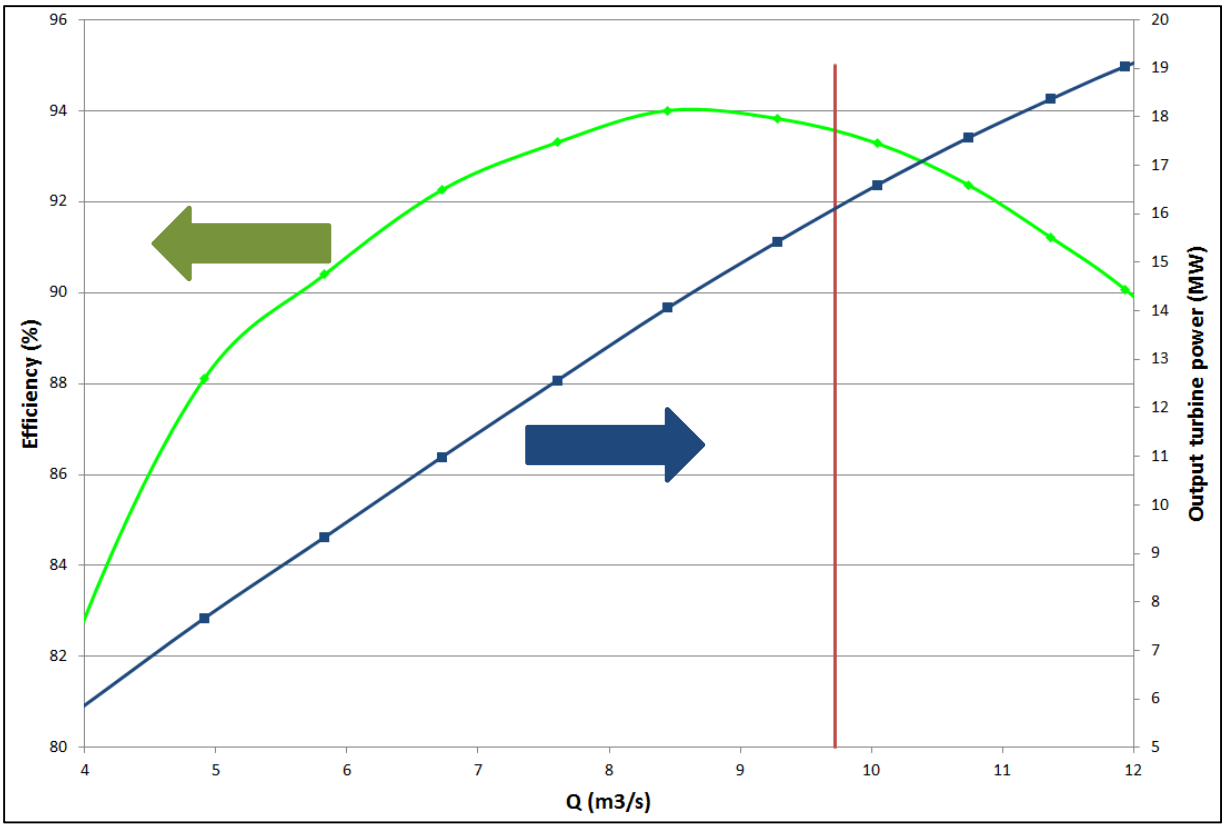


Figure 3: Expected performance for Hnet = 180.4 m and at tailwater level = 721.4 m.

The Figure 3 shows expected efficiency and power as single lines. However, at this stage of the process, a non-negligible uncertainty exists and as a consequence the efficiency line should be viewed rather as band with +0.5/-1% limits. The uncertainty comes from, on one part, the incomplete information received by Alstom.

Alstom will require some more information atop of the information already given to reduce the uncertainty. Amongst the additional required information, there are:

- The maximum and minimum net head. This information is necessary to ascertain that there is no cavitation induced at leading edge due to a net head not taken into account;

- The position of the pressure taps in the draft tube and spiral casing to measure the net head. In the drawings supplied, the draft tube appears to be much longer than Alstom's existing draft tube. This might just be wrongly assumed as the position of the end of the draft tube is not indicated;

- The installation/dismounting of the runner. Alstom has already made in the recent past another Francis runner whose shape in the meridian plane is even closer to Aishihik's shape than the shape of the first reference indicated above. The efficiency, cavitation, stability, mechanical and runaway behaviour of this runner is also very good. Its stability behavior for instance, is better than the stability behavior of the reference chosen to construct the expected performances. For this reason it seems that this second reference is also a very good starting point for Aishihik. One drawback however is the lower exit altitude of the blade near the crown. It is understood that the current runner may be dismantled from the shaft from underneath by first removing the runner cone and then removing the coupling nuts connecting the runner to the shaft. If dismantling from below is not required or unfrequently expected, we recommend indicating it in the RFQ. We will have to choose between keeping this second reference and modifying the shaft (for instance in order to have a sole central bolt to couple the runner to the shaft) and keeping the first reference identified whose trailing edge is at a higher altitude (closer to Aishihik current runner). The final choice will be a tradeoff amongst various criteria: price, stability, efficiency level, cavitation behaviour, lead time, etc. Currently there is not enough information within the KGS's document to make a choice. The evaluation criteria would be helpful in optimizing the proposed solution.

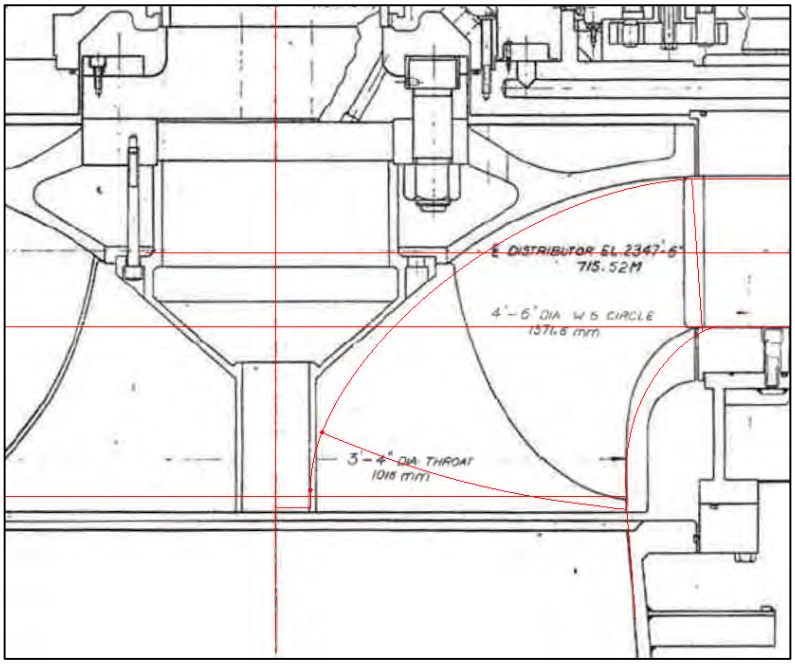


Figure 4: Alstom second possible reference for the Aishihik project

- Alstom will need drawings of gates and vanes with dimensions. For the purpose of the current performance estimate, rapid approximations were done. Refinement is required to narrow down the uncertainty;

- Volumetric losses through labyrinths for this head are important, Alstom needs to evaluate at best the expected leakage flow. The drawings supplied allowed us to see that the current configuration has both band and crown seals lengths shorter than our internal standards. Also, the radial gaps may be important and as a result the leakage flow is likely to be important. Further studies to determine if the current seal design is kept will need to be done following the reception of more complete information.

Alstom has already performed some rapid studies of the other components of the Aishihik turbine and brings attention to a potential refurbishment of the wicket gates. For instance, having gates cambered on the "opposite side" could give an estimated 0.4% to 0.8% gain in efficiency, see Figure 5 below. The efficiency gain would come from the greater inter-gates space which would allow a reduction of the water velocity and accompanying losses.

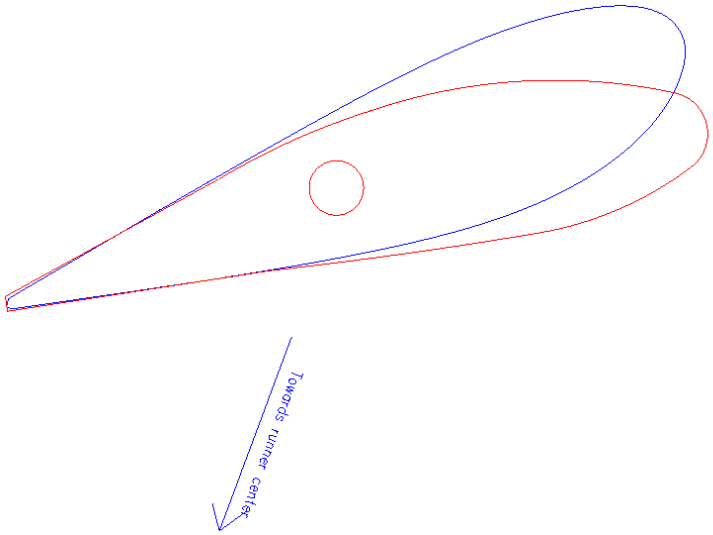


Figure 5: Comparison of the Aishihik gate (red) and a cambered gate (blue)

Alstom has a great expertise in vertical Francis turbines and we feel that our knowledge would be highly valuable for the Aishihik project. The preliminary studies performed indicate that at least two existing references would fit within Aishihik's configuration with minor adjustments required. More complete information is required to make a final choice between the two references. In both cases the proposed efficiency would provide an increase of the maximum power. As instance, using reference #1, we estimated that the maximum power would increase from the actual 15 MW to an expected 16.1 MW with the same amount of water of 9.72 m^3/s.

Regarding the axial thrust, further studies are required. Knowing the actual capacity of the thrust bearing would be useful to make an evaluation/verification.

Indeed, following the reception of complementary information during the firm RFQ, Alstom will perform further studies to ascertain the current assumptions and to propose a new runner and related components with the best characteristics for Aishihik power plant.

Work description

Alstom based their budget estimation on similar projects and on drawings supplied with the RFI, more details or a site visit will be necessary to firm up the budgets. For RFI purpose we have used a schedule of 6-1 days - 12/hrs per day for site works, it is considered that workers have to travel Haines Junction every days.

For the budget purpose we have calculated replacement parts directly related to the runner replacement, if other option are valuable to Yukon Energy we will be please to quote accordingly. Alstom also suggest to perform a condition assessment of the remaining turbine components this may identify if other components need to be replaced.

Table 1 – Site scope of work included in the budgetary price of **$250 500.00**

Scope of work	Included ✓
1. Turbine runner replacement.	
a) EHS site analyses.	✓
b) Turbine disassembly	✓
c) Parts inspections and recommandations.	✓
d) New runner and parts installation	✓
e) Turbine reassembly	✓
f) Commissioning	✓

Table 2 –Engineering scope of work included in the budgetary price of **$106 500.00**

Scope of work	Included ✓
2. Turbine Runner engineering	
a) Study for an adaptation of an Alstom runner profile to Aishihik turbine distributor and shaft.	✓
b) Drawings for fixed labyrinths adaptation to Alstom runner.	✓
c) Commissioning report.	✓

Table 3 – Parts for the project for a budgetary price of **$386 500.00**

Parts for project	Quantity	Parts total price
3. Replacement parts		
a) 1 Runner, cone and bolts.	1	$343 500.00
b) 1 Fixed labyrinths set and hardware.	2	$43 000.00

Included in this budgetary estimate

- 1 mobilization and 1 demobilization of ALSTOM SITCA INC;
- Transport of the parts to Aishihik Generating Station;
- Work and parts described in tables 1, 2 & 3;
- Standard required tooling;
- Travelling, meals and lodging expenses for required labour;
- Field report;

Excluded from this estimate

- Mobilization and demobilization of ALSTOM SITCA INC. labour and tooling in case of work interruption by others;
- Repairs, modifications, machining and all related costs deemed necessary for non-conform equipment and/or drawings;
- All damages, delays, or inconveniences resulting from work performed by other contractors, sub-contractors or employees provided by the Client;
- Special tools and lifting device required for this contract;
- Procedure, equipment, labour and costs associated to work in confined space;
- Dewatering and refilling of the power station unit(s);
- Overhead crane services;
- Any NDT testing;
- Absolute turbine effiency.
- Alignment correction work;
- All machining work (of other turbine parts and all generator parts) and the related costs;
- Waiting time and related costs;
- GST and PST

The Client also agrees to provide the following

- Procedure and lockout of equipment impacted by this contract;
- Adequately maintained access to reach working site allowing for equipment to be delivered by vehicle, for the duration of the contract;
- Sufficient opening (door, roof) to access the equipment;
- An easily accessible storing area on site for maritime-type containers;
- Containers for waste (components, waste oil and grease, soiled cloth, etc.) ensuing from ALSTOM SITCA INC. work and will be responsible for its disposal;
- Electrical and pneumatic power required for this contract;
- Asbestos-free environment;
- Valid inspection certificate for overhead crane and/or all permanent lifting devices on site;
- Adequate on-site facilities including but not limited to washrooms, lunchroom and office area;
- Scaffolding including drawings and installation procedure certified by an engineer;
- All drawings, maintenance manuals, procedures and specifications in his possession, at ALSTOM SITCA INC. request.

APPENDIX B-3

NORCAN PROPOSAL

NORCAN
HYDRAULIC TURBINE INC.

50 Bruce Crescent, Carleton Place, ON Canada K7C 3V6 **T** (613) 257-4755 **F** (613) 257-4215 **E** nht@norcanhydro.com **www.norcanhydro.com**

March 09, 2015

Joel Lambert, P. Eng.
KGS Group
3rd Floor
865 Waverly Street
Winnipeg, Ontario
R3T 5P4
(T) 204-896-1209
(C) 204-770-6411
jlambert@kgsgroup.com

Ref: Budget quote for the manufacturing of one (1) replacement Francis Runner for Aishihik Generating Station. Norcan Reference #15-2215 Rev 0

Dear Joel,

Norcan Hydraulic Turbine Inc. is pleased to submit the following budget proposal for the manufacturing and installation of one replacement Francis Runner for Aishihik Generating Station Unit 2 based on the supplied data on February 17, 2015 file no. 14-1404-004.

Attached, please find a general summary, pricing and detailed scope of supply. I hope this proposal meets your requirements.

If you have any questions or require clarifications, please let us know.

Sincerely,
Norcan Hydraulic Turbine Inc.

Henk de Ridder
Norcan Hydraulic Turbine Inc.
T613-257-4755 ext 11
F613-257-4215

TABLE OF CONTENTS

1.0 GENERAL SUMMARY 3
Pricing 3
Notes 3
2.0 DETAILED SCOPE OF SUPPLY 4
3.0 PRELIMINARY PERFORMANCE 5
4.0 COMMERCIAL TERMS 6
Delivery 6
Project Schedule 6
Payment Schedule 6
5.0 GENERAL CONDITIONS OF CONTRACT 7
6.0 NORCAN HYDRUALIC TURBINE INC. DIEM RATES AND TERMS 11

1.0 GENERAL SUMMARY

Pricing

Item	General Description	Qty	Amount (CAD/Dollar)
Equipment Supply	Manufacture one (1) 40.0" Dt Francis Runner.		(Itemized costs shall equal below sum):
	40.0" Dt Francis Runners	1 each	$268,033.00
	Delivery and Installation	1 each	$ 205,140.00
	Replacement Coupling Bolts	1 set	$ 8,600.00
	Blade Templates	1 set	$ 15,500.00
	Taxes *Not Included*		EXTRA if applicable

Notes

- Taxes are not included.
- Delivery time of 11-12 months from reception of P.O., receipt of down payment.
- Warranty for two (2) years from commissioning or thirty (30) months after delivery, whichever is sooner.
- Quote valid for 60 days.
- Quote based on existing runner removal from below. Existing removal equipment is present at site.
- Quote based on Norcan modifying existing runner removal and installation equipment to suit new runner.

2.0 DETAILED SCOPE OF SUPPLY

40.0" Dt Francis Runner 15 blade

Material
The Crown, Blades and Band components will be of cast ASTM A743 CA6NM or forged of A182 F6NM stainless steel or approved equivalent.

Construction
The Runners will be fabricated, machined, and ground in accordance with Norcan manufacturing design standards and tolerances stated in DWI050-Rev 3. The Runners will meet or exceed IEC standard publication 60193 1999-11.

For fabrication, the Crown and Band will be cast and/or forged and fully pre-machined. The Blades will be cast, pre-machined and hand ground. The Blades will be welded to the Crown and Band as follows:

The first 25% of the Blade length at the inlet and discharge will have 100% penetration. The remaining length of the Blade will have 1/3 of the Blade thickness V weld per side. A concave fillet weld will finish the Blade to Crown and Blade to Band. The fillet weld will be hand ground to the required finish with no permissible undercuts. The root weld filler material will be AWS No. 309 and the finish passes "cap" will be AWS No. E410 Ni Mo. All welders are qualified to QW-200.1, Section IX, ASME Boiler and Pressure Vessel Code or CSA W47.1. (Ref. DWI-059, DWI-013)

The Runner minimum finish will be as follows:

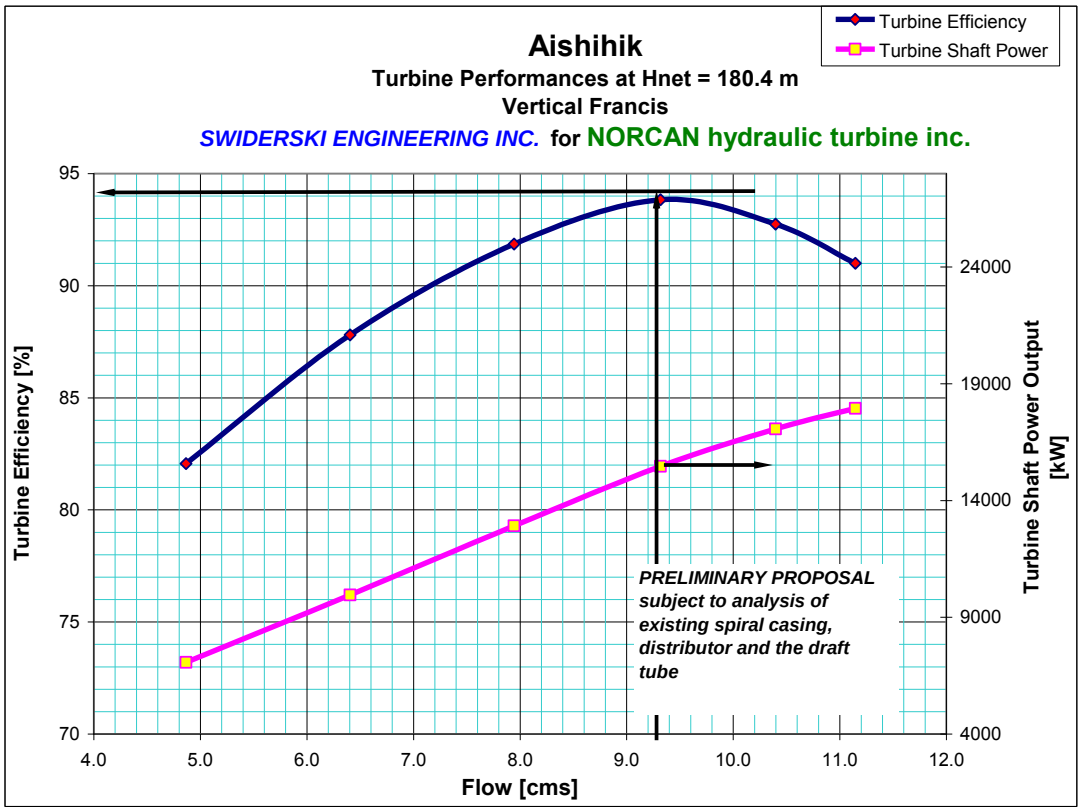
Water passages	
Upper two thirds of the Blade	125 finish
Lower one third of the Blade	63 finish
Runner	
Outside finish all over with axis	250 finish
Seal surfaces	125 finish
All other surfaces	125 finish

Balancing
The Runner will be dynamically balanced to meet or exceed the standards of ISO 1940 G2.5. Weights shall be added or removed in such a manner that there will be no projections or depressions from the finished surfaces. No eccentric machining will be performed.

3.0 PRELIMINARY PERFORMANCE

Hnet =	591.7	ft	=	180.40	m
Dth (nom) =	40.0	in	=	1.016	m
n =	720	rpm			

Turbine Efficiency	Flow	Flow	Turbine Shaft Power	Turbine Shaft Power	
[%]	[cms]	[cfs]	[kW]	[hp]	
82.06	4.87	171.7	7065	9474	
87.80	6.41	226.0	9950	13343	
91.86	7.94	280.3	12911	17314	
93.83	9.32	328.8	15466	20741	
92.74	10.40	366.9	17061	22879	
91.00	**11.15**	**393.4**	**17946**	**24066**	**CAVITATION LIMIT**



Performance above is based on best guess based on data supplied.

Analysis of existing hydraulic outline will be required to determine best runner fit using CFD.

Operational history will be required of existing performance of present runner.

Runaway speed and maximum thrust to be supplied upon completion of CFD and engineering.

4.0 COMMERCIAL TERMS

Delivery

Delivery will be 11-12 months after receipt of the contract, receipt of the down payment and supplied production drawings. All delivery times start from the date of acceptance of the order and receipt of the down payment.

Installation

Installation will be 6-8 weeks from time runner is delivered to site.

Project Schedule

A detailed schedule to be presented four (4) weeks after the award of the contract.

Payment Schedule

The following terms of Payment shall apply:

20% Down payment with the order.
10% Completion and approval manufacturing drawings and inspection test plan.
20% On receipt of construction materials (Castings, Forgings).
15% Completion of Runner fabrication.
15% Manufacturing complete, Runner ready to ship
10% Mobalized and on site old runner removed
10% New runner installed and commissioned

*Payment net 30 days from invoice issue date

5.0 GENERAL CONDITIONS OF CONTRACT

(Note: Any reference to "Norcan" is a reference to Norcan Hydraulic Turbine Inc.)

Indemnification

Norcan shall indemnify and hold harmless the Customer against all claims, demands, losses, damages and costs, all as finally judicially determined, excluding loss of profit and any punitive, exemplary, indirect, consequential or special losses or damages, whether in contract or in tort or otherwise, by third parties where such claims, demands, losses, damages and costs are:

(i) attributable to bodily injury, sickness, disease, or death, or to injury to or destruction of tangible property;

(ii) caused by negligent acts or omissions of Norcan or anyone for whose acts Norcan may be liable; and

(iii) made in writing within a period of two years from the date of delivery to the Customer of each Norcan supplied equipment.

The Customer expressly waives the right to indemnity for claims other than those stated above.

The obligations of Norcan to indemnify hereunder shall be limited to an aggregate amount no greater than the amount payable to Norcan under this Contract hereinafter referred to as the "total Contract price".

The Customer shall indemnify and hold harmless Norcan and Norcan's agents and employees from and against claims, demands, losses, costs, damages, actions, suits or proceedings arising out of Norcan's performance of the work under this Contract which are attributable to a lack of or defect in title or an alleged lack of or defect in title to the place where the Norcan supplied equipment is delivered and, or installed.

Force Majeure

Any delay or failure in the performance by Norcan hereunder shall be excused and no liability whatsoever will rest with Norcan where such delay or failure is caused by Force Majeure. For the purposes of this Agreement, Force Majeure shall mean an event or cause beyond Norcan's control and shall include, but is not limited to, acts of God, riots, wars, insurrection, acts of public enemy, sabotage, terrorism, vandalism, embargo, national emergency, accident, restraint of government, governmental acts, fires, floods and other natural disasters, explosions, severe weather including hurricanes and storms, injunctions, labour strikes or inability to obtain required labour, materials or manufacturing facilities from normal sources, acts of a customer and/or owner, wrecks or delays in transportation.

Warranty

The warranty period with respect to this Contract terminates on a date which is the sooner of:

(i) that day which is 12 months from the completion of the initial test runs of the installed Norcan equipment; and,

(ii) that day which is 18 months from the date of delivery of the Norcan supplied equipment.

Norcan shall be responsible for the proper performance of its work and for the work of those for whose acts Norcan may be liable to the extent that this Contract and related documents permits such performance, save that it is understood and agreed that:

(i) Norcan accepts no liability for the design of civil works, intake and trash racks, powerhouse or foundation stability, tail race or other associated water passages or for work improperly done by others, nor does Norcan accept liability for lack of or errors in water availability, flow duration studies or the condition of the water flowing into the turbine. Furthermore,

Norcan does not accept liability for damage to the turbine components due to debris (rock metal, lumber, etc.) passing through the turbine intake;

(ii) Norcan shall not be liable to remedy defects or deficiencies which have arisen as a result of the acts or omissions of those over whom Norcan does not exercise control;

(iii) This warranty is void and unenforceable unless Norcan is afforded the opportunity to complete a final inspection of the completed work within **14** (fourteen) days of installation of the Norcan supplied equipment.

Subject to the provisions of this clause Norcan shall correct promptly, at Norcan's expense, defects and deficiencies in its work which appear prior to and during the warranty period specified herein.

The Customer shall promptly give Norcan notice in writing of observed defects and deficiencies that occurred during the warranty period and Norcan shall be immediately afforded the opportunity to inspect and observe the alleged defects and deficiencies.

Where Norcan fails to correct defects or deficiencies brought to its attention for which it would otherwise be liable, it shall be liable to the Customer to pay for the reasonable costs incurred by the Customer in correcting such defects or deficiencies.

It is understood and agreed that Norcan's liability under this warranty is limited to an aggregate amount which shall not exceed 10 percent (10%) of the total Contract price.

Damages

It is agreed and understood that should turbine performance be within three percent (3%) of anticipated output, such shall not be considered a defect or deficiency in the work of Norcan and for the purposes of this Contract shall be

considered to be an acceptable outcome of the performance of the work by Norcan.

Norcan shall in no event be responsible for damages for loss of profit and other punitive, exemplary, indirect, consequential or special losses or damages, whether in contract or in tort or otherwise, including, without limitation, any business or commercial losses.

To the extent that Norcan is liable for damages as a result of the performance of its work or the performance of the work by those for whom it is liable, such damages shall not exceed, in the aggregate, an amount equal to 10 percent (10%) of the total Contract price.

The above is understood and agreed to by the following:

Signed and sealed this _____ day of _____ 20____.

In the presence of:

(Seal) (Seal)

NORCAN Hydraulic Turbine Inc.

6.0 NORCAN HYDRUALIC TURBINE INC. DIEM RATES AND TERMS.

(for the period of January 01, 2015 to December 31, 2015)

Description	Regular Rate per hour	Overtime per hour	Double time per hour
Turbine Engineering Technician	**$95.00**	**$125.00**	**$155.00**
Supervisor	**$95.00**	**$125.00**	**$155.00**
Turbine mechanic millwright	**$80.00**	**$120.00**	**$140.00**
Engineer	**$160.00**	**$210.00**	**$260.00**
Travel rate	**$60.00**	**$75.00**	**$75.00**
Drafting & Project Management	**$80.00**	**$120.00**	**$140.00**
Shop Machining (CNC)	**$105.00**	**$140.00**	**$170.00**
Shop General Machining	**$75.00**	**$110.00**	**$130.00**
Welder	**$75.00**	**$110.00**	**$130.00**
General Labour	**$55.00**	**$72.00**	**$88.00**
Field Machining: Rates as per equipment requirements			

Note: The above rates are for normal 8 hour days, Monday to Friday (Normal working hours are between 7:00 am to 6:00 pm. A 15% premium will apply to hours outside the normal hours)

Saturday - overtime for first 8 hours - double time
Sunday - double time
Statutory holidays - 2.5 * regular rate

Parts and materials **at cost plus 15%**

Meals & Accommodation	**$180.00 per day**
Mileage	**85¢ per Km**

General Terms:

1. Daily rates apply from the time the Norcan personnel leave the Office/Shop until their return to the Office/Shop. Should the Norcan personnel start from, return to, or proceed to a point other
than the office/shop, charges for travel expenses and per diem rates shall not exceed charges that normally would have been incurred from or to the Office/Shop. Travel time will be charged at the specific base rates for up to a maximum of "8" hours per day for each day
of travel.

2. Standby time: The time during which Norcan personnel are available for work, but are unable to do so because of circumstances beyond Norcan's control shall be considered as standby time and billing will be made as follows:
- At full applicable charges plus expenses for any weekdays (whether at site or not) and for any weekend days or holidays when the Norcan personnel is kept on standby at the jobsite or put on call off-site.

3. Unless otherwise specified and negotiated during the contract, weekdays, weekend, and holidays are defined as follows:
- Weekdays: Monday through Friday, working days
- Weekends: Saturday through Sunday
- Holidays: All recognized days that are celebrated in Canada
- A Workday is classified as an 8 hour day

4. For out of country work, the weekdays, weekends and holidays must be specified and agreed to during contract negotiation.

5. No additional charges will be made for the use of expendable small tools and test equipment normally carried by Norcan personnel. However, when additional expendable tools or hardware must be purchased for a particular job, then the charge for such tools or hardware will be billed to the customer at cost plus a 15% processing fee.

6. When special equipment is required a rental fee will be charged depending on the type of equipment and the length of time required. The customer will be billed for all special transportation costs plus a 15% processing fee. The customer is responsible for the safe storage at site, the timely return, and overall condition and function of said special equipment.

7. Subcontractors: Labour and material supplied through Norcan will be billed at cost plus a 15% processing fee.

8. The customer shall provide Norcan personnel with free and unobstructed access to the jobsite.

9. The customer shall provide safe and proper working conditions in accordance with all federal, provincial and local laws, rules and regulations.

10. The customer shall provide suitable required power, washroom facilities, and safe storage space for Norcan's equipment.

11. All oil, grease, water, and normal operating items required for the operation of the equipment will be provided by the customer. Disposal of above components is the responsibility of the customer.

12. All required permits and monitoring equipment are the responsibility of the customer

13. Technical Advisory Services:
These terms and conditions shall apply to Norcan's Technical Advisory Services incidental to the installation, overhaul, inspection, repair, modification or conversion of equipment which is located at the customers and/or owners location. Norcan's Technical Advisory Services function exclusively in an advisory capacity. The equipment, machinery and property shall be at all times in complete care, custody and control of the customer and/or owner. The buyer and/or customer will furnish qualified labour and supervisory personal to perform the required work.

14. Force Majeure:
Any delay or failure in the performance by Norcan hereunder shall be excused and no liability whatsoever will rest with Norcan where such delay or failure is caused by Force Majeure. For the purposes of this Agreement, Force Majeure shall mean an event or cause beyond Norcan's control and shall include, but is not limited to, acts of God, riots, wars, insurrection, acts of public enemy, sabotage, terrorism, vandalism, embargo, national emergency, accident, restraint of government, governmental acts, fires, floods and other natural disasters, explosions, severe weather including hurricanes and storms, injunctions, labour strikes or inability to obtain required labour, materials or manufacturing facilities from normal sources, acts of a customer and/or owner, wrecks or delays in transportation.

15. Limitation of Liability:
The remedies of the customer set forth herein are exclusive. The total liability of Norcan with respect to all claims under said services and contract, whether based on the services, contract, indemnity, tort, strict liability, or otherwise shall not exceed the purchase price of the services upon which such liability is based. Norcan shall in no event be liable for any consequential, incidental, or indirect damages arising out of said services (and the performance thereof) or out of any breach thereof, whether or not such loss or damage is based on the services, contract, indemnity, tort, strict liability, or otherwise.

APPENDIX C

ENERGY BENEFIT ANALYSIS

KGS GROUP CONSULTING ENGINEERS

MEMORANDUM

TO: **Dave Brown, P. Eng.**
Joel Lambert, P. Eng.

FROM: **Junying Qu, Ph.D., P. Eng.**
David Hinton, P. Eng.

DATE: **September 10, 2015**

FILE NO: **14-1404-04**

RE: **Aishihik Turbines Uprate Study – Energy Benefits Analysis**

1.0 INTRODUCTION

KGS Group was retained by Yukon Energy Corporation (YEC) to conduct a study into the potential upgrade options of the turbine runners on AH1 and AH2 at the Aishihik Generating Station (AGS). Alstom Power and Norcan Hydraulic Turbine Inc. provided the information for new runners that could be used for the potential upgrades of AH1 and AH2. These vendors will be referred to as Alstom and Norcan hereafter.

To help assess the benefits for the potential upgrades of AH1 and/or AH2 and compare the Alstom and Norcan proposed configurations, a hydro energy benefits analysis was conducted for the following seven scenarios using the YECSIM model.

- Existing condition
- Potential upgrades of AH1 only using the runners provided by Alstom
- Potential upgrades of AH1 only using the runners provided by Norcan
- Potential upgrades of AH2 only using the runners provided by Alstom
- Potential upgrades of AH2 only using the runners provided by Norcan
- Potential upgrades of both AH1 and AH2 using the runners provided by Alstom
- Potential upgrades of both AH1 and AH2 using the runners provided by Norcan

The YECSIM software is a detailed integrated power/water flow model operating on a weekly time step developed by KGS Group for YEC. It can be used for analysis of the operation and future expansion of the YEC electrical generating system including WAF (Whitehorse-Aishihik-Faro) and MD (Mayo-Dawson) systems. This model includes all assumed loads and load profiles, operating characteristics of each system power facility (e.g., unit efficiencies), licensed parameters for each plant as approved or proposed, and desired operating parameters for the system (such as reducing line losses or voltage stability) as well as the hydrological conditions. More information about the model can be found in the YECSIM User's Manual (Ref. 1).

This memorandum documents the detailed of energy benefits analysis for the potential upgrades of AH1 and/or AH2 at AGS.

2.0 TURBINE EFFICIENCY CURVES

For the energy benefits analysis using YECSIM model, the first step is to develop a combined turbine and generator efficiency curve for the entire power plant including AH1, AH2 and AH3 at the AGS for each of those scenarios.

The AGS consists of 3 turbines, including two 15 MW vertical Francis turbines installed originally in 1972 (AH1 and AH2), and a third 7 MW horizontal Francis turbine installed in 2011 (AH3). The two units AH1 and AH2 are very similar mechanically, except AH2 has a greater electrical capacity due to a rewind of the generator in 2006 (Ref. 2). Table 1 shows the unit efficiencies, including both turbine and generator efficiencies for AH1 based on the tests carried out on AH1 by Hatch in 2009 (Ref. 2). The existing AH2 operates similarly to AH1, and is assumed to be equal for this study. Table 2 shows the unit efficiencies for AH3 provided by YEC.

TABLE 1
CALCULATED UNIT EFFICIENCIES FOR THE EXISTING AH1

Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency
2000	1.99	54.62	6700	4.61	79.229	11400	7.19	86.85
2100	2.04	55.71	6800	4.66	79.491	11500	7.25	86.93
2200	2.10	56.75	6900	4.72	79.749	11600	7.31	87.01
2300	2.16	57.74	7000	4.77	80.001	11700	7.36	87.08
2400	2.22	58.69	7100	4.82	80.249	11800	7.42	87.16
2500	2.27	59.60	7200	4.88	80.492	11900	7.48	87.23
2600	2.33	60.47	7300	4.93	80.730	12000	7.53	87.30
2700	2.39	61.31	7400	4.98	80.963	12100	7.59	87.37
2800	2.45	62.10	7500	5.04	81.192	12200	7.65	87.43
2900	2.50	62.87	7600	5.09	81.416	12300	7.70	87.50
3000	2.56	63.60	7700	5.15	81.635	12400	7.76	87.56
3100	2.62	64.31	7800	5.20	81.850	12500	7.82	87.62
3200	2.68	64.98	7900	5.25	82.060	12600	7.88	87.68
3300	2.74	65.63	8000	5.31	82.265	12700	7.93	87.73
3400	2.79	66.26	8100	5.36	82.466	12800	7.99	87.79
3500	2.85	66.86	8200	5.42	82.662	12900	8.05	87.84
3600	2.91	67.44	8300	5.47	82.854	13000	8.11	87.88
3700	2.97	68.00	8400	5.52	83.041	13100	8.17	87.93
3800	3.02	68.54	8500	5.58	83.224	13200	8.23	87.97
3900	3.08	69.07	8600	5.63	83.403	13300	8.29	88.01
4000	3.14	69.57	8700	5.69	83.577	13400	8.35	88.04
4100	3.19	70.06	8800	5.74	83.746	13500	8.41	88.07
4200	3.25	70.54	8900	5.80	83.912	13600	8.47	88.10
4300	3.31	71.00	9000	5.85	84.073	13700	8.53	88.12
4400	3.36	71.44	9100	5.91	84.229	13800	8.59	88.14
4500	3.42	71.88	9200	5.96	84.382	13900	8.65	88.14
4600	3.47	72.30	9300	6.02	84.531	14000	8.72	88.15
4700	3.53	72.71	9400	6.07	84.675	14100	8.78	88.14
4800	3.58	73.11	9500	6.13	84.816	14200	8.85	88.13

Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency
4900	3.64	73.50	9600	6.18	84.952	14300	8.91	88.11
5000	3.69	73.88	9700	6.24	85.085	14400	8.98	88.08
5100	3.75	74.25	9800	6.30	85.214	14500	9.05	88.04
5200	3.80	74.61	9900	6.35	85.340	14600	9.12	87.99
5300	3.86	74.97	10000	6.41	85.462	14700	9.19	87.92
5400	3.91	75.31	10100	6.46	85.580	14800	9.26	87.85
5500	3.97	75.65	10200	6.52	85.695	14900	9.34	87.76
5600	4.02	75.98	10300	6.57	85.807	15000	9.42	87.65
5700	4.07	76.31	10400	6.63	85.916	15100	9.49	87.53
5800	4.13	76.63	10500	6.69	86.021	15200	9.57	87.39
5900	4.18	76.94	10600	6.74	86.124	15300	9.65	87.22
6000	4.23	77.24	10700	6.80	86.223	15400	9.74	87.04
6100	4.29	77.54	10800	6.86	86.320	15500	9.83	86.84
6200	4.34	77.84	10900	6.91	86.415	15600	9.91	86.61
6300	4.40	78.13	11000	6.97	86.506	15700	10.01	86.35
6400	4.45	78.41	11100	7.02	86.595	15800	10.10	86.07
6500	4.50	78.69	11200	7.08	86.682	15900	10.20	85.76
6600	4.56	78.96	11300	7.14	86.766	16000	10.30	85.41

Notes: Unit efficiencies include both Turbine and Generator efficiencies.

TABLE 2
CALCULATED UNIT EFFICIENCIES FOR THE EXISTING AH3

Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency
0	0.00	0.000	3600	2.34	0.839
100	0.36	0.152	3700	2.39	0.842
200	0.41	0.262	3800	2.45	0.844
300	0.47	0.346	3900	2.51	0.847
400	0.53	0.412	4000	2.56	0.850
500	0.58	0.465	4100	2.62	0.852
600	0.64	0.509	4200	2.68	0.855
700	0.70	0.546	4300	2.73	0.857
800	0.75	0.577	4400	2.79	0.859
900	0.81	0.604	4500	2.85	0.861
1000	0.87	0.627	4600	2.90	0.863
1100	0.92	0.647	4700	2.96	0.865
1200	0.98	0.666	4800	3.02	0.867
1300	1.04	0.682	4900	3.07	0.869
1400	1.09	0.696	5000	3.13	0.871
1500	1.15	0.709	5100	3.19	0.873
1600	1.21	0.721	5200	3.24	0.874
1700	1.26	0.732	5300	3.30	0.876
1800	1.32	0.742	5400	3.36	0.877
1900	1.38	0.751	5500	3.41	0.879
2000	1.43	0.759	5600	3.47	0.880
2100	1.49	0.767	5700	3.53	0.882
2200	1.55	0.774	5800	3.58	0.883

Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency
2300	1.60	0.781	5900	3.64	0.884
2400	1.66	0.787	6000	3.69	0.886
2500	1.72	0.793	6100	3.75	0.887
2600	1.77	0.798	6200	3.81	0.888
2700	1.83	0.803	6300	3.86	0.889
2800	1.88	0.808	6400	3.92	0.890
2900	1.94	0.813	6500	3.98	0.892
3000	2.00	0.817	6600	4.03	0.893
3100	2.05	0.821	6700	4.09	0.894
3200	2.11	0.825	6800	4.15	0.895
3300	2.17	0.829	6900	4.20	0.896
3400	2.22	0.832	7000	4.26	0.897
3500	2.28	0.835			

Notes: Unit efficiencies include both Turbine and Generator efficiencies.

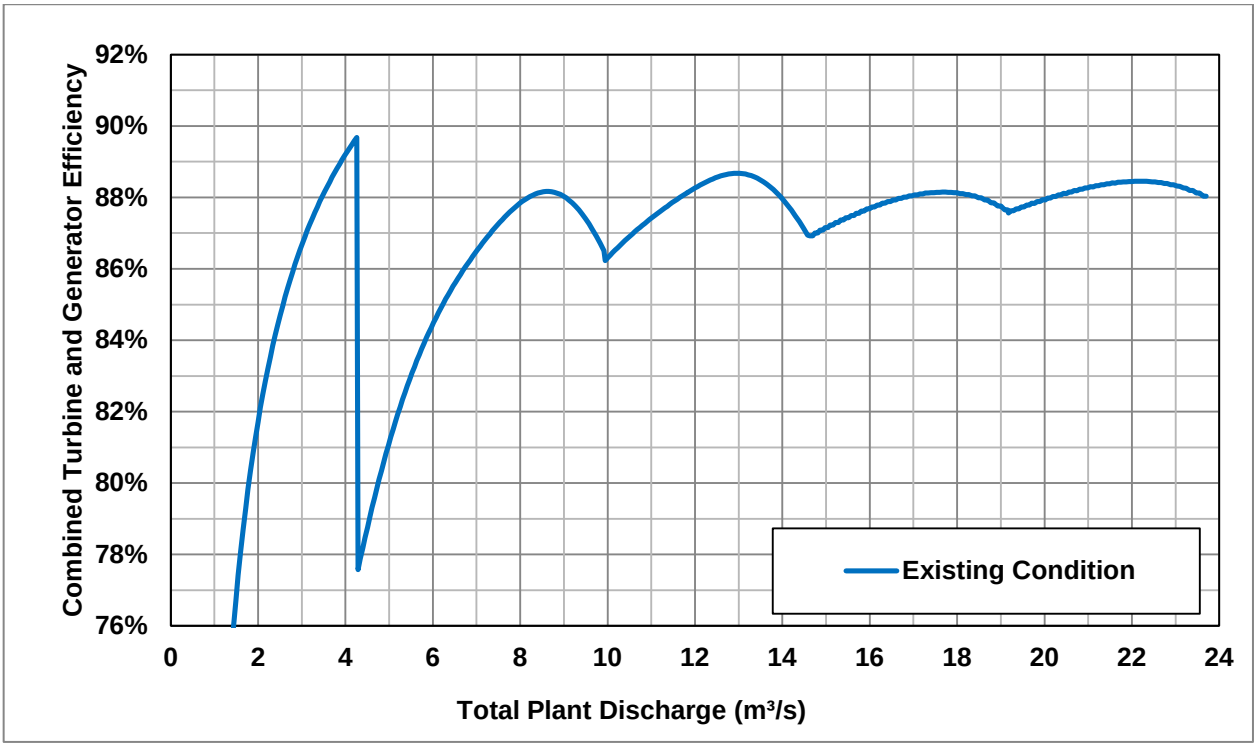
The best estimate optimized operation of AGS was determined based on the existing and proposed turbine characteristics provided by YEC. The plant was assumed to operate the most efficient combination of units for a given flow. To calculate plant output, typical net head was taken from Hatch's 2009 unit efficiency table according to Equation 1 (Ref. 3). This equation approximates net head as a function of plant output to account for increased tailwater level and headlosses with increased output.

$$Equation\ 1: \quad H_N = 187.91 - 0.12824P - 0.0012505P^2$$

Here H_N represents the net water head (m) and P represents the power output from the plant (W).

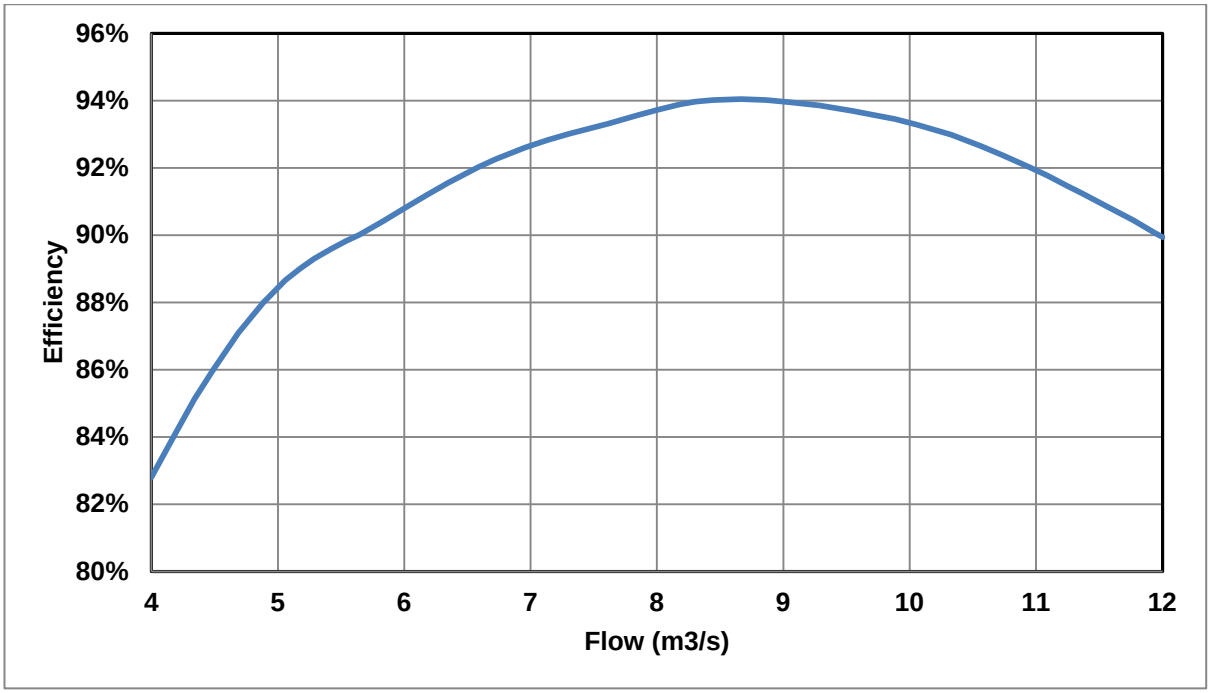
The combined turbine and generator efficiency curve for the entire existing 3 units at AGS were developed as shown in Figure 1.

FIGURE 1
COMBINED EFFICIENCY CURVE FOR EXISTING CONDITIONS



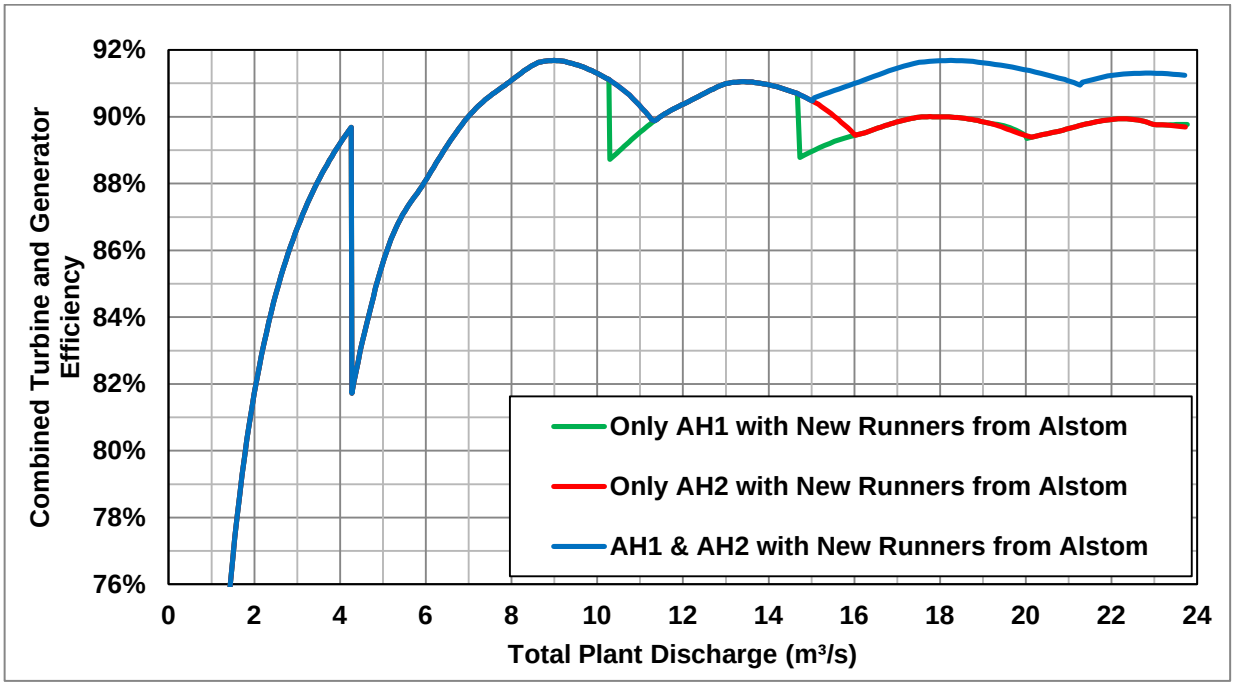
Alstom provided a preliminary performance curve for the proposed upgraded turbines as shown in Figure 2 (Ref. 3). The curve represents the best estimate efficiency at a constant head of 180.4 m but is subject to further study such as the analysis of the existing spiral casing, distributor and the draft tube. This efficiency curve was used in the model to calculate energy production using Equation 1 to approximate net head at given plant outputs.

FIGURE 2
ALSTOM EXPECTED PERFORMANCE FOR HNET = 180.4 M



A generator efficiency of 97.5% was assumed for AH1 and/or AH2 based on experience with similar generators. The AH2 generator is rated at 19,200 kVA and the AH1 generator is rated at 17,000 kVA. For the purpose of this study, a power factor of 1.0 was assumed to estimate plant operation. The developed efficiency curves for replacing AH1 and/or AH2 using Alstom runners are shown in Figure 3.

FIGURE 3
COMBINED EFFICIENCY CURVES FOR UPGRADES OF AH1 AND/OR AH2 USING ALSTOM RUNNERS



Similar to the development of efficiency curves for the upgrades using Alstom turbines, Norcan provided a preliminary performance curve for their proposed upgraded turbine as shown in Figure 4 (Ref. 4). The developed combined efficiency curves for replacing AH1 and/or AH2 using Norcan turbines are shown in Figure 5.

FIGURE 4
NORCAN PRELIMINARY PERFORMANCE FOR HNET = 180.4 M

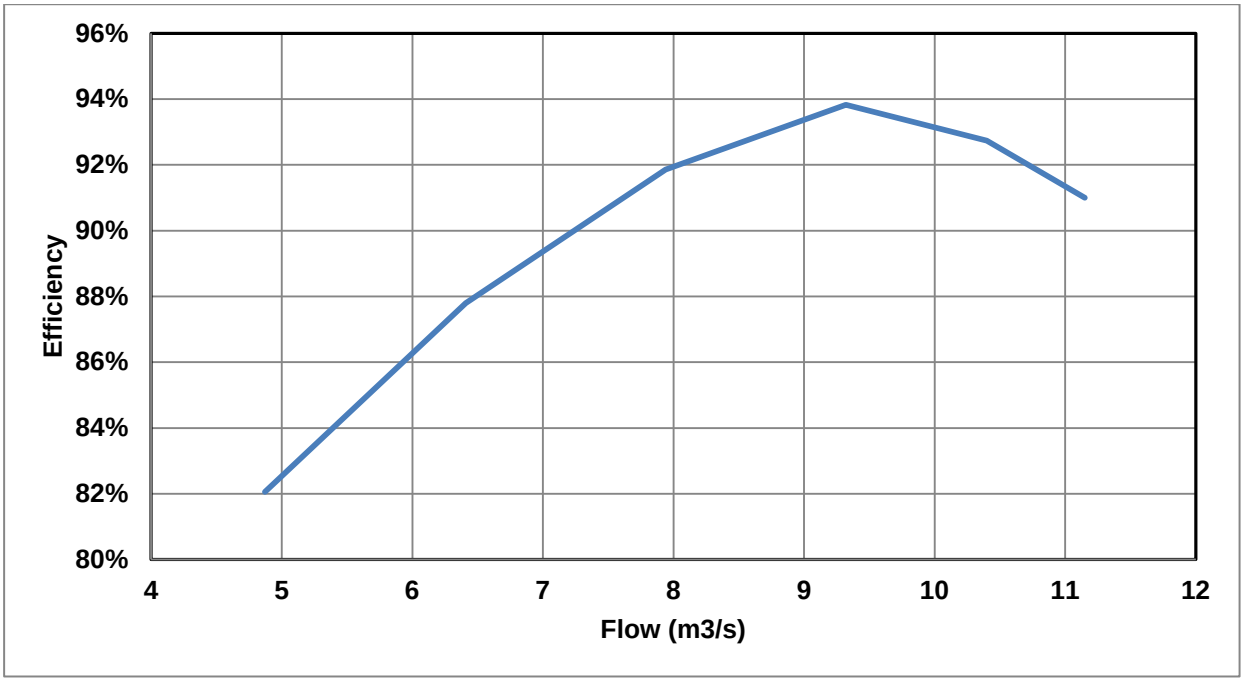
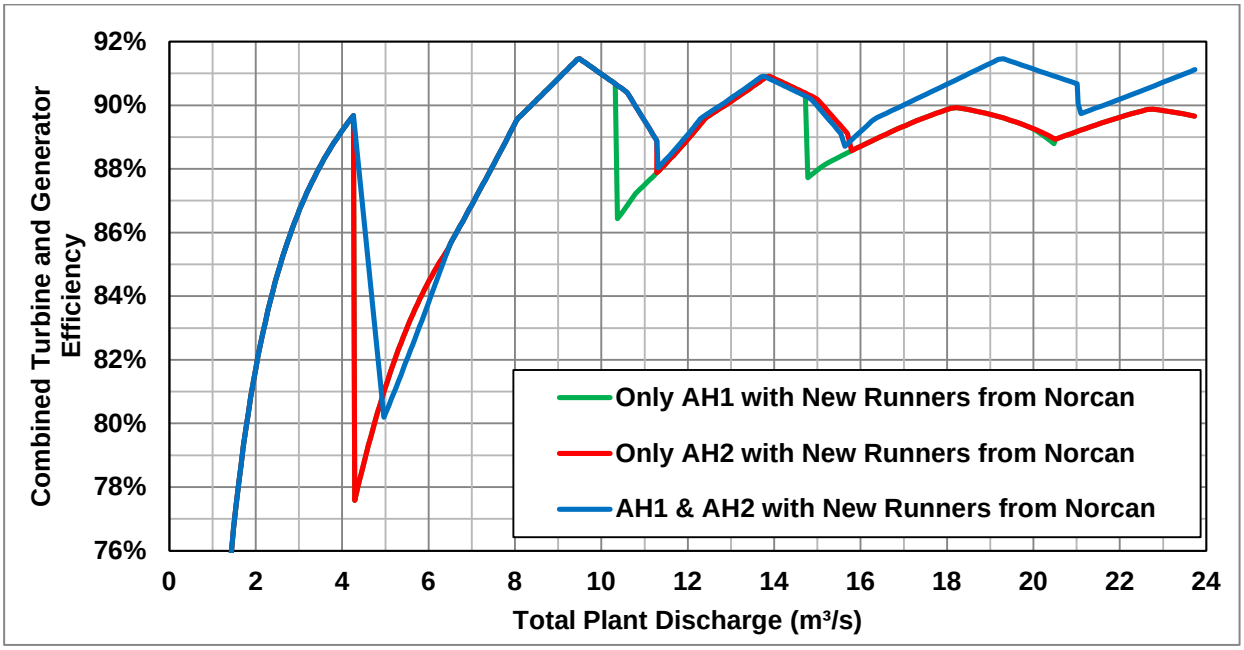


FIGURE 5
COMBINED EFFICIENCY CURVES FOR UPGRADES OF AH1 AND/OR AH2 USING NORCAN RUNNERS



For the purpose of this study, turbine efficiency curves for all three turbines were evaluated for the typical gross head and expected conveyance head losses. Plant operation was optimized for those seven scenarios based on the expected net head. Although the proposed replacement alternatives have higher flow capacity than the existing units, the total plant flow is still limited at the existing 23.7 m³/s, which is the summation of the original turbine capacity for AH1 and AH2 (19.46 m³/s in total) and the turbine capacity for AH3 (4.26 m³/s) based on the data provided by YEC. Without further study, it is not recommended to increase plant flow higher than the existing limit due to the possibility that emergency evacuation through the tailrace tunnel could be compromised, as described in KGS Group's Hydraulic Capacity Memo (Ref. 6).

3.0 THREE-TIER SYSTEM FOR SPECIFICATION OF EFFICIENCY

The 3-tier system for specification of efficiency is required in the YECSIM model to provide a reasonable representation of the range of efficiencies that may occur for the hydro energy generation from a powerhouse on weekly basis. The description of the 3 tiers can be found in the YECSIM User's Manual (Ref.1). The steps to calculate the 3 tiers for the AGS are described below:

- Estimation of the Minimum Flow through the AGS:

  The minimum flow through the powerhouse was estimated to be 2.8 m³/s at the AGS. According to the "Water Use License HY99-011, Correction to Clause 29" published by Yukon Territory Water Board in 2005, the minimum flow downstream of Canyon Pond is to be no less than 2.832 m³/s, including Giltana Creek flows (YECSIM User's Manual - Appendix E - Aishihik). The Water Use Licence HY99-011 - Clause 25 (2000) defines that the minimum flow over Otter Falls, which is located beside the AGS, is 0.142 m³/s from September 22 to April 30, 0.708 m³/s from May 19 to September 7, and 0.425 m³/s in the rest days. Usually the outflows from Aishihik Lake to Canyon Lake are greater than 2.832 m³/s in the spring and summer. Therefore, the flow through the powerhouse can be assumed no less than 2.8 m³/s.

- Calculation of the First Tier Efficiency:

  The first tier refers to a low range of total plant outflows. For the AGS, the low flow range was assumed from 2.8 m³/s to 4.26 m³/s with the operation Unit 3 only. The average energy efficiency of Unit 3 in this flow range is 0.880, which was assumed to be the first tier efficiency. The corresponding discharge for the first tier was defined as 3 m³/s in order to keep consistent with the flow used originally for the first tier in the YECSIM model.

- Calculation of the Second Tier Efficiency:

  The second tier efficiency, which represents the majority of operation wherein the plant outflow is less than the maximum, was estimated to be the average energy efficiency in the flow range from 3 m³/s to the maximum plant flow. The corresponding discharge for the second tier was defined as 6 m³/s in order to keep consistent with the flow used originally for the second tier in the YECSIM model.

- Calculation of the Third Tier Efficiency:

  The third tier efficiency, which represents the operation wherein the plant outflow is at the maximum, was estimated to be the average energy efficiency for the maximum flow and the second maximum flow with all units in operation. The corresponding discharge for the third tier was defined as the maximum allowable turbine flow with all units in operation. As mentioned in the previous section, the maximum plant discharge is limited to 23.7 m³/s.

Table 3 shows the estimated 3-tier systems for specification of efficiency for those seven scenarios including the existing condition and the proposed upgrade options. The coefficients for the first tier are the same for all of the scenarios since only AH3 at Aishihik GS was assumed to be running at the low flow range. For the second tier, the upgrades of both AH1 and AH2 using Alstom turbines provide the highest efficiency value. For the third tier, the upgrades of both AH1 and AH2 using Alstom turbines still provide the highest efficiency value. The efficiencies for all of the upgrade options are higher than the existing condition.

TABLE 3
THREE-TIER SYSTEMS FOR SPECIFICATION OF EFFICIENCY FOR AGS

3-Tier System	Station Flow (m³/s)	3-Tier System for Specification of Efficiency						
		Existing Condition	Turbine Upgrades (Alstom)			Turbine Upgrades (Norcan)		
			AH1 Only	AH2 Only	AH1 and AH2	AH1 Only	AH2 Only	AH1 and AH2
Tier 1	3	0.880	0.880	0.880	0.880	0.880	0.880	0.880
Tier 2	6	0.872	0.896	0.897	0.901	0.882	0.884	0.891
Tier 3	23.7	0.880	0.896	0.897	0.913	0.897	0.897	0.911

4.0 YECSIM MODEL

For the AGS, the new 3-tier system for specification of efficiency for each scenario and the maximum plant discharge (23.7 m³/s) were used in the YECSIM model. Since the maximum plant discharge is less than the plant capacity (approximate 25.5 m³/s for the existing units, 27.8 m³/s with the upgrade of Unit 2 using the Alstom turbine and 26.6 m³/s with the upgrade of Unit 2 using the Norcan turbine), the energy loss coefficient due to force outage at the AGS was assumed to be zero in the YECSIM model. Here the forced outages refer to the outages that occur unpredictably, or result from maintenance activities that exceed the length of time available in low-load periods (Ref.1).

For the input parameters for the other generating stations including Whitehorse GS, Mayo A and Mayo B GSs and the related lakes, the default values provided in the YECSIM model as listed in Appendix D of the YECSIM User's Manual (Ref.1) were used.

Two energy loads (468.1 GWh/year and 575.1 GWh/year) were used, which could reasonably be expected to occur or be surpassed within the future 20 to 30 years starting from 2009 as described in the report for the proposed Mayo Hydro Enhancement Project prepared by YEC (Ref. 2).

The simulation conditions that were used in the YECSIM model for those seven scenarios are summarized below:

- Simulation Period (or Energy Planning Period): 20 years
- Energy Systems: WAF/MD (including Mayo B GS)
- Energy load levels
  - Low Energy Demand: 468.1 GWh/year
  - High Energy Demand: 575.1 GWh/year
- Hydrologic water years from 1987 to 2007
- Water License Limits for Aishihik Lake
  - The minimum water level in a year is no lower than 913 m more than 2 in 5 years
  - The 10-year rolling average minimum water level is no lower than 913.3 m
  - The winter drawdown limit is 1.2 m
- Water License Limits for Mayo Lake
  - The water level difference between the beginning of the winter (Week 39) and the spring next year cannot be more than 2.5 m for 3 years in a row
- Marsh Lake Operation Policy
  - The change in flow from Marsh Lake is limited to +/- 20 m^3/s in the spring
- Operation Policy of Mayo A GS
  - The special turbine efficiencies were applied in the winter
  - The turbine capacity is increased up to 15 m^3/s when spilling water

5.0 PLANT CAPACITY

Incremental capacity represents an important benefit to the proposed turbine upgrade project. Although the proposed turbine capacity may exceed the existing turbine capacity, hydraulic conditions limit the effectiveness of this additional capacity. According to YEC, Aishihik GS is typically run at around 80% plant flow, so any excess turbine capacity requiring additional plant flow may not be realized. Therefore, the evaluation was based on plant capacity at 80% plant flow instead of the individual turbine capacity.

Plant capacity was estimated for each configuration based on the typical plant flow of 19 m^3/s. Net head at plant capacity was calculated using Equation 1. The estimated plant capacities for each proposed plant configuration are shown in Table 4.

TABLE 4
PLANT CAPACITY

Simulation Scenario	Plant Efficiency	Plant Capacity	Incremental Plant Capacity
	(%)	(MW)	(MW)
Existing Condition	87.8	29.8	-
New AH1 - Alstom	89.9	30.5	0.7
New AH1- Norcan	89.7	30.5	0.6
New AH2 - Alstom	89.9	30.5	0.7
New AH2 - Norcan	89.7	30.5	0.6
New AH1 and AH2 - Alstom	91.6	31.1	1.3
New AH1 and AH2 - Norcan	91.3	31.0	1.2

Incremental plant capacity varies depending how many units are upgraded. The selection of a turbine manufacturer is not a significant factor when comparing total plant capacity. Alstom units provide a marginal capacity benefit relative to Norcan units. Upgrading both AH1 and AH2 provides close to double the incremental capacity of upgrading only one unit.

For the purpose of designing electrical components, the plant capacity was evaluated at maximum flow and maximum expected net head using an optimistic estimate of conveyance system losses. For a plant flow of 23.7 m^3/s and net head of 182.2 m, the existing plant capacity is 37.2 MW. Proposed configurations range in capacity from 37.9 MW for the Norcan AH1 replacement to 38.6 MW for the Alstom 2 unit replacement.

6.0 YECSIM MODEL RESULTS

For each run, the results for the first 5 energy load years were abandoned to avoid the effects of the initial lake levels given at the start of the simulation as described in Section 6.1.4 in the YECSIM User's Manual (Ref.1). The last load year was also abandoned to avoid the effects of backwards calculation of lake operation rule curves during the YECSIM model simulation. Therefore the weekly average hydro energy generated from the AGS and the WAF + MD system was calculated for the remaining 14 energy load years. Then the annual hydro energy generated from the AGS or the WAF + MD system is the sum of the energy generated in 52 weeks of a year. Table 5 shows the model results at the low energy load level of 468.1 GWh/year and Table 6 shows the model results at the high energy load level of 575.1 GWh/year. Usually, the energy benefits to the WAF/MD system are of more interest than the energy benefits to the AGS itself. Here only the energy benefits to the system are discussed.

TABLE 5
ENERGY BENEFITS FOR AGS UPGRADES AT LOW ENERGY DEMAND

Simulation Scenario	Energy Generated at AGS	Total Hydro Energy Generated in the WAF/MD System	Net Energy Benefit to AGS	Net Energy Benefit to the WAF/MD System
	(GWh/Year)	(GWh/Year)	(GWh/Year)	(GWh/Year)
Existing Condition	114.30	429.05	-	-
New AH1 - Alstom	116.75	431.31	2.45	2.26
New AH1 - Norcan	115.34	430.01	1.05	0.96
New AH2 - Alstom	116.85	431.40	2.55	2.35
New AH2- Norcan	115.55	430.20	1.25	1.14
New AH1 and AH2 - Alstom	117.28	431.79	2.98	2.74
New AH1 and AH2 - Norcan	116.29	430.86	1.99	1.81

TABLE 6
ENERGY BENEFITS FOR AISHIHIK GS UPGRADES AT HIGH ENERGY DEMAND

Simulation Scenario	Energy Generated at AGS	Total Hydro Energy Generated in the WAF+MD System	Net Energy Benefit to AGS	Net Energy Benefit to the WAF+MD System
	(GWh/Year)	(GWh/Year)	(GWh/Year)	(GWh/Year)
Existing Condition	118.86	451.01	-	-
New AH1 - Alstom	121.27	453.20	2.41	2.19
New AH1 - Norcan	120.27	452.28	1.41	1.27
New AH2 - Alstom	121.34	453.26	2.47	2.25
New AH2- Norcan	120.41	452.41	1.55	1.40
New AH1 and AH2 - Alstom	122.17	454.05	3.31	3.04
New AH1 and AH2 - Norcan	121.45	453.38	2.58	2.37

As shown in Tables 5 and 6, the net energy contributions to the system with the upgrades using Alstom runners are always higher than the ones with the upgrades using Norcan runners at both the low energy demand and the high energy demand for the upgrades of AH1 and/or AH2 at AGS. The net energy benefits for the upgrades of AH2 are slightly higher than the benefits for the upgrades of AH1 because AH2 has a greater electrical capacity due to a rewind of the

generator in 2006. The net energy benefits for the upgrades of both AH1 and AH2 are higher than those for the upgrades of either AH1 or AH2 only.

Based on the net energy contributions provided in Tables 5 and 6, economic analysis related to the monetary values of energy benefits, capital costs and payback calculations becomes possible to assess the benefit values for the potential upgrades of AH1 and/or AH2 and choose a preferred turbine runner between Alstom and Norcan.

7.0 DISCUSSIONS AND CONCLUSIONS

Based on the energy benefits analysis, the following conclusions are made,

- For the upgrades of AH1 only, using Alstom runners would generate energy benefit from 2.19 GWh/year to 2.26 GWh/year to the system, while using Norcan runners would generate energy benefit from 0.96 GWh/year to 1.27 GWh/year to the system.
- For the upgrades of AH2 only, using Alstom runners would generate energy benefit from 2.25 GWh/year to 2.35 GWh/year to the system, while using Norcan runners would generate energy benefit from 1.14 GWh/year to 1.40 GWh/year to the system. The energy benefit for the upgrades of AH2 only is slightly higher than the one for the upgrade of AH1 only.
- For the upgrades of both AH1 and AH2, using Alstom runners would generate energy benefit from 2.74 GWh/year to 3.04 GWh/year to the system, while using Norcan runners would generate energy benefit from 1.81 GWh/year to 2.37 GWh/year to the system. The energy benefit for the upgrades of both AH1 and AH2 are higher than the one for the upgrades of either AH1 or AH2.

8.0 REFERENCES

1. Yukon Energy Corporation, “User Manual for YEC System Simulation Software (draft)”, September 2011.
2. Hatch, “Aishihik Turbine Peformance Test: Performance Test Results”, December 11, 2009.
3. Alstom, “Potential Runner Upgrade Request for Information 14-1404-004”, March 10, 2015.
4. Norcan Hydraulic Turbine Inc, “Budget quote for the manufacturing of one (1) replacement Francis Runner for Aishihik Generating Station”, March 9, 2015.
5. Yukon Energy Corporation, “Application for an Energy Project Certificate and an Energy Operation Certificate”, December 2009.

6. KGS Group, "Aishihik Rerate and Assessment Hydraulic Capacity Review", May 15, 2015.

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APPENDIX D

EXCITATION SYSTEM ASSESSMENT

KGS GROUP CONSULTING ENGINEERS

MEMORANDUM

TO: **JOEL LAMBERT**

CC:

FROM: **MONISH BHOWMIK**

DATED: **SEPTEMBER 18, 2015**

PROJECT NO: **14-1404-004**

RE: **AISHIHIK TURBINE UPGRADE - EXISTING EXCITATION CAPABILITIES**

1.0 BACKGROUND

Yukon Energy Corp. is currently considering a project to upgrade the turbine runner capacity to obtain uprated power from the existing Aishihik Unit 2. The Aishihik Unit 2 generator is equipped with a DC exciter and controlled by SR125E Basler AVR. Through a rewind project which was undertaken in 2006 the electrical capability of the generator was upgraded from 15.6 MVA to 19.2 MVA at 0.9 power factor. During the rewind project the unit was tested up to 16.5 MW as the available maximum mechanical power of the turbine is limited to 16.5 MW. As a part of the rewind project the generator rotor field poles were reinsulated, however, the DC exciter was not upgraded.

This memorandum is prepared to verify the capability of the existing exciter of the AH2 unit to produce 19.2 MVA at 0.9 p.f.

2.0 DOCUMENTS REVIEWED

The following documents were obtained from Yukon Energy Corp. and are used to estimate the exciter requirement for enhanced power:

1. Testing of Synchronous Unit Reactive Limits and Dynamic Testing/Model Validation for Yukon Energy Corporation, Aishihik Generating Station, prepared by Chaos electric Inc.
2. Aishihik Unit 2 Rewind & Protection Upgrade – 2006, Commissioning Report, Prepared by Ravindra P. Mutukutti, P.Eng.

3.0 FINDINGS

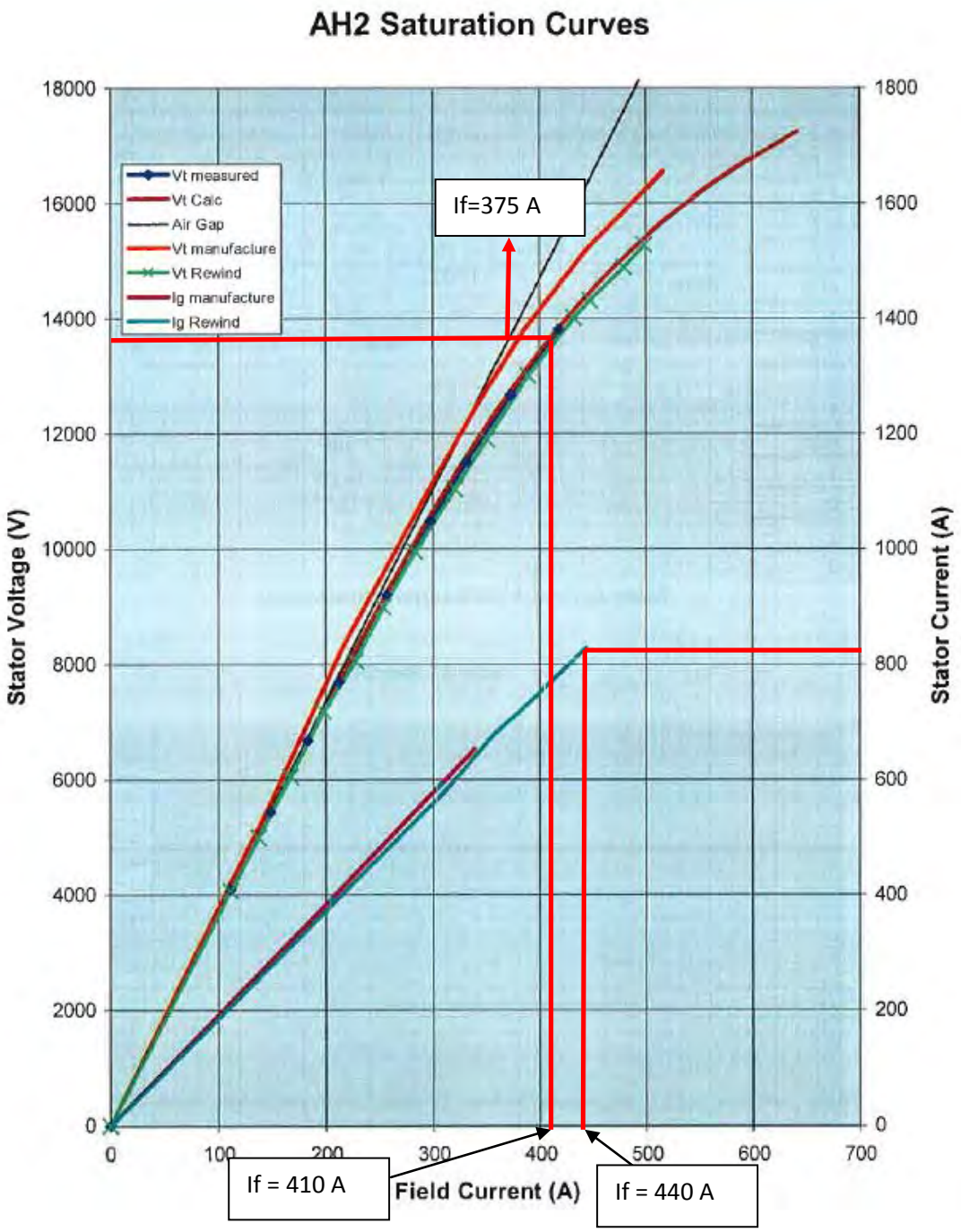
3.1 NAMEPLATE INFORMATION

The table below shows the comparison of the upgraded generator capacity and the DC exciter capacity:

Generator			
Items	**Before Upgrade**	**After Upgrade**	**Remark**
Field Voltage	75 V	75V	Stator rewind &
Field Current	630 A	720A	Rotor pole
Generator MVA	15.6 MVA	19.2 MVA	Re-insulation
Generator output current at rated condition	653 A	803 A	
Generator DC Exciter			
Volts at Full load	35 V	35 V	The DC exciter
Amps at Full Load	670 A	670 A	Was not upraded
KW	57 kW	57 kW	

3.2 OPEN CIRCUIT AND SHORT CIRCUIT SATURATION CURVE

From the review of the open circuit and short circuit saturation curve (Reference 1, Section 4.0) it was found that the field current required to produce the rated air gap line voltage (1 pu), rated open circuit terminal voltage (13.8 kV) and rated short circuit current (SCC test) is respectively 375A, 410A & 442A.

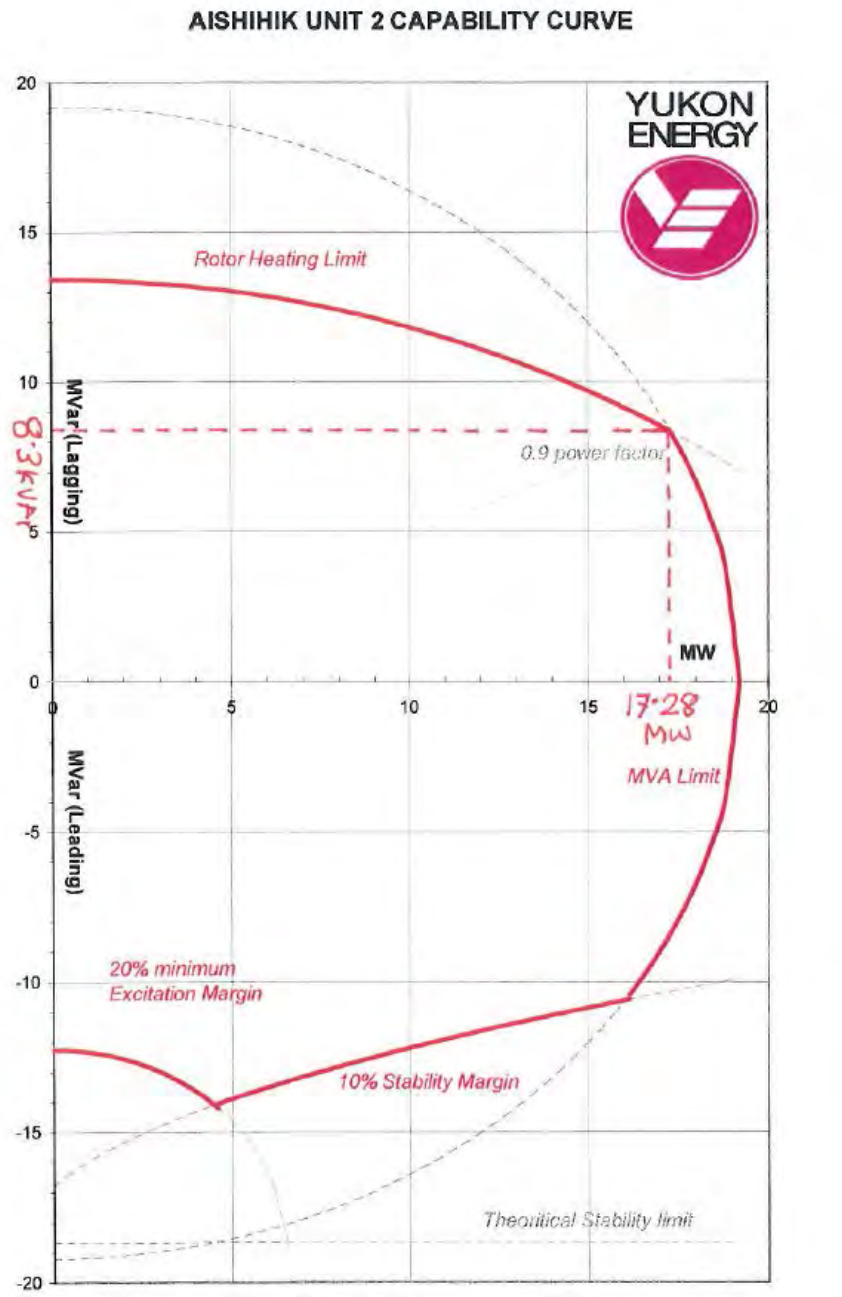


The above mentioned values were validated from the rewind commissioning report, which are provided in the following table:

Generator Short Circuit Condition			Generator Open Circuit Condition		
Field Voltage	**Field Current**	**Stator Current**	**Field Voltage**	**Field Current**	**Stator Voltage**
42 V	442 A	825 A	38 V	410 A	13.8 kV

3.3 GENERATOR CAPABILITY CURVE

The upgraded generator capability curve was reviewed, as provided in the generator rewind commissioning report (Reference 2, Section 2.0). According to the generator capability curve of the rewound, the generator will be able to produce 19.2 MVA at 0.9 power factor at the field voltage of 75 V and 720 A (Reference 1, section 3.2.2).



4.0 CONCLUSION

From the above information the following conclusions can be made:

- According to the rewind machine data provided by Voith-Siemens, to produce the rated power the generator rotor field voltage and field current requirement is 75 V and 720A respectively, while the DC exciter is rated at 670 A.
- The DC exciter will operate beyond its design limit to produce the rated voltage at 19.2 MVA, 0.9 power factor. This will cause rapid aging of the existing DC exciter.
- If Yukon Energy Corp. decides to operate the generator at 19.2 MVA at 0.9 power factor, a discussion with the OEM is requested to validate the impact on the DC exciter due to operation beyond its design ratings.
- If the existing exciter is operated at its maximum rating which is at 670 A, Voith-Siemens should be approached to obtained a new capability curve for the field limit of 670 A.

5.0 RECOMMENDATION

The following two alternatives are recommended related to the Aishihik Unit 2 exciter to accommodate enhanced power:

- **Alternative 1(Preferred):** The existing exciter is replaced with a static exciter to match the generator field requirement. The generator field leads and associated slip rings should be checked so that these are properly rated for enhanced power operation.
- **Alternative 2:** The rotating DC exciter is upgraded to meet the rewounded generator field requirement and the associated AVR should be replaced to meet the requirement of the upgraded exciter. The generator field leads and associated slip rings should be checked so that these are properly rated for enhanced power operation.

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APPENDIX E

BUSINESS CASE CALCULATIONS

E-1 Rerunner Costs

E-2 Capacity and Energy Benefits

E-3 Aishihik Turbine Uprate

E-4 Payback Calculations – 4 Cases:

E-4.1 One Unit (AH2) Upgrate – Low Energy Demand
E-4.2 One Unit (AH2) Uprate – High Energy Demand
E-4.3 Two Unit Uprate – Low Energy Demand
E-4.4 Two Unit Uprate – High Energy Demand

E-5 Payback Calculations, Sensitivity Analysis – 11 Trials:

E-5.0 Trial Parameters (1 – 11)
E-5.1 Trial 1 – Benefit of $1M per MW
E-5.2 Trial 2 – Benefit of $2.5M per MW
E-5.3 Trial 3 – Benefit of $5M per MW
E-5.4 Trial 4 – Benefit of $7.5M per MW
E-5.5 Trial 5 – Benefit of $10M per MW
E-5.6 Trial 6 – 100,000 $/GWh/yr
E-5.7 Trial 7 – 150,000 $/GWh/yr
E-5.8 Trial 8 – 200,000 $/GWh/yr
E-5.9 Trial 9 – 250,000 $/GWh/yr
E-5.10 Trial 10 – 300,000 $/GW/yr
E-5.11 Trial 11 – Capacity Benefit of $1M per MW

Appendix E-1
Rerunner Costs

TURBINE COSTS		
	Norcan	**Alstom**
Runner	$268,033	
Deliver and Install	$205,140	
Coupling Bolts	$8,600	
Blade Templates	$15,500	
Site Work		
a) EHS site analyses		
b) Turbine disassembly		
c) Parts inspections		Items a-f
d) New runner supply & ins tall		$250,000
e) Turbine reassembly		
f) Commissioning		
Engineering Package		
a) Adapt runner profile to Aishihik		Items a-c
b) Drawings for labyrinths		$106,500
c) Commisssioning report		
Replacement Parts		
a) Runner, cone and bolts		$343,500
b) fixed labyrinths		$43,000
Excluded from above (identified by Alstom)		
a) Mob & Demob in case of disruption	Contingency No. 1	Contingency No. 1
c) Damages or delays by others	for all excluded items	for all excluded items
d) Special tools and lifting devices		
e) Confined space tools		
f) Overhead crane services	$100,000	$100,000
g) NDT testing		
h) Absolute turbine efficiency test		
i) Alignment correction work		
j) Machining of TG parts		
k) GST and PST		
Services by Client		
a) Lockout procedures		
b) Maintain road access to site		
c) Roof/Door mods if req'd		
d) Storage Area for Sea-containers		
e) Electrical and Compressed Air Services		
f) Inspection and upgrade of cranes		
g) scaffolding by certified parties		
h) drawings, manuals, etc		
Evaluated cost	$597,273	$843,000
	Norcan	**Alstom**

Appendix E-2
Capacity and Energy Benefits

NET ENERGY CONTRIBUTION FROM PROPOSED RUNNERS

Unit Upgrade Option	Net Energy Contribution Alstom Runners (GWh/year)		Net Energy Contribution Norcan Runners (GWh/year)	
	Low Energy* Demand	High Energy** Demand	Low Energy* Demand	High Energy** Demand
Upgrade of AH1 Only	2.26	2.19	0.96	1.27
Upgrade of AH2 Only	2.35	2.25	1.14	1.40
Upgrade of AH1 and AH2	2.74	3.04	1.81	2.37

BENEFITS

BENEFIT OF INCREASED CAPACITY at 80% GATE	Increase in Capacity MW	Value of Increase in Capacity $ per MW	One Time Benefit
Upgrade AH2	0.7	$2,500,000	$1,750,000
Upgrade AH1 and AH2	1.3	$2,500,000	$3,250,000

BENEFIT OF INCREASED ENERGY FOR LOW ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.35	$200,000	$470,000
Upgrade AH1 and AH2	2.74	$200,000	$548,000

BENEFIT OF INCREASED ENERGY FOR HIGH ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.25	$200,000	$450,000
Upgrade AH1 and AH2	3.04	$200,000	$608,000

Appendix E-3
Aishihik Turbine Uprate

Item	Description / Assumptions	One Unit	Multiplier for 2nd Unit	Two Units
Turbine Uprate - Alstom				
Turbine field work		$250,000	2.0	$500,000
Turbine runner engineering		$106,000	1.3	$137,800
Runner and coupling bolts, supply		$343,000	2.0	$686,000
Fix labyrinths		$43,000	2.0	$86,000
Extra to T/G Vendor scope Work				$0
Performance / Efficiency Test		$125,000	1.0	$125,000
Crane operator and station operator	240 hours x $200/hr	$48,000	2.0	$96,000
Drawings, manuals, etc		$5,000	1.3	$6,500
Generator Surface Air Coolers		$50,000	2.0	$100,000
Excitation System Uprate, AH2 only		$750,000	1.0	$750,000
Replace cable from AH2 to Cct Brkr.		$150,000	1.0	$150,000
Replace cables from S167 to T1 & T2	Under review.	$150,000	1.0	$150,000
Contingency No. 1*	Repairs, machining	$100,000	2.0	$200,000
Contingency No. 2**	Scaffolding	$50,000	2.0	$100,000
Sub-Total A		$2,170,000		$3,087,300
Engineering support	12% of Sub-Total A	$260,400		$370,476
Sub-Total B		$2,430,400		$3,457,776
Goods and Services Sales Tax	5% of Sub-Total B	$121,520		$172,889
Sub-Total C		$2,291,520		$3,630,665
Contingency No.3***	30% of Sub-Total C	$687,456		$1,089,199
Total of Class 4 Estimate (-30% +50%)		**$2,978,976**		**$4,719,864**
Excluded from this estimate:				
Opportunity Work	Other Work:			
Turbine, generator, intake gates,	Camp services			
Turbine inlet valve	YEC engineering			
Distribution Pipe repairs	Project management			
Power cables and switchgear				
Generator Breaker				
Unit step-up transformer				
Controls and Protection				

* Contingency No. 1 accounts for unforeseen items that may need to be repaired when unit is dismantled.
** Contingency: No. 2 accounts for scaffolding, if required, at Owner's responsibility
***Contingency No. 3 accounts for unforeseen scope of work and changing market conditions.

Appendix E - 4.1

Discounted and Simple Payback Analysis

Project One Unit (AH2) Uprate
Low Energy Demand

Date 17-Sep-15

Capital Cost -$2,978,976
Discount Rate 7.2%

Simple Payback: ***5*** years
Discounted Payback: ***6*** years

Base Year 2016
In-service Year 2018

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019		$470,000	$470,000	-$758,976	3	$381,303	-$810,691	3
2020		$470,000	$470,000	-$288,976	4	$355,627	-$455,064	4
2021		$470,000	$470,000	$181,024	5	$331,680	-$123,385	5
2022		$470,000	$470,000	$651,024	6	$309,345	$185,960	6
2023		$470,000	$470,000	$1,121,024	7	$288,514	$474,474	7
2024		$470,000	$470,000	$1,591,024	8	$269,086	$743,561	8
2025		$470,000	$470,000	$2,061,024	9	$250,966	$994,527	9
2026		$470,000	$470,000	$2,531,024	10	$234,067	$1,228,594	10
2027		$470,000	$470,000	$3,001,024	11	$218,305	$1,446,899	11
2028		$470,000	$470,000	$3,471,024	12	$203,605	$1,650,504	12
2029		$470,000	$470,000	$3,941,024	13	$189,895	$1,840,398	13
2030		$470,000	$470,000	$4,411,024	14	$177,107	$2,017,506	14
2031		$470,000	$470,000	$4,881,024	15	$165,181	$2,182,687	15
2032		$470,000	$470,000	$5,351,024	16	$154,058	$2,336,745	16
2033		$470,000	$470,000	$5,821,024	17	$143,684	$2,480,430	17
2034		$470,000	$470,000	$6,291,024	18	$134,009	$2,614,438	18
2035		$470,000	$470,000	$6,761,024	19	$124,985	$2,739,423	19
2036		$470,000	$470,000	$7,231,024	20	$116,569	$2,855,992	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in Column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Appendix E - 4.2

Discounted and Simple Payback Analysis

Project One Unit (AH2) Uprate
High Energy Demand

Date 17-Sep-15

Capital Cost -$2,978,976
Discount Rate 7.2%

Simple Payback: ***5*** years
Discounted Payback: ***6*** years

Base Year 2017
In-service Year 2018

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2017	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2018	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2019	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2020		$450,000	$450,000	-$778,976	3	$365,078	-$826,917	3
2021		$450,000	$450,000	-$328,976	4	$340,494	-$486,423	4
2022		$450,000	$450,000	$121,024	5	$317,566	-$168,858	5
2023		$450,000	$450,000	$571,024	6	$296,181	$127,324	6
2024		$450,000	$450,000	$1,021,024	7	$276,237	$403,561	7
2025		$450,000	$450,000	$1,471,024	8	$257,636	$661,197	8
2026		$450,000	$450,000	$1,921,024	9	$240,287	$901,484	9
2027		$450,000	$450,000	$2,371,024	10	$224,107	$1,125,590	10
2028		$450,000	$450,000	$2,821,024	11	$209,016	$1,334,606	11
2029		$450,000	$450,000	$3,271,024	12	$194,941	$1,529,547	12
2030		$450,000	$450,000	$3,721,024	13	$181,814	$1,711,360	13
2031		$450,000	$450,000	$4,171,024	14	$169,571	$1,880,931	14
2032		$450,000	$450,000	$4,621,024	15	$158,152	$2,039,084	15
2033		$450,000	$450,000	$5,071,024	16	$147,503	$2,186,586	16
2034		$450,000	$450,000	$5,521,024	17	$137,570	$2,324,156	17
2035		$450,000	$450,000	$5,971,024	18	$128,306	$2,452,463	18
2036		$450,000	$450,000	$6,421,024	19	$119,666	$2,572,129	19
2037		$450,000	$450,000	$6,871,024	20	$111,608	$2,683,737	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in Column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Appendix E - 4.3

Discounted and Simple Payback Analysis

Project Two Unit Uprate
Low Energy Demand

Date 17-Sep-15

Capital Cost -$4,719,864
Discount Rate 7.2%

Simple Payback: *6* years
Discounted Payback: *7* years

Base Year 2017
In-service Year 2019 & 2020

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2017	-471,986	$0	-$471,986	-$471,986	0	-$471,986	-$471,986	0
2018	-1,415,959	$0	-$1,415,959	-$1,887,946	1	-$1,320,611	-$1,792,598	1
2019	-1,415,959	$0	-$1,415,959	-$1,678,905	2	-$1,231,684	-$1,610,762	2
2020	-1,415,959	$0	-$1,415,959	-$1,195,864	3	-$1,148,744	-$1,218,879	3
2021		$0	$0	-$647,864	4	$0	-$804,233	4
2022		$548,000	$548,000	-$99,864	5	$386,724	-$417,509	5
2023		$548,000	$548,000	$448,136	6	$360,683	-$56,826	6
2024		$548,000	$548,000	$996,136	7	$336,395	$279,570	7
2025		$548,000	$548,000	$1,544,136	8	$313,743	$593,313	8
2026		$548,000	$548,000	$2,092,136	9	$292,616	$885,929	9
2027		$548,000	$548,000	$2,640,136	10	$272,912	$1,158,841	10
2028		$548,000	$548,000	$3,188,136	11	$254,535	$1,413,375	11
2029		$548,000	$548,000	$3,736,136	12	$237,395	$1,650,770	12
2030		$548,000	$548,000	$4,284,136	13	$221,409	$1,872,179	13
2031		$548,000	$548,000	$4,832,136	14	$206,500	$2,078,679	14
2032		$548,000	$548,000	$5,380,136	15	$192,594	$2,271,273	15
2033		$548,000	$548,000	$5,928,136	16	$179,625	$2,450,898	16
2034		$548,000	$548,000	$6,476,136	17	$167,530	$2,618,428	17
2035		$548,000	$548,000	$7,024,136	18	$156,249	$2,774,677	18
2036		$548,000	$548,000	$7,572,136	19	$145,727	$2,920,404	19
2037		$548,000	$548,000	$8,120,136	20	$135,914	$3,056,318	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Appendix E - 4.4

Discounted and Simple Payback Analysis

Project Two Unit Uprate
High Energy Demand

Date 17-Sep-15

Capital Cost -$4,719,864
Discount Rate 7.2%

Simple Payback: ***5*** years
Discounted Payback: ***6*** years

Base Year 2017
In-service Year 2019 & 2020

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2017	-471,986	$0	-$471,986	-$471,986	0	-$471,986	-$471,986	0
2018	-1,415,959	$0	-$1,415,959.27	-$1,887,946	1	-$1,320,611	-$1,792,598	1
2019	-1,415,959	$0	-$1,415,959.27	-$1,678,905	2	-$1,231,684	-$1,610,762	2
2020	-1,415,959	$0	-$1,415,959.27	-$1,165,864	3	-$1,148,744	-$1,194,540	3
2021		$0	$0	-$557,864	4	$0	-$734,495	4
2022		$608,000	$608,000	$50,136	5	$429,066	-$305,429	5
2023		$608,000	$608,000	$658,136	6	$400,174	$94,745	6
2024		$608,000	$608,000	$1,266,136	7	$373,227	$467,972	7
2025		$608,000	$608,000	$1,874,136	8	$348,094	$816,066	8
2026		$608,000	$608,000	$2,482,136	9	$324,654	$1,140,721	9
2027		$608,000	$608,000	$3,090,136	10	$302,793	$1,443,514	10
2028		$608,000	$608,000	$3,698,136	11	$282,403	$1,725,917	11
2029		$608,000	$608,000	$4,306,136	12	$263,387	$1,989,304	12
2030		$608,000	$608,000	$4,914,136	13	$245,651	$2,234,955	13
2031		$608,000	$608,000	$5,522,136	14	$229,109	$2,464,064	14
2032		$608,000	$608,000	$6,130,136	15	$213,681	$2,677,745	15
2033		$608,000	$608,000	$6,738,136	16	$199,292	$2,877,037	16
2034		$608,000	$608,000	$7,346,136	17	$185,872	$3,062,910	17
2035		$608,000	$608,000	$7,954,136	18	$173,356	$3,236,266	18
2036		$608,000	$608,000	$8,562,136	19	$161,683	$3,397,948	19
2037		$608,000	$608,000	$9,170,136	20	$150,795	$3,548,744	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in Column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Appendix E - 5.0

SENSITIVITY ANALYSIS
CAPACITY
TRIAL PARAMETERS

Trial	1	2	3	4	5
Capacity, MW	0.7	0.7	0.7	0.7	0.7
Benefit	$1,000,000	$2,500,000	$5,000,000	$7,500,000	$10,000,000
One time benefit	$700,000	$1,750,000	$3,500,000	$5,250,000	$7,000,000

Trial	6	7	8	9	10
Energy	2.26	2.26	2.26	2.26	2.26
Benefit $/GWh/yr	$100,000	$150,000	$200,000	$250,000	$300,000
Annual benefit	$226,000	$339,000	$452,000	$565,000	$678,000

Trial	11
Capacity Benefit per MW	$1,000,000
Energy Benefit $/GWh/yr	$100,000

Appendix E - 5.1

SENSITIVITY ANALYSIS
CAPACITY
TRIAL 1- Benefit of $1M per MW

Project ***Date*** 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***8***	years	
Discount Rate	7.2%	***Discounted Payback:***	***11***	years	
Base Year	2016				
In-service Year	2018				

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$0	-$1,340,539	-$2,978,976	2	-$1,166,079	-$2,714,246	2
2019	$0	$700,000	$700,000	-$2,278,976	3	$567,898	-$2,146,348	3
2020		$470,000	$470,000	-$1,808,976	4	$355,627	-$1,790,721	4
2021		$470,000	$470,000	-$1,338,976	5	$331,680	-$1,459,041	5
2022		$470,000	$470,000	-$868,976	6	$309,345	-$1,149,696	6
2023		$470,000	$470,000	-$398,976	7	$288,514	-$861,182	7
2024		$470,000	$470,000	$71,024	8	$269,086	-$592,096	8
2025		$470,000	$470,000	$541,024	9	$250,966	-$341,129	9
2026		$470,000	$470,000	$1,011,024	10	$234,067	-$107,063	10
2027		$470,000	$470,000	$1,481,024	11	$218,305	$111,243	11
2028		$470,000	$470,000	$1,951,024	12	$203,605	$314,848	12
2029		$470,000	$470,000	$2,421,024	13	$189,895	$504,742	13
2030		$470,000	$470,000	$2,891,024	14	$177,107	$681,849	14
2031		$470,000	$470,000	$3,361,024	15	$165,181	$847,031	15
2032		$470,000	$470,000	$3,831,024	16	$154,058	$1,001,089	16
2033		$470,000	$470,000	$4,301,024	17	$143,684	$1,144,773	17
2034		$470,000	$470,000	$4,771,024	18	$134,009	$1,278,782	18
2035		$470,000	$470,000	$5,241,024	19	$124,985	$1,403,767	19
2036		$470,000	$470,000	$5,711,024	20	$116,569	$1,520,336	20

Appendix E - 5.2

Project SENSITIVITY ANALYSIS CAPACITY TRIAL 2 - Benefit of $2.5M per MW ***Date*** 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***5***	years	
Discount Rate	7.2%	***Discounted Payback:***	***6***	years	
Base Year	2016				
In-service Year	2018				

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$470,000	$470,000	-$758,976	3	$381,303	-$810,691	3
2020		$470,000	$470,000	-$288,976	4	$355,627	-$455,064	4
2021		$470,000	$470,000	$181,024	5	$331,680	-$123,385	5
2022		$470,000	$470,000	$651,024	6	$309,345	$185,960	6
2023		$470,000	$470,000	$1,121,024	7	$288,514	$474,474	7
2024		$470,000	$470,000	$1,591,024	8	$269,086	$743,561	8
2025		$470,000	$470,000	$2,061,024	9	$250,966	$994,527	9
2026		$470,000	$470,000	$2,531,024	10	$234,067	$1,228,594	10
2027		$470,000	$470,000	$3,001,024	11	$218,305	$1,446,899	11
2028		$470,000	$470,000	$3,471,024	12	$203,605	$1,650,504	12
2029		$470,000	$470,000	$3,941,024	13	$189,895	$1,840,398	13
2030		$470,000	$470,000	$4,411,024	14	$177,107	$2,017,506	14
2031		$470,000	$470,000	$4,881,024	15	$165,181	$2,182,687	15
2032		$470,000	$470,000	$5,351,024	16	$154,058	$2,336,745	16
2033		$470,000	$470,000	$5,821,024	17	$143,684	$2,480,430	17
2034		$470,000	$470,000	$6,291,024	18	$134,009	$2,614,438	18
2035		$470,000	$470,000	$6,761,024	19	$124,985	$2,739,423	19
2036		$470,000	$470,000	$7,231,024	20	$116,569	$2,855,992	20

Appendix E - 5.3

Project SENSITIVITY ANALYSIS CAPACITY TRIAL 3- Benefit of $5M per MW

Date 17-Sep-15

Capital Cost -$2,978,976
Discount Rate 7.2%

Simple Payback: *2* years
Discounted Payback: *2* years

Base Year 2016
In-service Year 2018

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$3,500,000	$2,159,461	$521,024	2	$1,878,424	$330,257	2
2019	$0	$470,000	$470,000	$991,024	3	$381,303	$711,560	3
2020		$470,000	$470,000	$1,461,024	4	$355,627	$1,067,187	4
2021		$470,000	$470,000	$1,931,024	5	$331,680	$1,398,867	5
2022		$470,000	$470,000	$2,401,024	6	$309,345	$1,708,212	6
2023		$470,000	$470,000	$2,871,024	7	$288,514	$1,996,726	7
2024		$470,000	$470,000	$3,341,024	8	$269,086	$2,265,812	8
2025		$470,000	$470,000	$3,811,024	9	$250,966	$2,516,779	9
2026		$470,000	$470,000	$4,281,024	10	$234,067	$2,750,845	10
2027		$470,000	$470,000	$4,751,024	11	$218,305	$2,969,151	11
2028		$470,000	$470,000	$5,221,024	12	$203,605	$3,172,756	12
2029		$470,000	$470,000	$5,691,024	13	$189,895	$3,362,650	13
2030		$470,000	$470,000	$6,161,024	14	$177,107	$3,539,757	14
2031		$470,000	$470,000	$6,631,024	15	$165,181	$3,704,939	15
2032		$470,000	$470,000	$7,101,024	16	$154,058	$3,858,997	16
2033		$470,000	$470,000	$7,571,024	17	$143,684	$4,002,681	17
2034		$470,000	$470,000	$8,041,024	18	$134,009	$4,136,690	18
2035		$470,000	$470,000	$8,511,024	19	$124,985	$4,261,675	19
2036		$470,000	$470,000	$8,981,024	20	$116,569	$4,378,244	20

Appendix E - 5.4

Project SENSITIVITY ANALYSIS CAPACITY TRIAL 4- Benefit of $7.5M per MW

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***2***	years
Discount Rate	7.2%	***Discounted Payback:***	***2***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$5,250,000	$3,909,461	$2,271,024	2	$3,400,676	$1,852,509	2
2019	$0	$470,000	$470,000	$2,741,024	3	$381,303	$2,233,812	3
2020		$470,000	$470,000	$3,211,024	4	$355,627	$2,589,439	4
2021		$470,000	$470,000	$3,681,024	5	$331,680	$2,921,118	5
2022		$470,000	$470,000	$4,151,024	6	$309,345	$3,230,463	6
2023		$470,000	$470,000	$4,621,024	7	$288,514	$3,518,978	7
2024		$470,000	$470,000	$5,091,024	8	$269,086	$3,788,064	8
2025		$470,000	$470,000	$5,561,024	9	$250,966	$4,039,030	9
2026		$470,000	$470,000	$6,031,024	10	$234,067	$4,273,097	10
2027		$470,000	$470,000	$6,501,024	11	$218,305	$4,491,402	11
2028		$470,000	$470,000	$6,971,024	12	$203,605	$4,695,007	12
2029		$470,000	$470,000	$7,441,024	13	$189,895	$4,884,902	13
2030		$470,000	$470,000	$7,911,024	14	$177,107	$5,062,009	14
2031		$470,000	$470,000	$8,381,024	15	$165,181	$5,227,190	15
2032		$470,000	$470,000	$8,851,024	16	$154,058	$5,381,249	16
2033		$470,000	$470,000	$9,321,024	17	$143,684	$5,524,933	17
2034		$470,000	$470,000	$9,791,024	18	$134,009	$5,658,942	18
2035		$470,000	$470,000	$10,261,024	19	$124,985	$5,783,927	19
2036		$470,000	$470,000	$10,731,024	20	$116,569	$5,900,495	20

Appendix E - 5.5

Project SENSITIVITY ANALYSIS CAPACITY TRIAL 5- Benefit of $10M per MW

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***2***	years
Discount Rate	7.2%	***Discounted Payback:***	***2***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$7,000,000	$5,659,461	$4,021,024	2	$4,922,928	$3,374,760	2
2019	$0	$470,000	$470,000	$4,491,024	3	$381,303	$3,756,063	3
2020		$470,000	$470,000	$4,961,024	4	$355,627	$4,111,690	4
2021		$470,000	$470,000	$5,431,024	5	$331,680	$4,443,370	5
2022		$470,000	$470,000	$5,901,024	6	$309,345	$4,752,715	6
2023		$470,000	$470,000	$6,371,024	7	$288,514	$5,041,229	7
2024		$470,000	$470,000	$6,841,024	8	$269,086	$5,310,315	8
2025		$470,000	$470,000	$7,311,024	9	$250,966	$5,561,282	9
2026		$470,000	$470,000	$7,781,024	10	$234,067	$5,795,349	10
2027		$470,000	$470,000	$8,251,024	11	$218,305	$6,013,654	11
2028		$470,000	$470,000	$8,721,024	12	$203,605	$6,217,259	12
2029		$470,000	$470,000	$9,191,024	13	$189,895	$6,407,153	13
2030		$470,000	$470,000	$9,661,024	14	$177,107	$6,584,261	14
2031		$470,000	$470,000	$10,131,024	15	$165,181	$6,749,442	15
2032		$470,000	$470,000	$10,601,024	16	$154,058	$6,903,500	16
2033		$470,000	$470,000	$11,071,024	17	$143,684	$7,047,184	17
2034		$470,000	$470,000	$11,541,024	18	$134,009	$7,181,193	18
2035		$470,000	$470,000	$12,011,024	19	$124,985	$7,306,178	19
2036		$470,000	$470,000	$12,481,024	20	$116,569	$7,422,747	20

Appendix E - 5.6

Project SENSITIVITY ANALYSIS ENERGY TRIAL 6: 100,000 $/GWh/yr ***Date*** 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***8***	years	
Discount Rate	7.2%	***Discounted Payback:***	***11***	years	
Base Year	2016				
In-service Year	2018				

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$226,000	$226,000	-$1,002,976	3	$183,350	-$1,008,644	3
2020		$226,000	$226,000	-$776,976	4	$171,004	-$837,641	4
2021		$226,000	$226,000	-$550,976	5	$159,489	-$678,152	5
2022		$226,000	$226,000	-$324,976	6	$148,749	-$529,404	6
2023		$226,000	$226,000	-$98,976	7	$138,732	-$390,671	7
2024		$226,000	$226,000	$127,024	8	$129,390	-$261,281	8
2025		$226,000	$226,000	$353,024	9	$120,677	-$140,603	9
2026		$226,000	$226,000	$579,024	10	$112,551	-$28,052	10
2027		$226,000	$226,000	$805,024	11	$104,972	$76,920	11
2028		$226,000	$226,000	$1,031,024	12	$97,904	$174,824	12
2029		$226,000	$226,000	$1,257,024	13	$91,311	$266,135	13
2030		$226,000	$226,000	$1,483,024	14	$85,162	$351,297	14
2031		$226,000	$226,000	$1,709,024	15	$79,428	$430,725	15
2032		$226,000	$226,000	$1,935,024	16	$74,079	$504,804	16
2033		$226,000	$226,000	$2,161,024	17	$69,091	$573,895	17
2034		$226,000	$226,000	$2,387,024	18	$64,438	$638,333	18
2035		$226,000	$226,000	$2,613,024	19	$60,099	$698,432	19
2036		$226,000	$226,000	$2,839,024	20	$56,052	$754,484	20

Appendix E - 5.7

Project SENSITIVITY ANALYSIS ENERGY TRIAL 7: 150,000 $/GWh/yr ***Date*** 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	*6*	years	
Discount Rate	7.2%	***Discounted Payback:***	*7*	years	
Base Year	2016				
In-service Year	2018				

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$339,000	$339,000	-$889,976	3	$275,025	-$916,969	3
2020		$339,000	$339,000	-$550,976	4	$256,505	-$660,464	4
2021		$339,000	$339,000	-$211,976	5	$239,233	-$421,231	5
2022		$339,000	$339,000	$127,024	6	$223,123	-$198,108	6
2023		$339,000	$339,000	$466,024	7	$208,099	$9,991	7
2024		$339,000	$339,000	$805,024	8	$194,086	$204,076	8
2025		$339,000	$339,000	$1,144,024	9	$181,016	$385,092	9
2026		$339,000	$339,000	$1,483,024	10	$168,827	$553,919	10
2027		$339,000	$339,000	$1,822,024	11	$157,458	$711,378	11
2028		$339,000	$339,000	$2,161,024	12	$146,855	$858,233	12
2029		$339,000	$339,000	$2,500,024	13	$136,966	$995,200	13
2030		$339,000	$339,000	$2,839,024	14	$127,743	$1,122,943	14
2031		$339,000	$339,000	$3,178,024	15	$119,141	$1,242,084	15
2032		$339,000	$339,000	$3,517,024	16	$111,119	$1,353,203	16
2033		$339,000	$339,000	$3,856,024	17	$103,636	$1,456,839	17
2034		$339,000	$339,000	$4,195,024	18	$96,657	$1,553,496	18
2035		$339,000	$339,000	$4,534,024	19	$90,149	$1,643,645	19
2036		$339,000	$339,000	$4,873,024	20	$84,078	$1,727,723	20

Appendix E - 5.8

Project SENSITIVITY ANALYSIS ENERGY TRIAL 8: 200,000 $/GWh/yr ***Date*** 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***5***	years	
Discount Rate	7.2%	***Discounted Payback:***	***6***	years	
Base Year	2016				
In-service Year	2018				

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$452,000	$452,000	-$776,976	3	$366,700	-$825,294	3
2020		$452,000	$452,000	-$324,976	4	$342,007	-$483,287	4
2021		$452,000	$452,000	$127,024	5	$318,977	-$164,310	5
2022		$452,000	$452,000	$579,024	6	$297,498	$133,187	6
2023		$452,000	$452,000	$1,031,024	7	$277,465	$410,652	7
2024		$452,000	$452,000	$1,483,024	8	$258,781	$669,433	8
2025		$452,000	$452,000	$1,935,024	9	$241,355	$910,788	9
2026		$452,000	$452,000	$2,387,024	10	$225,103	$1,135,890	10
2027		$452,000	$452,000	$2,839,024	11	$209,945	$1,345,835	11
2028		$452,000	$452,000	$3,291,024	12	$195,807	$1,541,642	12
2029		$452,000	$452,000	$3,743,024	13	$182,622	$1,724,264	13
2030		$452,000	$452,000	$4,195,024	14	$170,325	$1,894,589	14
2031		$452,000	$452,000	$4,647,024	15	$158,855	$2,053,444	15
2032		$452,000	$452,000	$5,099,024	16	$148,158	$2,201,602	16
2033		$452,000	$452,000	$5,551,024	17	$138,181	$2,339,784	17
2034		$452,000	$452,000	$6,003,024	18	$128,877	$2,468,660	18
2035		$452,000	$452,000	$6,455,024	19	$120,198	$2,588,858	19
2036		$452,000	$452,000	$6,907,024	20	$112,104	$2,700,963	20

Appendix E - 5.9

Project SENSITIVITY ANALYSIS ENERGY TRIAL 9: 250,000 $/GWh/yr

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***5***	years
Discount Rate	7.2%	***Discounted Payback:***	***5***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$565,000	$565,000	-$663,976	3	$458,375	-$733,619	3
2020		$565,000	$565,000	-$98,976	4	$427,509	-$306,110	4
2021		$565,000	$565,000	$466,024	5	$398,721	$92,611	5
2022		$565,000	$565,000	$1,031,024	6	$371,872	$464,483	6
2023		$565,000	$565,000	$1,596,024	7	$346,831	$811,314	7
2024		$565,000	$565,000	$2,161,024	8	$323,476	$1,134,790	8
2025		$565,000	$565,000	$2,726,024	9	$301,694	$1,436,484	9
2026		$565,000	$565,000	$3,291,024	10	$281,378	$1,717,862	10
2027		$565,000	$565,000	$3,856,024	11	$262,431	$1,980,292	11
2028		$565,000	$565,000	$4,421,024	12	$244,759	$2,225,052	12
2029		$565,000	$565,000	$4,986,024	13	$228,277	$2,453,329	13
2030		$565,000	$565,000	$5,551,024	14	$212,906	$2,666,235	14
2031		$565,000	$565,000	$6,116,024	15	$198,569	$2,864,804	15
2032		$565,000	$565,000	$6,681,024	16	$185,198	$3,050,001	16
2033		$565,000	$565,000	$7,246,024	17	$172,727	$3,222,728	17
2034		$565,000	$565,000	$7,811,024	18	$161,096	$3,383,824	18
2035		$565,000	$565,000	$8,376,024	19	$150,248	$3,534,072	19
2036		$565,000	$565,000	$8,941,024	20	$140,130	$3,674,202	20

Appendix E - 5.10

Project SENSITIVITY ANALYSIS ENERGY TRIAL 10: 300,000 $/GWh/yr

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***4***	years	
Discount Rate	7.2%	***Discounted Payback:***	***5***	years	
Base Year	2016				
In-service Year	2018				

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$678,000	$678,000	-$550,976	3	$550,050	-$641,944	3
2020		$678,000	$678,000	$127,024	4	$513,011	-$128,934	4
2021		$678,000	$678,000	$805,024	5	$478,466	$349,532	5
2022		$678,000	$678,000	$1,483,024	6	$446,247	$795,778	6
2023		$678,000	$678,000	$2,161,024	7	$416,197	$1,211,976	7
2024		$678,000	$678,000	$2,839,024	8	$388,171	$1,600,147	8
2025		$678,000	$678,000	$3,517,024	9	$362,032	$1,962,179	9
2026		$678,000	$678,000	$4,195,024	10	$337,654	$2,299,833	10
2027		$678,000	$678,000	$4,873,024	11	$314,917	$2,614,750	11
2028		$678,000	$678,000	$5,551,024	12	$293,711	$2,908,461	12
2029		$678,000	$678,000	$6,229,024	13	$273,933	$3,182,394	13
2030		$678,000	$678,000	$6,907,024	14	$255,487	$3,437,880	14
2031		$678,000	$678,000	$7,585,024	15	$238,283	$3,676,163	15
2032		$678,000	$678,000	$8,263,024	16	$222,237	$3,898,400	16
2033		$678,000	$678,000	$8,941,024	17	$207,272	$4,105,673	17
2034		$678,000	$678,000	$9,619,024	18	$193,315	$4,298,988	18
2035		$678,000	$678,000	$10,297,024	19	$180,297	$4,479,285	19
2036		$678,000	$678,000	$10,975,024	20	$168,156	$4,647,441	20

Appendix E - 5.11

Project

SENSITIVITY ANALYSIS
WORST CASE
TRIAL 11-
Capacity Benefit of $1M per MW
Energy Benefit of 100,000 $/GWh/y

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***13***	years
Discount Rate	7.2%	***Discounted Payback:***	***21***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$700,000	-$640,539	-$2,278,976	2	-$557,178	-$2,105,346	2
2019		$226,000	$226,000	-$2,052,976	3	$183,350	-$1,921,995	3
2020		$226,000	$226,000	-$1,826,976	4	$171,004	-$1,750,992	4
2021		$226,000	$226,000	-$1,600,976	5	$159,489	-$1,591,503	5
2022		$226,000	$226,000	-$1,374,976	6	$148,749	-$1,442,755	6
2023		$226,000	$226,000	-$1,148,976	7	$138,732	-$1,304,022	7
2024		$226,000	$226,000	-$922,976	8	$129,390	-$1,174,632	8
2025		$226,000	$226,000	-$696,976	9	$120,677	-$1,053,954	9
2026		$226,000	$226,000	-$470,976	10	$112,551	-$941,403	10
2027		$226,000	$226,000	-$244,976	11	$104,972	-$836,431	11
2028		$226,000	$226,000	-$18,976	12	$97,904	-$738,527	12
2029		$226,000	$226,000	$207,024	13	$91,311	-$647,216	13
2030		$226,000	$226,000	$433,024	14	$85,162	-$562,054	14
2031		$226,000	$226,000	$659,024	15	$79,428	-$482,626	15
2032		$226,000	$226,000	$885,024	16	$74,079	-$408,547	16
2033		$226,000	$226,000	$1,111,024	17	$69,091	-$339,456	17
2034		$226,000	$226,000	$1,337,024	18	$64,438	-$275,018	18
2035		$226,000	$226,000	$1,563,024	19	$60,099	-$214,919	19
2036		$226,000	$226,000	$1,789,024	20	$56,052	-$158,867	20
2037		$226,000	$226,000	$2,015,024	21	$52,278	-$106,589	21
2038		$226,000	$226,000	$2,241,024	22	$48,757	-$57,832	22
2039		$226,000	$226,000	$2,467,024	23	$45,474	-$12,358	23
2040		$226,000	$226,000	$2,693,024	24	$42,412	$30,055	24
2041		$226,000	$226,000	$2,919,024	25	$39,556	$69,611	25
2042		$226,000	$226,000	$3,145,024	26	$36,892	$106,503	26
2043		$226,000	$226,000	$3,371,024	27	$34,408	$140,911	27
2044		$226,000	$226,000	$3,597,024	28	$32,091	$173,002	28
2045		$226,000	$226,000	$3,823,024	29	$29,930	$202,933	29
2046		$226,000	$226,000	$4,049,024	30	$27,915	$230,847	30
2047		$226,000	$226,000	$4,275,024	31	$26,035	$256,883	31
2048		$226,000	$226,000	$4,501,024	32	$24,282	$281,164	32
2049		$226,000	$226,000	$4,727,024	33	$22,647	$303,811	33
2050		$226,000	$226,000	$4,953,024	34	$21,122	$324,933	34
2051		$226,000	$226,000	$5,179,024	35	$19,700	$344,633	35
2052		$226,000	$226,000	$5,405,024	36	$18,373	$363,006	36

Appendix 5.6
Mayo Hydro Future Facility Options Report (KGS 2016)

Mayo Hydro (MH0) Future Facility Options
Concept Design Report

FINAL – REV 0

KGS 16-1404-002
August 2016

KGS Group
Winnipeg, Manitoba

Concept Design Report

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EXECUTIVE SUMMARY

This concept design report assesses four options for the future of the Mayo Hydro (MH0) facility. It presents a conceptual design, cost estimates and an economic assessment of each option. The four options considered are:

1. Option #1 – Replace the Mayo Hydro station.
2. Option #2 – Refurbish the Mayo Hydro station.
3. Option #3 – Remove the facility and return the site to a near greenfield condition.
4. Option #4 – Make safe and abandon in situ.

It is expected that, given appropriate maintenance and overhauls, Options 1 and 2 would provide 65 years or move of plant life.

The total present value was compared for all four options and found that Option 2 was the most economical with a total present value of $10,000,000 and a levelized cost of energy of $0.15/kWhr. Option 1 had the next highest total present value of $6,600,000 and a levelized cost of energy of $0.17/kWhr. These were followed by Option 4 and then Option 3 which had net present values of $2,950,000 and $1,250,000, respectively.

A 7.6 m/s design capacity for Option 1 and Option 2 was selected based on a combination of the minimum flow requirements of the Mayo Hydro tailrace (as per the water license), and maximum flows allowed while both Mayo B Hydro units are operating. Design capacities using higher flows were not financially attractive because they would result in very little additional energy and the additional capacity would only be usable when at least one of the Mayo B units is forced off-line, which occurs for a limited number of hours throughout a typical year.

Option 1 entails the replacement of the hydro facility, retaining the foundations and select embedded parts. It would provide one new turbine and generator unit, powerhouse, balance of plant systems, support systems, control room, powerhouse crane and surge tank. This option would include geotechnical work to stabilize slopes, and make repairs to the access road and tailrace.

Option 2 involves the refurbishment of the existing facility, retaining the foundations, embedded parts, powerhouse superstructure and the embedded spiral case, stay ring and discharge cone of the Unit 2 turbine. It would provide one new generator, new turbine components, other than those mentioned above, a new turbine inlet valve (TIV), balance of plant systems, support systems, control room and surge tank. Repairs/upgrades to the existing powerhouse superstructure and modernization of the crane were included. This option would include geotechnical work to stabilize slopes, and repair the roads and the tailrace.

Option 3 entails the complete demolition of the powerhouse (excluding the foundation) and the surge tank. It includes permanently plugging the tunnel upstream of the surge tank take-off and backfilling the powerhouse foundation and tailrace to return the site to a near greenfield condition.

Option 4 will abandon the powerhouse in place. The facility would be made safe for abandonment, the tunnel would be permanently plugged upstream of the surge tank, and the tailrace would be backfilled.

Complete cost estimates were prepared for each option and included all costs and a 30% contingency to account for unknowns given the level of design. An economic assessment was performed using a 65 year facility life span, 5.45% (nominal) weighted average cost of capital and 2% inflation for computing present value. Assumptions were made for the operating and maintenance cost, the capital expenditures cost, benefit of an increase in capacity and the benefit of an increase in annual energy production. Option 3 and 4 were assumed to be operational for an additional 10 years prior to removing the facility from service.

TABLE OF CONTENTS

PAGE

ASSET ASSESSMENT i

ACKNOWLEDGEMENTS ii

1.0 INTRODUCTION 1

2.0 THE FACILITY 3

3.0 OPTION 1 – REPLACE THE FACILITY 4

- 3.1 PLANT CAPACITY 4
- 3.2 SELECTION OF CAPACITY 6
- 3.3 DEMOLITION 8
- 3.4 MECHANICAL AND ELECTRICAL 8
  - 3.4.1 TURBINE AND GENERATOR 8
  - 3.4.2 BALANCE OF PLANT 10
- 3.5 STRUCTURAL 12
- 3.6 GEOTECHNICAL 13
  - 3.6.1 SLOPE ABOVE POWERHOUSE 13
  - 3.6.2 TAILRACE 13
  - 3.6.3 ACCESS ROAD 13
- 3.7 COST ESTIMATE 14
- 3.8 SCHEDULE 16

4.0 OPTION 2 – REFURBISH THE EXISTING FACILITY 17

- 4.1 DEMOLITION 18
- 4.2 MECHANICAL AND ELECTRICAL 19
  - 4.2.1 TURBINE AND GENERATOR 19
  - 4.2.2 BALANCE OF PLANT 21
- 4.3 STRUCTURAL 23
- 4.4 GEOTECHNICAL 24
- 4.5 COST ESTIMATE 24
- 4.6 SCHEDULE 26

5.0 OPTION 3 – REMOVE THE FACILITY AND RETURN SITE TO NEAR GREENFIELD CONDITION 27

- 5.1 DEMOLITION 27
- 5.2 COMMUNICATIONS 27
- 5.3 STRUCTURAL 28
- 5.4 GEOTECHNICAL 28
- 5.5 COST ESTIMATE 28
- 5.6 SCHEDULE 30

6.0 OPTION 4 – ABANDON THE FACILITY IN PLACE AND MAKE SAFE 31

- 6.1 DEMOLITION 31
- 6.2 COMMUNICATIONS 31

TABLE OF CONTENTS (CONTINUED)

6.3 STRUCTURAL....31
6.4 GEOTECHNICAL....32
6.5 COST ESTIMATE....32
6.6 SCHEDULE....33

7.0 ECONOMIC ASSESSMENT....35

8.0 RECOMMENDATION....40

9.0 STATEMENT OF LIMITATIONS AND CONDITIONS....41
9.1 THIRD PARTY USE OF REPORT....41
9.2 CAPITAL COST ESTIMATE STATEMENT OF LIMITATIONS....41

TABLES
FIGURES
APPENDICES

LIST OF TABLES

1. Total Project Cost - Option 1 – Replacement
2. Total Project Cost - Option 2 – Refurbishment
3. Total Project Cost - Option 3 – Demolish and Return to Greenfield
4. Total Project Cost - Option 4 – Abandon in Situ
5. Economic Analysis Summary
6. Energy Benefits Sensitivity Analysis
7. Increased Capacity Benefits Sensitivity Analysis

LIST OF FIGURES

1. Time Spent (%) in Flow Range (m^3/s) - Overall
2. Option 1 – Replace the Facility, Powerhouse Plan Main Floor Layout
3. Option 1 – Replace the Facility, Powerhouse Plan Basement Layout
4. Option 2 – Refurbish the Facility, Powerhouse Plan Main Floor Layout
5. Option 2 – Refurbish the Facility, Powerhouse Plan Basement Layout
6. NPV vs $/MWhr
7. Mayo Hydro Preliminary Schedule – Option 1
8. Mayo Hydro Preliminary Schedule – Option 2
9. Mayo Hydro Preliminary Schedule – Option 3
10. Mayo Hydro Preliminary Schedule – Option 4

LIST OF APPENDICES

A. Mayo Hydro and Mayo B Generating Stations Optimizing Plant Operations Testing Results, May 2013
B. Emails: Andritz – Francis Turbine/Generator Redevelopment Study (April 11, 2016)
C. Mayo Hydro Detailed Contractor Direct Costs
D. Economic Assessments
E. Email: Aishihik Rerate Study (April 13, 2015)

1.0 INTRODUCTION

Yukon Energy Corporation (YEC), established in 1987, is a publicly owned electrical utility which provides reliable electricity to almost 15,000 consumers. The hydro facilities at Whitehorse, Mayo, and Aishihik Lake provide 92 megawatts of power to the surrounding communities. With 31 megawatts produced by diesel generators (primarily used for back up), 8.8 megawatts by liquefied natural gas (used for back up), and .65 megawatts by a small wind turbine on Haeckel Hill near Whitehorse, Yukon Energy has the capacity to generate close to 132 megawatts.

The Mayo Hydro and Mayo B Hydro stations are located approximately 400 kilometers north of Whitehorse. Mayo Hydro started to produce power in 1952 and Mayo B Hydro in 2012. Mayo Hydro and Mayo B Hydro are fed from Wareham Lake and operate with a maximum total combined flow of 25 cubic meters per second (m^3/s) (19 m^3/s through Mayo B Hydro and 6 m^3/s through Mayo Hydro). Mayo Hydro has the capacity to pass up to 17 m^3/s; however, the design of the intake and penstocks restrict the combined flow to 25 m^3/s.

As per the water license for the Mayo River and Mayo Lake, in the channels downstream of the Mayo Hydro Powerhouse, a minimum instantaneous flow of 6 m^3/s is required from May 1 to September 30, and a minimum flow of 5 m^3/s is required for the remainder of the year. If Mayo Hydro is not operating, this minimum flow and potential energy must be passed through the spillway. Due to the higher water head available at Mayo B Hydro, the preference is to operate both Mayo B units and to operate Mayo Hydro at the minimum required flow.

The Yukon Energy Corporation is considering 4 options for the future of the Mayo Hydro facility.

- Option #1 – Replace the Mayo Hydro station.
- Option #2 – Refurbish the Mayo Hydro station.
- Option #3 – Remove the Mayo Hydro facility and return the site to a near greenfield condition.
- Option #4 – Make the facility safe and abandon in situ.

KGS Group was retained to assess each option at a conceptual level and recommend the most economical choice. The design life of Option 1 and Option 2 will be 65 years.

This Conceptual Design Report covers the economic assessment and cost estimates for the future options. The following sections summarize and explain the results of the analysis and a final recommendation is provided.

A condition assessment of the Mayo Hydro powerhouse was done in 2013/2014. This assessment and the associated report were updated by KGS Group in 2016. The study assesses the current condition of the facility and its components, prioritizes the required upgrades and presents costs estimates for the work required. It found that many of the systems have reached the end of their useful life and that extensive repairs/upgrades are required to maintain the facility in operation. The age and condition of the facility and the need for significant repairs or upgrades provide context for, and support, the recommendations of this report. Refer to the “Mayo Hydro (MH0) Asset Assessment Update” report for a detailed review of the facility’s condition.

2.0 THE FACILITY

Mayo Hydro is a two vertical Francis unit hydroelectric generating station located just north and outside of the town of Mayo, in the Yukon Territory. It has a maximum continuous rating of 5.1 MW. The facility was placed into service in 1952 with the commissioning of Unit MH1. Unit MH2 was placed into service in 1957.

The Mayo Hydro facility includes the following structures:

- One powerhouse building.
- One switchgear building (blue building).
- One surge tank.
- One tunnel.
- One substation/transformer yard.
- One intake structure.
- One spillway control structure.

The substation/transformer yard, intake structure and spillway control structure are not included in the scope of work for this project because these components are shared with Mayo B Hydro and will be required regardless of which option is chosen for the future of the Mayo Hydro facility. The switchgear building is not included in the scope of work because it will be relocated to the Mayo S249 substation as part of a separate project, regardless of which option is chosen.

3.0 OPTION 1 – REPLACE THE FACILITY

In accordance with the terms of reference, Option 1 entails replacement of the hydro facility, retaining only the foundations and other embedded parts. As discussed in Section 3.3, the surge tank will also be replaced. The hydro facility replacement will include a new powerhouse building, balance of plant systems and one new turbine/generator unit and its supporting equipment, complete with a new control room and powerhouse crane. Given appropriate maintenance and overhauls, it is expected that the life of the plant, post-replacement, would be 65 years or more.

3.1 PLANT CAPACITY

Prior to construction of Mayo B, Mayo Hydro had a plant design flow of 17 m^3/s. As detailed in the "Mayo A and Mayo B Generating Stations Optimizing Plant Operations Testing Results, May 2013" KGS Group (Appendix A), for most Wareham Lake levels, Mayo Hydro is restricted to operate at 6 m^3/s while two Mayo B units are running.

In order to determine a design capacity of a new turbine/generator unit for this study, Yukon Energy Corporation provided historical flow data for the Mayo Hydro plant. Flow data for the period of February 8, 2013 to February 18, 2016 was used, refer to Figure 1.

Because of the operational constraints of the Mayo Hydro/Mayo B Hydro complex (i.e. flow limitations at Mayo Hydro) and supported by the flow data in Figure 1, possible plant flows in the range of 6 m^3/s to 10 m^3/s were investigated. The four options that were considered are:

- Case 1: 1 unit sized for 9.7 m^3/s.
- Case 2: 2 units sized for 5 m^3/s each.
- Case 3: 1 unit sized for 6 m^3/s.
- Case 4: 1 unit sized so winter flow results in approximately 90% turbine efficiency.

To review the four cases, Andritz's Francis turbine efficiency curve data from the Mayo B bid was used. To estimate efficiencies using this efficiency curve, the axis with absolute flow values was converted to a percentage of rated flow and the efficiency for a given percentage of rated

flow was assumed to be the same, regardless of the rated flow. For example, the efficiency for a unit operating at 75% rated flow was the same regardless of the unit size.

The efficiency curve data is proprietary information that is closely guarded by the turbine suppliers. As such, the source curve has not been included in this report. However, Yukon Energy Corporation is in possession of this information from the Mayo B Hydro project.

Case 1: Single unit sized to maximize MH0 capacity (peak flow of 9.7 m^3/s).

This case coincides with the maximum possible flow that can be passed simultaneously through Mayo B Hydro and Mayo Hydro. This corresponds to 19 m^3/s through Mayo B and 9.7 m^3/s through Mayo Hydro. Note that this case is only reasonable if Wareham Lake is operated at or near the maximum license level of 574.5 masl.

In the winter, the single unit would run at 5 m^3/s (51.5% of rated flow). This results in a relatively low turbine efficiency (generator and transformer efficiency not considered here) of 82.5%. In the summer, the single unit would run at 6 m^3/s (61.8% of rated flow, with a turbine efficiency of approximately 89%). When needed, and the Wareham Lake levels and Mayo B operation allow, the flow could be ramped up to 9.7 m^3/s.

The current MH0 units are rated for 8.5 m^3/s each. Given newer technology, it is likely that the 9.7 m^3/s can be passed safely through the existing, or similar, water passage dimensions. This is an increase of 15% in the flow. Recent turbine upgrades have shown that flow increases on the order of 20% are usually possible without risking excessive cavitation, etc. The new manufacturing techniques in use today allow for more precise manufacturing and the increased flows.

Case 2: Two units sized for 5 m^3/s each.

- In winter, run one unit at rated flow for an approximate turbine efficiency of 94%.
- In summer, run two units at 60% flow with an approximate turbine efficiency of 88%.
- When conditions at Wareham Lake and Mayo B allow, run both units up to 97% flow.

This case is similar to Case 1, as it provides the installed capacity to fully utilize the capacity at the site, except that two units are provided instead of one. This would allow for the plant to produce electricity with a higher efficiency. Again, this capacity is only available when Wareham Lake is operated at the maximum license limit or when at least one Mayo B unit is off line.

A disadvantage of this option is that both units would be required to pass the minimum riparian flows in the summer.

Case 3: One unit rated for 6 m^3/s.

- In winter, run one unit at 83.3% of rated flow for an approximate turbine efficiency of 93%.
- In summer, run the unit at 100% of rated flow with an approximate turbine efficiency of 94%.
- With this case, the unit would always operate at very high efficiency. It would essentially be base loaded. It would contribute only limited spinning reserve in the winter and none in the summer.

Case 4: One unit sized so winter flow results in 90% turbine efficiency.

On the representative turbine efficiency curve used, 90% efficiency occurs at approximately 66% of rated flow, resulting in a unit sized for a maximum flow of 7.6 m^3/s.

- In winter, run the unit at 66% of rated flow for an approximate turbine efficiency of 90%.
- In summer, run the unit at 80% of rated flow with an approximate turbine efficiency of 92%.
- With this case, the unit would always operate at relatively high efficiency. It would essentially be base loaded. It would contribute limited spinning reserve in both winter and summer.

3.2 SELECTION OF CAPACITY

After reviewing the options, Case 4 was selected. That is, one unit rated for a maximum flow of 7.6 m^3/s.

Cases 1 and 2 were discounted because with these options, the plant would seldom run at rated load because of the flow limitations of the combined Mayo Complex. The full capacity can only be used when at least one Mayo B unit is off-line or when Wareham Lake is operated at or very near its maximum licence level. Wareham Lake is not usually operated at or very near the maximum license limit level because doing so causes some flooding upstream, reduces the time available for staff to react in the event of a load rejection (need to operate the spillway faster) and there is limited freeboard at the spillway gates which prevents raising the lake level too much. Also, Mayo B units are offline for a limited number of hours throughout the year.

Although a two unit arrangement (Case 2) provides redundancy and some increased capacity that could be used when Mayo B Hydro is shut down or running with a single unit, it significantly increases cost and given the very limited operating time a second unit would run, it is not financially justifiable. To illustrate this, a rough costing exercise was undertaken and it was determined that providing two units instead of one would increase the total project cost by approximately $9,000,000 to $14,800,000, depending on size of the units and if they are new or refurbished. Since the total annual production for Mayo Hydro will remain nearly the same, due to the 6 m^3/s flow limitation most of the time, a second unit will account for an approximate increase of $0.044/kW.h to $0.073/kW.h in the levelized cost of energy. Furthermore, since Mayo B Hydro operates at much higher head (approx. 60 m net head versus 34.6 m for Mayo Hydro), more energy is produced by a given amount of water at Mayo B.
Case 4 was chosen over Case 3 because it provides minimal additional capacity and spinning reserve and it more closely matches the recent historical plant flows shown in Figure 1.

Andritz Hydro, a turbine and generator supplier provided a preliminary unit selection (Appendix B). Selection was limited to vertical units that could re-use the existing foundation and water passages. The setting elevation of the turbine runner was considered given the constraints of the existing foundation.

The following sections detail the concept design to replace the Mayo Hydro facility.

3.3 DEMOLITION

The demolition will include the removal of:

- The existing powerhouse superstructure.
- Turbine/generators, TIVs and their related components.
- There are no electrical systems with sufficient value to justify retaining for reuse. To be re-used, a component would have to be carefully removed, packaged, stored and re-installed in a new installation. It is expected that the added complexity in design, construction and commissioning would negate any cost savings associated with the reuse of the components. Therefore, all electrical systems (generator, balance of plant, building systems) should be demolished and replaced with new.
- Asbestos abatement (generators, roof panels).
- Disposal of any PCBs, lead, oil, and potentially small amounts of mercury.
- Spiral cases and both TIV pedestals.
- The powerhouse mechanical systems, including: domestic, sanitary, compressed air, fire protection, HVAC systems.
- Surge tank superstructure.
- Surge tank mechanical and electrical.

The existing septic field will be abandoned in place.

The existing draft tube sectional gates and guides will be re-used for Unit 1.

The replacement of the surge tank is included in this study as its interior condition is unknown. If inspections during later phases of the project show that the surge tank is in good condition, it may be reused to reduce costs.

3.4 MECHANICAL AND ELECTRICAL

3.4.1 Turbine and Generator

The new turbine/generator will be placed in Unit 1's current location since this allows for a larger service bay on the access road side of the powerhouse (Figure 2 and Figure 3). A service bay

incorporating the space formerly occupied by Unit 2 will allow trucks to back directly into the powerhouse to unload/load. The penstock feeding the unused turbine pit will be permanently plugged and its TIV pit modified to suit the needs of the new facility. The new unit will be:

- Vertical Francis turbine.
- 7.6 m^3/s at 34.6 m of net head.
- 2300 kW, 6.9 kV synchronous generator with static excitation, 600 rpm.
- 986 mm runner diameter.

The turbine and generator will be supplied with a new electronic governor system.

At this concept stage, the design details of the equipment were not specified, but it is assumed that the new turbine and generator equipment would consist of:

- Generator:
    a. Standard catalogued air-cooled generator. That is, the generator would not be a custom design.
    b. Global VPI type insulation with resins that do not support combustion when energy sources are removed.
    c. Inertia would consist of the natural inertia of the unit only.
    d. Capable of withstanding runaway speeds for extended periods.
- Turbine:
    a. Stainless steel runner and wicket gates.
    b. Greaseless bushings throughout.
- Turbine Inlet Valve (TIV):
    a. New butterfly valve, complete with new hydraulic actuator and counterweight closure capability, rated for single point of isolation.
- Governor:
    a. Digital PLC-based governor.
    b. High pressure HPU with a backup pump and motor.
    c. Nitrogen charged bladder-type accumulators sized to provide stored energy for two close strokes and one open stroke of the wicket gates and one open stroke of the TIV.
- Excitation:

a. No redundant bridge.
b. Ceiling voltage capability: 2 pu.

- The unit will be provided with vibration monitoring equipment.
- Unit control and monitoring systems and SCADA systems.
- Neutral grounding resistor cubicle and a new phase (power lead connection) cubicle, complete with surge arrestors and capacitors.
- A cooling water filtering skid will be provided to filter cooling and shaft seal water.

The above parameters have been assumed at this time. The detailed design phase should include appropriate grid and hydraulic transient studies to determine generator and excitation system requirements. For example, these studies should include an assessment of whether brushless excitation would be acceptable instead of the more expensive static excitation included herein and ceiling voltage requirements, as well as the required generator inertia and electrical parameters.

The concept design includes the capability to restart the unit using on site stored energy (in accumulators and DC battery banks), in a fashion that is similar to the current plant and no diesel generator has been allowed for at this time. This would allow staff to restart the unit to power the station service, etc. Given the smaller size of the unit, it is unclear at this time what line charging and grid restoring capabilities this unit would have. This would have to be determined at the beginning of the detailed design phase following the results of the above-mentioned grid and hydraulic transient studies.

3.4.2 Balance of Plant

The powerhouse will require the following new mechanical balance of plant systems:

- Domestic water.
- Sanitary waste (including holding tank).
- Station drainage (including an oil/water separator).
- Compressed air.
- HVAC (including surge tank).
- Fire protection.

- Powerhouse crane.
- Draft tube crane.

Due to the powerhouse's proximity to the river, a new septic field is not feasible. Instead, a sewage holding tank will be provided. The holding tank will be buried and be equipped with heat tracing for the drain lines.

The TIV pit of Unit 2 will be converted into an oil/water separator, complete with coalescing filters/plate pack and drainage pumps (Figure 3). The oil-water-separator will be housed in a concrete pit and sized to accommodate normal station drainage and fire protection water flows.

The fire protection system will be fed from the penstock and will be comprised of listed strainers, piping, hose stations and a fire detection and alarm system. The new generators will be fabricated with self-extinguishing insulating materials; therefore a generator deluge system will not be required.

The powerhouse crane will be an overhead top running bridge crane. The draft tube crane will be an electric monorail crane.

The powerhouse will require the following electrical balance of plant systems:

- Grounding systems.
- Lighting and emergency lighting.
- Fire alarm system.
- Telephone system.
- Control and corporate data networks.
- Security and card access systems.
- Station service distribution panels and convenience transformer.
- Communication relocation.
- New cables and cable trays.
- DC power system.
- Station service transformer (SST) with an automatic transfer scheme.

- 15 kV arc-proof metal-clad switchgear (with unit protections).

All communications from Mayo B, Mayo Hydro, the Wareham spillway and the intake have fibre communication which route through Mayo Hydro. Prior to performing demolition, the communications/fibre will need to be relocated to the switchyard or otherwise bypassed. It is proposed that this equipment and cabling be permanently relocated to a new communications building in the switchyard.

3.5 STRUCTURAL

A new insulated metal clad powerhouse superstructure will be installed on the existing foundation. The powerhouse will be designed to current design standards to withstand seismic loads and loads from the cranes, wind, snow, etc.

The new spiral case and discharge cone will be anchored/grouted in place of the removed Unit 1. Unused openings within the generator and turbine floors will be filled with concrete. If additional laydown space is required on the turbine floor, the concrete that supported the Unit 2 generator may be removed and the floor reinforced as required; it is expected that the cost of this rework would be significant. Minor concrete rehabilitation is likely required over the concrete foundation.

Unit 2's draft tube will be sealed with a structural wall immediately behind the gate guides and then infilled with lean concrete to the generator floor level for improved structural stability. Unit 2's penstock will be plugged and a blanking plate will be installed in the powerhouse.

In addition to the added mass from infilling the decommissioned draft tube, allowances have been included for the installation of post-tensioned rock anchorage to improve powerhouse stability (powerhouse anchors) for updated seismic loading.

A new control room, complete with fire rated wall separations will be provided. The switchgear will be located on the generator floor.

As discussed in Section 3.3, a new surge tank superstructure will be provided. The concrete foundation has been assumed to be suitable for reuse; however, a detailed inspection will be required to confirm this assumption.

3.6 GEOTECHNICAL

3.6.1 Slope Above Powerhouse

The stability of the slope immediately behind the powerhouse structure has been, and continues to be, of concern due to the possibility of a slope failure damaging the critical infrastructure (surge tank, powerhouse, electrical, etc.) that is supported on the slope. The rock mass behind the powerhouse structure will need to be stabilized in order to reduce the risk for damage to the building and/or injury to employees. This is achieved by:

- Scaling and removal of loose rock and debris through hand removal (using rope access) or mechanical means (using long arm backhoe or jackhammer).
- Installation of rockfill catch ditches and catch fences to impede rockfall from traveling onto the back of the powerhouse
- Flatten the top of the slope area and grade it such that positive drainage is achieved in order to reduce the potential for erosion and surface water infiltration into the rock mass.
- Reinforce the excavated rock faces to prevent any loose rock from potentially damaging the structures by installing new wire mesh and rock anchors.

3.6.2 Tailrace

The bottom row of gabion baskets and the underlying gabion mattress below the tailrace water level has failed due to the constant wear of high velocity streams and ice on the galvanized wire baskets. The gabion wall will be repaired.

3.6.3 Access Road

There is a steep section of the road immediately east of the 69 kV substation where runoff water has been allowed to flow directly down the shoulder of the road resulting in gully erosion which also affects the access road to Mayo Hydro. The shoulder area where the gully has formed will

need to be repaired and an appropriately sized rip-rap lined ditch will be designed and constructed at the location of the gully to convey surface run-off. The access road to the surge tank location will also require upgrading to facilitate demolition and re-construction of the new structure.

3.7 COST ESTIMATE

Table 1 provides a summary of the total project costs. For a detailed contractor direct cost estimate, refer to Appendix C.

TABLE 1
TOTAL PROJECT COST - OPTION 1 – REPLACEMENT

ITEM			COST
Contractor Direct Costs			**$13,284,000**
Site Work			$120,000
Slope, Tailrace & Access Road Stabilization			$1,897,000
Decommissioning and Demolition			$799,000
Structure Rehabilitation (Concrete, Anchoring, Repairs)			$1,014,000
New Structures (Powerhouse and Surge Tank)			$1,062,000
New Turbine, Generator & TIV			$4,416,000
Electrical and Mechanical Balance of Plant			$3,976,000
General Contractor Indirect Costs	**35%**	**of Directs**	**$4,650,000**
Travel and Camp Costs (or accommodations)	**6%**	**of Directs**	**$800,000**
Subtotal			**$18,734,000**
Contingency	**30%**	**of Subtotal**	**$5,620,000**
Total Construction Cost			**$24,354,000**
Contractor Markups			**$4,920,000**
Profit	*12%*	*of Const.*	$2,922,000
Head Office Overhead	*7.0%*	*of Const.*	$1,705,000
Bonding & Insurance	*1.2%*	*of Const.*	$292,000
Total Contractor Price			**$29,274,000**
Owner Costs			**$2,710,000**
Environmental Licencing/Consulting	*3.0%*	*of Directs*	$399,000
Final Design	*7.0%*	*of Directs*	$930,000
Site Assistance & Quality Assurance	*6.0%*	*of Directs*	$797,000
Owner's Administration	*2.0%*	*of Contract*	$585,000
Total Project Cost			**$32,000,000**

The total project cost of $32,000,000 is expected to be inclusive of all project costs. Given the limited amount of design work performed to date, a contingency of 30% has been included. Also, the allowances for contractor indirect costs, travel and accommodation, profit, overhead, etc. are based on KGS Group's recent experience on hydroelectric development projects in various remote locations in Canada (including the Mayo B Hydroelectric project).

3.8 SCHEDULE

A preliminary design and construction schedule is shown on Figure 7 (end of report). A pre-design phase includes the environmental licensing and would begin immediately. The detailed design phase would include inspections of the surge tank and spiral cases, multiple studies to refine the turbine/generator selection, hydraulic transient study, grid/electrical study, and drawings and specifications.

Turbine and Generator procurement will commence during detailed design and span into the construction schedule.

During construction, a total of three Mayo B plant outages are expected (1 month, 2 months, 2 weeks). The total process from pre-design to commercial operation is expected to span 2.25 to 2.5 years in duration.

4.0 OPTION 2 – REFURBISH THE EXISTING FACILITY

Option 2 involves the refurbishment of the existing facility. The work entails the refurbishment of Unit 2 only, replacement of the powerhouse mechanical and electrical balance of plant systems, replacement of the surge tank, and the removal of Unit 1. Unit 2 will be refurbished since its embedded spiral case and stay ring will be reused and they are newer (1969 compared to 1952) than Unit 1. Additionally, Unit 2 has a slightly higher capacity than Unit 1 (2.9 MW vs 2.7 MW). At the beginning of the detailed design phase, both units should be inspected and a final decision should be made as to which unit is to be refurbished.

The intent is to essentially replace all of Unit 2, with the exception of the embedded spiral case, stay ring and discharge cone. These embedded components would be refurbished in situ, thereby eliminating the need to cut them out of the concrete substructure. Although the existing turbine runner is only approximately 15 years old, a new runner is contemplated at this time. This allows for the selection of a higher synchronous speed, thereby requiring a less expensive generator; resulting in a lower overall cost along with a new runner. A new TIV, certified for use as a single point of isolation, will also be provided, as it is not expected that the existing one will provide reliable service for the life of the station (assumed to be 65 years from the date of refurbishment).

Given appropriate maintenance and overhauls, it is expected that the life of the plant, post-refurbishment would be 65 years or more.

The Unit 1 penstock will be plugged and its TIV pit modified to suit the needs of the facility. The proposed refurbished unit will have the same capacity as the unit described in Option 1. The service bay will be placed in the current location of Unit 1 (Figure 4). The powerhouse crane will be used to hoist loads off of trucks that are backed into the powerhouse. Clearances between the truck and new generator will be limited, but there is sufficient space. Loads will be lifted and moved over the new unit into the service bay.

This option is similar to Option 1, with the exception that the powerhouse building superstructure, the powerhouse crane, and embedded components will be retained and refurbished. All other systems will be replaced with new systems. Most of the mechanical and

electrical balance of plant systems have reached the end of their life and require either replacement or refurbishment. Given the extent of work proposed, the replacement of the balance of plant systems is warranted. It is expected that this option will provide similar reliability and service as Option 1.

The arrangement of the refurbished powerhouse is shown in Figure 4 and Figure 5. The following sections further detail the concept design to refurbish the Mayo Hydro facility.

4.1 DEMOLITION

The demolition will include the removal of:

- Unit 1 generator and associated equipment.
- Unit 2 generator and governor, turbine bearing, head cover.
- There are no electrical systems with sufficient value to justify retaining for reuse. To be re-used, a component would have to be carefully removed, packaged, stored and re-installed in a new installation. It is expected that the added complexity in design, construction and commissioning would negate any cost savings associated with the reuse of the components. Therefore, all electrical systems (generator, balance of plant, building systems) should be demolished and replaced with new.
- Disposal of any PCBs, lead, oil, and potentially small amounts of mercury.
- Unit 1 spiral case and TIV pedestal.
- The powerhouse balance of plant mechanical systems, including: domestic water, sanitary sewer, fire protection, and HVAC systems.
- Compressed air system excluding the compressors and receiver tank. Re-use of the relatively new compressors has been assumed.
- Surge tank superstructure.
- Surge tank mechanical and electrical.

The existing septic field will be abandoned in place.

The existing draft tube sectional gates and the Unit 2 guides will be re-used.

The replacement of the surge tank is included in this study as its interior condition is unknown. If inspections during later phases of the project show that the surge tank is in good condition, it may be reused to reduce costs.

The existing governor has been problematic ever since an upgrade to an electronic Woodward 505 governor was performed. The supplier's prior attempts to correct the problems have failed. For this reason, a new electronic governor and HPU will be provided.

4.2 MECHANICAL AND ELECTRICAL

4.2.1 Turbine and Generator

As discussed above, the Unit 2 will be refurbished. The refurbished unit would entail:

- New vertical Francis turbine runner (to match existing spiral case).
- Rated 7.6 m^3/s at 34.6 m of net head.
- New 2300 kW, 6.9 kV synchronous generator with static excitation, 600 rpm.
- New head cover, wicket gates, servo and bearings.

The spiral case, discharge cone and stay ring will be sandblasted, inspected and, if required, repaired in situ, then repainted.

The turbine and generator will be supplied with a new electronic governor system.

A service bay incorporating the space formerly occupied by Unit 1 will allow for sufficient lay down and maintenance space. The penstock feeding the unused turbine pit will be permanently plugged and its TIV pit modified to suit the needs of the new facility.

At this concept stage, the design details of the equipment were not specified, but it is assumed that the new/refurbished turbine and generator equipment would consist of:

- Generator:

a. Standard catalogued air-cooled generator. That is, the generator would not be a custom design.
b. Global VPI type insulation with resins that do not support combustion when energy sources are removed.
c. Inertia would consist of the natural inertia of the unit only.
d. Capable of withstanding runaway speeds for extended periods.

- Turbine:

  a. Stainless steel wicket gates.
  b. Greaseless bushings throughout.

- Turbine Inlet Valve (TIV):

  a. New butterfly valve, complete with new hydraulic actuator and counterweight closure capability, rated for single point of isolation.

- Governor:

  a. Digital PLC-based governor.
  b. High pressure HPU with a backup pump and motor.
  c. Nitrogen charged bladder-type accumulators sized to provide stored energy for 2 close strokes and one open stroke of the wicket gates and one open stroke of the TIV.

- Excitation:

  a. Static excitation.
  b. No redundant bridge.
  c. Ceiling voltage capability: 2 pu.

- The unit will be provided with vibration monitoring equipment.
- Unit control and monitoring systems and SCADA systems.
- Neutral grounding resistor.
- A cooling water filtering skid will be provided to filter cooling and shaft seal water.

The above parameters have been assumed at this time. The detailed design phase should include appropriate grid and hydraulic transient studies to determine generator and excitation system requirements. For example, these studies should include an assessment of whether brushless excitation would be acceptable instead of the more expensive static excitation included herein and ceiling voltage requirements, as well as the required generator inertia and electrical parameters.

The concept design includes the capability to restart the unit using on site stored energy (in accumulators and DC battery banks), in a fashion that is similar to the current plant and no diesel generator has been allowed for at this time. This would allow staff to restart the unit to power the station service, etc. Given the smaller size of the unit, it is unclear at this time what line charging and grid restoring capabilities this unit would have. This would have to be determined at the beginning of the detailed design phase following the results of the above-mentioned grid and hydraulic transient studies.

4.2.2 Balance of Plant

The following new mechanical balance of plant systems will be provided:

- Domestic water system.
- Sanitary waste (including holding tank and heat traced piping).
- Station drainage (including an oil/water separator).
- Compressed air system.
- HVAC (including surge tank).
- Fire protection.

Due to the powerhouse's proximity to the river, a new septic field is not feasible. Instead, a sewage holding tank will be provided. The holding tank will be buried and be equipped with heat tracing for the drain lines.

The TIV pit of Unit 1 will be converted into an oil/water separator, complete with coalescing filters/plate pack and drainage pumps (Figure 5). The oil/water separator will be housed in a concrete pit and will be sized to accommodate normal station drainage and fire protection water flows.

The fire protection system will be fed from the penstock and will be comprised of listed strainers, piping, hose stations and a fire detection and alarm system. The new generators will be fabricated with self-extinguishing insulating materials; therefore a generator deluge system will not be required.

The powerhouse and draft tube cranes will be modernized.

The powerhouse will require the following electrical balance of plant systems:

- Unit control and monitoring systems and SCADA systems.
- Neutral grounding resistor and phase cubicle (c/w surge arrestors and capacitors).
- Lighting and emergency lighting.
- Fire alarm system.
- Telephone system.
- Control and corporate data networks.
- Security and card access systems.
- Station service distribution panels and convenience transformer.
- Communication relocation.
- New cables and cable trays.
- DC power system.
- Station service transformer (SST) with an automatic transfer scheme.
- 15 kV arc-proof metal-clad switchgear (with unit protections).

All communications from Mayo B, Mayo Hydro, the Wareham spillway and the intake have fibre communication which route through Mayo Hydro. Prior to performing demolition, the communications/fibre will need to be relocated to the switchyard or otherwise bypassed. It is proposed that this equipment and cabling be permanently relocated to a new communications building in the switchyard.

Grounding for the Mayo Hydro plant appears to be provided embedded into the structure itself and where exposed, appears to be in reasonable condition. The grounding will require a ground resistivity measurement and potential upgrade.

The neutral grounding resistor will need to be replaced due to its age and to better suit the new generator. The new generator would be provided with a phase cubicle for connection of the power leads.

It has been assumed that all of the electrical balance of plant systems will be replaced. Most of the systems are at the end of their useful lives and the amount of effort and cost to reuse select components or subsystems greatly outweighs the cost of its replacement. This will apply to security and card access systems, communications, lighting, etc.

4.3 STRUCTURAL

The existing structure will need reinforcements and anchoring to meet current design codes, particularly for seismic load conditions. The existing powerhouse roof reportedly contains asbestos and would need to be encapsulated in place or removed. A new roof membrane will be installed on top of the existing structure. All windows and doors will be replaced with maintenance-free and energy efficient products.

The powerhouse block walls will need to be repointed and a new fire-rated control room will be constructed. Insulation for the roof and walls will be added. Any openings within the generator and turbine floors will be filled with concrete. If additional laydown space is required on the turbine floor, the support concrete that supported the Unit 1 generator may be removed and the floor reinforced as required; it is expected that the cost of this rework would be significant. Minor concrete rehabilitation is likely required over the concrete foundation.

Unit 1's draft tube will be sealed with a structural wall immediately behind the gate guides and then infilled with lean concrete to the generator floor level for improved structural stability. Unit 1's penstock will be plugged and a blanking plate will be installed in the powerhouse. In addition to the added mass from infilling the decommissioned draft tube, allowances have been included for the installation of post-tensioned rock anchorage to improve powerhouse stability (powerhouse anchors) for updated seismic loading.

As discussed in Section 4.1, a new surge tank superstructure will be provided. The concrete foundation has been assumed to be suitable for reuse; however, a detailed inspection will be required to confirm this.

4.4 GEOTECHNICAL

The geotechnical considerations for this option are the same as they are for Option 1. Refer to Section 3.5 for details.

4.5 COST ESTIMATE

Table 2 below outlines the total project costs. For a detailed contractor direct cost estimate, refer to Appendix C.

TABLE 2
TOTAL PROJECT COST - OPTION 2 – REFURBISHMENT

ITEM			COST
Contractor Direct Costs			**$11,870,000**
Site Work			*$120,000*
Slope, Tailrace & Access Road Stabilization			*$1,897,000*
Decommissioning and Demolition			*$497,000*
Structure Rehabilitation (Concrete, Anchoring, Repairs)			*$1,559,000*
New Structures (Powerhouse and Surge Tank)			*$266,000*
New Turbine, Generator & TIV			*$3,142,000*
Electrical and Mechanical Balance of Plant			*$4,389,000*
General Contractor Indirect Costs	**35%**	**of Directs**	**$4,150,000**
Travel and Camp Costs (or accommodations)	**6%**	**of Directs**	**$710,000**
Subtotal			**$16,730,000**
Contingency	**30%**	**of Subtotal**	**$5,020,000**
Total Construction Cost			**$21,750,000**
Contractor Markups			**$4,390,000**
Profit	*12%*	*of Const.*	*$2,610,000*
Head Office Overhead	*7.0%*	*of Const.*	*$1,523,000*
Bonding & Insurance	*1.2%*	*of Const.*	*$261,000*
Total Contractor Price			**$26,140,000**
Owner Costs			**$2,420,000**
Environmental Licencing/Consulting	*3.0%*	*of Directs*	*$356,000*
Final Design	*7.0%*	*of Directs*	*$831,000*
Site Assistance & Quality Assurance	*6.0%*	*of Directs*	*$712,000*
Owner's Administration	*2.0%*	*of Contract*	*$523,000*
Total Project Cost			**$28,600,000**

4.6 SCHEDULE

A preliminary design and construction schedule is shown on Figure 8 (end of report). A pre-design phase includes the environmental licensing and would begin immediately. The detailed design phase would include inspections of the surge tank and spiral cases, multiple studies to refine the turbine refurbishment, the generator selection, transient study, grid/electrical study, and drawings and specifications.

Turbine and generator procurement will commence during detailed design and span into the construction phase.

During construction, a total of three Mayo B plant outages are expected (1 month, 2 months, 2 weeks). The total process from pre-design to commercial operation is expected to span 2.25 to 2.5 years in duration.

5.0 OPTION 3 – REMOVE THE FACILITY AND RETURN SITE TO NEAR GREENFIELD CONDITION

Option 3 consists of returning the site to a near greenfield condition. This includes the removal of the surge tank and powerhouse, but the foundations would remain in place and be backfilled.

The following sections detail the concept design to return the site to a near greenfield condition.

5.1 DEMOLITION

The demolition will include the removal of:

- The existing powerhouse superstructure.
- Turbine/generators and their components.
- Disposal of any PCBs, lead, oil, and potentially small amounts of mercury.
- Both TIVs.
- All powerhouse mechanical and electrical systems.
- Surge tank.
- Surge tank mechanical and electrical systems.
- Draft tube gates.

The existing septic field will be abandoned in place.

5.2 COMMUNICATIONS

All communications from Mayo B, Mayo Hydro, the Wareham spillway and the intake have fibre communication which route through Mayo Hydro. Prior to performing demolition, the communications/fibre will need to be relocated to the switchyard or otherwise bypassed. It is proposed that this equipment and cabling be permanently relocated to a new communications building in the switchyard.

5.3 STRUCTURAL

The penstock upstream of the surge tank take-off would be plugged and sealed with a concrete wall.

5.4 GEOTECHNICAL

The powerhouse foundation will be backfilled, topped with topsoil, graded and potentially seeded with grass. The topsoil will extend into the existing parking lot area. The tailrace will be infilled with rockfill.

The slope stabilization, the tailrace gabion basket repair and the road repairs that are described in Section 3.5 will not be required for this option.

Following the completion of the work, the road down to Mayo Hydro will be barricaded with a barrier and a fence to prevent access.

5.5 COST ESTIMATE

Table 3 below outlines the total project costs. For a detailed contractor direct cost estimate, refer to Appendix C.

TABLE 3
TOTAL PROJECT COST - OPTION 3 – DEMOLISH AND RETURN TO GREENFIELD

ITEM			COST
Contractor Direct Costs			**$1,675,000**
Site Work			*$60,000*
Slope, Tailrace & Access Road Stabilization			*$0*
Decommissioning and Demolition			*$1,040,000*
Structure Rehabilitation (Concrete, Anchoring, Repairs)			*$0*
New Structures (Powerhouse and Surge Tank)			*$0*
New Turbine, Generator & TIV			*$0*
Electrical and Mechanical Balance of Plant			*$575,000*
General Contractor Indirect Costs	**35%**	**of Directs**	**$590,000**
Travel and Camp Costs (or accommodations)	**6%**	**of Directs**	**$100,000**
Subtotal			**$2,365,000**
Contingency	**30%**	**of Subtotal**	**$710,000**
Total Construction Cost			**$3,075,000**
Contractor Markups			**$620,000**
Profit	*12%*	*of Const.*	*$369,000*
Head Office Overhead	*7.0%*	*of Const.*	*$215,000*
Bonding & Insurance	*1.2%*	*of Const.*	*$37,000*
Total Contractor Price			**$3,695,000**
Owner Costs			**$330,000**
Environmental Licencing/Consulting	*3.0%*	*of Directs*	*$50,000*
Final Design		*	*$100,000*
Site Assistance & Quality Assurance	*6.0%*	*of Directs*	*$101,000*
Owner's Administration	*2.0%*	*of Contract*	*$74,000*
Total Project Cost			**$4,000,000**

* For options 3 & 4, design cost would be more than 7%. An allowance of $100,000 was used.

5.6 SCHEDULE

A preliminary design and construction schedule is shown on Figure 9 (end of report). A pre-design phase includes the environmental licensing and would begin immediately. The detailed design phase would include demolition, drawings and specifications detailing the work.

During construction, one Mayo B plant outage is expected (2 months) to plug the tunnel upstream of the surge tank. The total process from pre-design to project completion is expected to span 1 to 1.25 years in duration.

6.0 OPTION 4 – ABANDON THE FACILITY IN PLACE AND MAKE SAFE

Option 4 will abandon the powerhouse in place and make the site safe as required. The following sections detail the concept design to render the station safe for abandonment.

6.1 DEMOLITION

The demolition will include the removal of:

- Access ladders on the surge tank and powerhouse.
- Disposal of any PCBs, lead, oil, and potentially small amounts of mercury.
- Electrical feeds to the powerhouse.

6.2 COMMUNICATIONS

All communications from Mayo B, Mayo Hydro, the Wareham spillway and the intake have fibre communication which route through Mayo Hydro. Prior to performing demolition, the communications/fibre will need to be relocated to the switchyard or otherwise bypassed. It is proposed that this equipment and cabling be permanently relocated to a new communications building in the switchyard.

6.3 STRUCTURAL

The penstock upstream of the surge tank take-off will be plugged and sealed with a concrete wall.

The windows and doors in the powerhouse will be boarded and sealed to prevent access into the powerhouse. Access hatches to confined spaces (spiral case, surge tank, etc) will be welded shut.

6.4 GEOTECHNICAL

The slope stabilization, the tailrace gabion basket repair and the road repairs that are described in Section 3.5 will not be required for this option. The tailrace will be infilled with rockfill. Following the completion of the work, the road down to Mayo Hydro will be barricaded with a barrier and a fence to prevent access.

6.5 COST ESTIMATE

Table 4 below outlines the total project costs. For a detailed contractor direct cost estimate view Appendix C.

TABLE 4
TOTAL PROJECT COST - OPTION 4 – ABANDON IN SITU

ITEM			COST
Contractor Direct Costs			**$945,000**
Site Work			*$60,000*
Slope, Tailrace & Access Road Stabilization			*$0*
Decommissioning and Demolition			*$290,000*
Structure Rehabilitation (Concrete, Anchoring, Repairs)			*$20,000*
New Structures (Powerhouse and Surge Tank)			*$0*
New Turbine, Generator & TIV			*$0*
Electrical and Mechanical Balance of Plant			*$575,000*
General Contractor Indirect Costs	**35%**	**of Directs**	**$330,000**
Travel and Camp Costs (or accommodations)	**6%**	**of Directs**	**$60,000**
Subtotal			**1,335,000**
Contingency	**30%**	**of Subtotal**	**$400,000**
Total Construction Cost			**$1,735,000**
Contractor Markups			**$350,000**
Profit	*12%*	*of Const.*	*$208,000*
Head Office Overhead	*7.0%*	*of Const.*	*$121,000*
Bonding & Insurance	*1.2%*	*of Const.*	*$21,000*
Total Contractor Price			**$2,085,000**
Owner Costs			**$230,000**
Environmental Licencing/Consulting	*3.0%*	*of Directs*	*$28,000*
Final Design		*	*$100,000*
Site Assistance & Quality Assurance	*6.0%*	*of Directs*	*$57,000*
Owner's Administration	*2.0%*	*of Contract*	*$42,000*
Total Project Cost			**$2,300,000**

* For options 3 & 4, design cost would be more than 7%. An allowance of $100,000 was used.

6.6 SCHEDULE

A preliminary design and construction schedule is shown on Figure 10 (end of report). A pre-design phase includes the environmental licensing and would begin immediately. The

detailed design phase would include demolition, drawings and specifications detailing the greenfield site.

During construction, one Mayo B plant outage is expected (2 months) to plug the tunnel upstream of the surge tank. The total process from pre-design to project completion is expected to take less than one year.

7.0 ECONOMIC ASSESSMENT

The economic assessment of the options is summarized in Table 5 and the detailed economic assessment for each Option is detailed in Appendix D. The economic assessment of Option 1 and Option 2 was performed using the following:

- 65 year life span.
- 5.45% (nominal) weighted average cost of capital.
- 2% inflation for computing the present value.
- An assumed $7.10/MWhr operating and maintenance cost.
- $1.15/MWhr capital expenditure costs were taken from similar KGS Group projects.
- No water rental cost.

For Option 3 and 4, it was assumed that the hydro plant would continue in operation until the plant could no longer be operated. During that period regular maintenance activities would continue, however no dollars will be spent on capital expenditures. By operating only 1 unit at a time, it is assumed that:

- A 10 year remaining life span could be achieved with the hydro plant.
- 2% inflation for computing the present value.
- An assumed $7.10/MWhr operating and maintenance cost.
- No water rental cost.

YEC provided the energy benefit per MWhr for all four Options for years 2006 to 2035. The economic analysis performed in this study started at year 2016 in the provided data, and the 2035 projection was taken and extended for years 2036 to 2081 (Options 1 and 2 only).

The existing station switchgear is operating well beyond its expected life. The switchgear may operate for another 10 years of service, but proper consideration of safe working distances and operating boundaries should be incorporated into the work procedures for the site to limit potential for worker hazard in case of unexpected failure.

For all options it was assumed that the units will operate at a maximum of 2.3 MW. This reduces the power rating of Options 3 and Option 4, however with the max flow rate of 6 m^3/s (while both Mayo B units are running) this is assumed to be an accurate assumption that allows a more direct comparison between options.

To aid in comparing all options on a total present value basis, KGS Group incorporated costs of construction, operation, capital expenditures, produced energy benefit and the benefit of an increase in capacity. The energy and capacity benefit were taken from an email sent by YEC (Appendix E). The email pertains to the "Aishihik Rerate and Assessment" project performed by KGS Group, which assessed a comparable project and was assumed to be acceptable for this analysis. The email states the following:

- Benefit of an increase in capacity - $2.5M per MW based on avoided capital cost of new natural gas generation.
- Benefit of an increase in annual energy - $200,000 per GWh based on avoided operating (i.e. variable cost) cost of natural gas.
- Sensitivity analysis for energy benefit going from $100,000 (best possible natural gas operating cost) to $300,000 (diesel operating cost).

These options do not increase the total capacity of YEC system, however Option 3 and 4 will reduce the capacity and the "benefit of an increase in capacity" will act negatively to those options.

TABLE 5
ECONOMIC ANALYSIS SUMMARY

	OPTION 1 REDEVELOPMENT	OPTION 2 REFURBISHMENT	OPTION 3 DEMOLITION	OPTION 4 ABANDON IN SITU
Assessment Factors				
Total Project Cost	$32,000,000	$28,600,000	$4,000,000	$2,300,000
Plant Size (MW)	2.3	2.3	2.3	2.3
Annual Energy (GWhrs/yr)	10.4	10.4	7.2	7.2
Life Cycle Costs - Present Value				
Total Operating Costs	$2,100,000	$2,100,000	$500,000	$500,000
Total Capital Expenditures	$400,000	$400,000	$0	$0
Energy Benefits - Present Value				
MWhr Produced - Year 1 to 10 (Present Value)	98,771	98,771	57,278	57,278
MWhr Produced - Year 11 to 65 (Present Value)	106,528	106,528	0	0
Total MWhr Produced (Present Value)	205,300	205,300	57,278	57,278
Total Energy Benefit (@ $200/MWhr)	$41,100,000	$41,100,000	$11,500,000	$11,500,000
Increased Capacity Benefit - Present Value				
Capacity Increase (MW)	0	0	-2.3	-2.3
Total Benefit (@ $2.5M/MW)	$0	$0	-$5,750,000	-$5,750,000
Cost Indicators				
Total Present Value	$6,600,000	$10,000,000	$1,250,000	$2,950,000
Installed Project Cost ($/kW)	$13,910	$12,430		
Levelized Cost ($/kWhr)	$0.17	$0.15		
Levelized Cost ($/MWhr)	$166	$150		

The assessment in Table 5 shows that Option 2 has the greatest total present value and lowest levelized cost. Both Option 1 and 2 have a large present value compared to Option 3 and 4. Option 1 and 2 do have a large initial cost, however this cost does contain a 30% contingency and would need to be developed further to achieve a cost estimate with an improved accuracy. Option 2 is more viable than Option 1 mainly due to costs associated with demolition and construction of a new powerhouse, new cranes, new embedded components (spiral case and stay ring) and additional concrete work. Otherwise, Option 1 and 2 will have the same produced

energy benefit, maintenance costs and capital expenditures. The success of Option 1 and 2 may be highly dependent on the assumed energy benefits, so a sensitivity analysis was performed and the results are summarized in Table 6 below and they are graphically represented in Figure 6.

TABLE 6
ENERGY BENEFITS SENSITIVITY ANALYSIS

	OPTION 1 REDEVELOPMENT	OPTION 2 REFURBISHMENT	OPTION 3 DEMOLITION	OPTION 4 ABANDON IN SITU
Total Present Value (@ $100/MWhr)	-$14,000,000	-$10,600,000	-$4,600,000	**-$2,900,000**
Total Present Value (@ $125/MWhr)	-$8,900,000	-$5,500,000	-$3,100,000	**-$1,400,000**
Total Present Value (@ $150/MWhr)	-$3,800,000	-$400,000	-$1,700,000	**$100,000**
Total Present Value (@ $175/MWhr)	$1,500,000	**$4,900,000**	-$300,000	$1,500,000
Total Present Value (@ $200/MWhr – Reference Price)	$6,600,000	**$10,000,000**	$1,300,000	$3,000,000
Total Present Value (@ $225/MWhr)	$11,700,000	**$15,100,000**	$2,700,000	$4,400,000
Total Present Value (@ $250/MWhr)	$16,900,000	**$20,300,000**	$4,100,000	$5,800,000
Total Present Value (@ $275/MWhr)	$22,000,000	**$25,400,000**	$5,600,000	$7,300,000
Total Present Value (@ $300/MWhr)	$27,100,000	**$30,500,000**	$7,000,000	$8,700,000

Note 1: Bolded cells indicate the highest present value for each energy benefit rate.
Note 2: Shaded cells indicate a positive present value.

Table 6 shows that Option 2 has the best total present value at energy benefits slightly above $150/MWhr and higher, and that Option 1 becomes more viable than Option 3 and 4 for an energy benefit of approximately $175/MWhr and higher.

The economics of Option 3 and 4 are highly dependent on the assumed increased capacity benefits, so a sensitivity analysis was performed using a constant energy benefit of $200,000 per GWHr and the results are summarized in Table 7.

TABLE 7
INCREASED CAPACITY BENEFITS SENSITIVITY ANALYSIS

	OPTION 1 REDEVELOPMENT	OPTION 2 REFURBISHMENT	OPTION 3 DEMOLITION	OPTION 4 ABANDON IN SITU
Total Present Value (@ $2.5M/MW – Reference Benefit)	$6,600,000	$10,000,000	$1,250,000	$2,950,000
Total Present Value (@ $4.5M/MW)	$6,600,000	$10,000,000	-$3,350,000	-$1,650,000
Total Present Value (@ $6M/MW)	$6,600,000	$10,000,000	-$6,800,000	-$5,100,000

Table 7 shows that the economics of Option 3 and 4 become progressively worse as the increased capacity benefit increases.

8.0 RECOMMENDATION

Based on the results of the economic assessment, the refurbishment of the existing plant (Option 2) is recommended as it has the highest present value and lowest levelized cost of energy for energy benefit rates slightly in excess of $150,000 per GWHr and higher, for all capacity benefit rates studied.

Should this project proceed, the following is a list of activities that will be required:

- Environmental Approval and Licensing.
- Inspection of surge tank and spiral cases.
- Study on whether to replace or reuse the runner.
- Refinement of runner/turbine rating (if runner is replaced).
- Hydraulic transient study.
- Grid/electrical parameters study.
- Detailed design, drawings and specifications.
- Equipment procurement.
- Construction.
- Commissioning.

9.0 STATEMENT OF LIMITATIONS AND CONDITIONS

9.1 THIRD PARTY USE OF REPORT

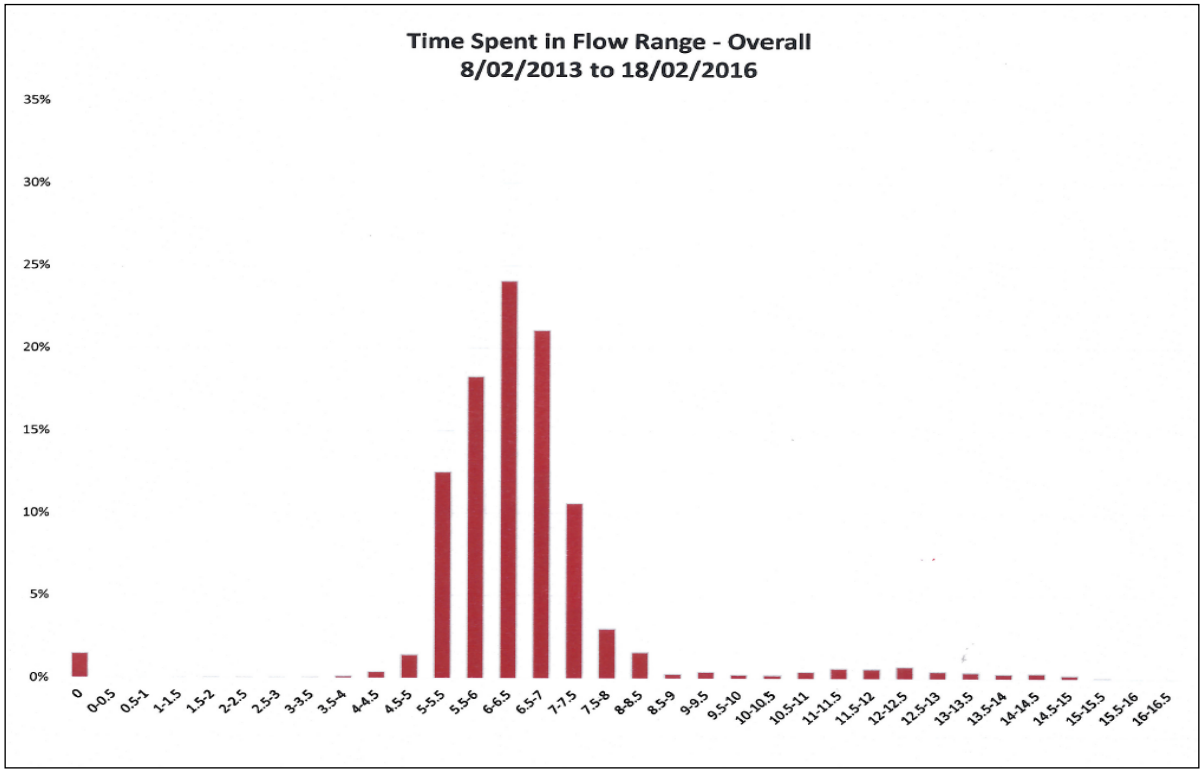
This report has been prepared for the Yukon Energy Corporation to whom this report has been addressed and any use a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

9.2 CAPITAL COST ESTIMATE STATEMENT OF LIMITATIONS

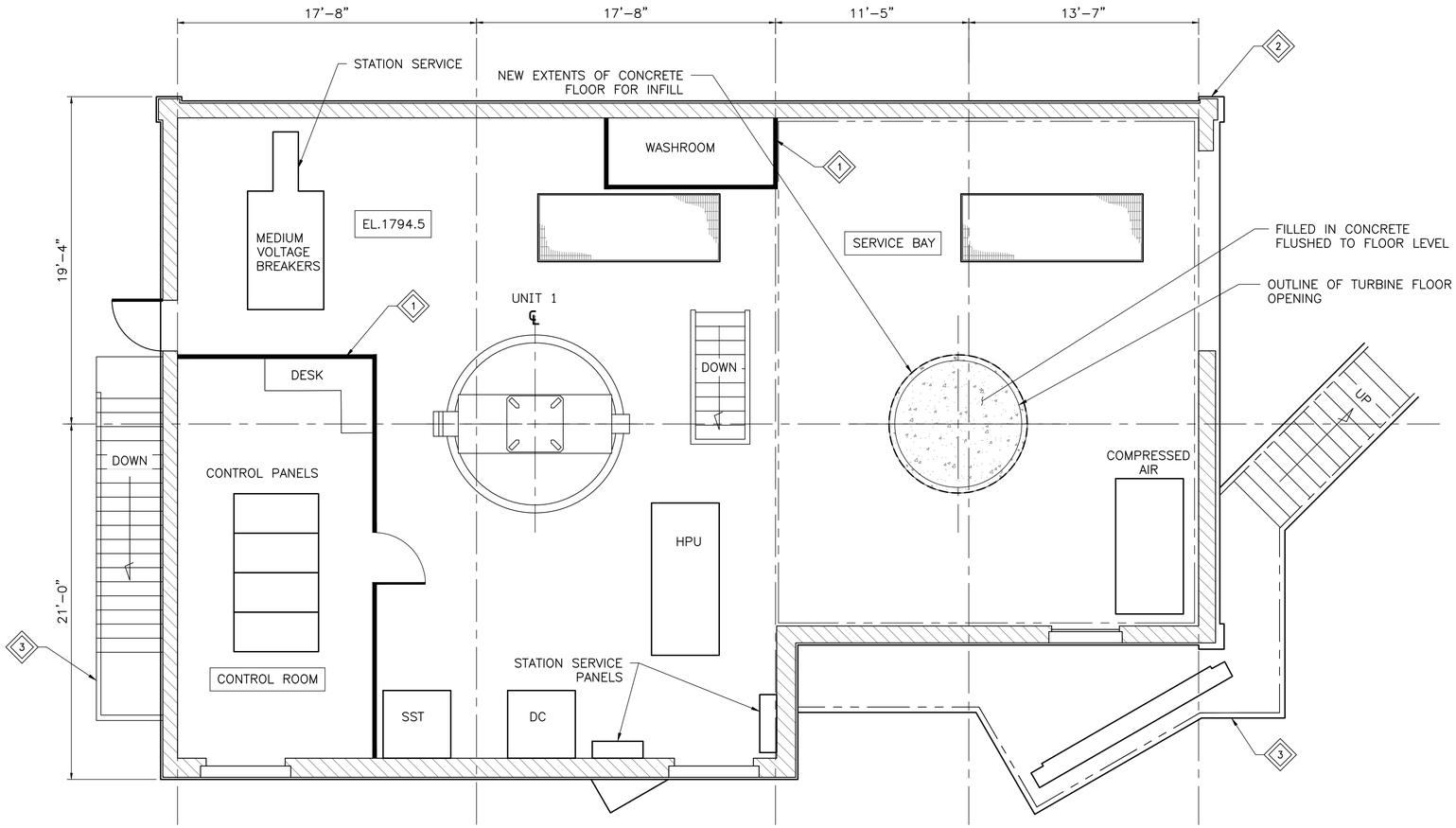
The cost estimates included with this report have been prepared by KGS Group using its professional judgment and exercising due care consistent with the level of detail required for the stage of the project for which the estimate has been developed. These estimates represent KGS Group's opinion of the probable costs and are based on factors over which KGS Group has no control. These factors include, without limitation, site conditions, availability of qualified labour and materials, present workload of the Bidders at the time of tendering and overall market conditions. KGS Group does not assume any responsibility to the Client, in contract, tort or otherwise in connection with such estimates and shall not be liable to the Client if such estimates prove to be inaccurate or incorrect.

FIGURES

FIGURE 1
TIME SPENT (%) IN FLOW RANGE (M^3/S) – OVERALL



11x17



TURBINE GENERATOR ARRANGEMENT PLAN

5 0 5 10 FT.

SCALE: 1/4"=1'-0" (24" X 36")

NOTES:

1. ONLY MAJOR EQUIPMENT LAYOUT IS SHOWN.
2. ALL EQUIPMENT IS NEW UNLESS LABELED AS EXISTING

KEY NOTES:

1. NEW ROOM
2. NEW POWERHOUSE SUPERSTRUCTURE
3. EXISTING TO REMAIN

LEGEND:

SST	STATION SERVICE TRANSFORMER
DC	DIRECT CURRENT
HPU	HYDRAULIC POWER UNIT

NO.	YY/MM/DD	DESCRIPTION	ISSUED BY	CHECK BY
B	16/07/25	ISSUED FOR DESIGN REPORT	DAG	JCL
A	16/05/10	ISSUED FOR DESIGN REPORT	DAG	JCL

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YUKON ENERGY

MAYO A FUTURE OPTIONS
OPTION 1 – REPLACE THE FACILITY

POWERHOUSE PLAN
MAIN FLOOR LAYOUT

JULY_2016 | FIGURE 2 | REV: B

FileName: U:\FMS\16-1404-002\16-1404-002_FIGURE 2.dwg – Tab: Rev B Plotted By: cabellanosa 16/07/22 [Fri 2:44pm]
11"x17" PLOT SCALE: 1:2

11x17

N

NOTES:

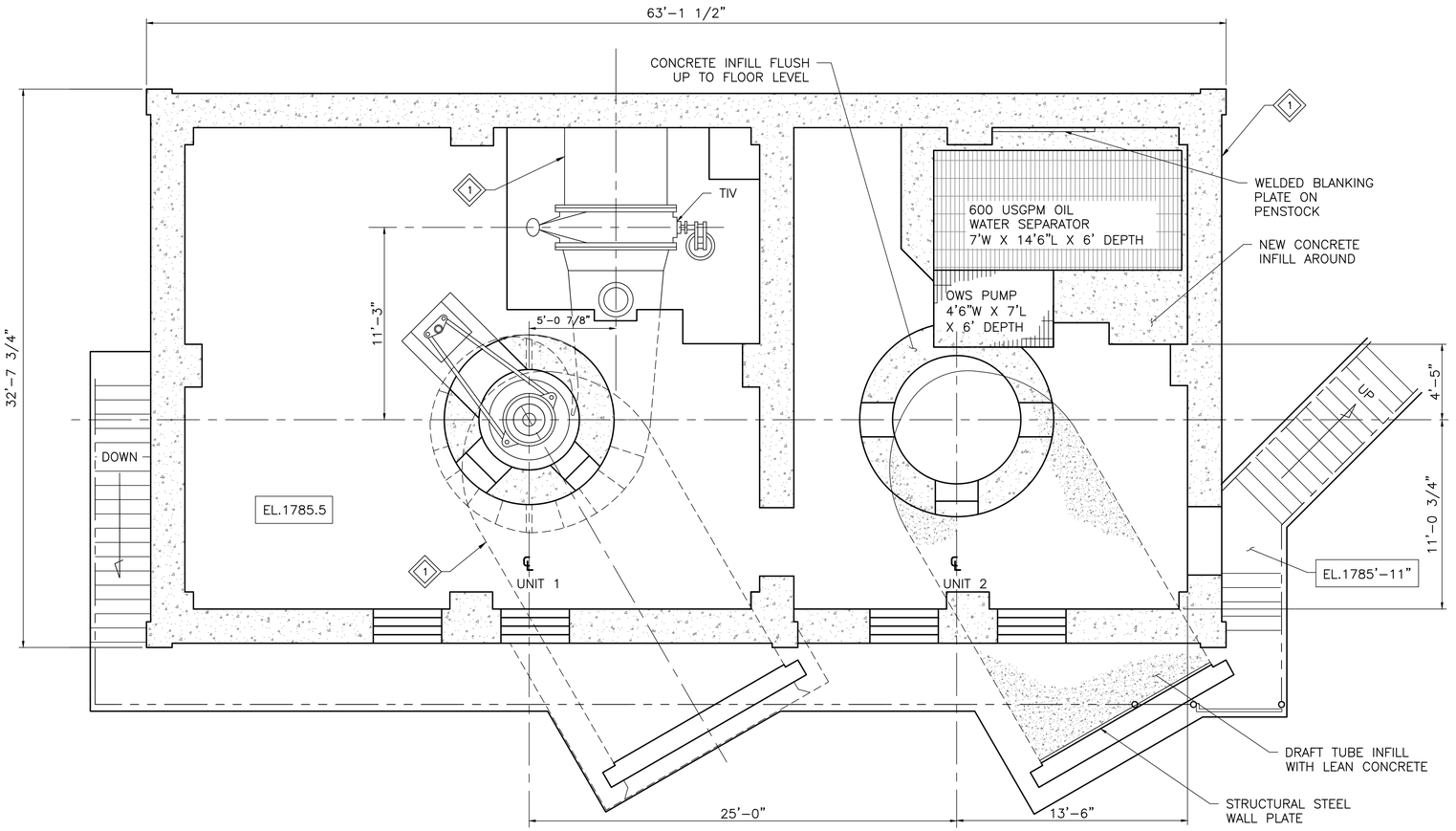
1. ONLY MAJOR EQUIPMENT LAYOUT IS SHOWN.
2. ALL EQUIPMENT IS NEW UNLESS LABELED AS EXISTING

KEY NOTES:

1 EXISTING TO REMAIN

LEGEND:

OWS	OIL WATER SEPARATOR
TIV	TURBINE INLET VALVE



TURBINE ARRANGEMENT BASEMENT PLAN

5 0 5 10 FT.

SCALE: 1/4"=1'-0" (24" X 36")

NO.	YY/MM/DD	DESCRIPTION	ISSUED BY	CHECK BY
B	16/07/25	ISSUED FOR DESIGN REPORT	DAG	JCL
A	16/05/10	ISSUED FOR DESIGN REPORT	DAG	JCL

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MAYO A FUTURE OPTIONS
OPTION 1 – REPLACE THE FACILITY

POWERHOUSE PLAN
BASEMENT LAYOUT

JULY_2016	FIGURE 3	REV: B

FileName: U:\PMS\16-1404-002\16-1404-002_FIGURE 3.dwg – Tab: Rev B Plotted By: cabellanosa 16/07/22 [Fri 2:43pm]
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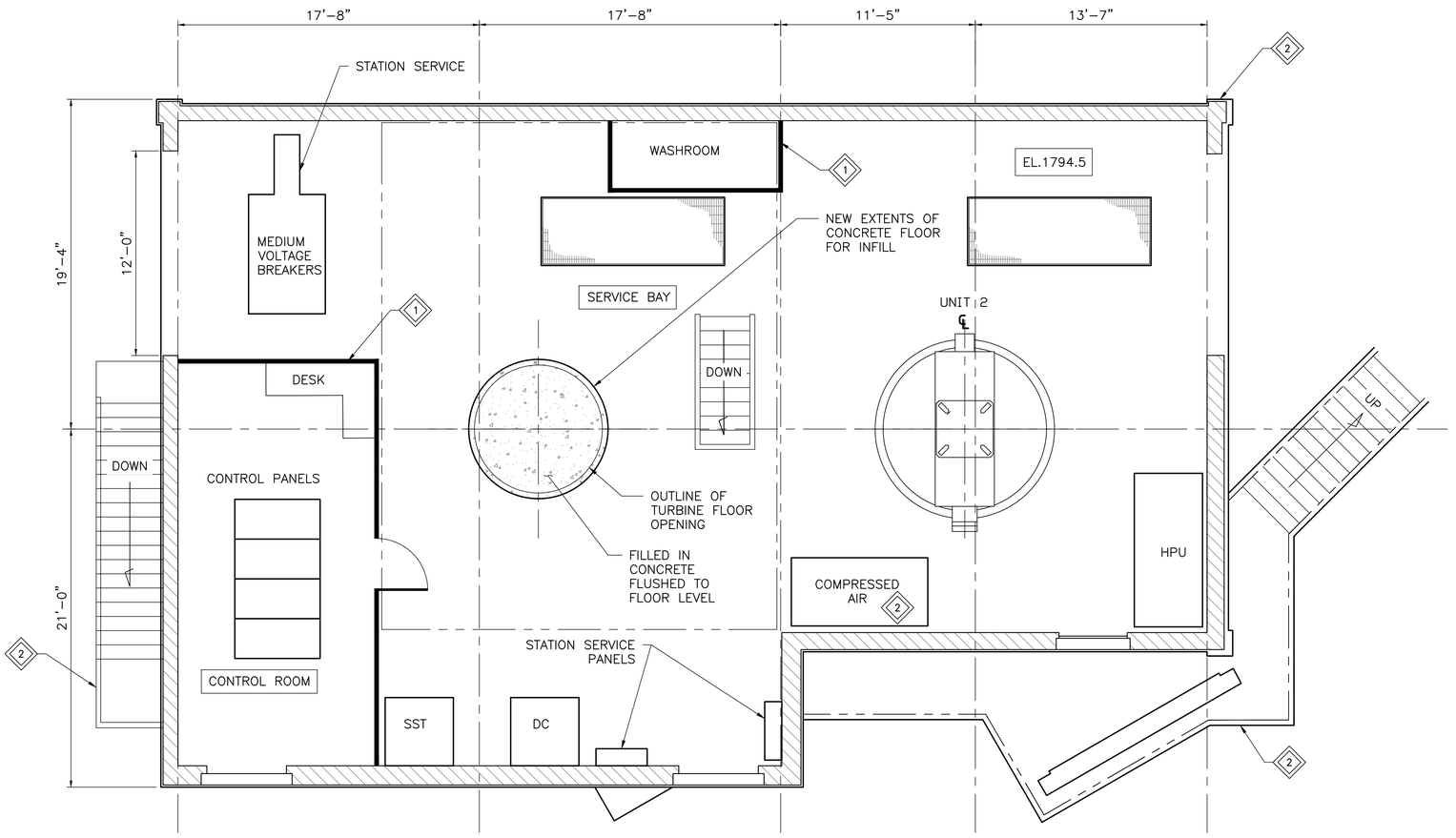
11x17



NOTES:

1. ONLY MAJOR EQUIPMENT LAYOUT IS SHOWN.
2. ALL EQUIPMENT IS NEW UNLESS LABELED AS EXISTING

KEY NOTES:

1 NEW ROOM

2 EXISTING TO REMAIN

LEGEND:

SST	STATION SERVICE TRANSFORMER
DC	DIRECT CURRENT
HPU	HYDRAULIC POWER UNIT

TURBINE GENERATOR ARRANGEMENT PLAN

5 0 5 10 FT.

SCALE: 1/4"=1'-0" (24" X 36")

NO.	YY/MM/DD	DESCRIPTION	ISSUED BY	CHECK BY
B	16/07/25	ISSUED FOR DESIGN REPORT	DAG	JCL
A	16/05/10	ISSUED FOR DESIGN REPORT	DAG	JCL

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YUKON ENERGY

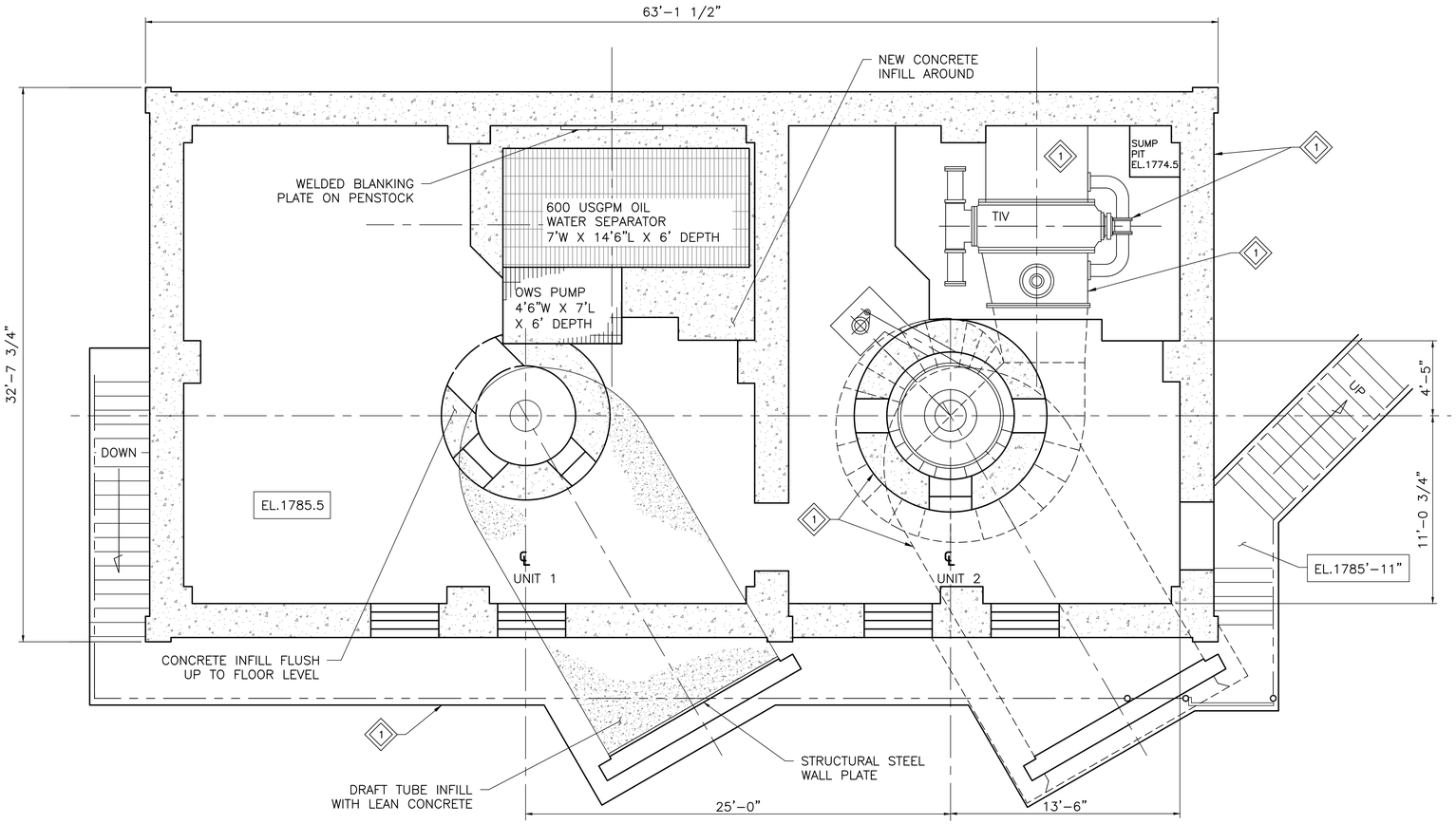
MAYO A FUTURE OPTIONS
OPTION 2 – REFURBISH THE FACILITY

POWERHOUSE PLAN
MAIN FLOOR LAYOUT

JULY_2016 | FIGURE 4 | REV: B

FileName: U:\PMS\16-1404-002\16-1404-002_FIGURE 4.dwg – Tab: Rev B Plotted By: cabellanosa 16/07/22 [Fri 2:42pm]
11"x17" PLOT SCALE: 1:2

11x17



TURBINE ARRANGEMENT BASEMENT PLAN

5 0 5 10 FT.

SCALE: 1/4"=1'–0" (24" X 36")

NOTES:

1. ONLY MAJOR EQUIPMENT LAYOUT IS SHOWN.
2. ALL EQUIPMENT IS NEW UNLESS LABELED AS EXISTING

KEY NOTES:

1 EXISTING TO REMAIN

LEGEND:

OWS	OIL WATER SEPARATOR
TIV	TURBINE INLET VALVE

NO.	YY/MM/DD	DESCRIPTION	ISSUED BY	CHECK BY
B	16/07/25	ISSUED FOR DESIGN REPORT	DAG	JCL
A	16/05/10	ISSUED FOR DESIGN REPORT	DAG	JCL

REVISIONS / ISSUE

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YUKON ENERGY

MAYO A FUTURE OPTIONS
OPTION 2 – REFURBISH THE FACILITY

POWERHOUSE PLAN
BASEMENT LAYOUT

JULY_2016 | FIGURE 5 | REV: B

FileName: U:\FMS\16-1404-002\16-1404-002_FIGURE 5.dwg – Tab: Rev B Plotted By: cabellanosa 16/07/22 [Fri 2:42pm]
11"x17" PLOT SCALE: 1:2

FIGURE 6
NET PRESENT VALUE (NPV) VS ENERGY BENEFIT ($/MWHR)

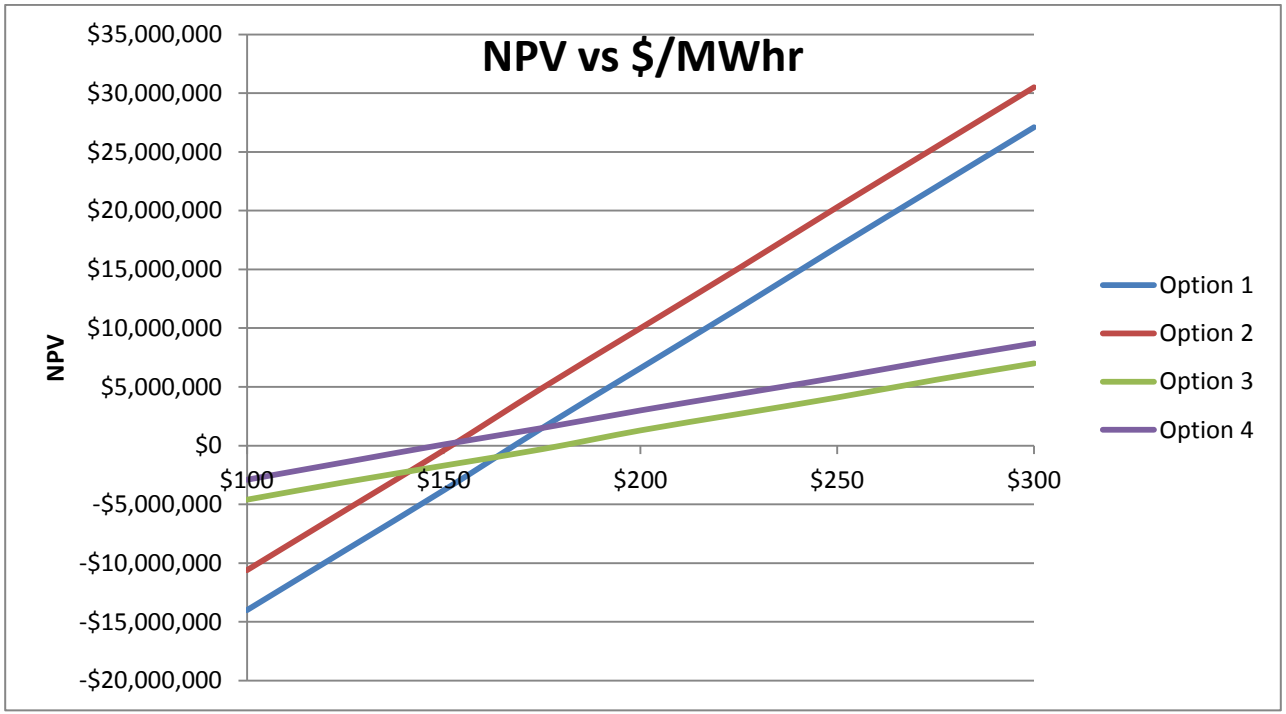
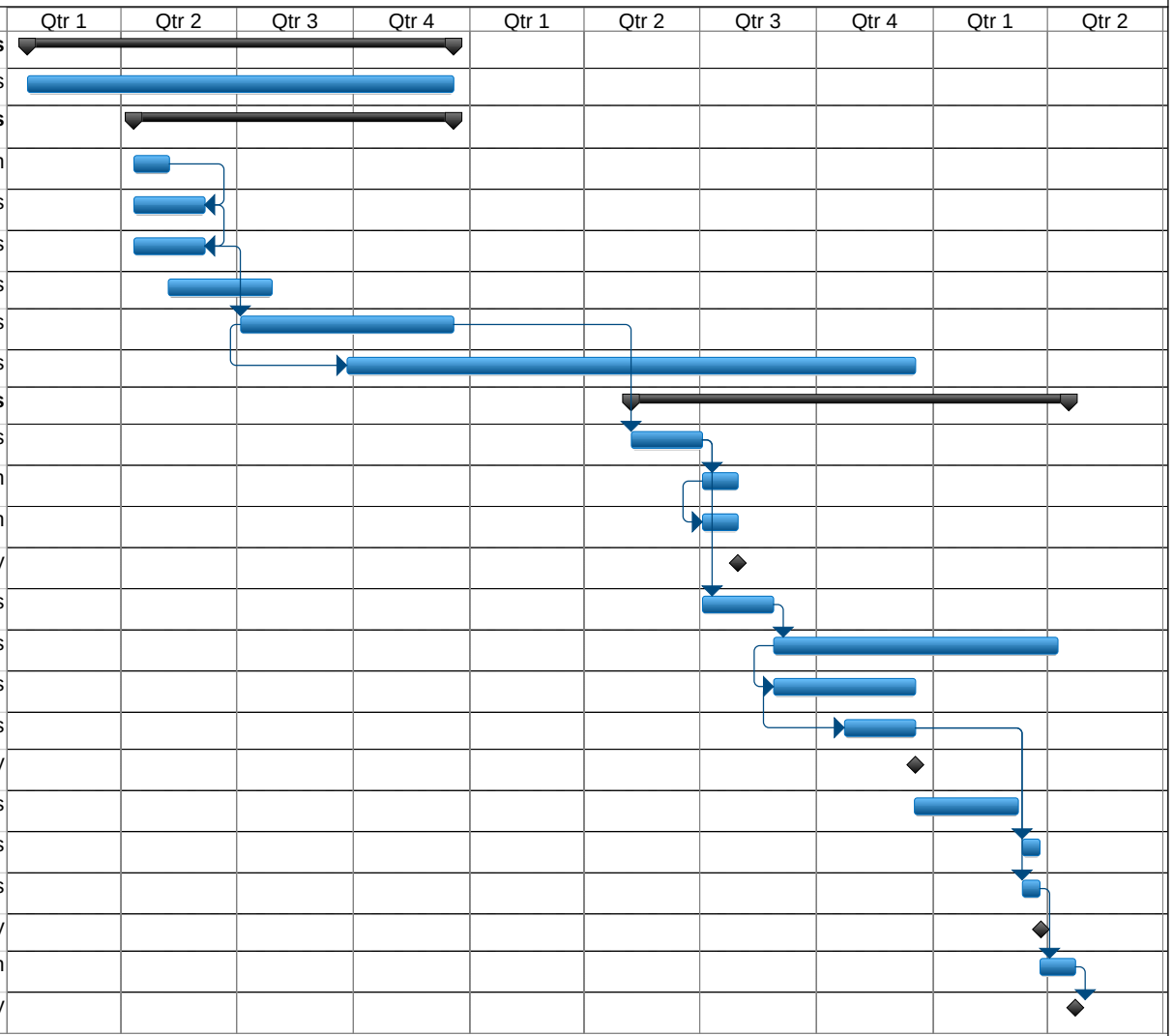


Figure 7: Mayo Hydro Preliminary Schedule - Option 1

ID	Task Name	Duration
1	**Pre-design Phase**	**240 days**
2	Environmental Approval & Licensing	12 mons
3	**Detailed Design Phase**	**9 mons**
4	Inspection of surge tank and scroll cases	1 mon
5	Refinement of runner study	2 mons
6	Transient Study	2 mons
7	Grid study/electrical parameters	3 mons
8	Drawings and specifications	6 mons
9	T&G Procurement	16 mons
10	**Construction**	**247 days**
11	Mobilization and start-up	2 mons
12	Dewater Mayo Hydro & Mayo B	1 mon
13	Plug unused penstock, blank off TIV	1 mon
14	Rewater Mayo B	1 day
15	Demolition	2 mons
16	Mechanical and Electrical Balance of Plant	8 mons
17	Powerhouse structural work	4 mons
18	Dewater Mayo B and install surge tank, install new TIV	2 mons
19	Rewater Mayo B	1 day
20	Install Turbine and Generator equipment	3 mons
21	Dewater Mayo B	2 wks
22	Commission TIV	2 wks
23	Rewater Mayo B	1 day
24	Commission Turbine and generators	1 mon
25	Commercial Operation	1 day

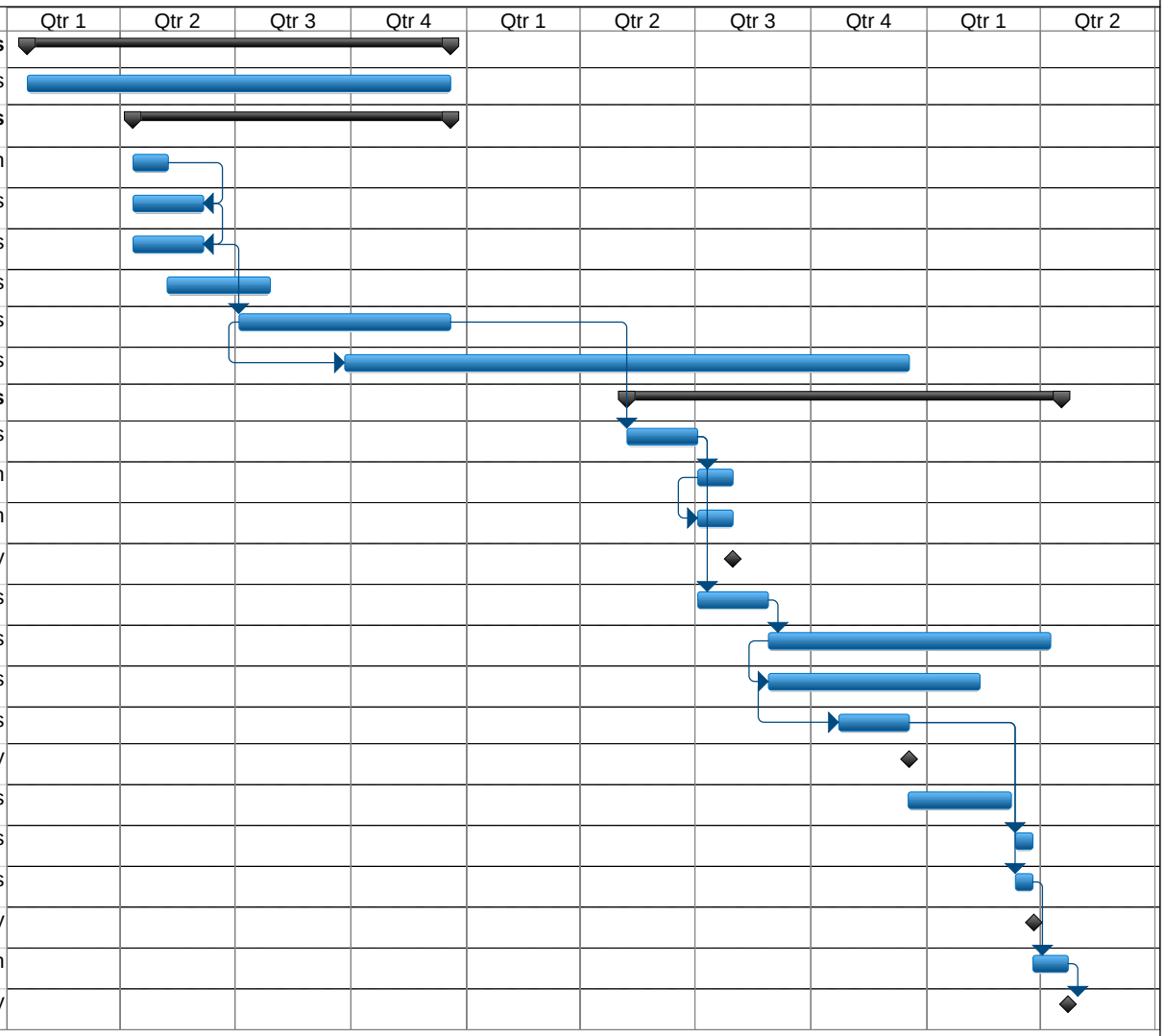


Date: 18/07/2016

Summary Task Milestone

Figure 8: Mayo Hydro Preliminary Schedule - Option 2

ID	Task Name	Duration
1	**Pre-design Phase**	**240 days**
2	Environmental Approval & Licensing	12 mons
3	**Detailed Design Phase**	**9 mons**
4	Inspection of surge tank and scroll cases	1 mon
5	Refinement of runner study	2 mons
6	Transient Study	2 mons
7	Grid study/electrical parameters	3 mons
8	Drawings and specifications	6 mons
9	T&G Procurement	16 mons
10	**Construction**	**247 days**
11	Mobilization and start-up	2 mons
12	Dewater Mayo Hydro & Mayo B	1 mon
13	Plug unused penstock, blank off TIV	1 mon
14	Rewater Mayo B	1 day
15	Demolition	2 mons
16	Mechanical and Electrical Balance of Plant	8 mons
17	Powerhouse structural work	6 mons
18	Dewater Mayo B and install surge tank, install new TIV	2 mons
19	Rewater Mayo B	1 day
20	Install Turbine and Generator equipment	3 mons
21	Dewater Mayo B	2 wks
22	Commission TIV	2 wks
23	Rewater Mayo B	1 day
24	Commission Turbine and generators	1 mon
25	Commercial Operation	1 day



Date: 18/07/2016

Summary Task Milestone

Figure 9: Mayo Hydro Preliminary Schedule - Option 3

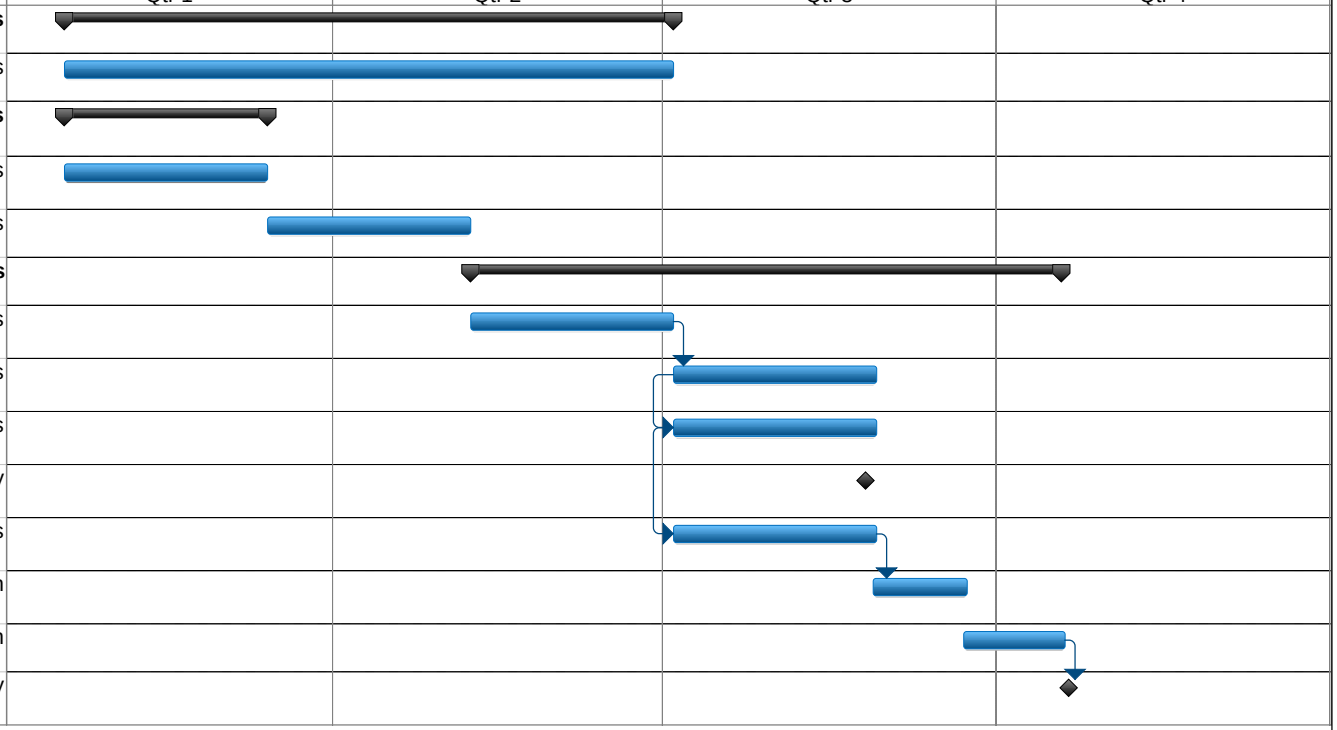
ID	Task Name	Duration
1	**Pre-design Phase**	**120 days**
2	Environmental Approval & Licensing	6 mons
3	**Detailed Design Phase**	**3 mons**
4	Drawings and specifications	3 mons
5	Tender	2 mons
6	**Construction**	**179 days**
7	Mobilization and start-up	2 mons
8	Dewater Mayo Hydro & Mayo B	2 mons
9	Plug tunnel	2 mons
10	Rewater Mayo B	1 day
11	Communication relocation	2 mons
12	Demolition	2 mons
13	Backfill and grade powerhouse and tailrace	2 mons
14	Access barriers	1 mon
15	Project Completion	1 day

Date: 18/07/2016

Summary Task Milestone

Figure 10: Mayo Hydro Preliminary Schedule - Option 4

ID	Task Name	Duration
1	**Pre-design Phase**	**120 days**
2	Environmental Approval & Licensing	6 mons
3	**Detailed Design Phase**	**2 mons**
4	Drawings and specifications	2 mons
5	Tender	2 mons
6	**Construction**	**117 days**
7	Mobilization and start-up	2 mons
8	Dewater Mayo Hydro & Mayo B	2 mons
9	Plug tunnel	2 mons
10	Rewater Mayo B	1 day
11	Communication relocation	2 mons
12	Demolition	1 mon
13	Access barriers	1 mon
14	Project Completion	1 day



Date: 18/07/2016

Summary Task Milestone

APPENDIX A

MAYO HYDRO AND MAYO B GENERATING STATIONS
OPTIMIZING PLANT OPERATIONS TESTING RESULTS, MAY 2013

Kontzamanis Graumann Smith MacMillan Inc.

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May 9, 2014 File No. 09-1404-01.02.08.DN300.44.0

Yukon Energy Corporation
P.O. Box 4190
Whitehorse, Yukon
Y1A 3T4

ATTENTION: Mr. Ron Gee
Water Management Engineer

RE: Mayo A and Mayo B Generating Stations
Optimizing Plant Operations Testing Results, May 2013

Dear Mr. Gee:

The Mayo B Hydroelectric Project was designed to operate with a total combined Mayo A and Mayo B flow of 25 m^3/s (19 m^3/s through Mayo B and 6 m^3/s through Mayo A). Yukon Energy Corporation (YEC) has indicated their wish to maximize the capacity of the Mayo complex by increasing these combined flows. The purpose of this letter is to describe the findings of the testing done in May 2013 and the subsequent analysis that was carried out to investigate the extent to which this can be achieved, while ensuring that adequate pressures are maintained in the penstock to Mayo B. Operating the Mayo A and B plants outside of the original design flow conditions can augment energy production; but it also carries increased risk to the penstock unless the acceptable operating conditions are maintained.

The analysis and recommendations are presented in detail in Appendix A.

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Recommended maximum Mayo A flows for given Wareham Lake levels and Mayo B flows are presented in the following table:

RECOMMENDED ALLOWABLE MAYO A FLOWS

Wareham Lake Water Level (m)	Mayo A Maximum Flows (m^3/s)						
	One Mayo B Unit Running at Any Flow	Two Mayo B units Running at:					
		8.0 m^3/s Total	10.0 m^3/s Total	12.5 m^3/s Total	15.0 m^3/s Total	17.5 m^3/s Total	20.5 m^3/s Total
573.5	8.7	**Wareham Lake below Minimum Level for Operation of 2 Mayo B Units**					
573.6	10.0						
573.7	11.2						
573.8	12.3						
573.9	13.3	6.0	6.0	6.0	6.0	6.0	
574.0	14.2	6.0	6.0	6.0	6.0	6.0	
574.1	15.1	6.0	6.0	6.0	6.0	6.0	
574.2	15.9	6.0	6.0	6.0	6.0	6.0	
574.3	16.7	6.0	6.0	6.0	6.0	6.7	6.7
574.4	17.0	6.0	6.0	6.0	6.0	8.3	8.3
574.5	**17.0**	**6.0**	**6.0**	**6.0**	**7.5**	**9.7**	**9.7**

MAXIMUM ALLOWABLE MAYO A FLOWS

The effect of limiting wicket gate openings at Mayo B to 83% was investigated and calculated values for maximum allowable Mayo A flows are presented in Table 4 of Appendix A. The flows shown in that table are theoretically acceptable if the Mayo B wicket gates are limited to 83% or less. However, there is a risk that wicket gate limits which are not physically imposed could be inadvertently removed or defeated in the future, putting the penstock at risk.

The following limits are recommended for pressure levels at the air vent shaft at the tunnel intake:

- Minimum with two Mayo B units in operation: El. 573.4 m
- Minimum with one Mayo B unit in operation: El. 572.9 m

It is recommended that the overall head losses along the intake and conveyance system be monitored and reviewed periodically (suggest minimum of every 3 years) and if/when an event occurs that raises concerns about the integrity of the system, and that the water levels at PI2 and at the air vent shaft be monitored continuously.

If monitoring data shows increased head losses with respect to those obtained during the May 2013 tests, it is recommended to assess the situation and adjust the plant flows to maintain the

levels at PI2 stipulated in the plant operational limits. Increased head losses are indication of changes in the conveyance system, possibly debris accumulation or ice blockage at the trashracks or along the tunnel or penstock. These would need to be corrected to restore the allowable flows indicated in this letter.

Other operational conditions at the Mayo plants are recommended to be maintained. These are:

Mayo B Flows:

- Minimum: 4 m^3/s per unit

Mayo A Flows:

- No limits when Mayo B not operated

Levels at PI2 (highest point in the Mayo B penstock):

- Low Alarm: El. 572.5 m
- Low-Low Alarm (Shutdown): El. 572.2 m

In preparing this letter, KGS Group has assumed that YEC will confirm that intake flows in excess of 25 m^3/s are in full accordance with the environmental license for the tunnel intake at Wareham Lake and its trashrack, and that YEC will undertake any regulatory requirements, if necessary, to modify the terms and conditions of the license to allow these flows. This report addresses only the technical aspects of increasing the maximum flow at the plants beyond the design values and the implications with respect to penstock pressures.

This letter has been prepared for Yukon Energy Corporation to whom it has been addressed and any use that a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

Should you have questions regarding this assessment, please contact the undersigned.

Prepared By:

Fuad Curi, P.Eng.
Senior Water Resources Engineer

Approved By:

Gord McPhail, P.Eng.
Senior Specialist Engineer

cc: Lawrence Joudry and Guy Morgan of Yukon Energy Corporation
Rick Martin and Joel Lambert of KGS Group

PROFESSIONAL ENGINEER
YUKON TERRITORY
GORDON D. McPHAIL
May 9 2017

APPENDIX A

MAYO A AND MAYO B GENERATING STATIONS
OPTIMIZING PLANT OPERATIONS TESTING RESULTS, MAY 2013
DETAILED ANALYSIS AND RECOMMENDATIONS

1.0 BACKGROUND INFORMATION

The operational limits for Mayo B (range of forebay levels and flows) have been revised using data obtained during the first two years of operation of the plant and are summarized in the KGS Group letter: *Mayo B Hydroelectric Project – Operational Conditions for the Mayo B Plant (Ref. 1)*. The conditions indicated in that letter are as follows:

Forebay Levels at Wareham Lake:

- Maximum: El. 574.5 m
- Minimum with two Mayo B units in operation: El. 573.9 m
- Minimum with one Mayo B unit in operation: El. 573.5 m

Mayo B Flows:

- Minimum: 4 m^3/s per unit
- Maximum: 9.5 m^3/s per unit

Mayo A Flows:

- Maximum: 6 m^3/s with two Mayo B units in operation: El. 573.9 m
- No limits when Mayo B not operated

Levels at PI2 (highest point in the Mayo B penstock):

- Low Alarm: El. 572.5 m
- Low-Low Alarm (Shutdown): El. 572.2 m

Levels downstream of the trashracks:

- Minimum with two Mayo B units in operation: El. 573.7 m
- Minimum with one Mayo B unit in operation: El. 573.3 m

The stipulated minimum level at PI2 ensures that at this point the design safety margins will be maintained in all operation conditions considered during the design.

2.0 TEST DATA COLLECTED

The data collected from tests conducted on May 28 and 29 of 2013 allowed the review of the operational limits described in this letter. The recommendations here provided are based on the status of the system during these tests. Conditions could arise in the future that could cause exacerbated head losses at any point in the system. For instance, the trashracks could become severely blocked by debris or, with time, there is algae growth or physical deterioration of the tunnel, or corrosion of the penstock. Should any factor change with time to increase the system head losses observed, the allowable flows presented in this letter would need to be reduced to maintain operation of the plants within the specified limits.

Overall monitoring of pressure levels and the alarms at PI2 is required to allow early detection of conditions within the conveyance system that exceed the specified design conditions. It is recommended that the overall conveyance system head losses be reviewed periodically (every 3 years would be a reasonable guide) and/or if an event occurs that raises concerns about the integrity of the system. The water levels at PI2 and at the trashrack shall continue to be monitored continuously.

2.1 CONVEYANCE SYSTEM FLOWS, PRESSURES AND POWER AT THE PLANTS

The measurements obtained during the tests included flows at Mayo B, Wareham Lake levels, pressures at PI2, pressures at the inlet of the Mayo B turbines as well as generated power and wicket gate openings at the Mayo A and Mayo B turbines. These were obtained for various conditions of flows in Mayo A and Mayo B and are summarized in Table 1.

TABLE 1: SUMMARY OF COLLECTED DATA IN MAY 2013

Time Frame		Average Wareham Lake Level (m)	Average PI2 Level (m)	Average Flow (m^3/s)		Power (MW)		Gate Opening % (Mayo A)		Gate Opening % (Mayo B)		Piezometric head difference Lake - PI2 (m)
From	To			Mayo A	Mayo B	Mayo A	Mayo B	MH1	MH2	MBH1	MBH2	
28/05/2013 8:00	28/05/2013 9:00	574.32	572.98	5.9	17.2	1.6	8.7	0	49	82	80	1.34
28/05/2013 10:31	28/05/2013 11:00	574.33	572.62	6.1	20.6	1.7	9.9	0	52	99	99	1.71
28/05/2013 11:21	28/05/2013 11:30	574.32	572.51	7.2	20.5	1.7	9.8	21	53	99	99	1.82
28/05/2013 11:40	28/05/2013 12:20	574.32	572.32	10.1	20.5	2.7	9.8	47	49	99	99	2.00
28/05/2013 13:20	28/05/2013 14:00	574.30	572.10	12.3	20.5	3.5	9.7	61	57	99	99	2.20
28/05/2013 14:55	28/05/2013 14:55	574.29	572.13	16.8	15.0	4.9	7.4	87	87	73	73	2.16
28/05/2013 15:50	28/05/2013 16:00	574.28	572.83	6.2	18.1	1.7	9.2	0	53	86	86	1.45
28/05/2013 16:30	28/05/2013 17:00	574.28	573.02	5.6	16.5	1.5	8.4	0	47	78	78	1.26
29/05/2013 8:30	29/05/2013 9:00	574.25	572.02	12.7	20.5	3.6	9.7	62	58	99	99	2.23
29/05/2013 9:15	29/05/2013 9:35	574.24	571.75	15.2	20.5	4.5	9.6	75	70	99	99	2.49
29/05/2013 9:44	29/05/2013 9:48	574.24	572.06	12.3	20.6	3.5	9.7	60	56	99	99	2.18
29/05/2013 9:55	29/05/2013 10:05	574.24	572.26	10.0	20.5	2.6	9.8	48	44	99	99	1.98
29/05/2013 10:20	29/05/2013 10:35	574.23	572.84	6.0	17.7	1.6	9.0	0	51	84	84	1.40
29/05/2013 11:50	29/05/2013 12:10	574.23	573.17	16.4	4.6	4.8	2.0	79	76	49	0	1.06
29/05/2013 14:00	29/05/2013 15:00	574.21	572.76	6.4	18.0	1.8	9.1	0	55	86	86	1.45

2.2 WATER LEVEL CHANGES AND HEAD LOSSES AT THE TRASHRACK AND INTAKE

The water level changes between the reservoir and various locations in the intake were measured in order to confirm the estimated head losses in the intake entrance and trashrack. The water levels were measured on site during the tests (at the forebay, the intake gate slot and the air vent shaft) and they form the baseline for this analysis. The measured elevation differentials from the lake to the intake gate slot and the air vent comprise not only intake and trashrack head losses but also what is termed the “velocity head” at each point. The latter is not a head loss but rather corresponds to the kinetic energy in the flow. Both head losses and velocity head were considered in the verifications summarized in Table 2 below. The table shows the level differentials measured during the tests and the corresponding values that were estimated during the design for the location of the air vent, based on the design assumptions for head losses and velocities and the reported conditions at the intake. The table includes a range of values that were calculated during the design. These include the “best estimate” as well as a range of low (optimistic) and high (conservative) head loss values. The best estimate values most closely match the level differences that were measured up to the air vent shaft.

TABLE 2: MEASURED LEVELS AT THE INTAKE OF THE MAYO GS TUNNEL WITH RESPECT TO WAREHAM LAKE

Total Intake Flow [m^3/s]	Mayo A Flow [m^3/s]	Mayo B Flow [m^3/s]	Difference in Level with Respect to Wareham Lake (m)				
			Measured up to the Intake Gate Slot	Measured up to the Air Vent Shaft	Estimated for the Entire Intake Structure		
					Optimistic	Best Estimate	Conservative
26.4	6	20.4	Not measured	0.52	0.49	0.55	0.62
30.4	10	20.4	0.52	0.71	0.65	0.73	0.83
32.8	12.5	20.3	0.60	0.82	0.76	0.85	0.96
35.2	15	20.2	0.73	0.99	0.88	0.98	1.11

Note: These measurements were taken on May 29, 2013, directly by Ron Gee and Joel Lambert. These values are not based on SCADA data.

It must be noted that the measurements summarized in Table 2 were performed with a relatively clean trashrack. Significant debris blockage of the trashrack in the future will increase the measured differences from those observed at the various flows. Any increase in excess of 0.3 m from the intake water levels measured would warrant review of the combined plant operation as well as inspection of the trashrack.

2.3 MAYO B FLOWS

The combined flows at Mayo B were measured by instrumentation and collected through SCADA. The flows at Mayo A are estimated based on the measured power and with relationships used by YEC in the past. These relationships have not been reviewed in detail by KGS Group but result in flows that are within the expected range of values. The recommendations provided in this letter are based on application of those relationships for estimation of Mayo A flows and should be revised if these were modified.

The May 2013 tests results showed that a combined flow of 20.5 m^3/s for the two Mayo B turbines was required to obtain full plant capacity (close to 10 MW). This flow exceeded the maximum of 9.5 m^3/s per unit used in the project design as indicated in the Operational Condition Letter. This greater than expected flow was consistent with the findings of the performance testing conducted by Accusonic which suggest that the efficiency of the turbines and generators would not meet the guaranteed level.

The greater flow needed by Mayo B to produce maximum plant capacity limited the amount of flow that could be concurrently passed through Mayo A while maintaining the pressures in the system above the required minimum values.

The efficiency shortfall of the Mayo B units was rectified by closing the draft tube air admission valves. With the air admission valves closed Mayo B now produces the rated plant capacity closer to the expected flow. YEC has now implemented a wicket gate limit at Mayo of 83% in the plant's control system software.

3.0 DATA ANALYSIS AND DISCUSSION

3.1 ALLOWABLE MAYO A FLOWS

Based on the data listed in Table 1, a relationship was developed between the Mayo A and Mayo B flows and the resulting pressure head difference between Wareham Lake and PI2. That relationship in metric units is as follows:

$$\textit{Pressure Head Difference} = 0.00396\ Q_A^2 + 0.00387\ Q_B^2$$

Where: Q_A= Total flow through the Mayo A powerhouse (m^3/s)

Q_B = Total flow through the Mayo B powerhouse (m^3/s)

Figure 1 shows the values of pressure head difference between Wareham Lake and PI2 according to the above relationship, compared with the values obtained from the tests.

As was noted above, it cannot be over-emphasized that the above relationship reflects the conditions found during the tests, including a relatively clean trashrack, and could change if these conditions were altered. For instance, if there is debris or ice blockage at the trashracks, these would need to be cleaned to restore the assumed losses. Otherwise, the relationship would need to be modified.

It must also be noted that at times the levels at PI2 can oscillate within a 0.5 m range. This has been observed (through the instrumentation as well as with direct measurements using a string line and a float) at several instances during the first two years of operation of Mayo B, and occurs even when the Mayo B units are shut off and there is only flow through Mayo A. This fact confirms the need to monitor the water levels at PI2 and to maintain the safe margins reflected in the recommended alarm levels.

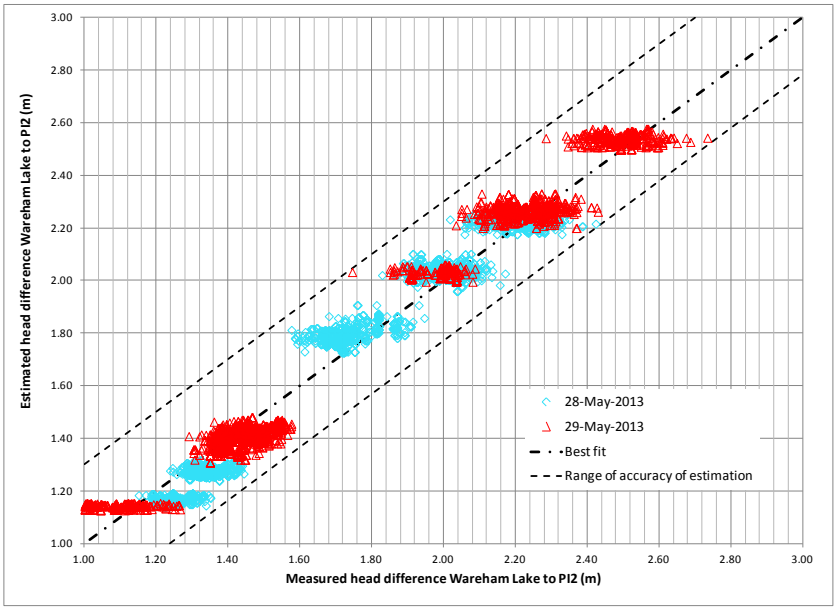

Figure 1: Piezometric Head Difference Wareham Lake to PI2 (estimated vs. measured)

Based on the test results and the relationships derived from them, the maximum allowable flows at Mayo A, for various conditions at Mayo B and Wareham Lake are indicated in Tables 3 and 4. These tables show the amount of water that can be safely directed to Mayo A, given the water level in Wareham Lake and the steady-state flow through Mayo B. The first column in the tables shows the Wareham Lake level and the title row shows the total steady state flow (two units combined) at Mayo B. For example, if Wareham Lake is at El. 574.2 m and Mayo B is operating with a total flow of 12.5 m^3/s, Mayo A can safely be operated up to a maximum of 6.0 m^3/s (Table 3) for unrestricted opening of the Mayo B units. If the wicket gates at Mayo B are physically limited to 83% opening under all operating modes (Table 4), then Mayo A can safely be operated up to a maximum of 8.4 m^3/s.

TABLE 3: ALLOWABLE MAYO A FLOW
IF MAYO B WICKET GATES ARE ALLOWED TO OPEN TO 100%

Wareham Lake Water Level (m)	Mayo A Maximum Flows (m^3/s) with No Limit on Mayo B Wicket Gate Opening						
	One Mayo B Unit Running at Any Flow	Two Mayo B units Running at:					
		8.0 m^3/s Total	10.0 m^3/s Total	12.5 m^3/s Total	15.0 m^3/s Total	17.5 m^3/s Total	20.5 m^3/s Total
573.5	8.7	Wareham Lake below Minimum Level for Operation of 2 Mayo B Units					
573.6	10.0						
573.7	11.2						
573.8	12.3						
573.9	13.3	6.0	6.0	6.0	6.0	6.0	
574.0	14.2	6.0	6.0	6.0	6.0	6.0	
574.1	15.1	6.0	6.0	6.0	6.0	6.0	
574.2	15.9	6.0	6.0	6.0	6.0	6.0	
574.3	16.7	6.0	6.0	6.0	6.0	6.7	6.7
574.4	17.0	6.0	6.0	6.0	6.0	8.3	8.3
574.5	**17.0**	**6.0**	**6.0**	**6.0**	**7.5**	**9.7**	**9.7**

The criteria used for determining the allowable Mayo A flow rates was to maintain a safety margin for the water level at PI2 in the event that Mayo B was loaded from the steady state condition (shown in the title row in the tables) to full load, at the maximum wicket gate opening rate. The shaded areas indicate that the safety margin on the water level at PI2 is less than what was originally adopted for the design (2 m in transient conditions). Mayo B should not be continuously operated in this region, except for when restoring the grid.

Table 3 is based on a full capacity of 10.25 m^3/s for each unit at Mayo B, which is more than the previously stipulated 9.5 m^3/s but corresponds to the test measurements for maximum power at the plant with the draft tube air admission valves open.

Table 4 takes into account a physical limit to the wicket gate opening at Mayo B of 83%. Table 4 can only be used if the wicket gates at Mayo B are limited to a maximum 83% opening.

**TABLE 4: ALLOWABLE MAYO A FLOW
IF MAYO B WICKET GATES LIMITED TO 83%**

Wareham Lake water level (m)	Mayo A Maximum Flows (m^3/s) with Mayo B wicket gates limited to 83% opening						
	One Mayo B Unit Running at any flow	Two Mayo B units Running at:					
		8.0 m^3/s Total	10.0 m^3/s Total	12.5 m^3/s Total	15.0 m^3/s Total	17.5 m^3/s Total	19.5 m^3/s Total
573.5	9.7	Wareham Lake below Minimum Level for Operation of 2 Mayo B Units					
573.6	10.9						
573.7	12.0						
573.8	13.0						
573.9	13.9	6.0	6.0	6.0	6.4	7.3	
574	14.8	6.0	6.0	6.0	8.1	8.9	
574.1	15.6	6.0	6.0	6.7	9.5	10.2	6.0
574.2	16.4	6.0	6.0	8.4	10.8	11.4	7.6
574.3	17.0	6.0	7.0	9.7	11.9	12.4	9.1
574.4	17.0	6.2	8.6	11.0	12.9	13.4	10.4
574.5	17.0	8.0	10.0	12.0	13.8	14.3	11.5

The basis for Tables 3 and 4 includes:

- A rate of Mayo B wicket gate opening limited to 100% per 45 seconds.
- The assumption that Figure 1 represents, and will continue to represent, actual conditions in the Mayo A / Mayo B water conveyance. Increased losses in the water conveyance will invalidate Tables 3 and 4.

The largest factor contributing to the limits shown in Tables 3 and 4 is the potential transient effect of accepting load at Mayo B. The magnitude of this transient effect is less pronounced when the initial steady state flow at Mayo B is closer to its full capacity; as a result, more flow can be passed through Mayo A.

When the initial steady-state flow at Mayo B is near 17.5 m^3/s the head losses in steady state condition increase to the point where the allowable flows at Mayo A need to be reduced to maintain the steady state pressure at PI2 above current alarm levels.

3.2 TRASH RACK HEAD LOSSES

Divers have previously reported that rock rubble is partially blocking the trashrack at the intake by 20% to 30% of the opening. Removing this rubble was not considered prudent as it was not evident to the divers that the removal could be done in safe manner. There was potential that this would lead to further deterioration of the slope adjacent to the intake. The differences in water levels from Wareham Lake to the air vent shaft, shown in Table 2, correspond closely to the values estimated by KGS Group at the design stage, when adjusted to include a 20% blockage in front of the trashracks. The measured and estimated values are shown in Figure 2.

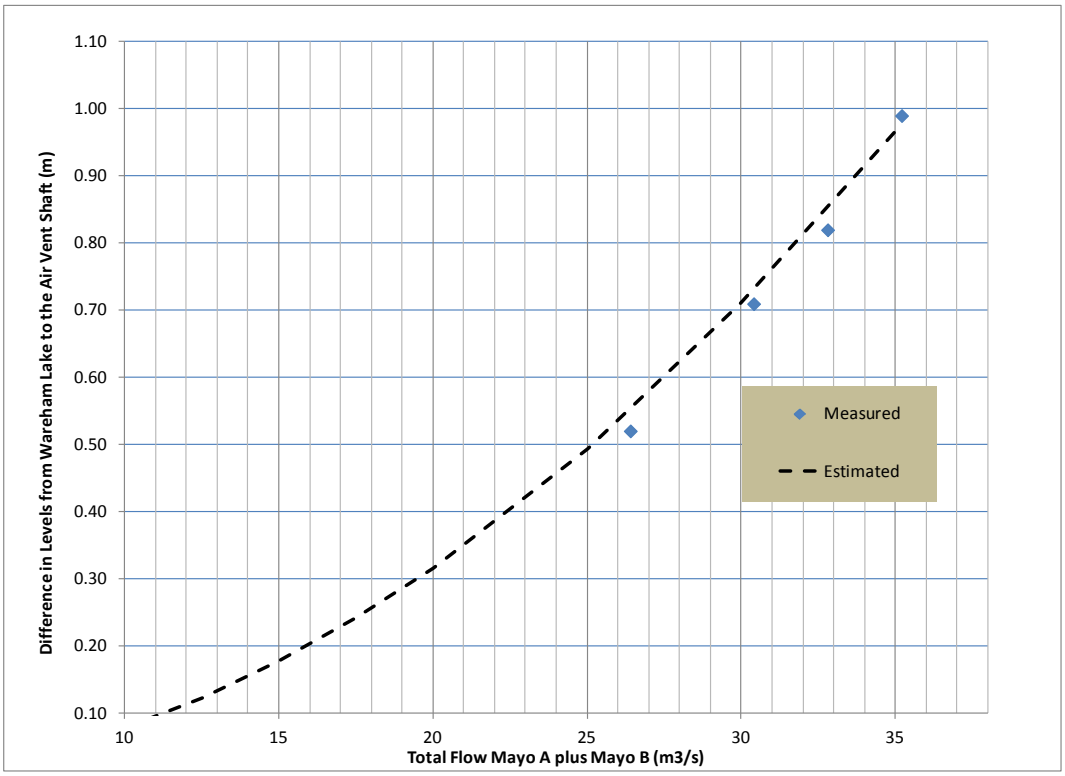

Figure 2: Level Difference between Wareham Lake and Intake Air Vent Shaft

The values provided in Figure 2, and the corresponding minimum levels at PI2, suggest that the following levels at the air vent shaft could be adopted:

- Minimum with two Mayo B units in operation: El. 573.4 m
- Minimum with one Mayo B unit in operation: El. 572.9 m

These are lower than those indicated in Ref.1. The water levels at the air vent shaft are currently collected through SCADA. It is important that these levels and the levels at Wareham Lake are monitored and that YEC maintains a record of the corresponding readings before and after cleaning and/or inspecting the trashracks, as well as a record of the conditions encountered there. This data can then be used as a basis for early detection of debris blockage and for possible future modification to the operational limits.

4.0 RECOMMENDATIONS

KGS Group recommends that the flows through the Mayo A and Mayo B powerhouses be limited to the levels listed in Table 3 as these flow rates provide the design margin of safety on the water levels at the penstock high point vent (PI2) even if the Mayo B wicket limit is not in place. The values listed in Table 4 are only safe if the Mayo B wicket gate opening is limited to 83% or less.

The following limits are recommended for pressure levels at the air vent shaft at the tunnel intake:

- Minimum with two Mayo B units in operation: El. 573.4 m
- Minimum with one Mayo B unit in operation: El. 572.9 m

Other operational conditions at the Mayo plants are recommended to be maintained. These are:

Mayo B Flows:

- Minimum: 4 m^3/s per unit

Mayo A Flows:

- No limits when Mayo B not operated

Levels at PI2 (highest point in the Mayo B penstock):

- Low Alarm: El. 572.5 m
- Low-Low Alarm (Shutdown): El. 572.2 m

It is recommended that the overall head losses along the conveyance system be reviewed periodically (suggest minimum of every 3 years) and if/when an event occurs that raises concerns about the integrity of the system, and that the water levels at PI2 and at the air vent shaft be monitored continuously.

If monitoring data shows increased head losses with respect to those obtained during the May 2013 tests, it is recommended to assess the situation and adjust the plant flows to maintain the levels at PI2 stipulated in the plant operational limits. Increased head losses are indication of changes in the conveyance system, possibly debris accumulation at the trashracks or along the tunnel or penstock. These would need to be corrected to restore the allowable flows indicated in this letter.

5.0 REFERENCES

1. Letter from Gord McPhail (KGS Group) to Guy Morgan (YEC) Re: Mayo B Hydroelectric Project – Operational Conditions for the Mayo B Plant. January 25, 2012.

APPENDIX B

EMAIL: ANDRITZ – FRANCIS TURBINE/GENERATOR REDEVELOPMENT STUDY (APRIL 11, 2016)

From: Broadhurst Gary
To: Joel Lambert; Daniel Giesbrecht
Cc: Taylor Thomas
Subject: 2016.04.11 / YEC / Mayo A GS / KGS - Redevelopment Study / Francis Turbine+Generator Budget Price Request / Q&A"s
Date: April-11-16 4:41:52 PM
Attachments: image002.png
image001.png

Hi Joel,

Find below our responses to your questions

1. Turbine full load efficiency is 91.7% giving turbine output = 2366 KW. With generator eff = 97% you get generator output = 2295 rather than 2200. Initial offer was rounded down to 2200 KW. Though, same price.
2. There would be cost premiums rather than savings to go with generator voltage of 6.9KV. In addition to extra cost for generator there would also be need for 15KV switchgear rather than 5KV, which would result in cost increase due to change in voltage class. For such small generator outputs, the 4.160 kV voltage is a better solution.

We trust these responses answer your questions appropriately.

Kind regards,
Gary

From: Joel Lambert [mailto:JLambert@kgsgroup.com]
Sent: April-11-16 12:23 PM
To: Broadhurst Gary; Daniel Giesbrecht
Cc: Taylor Thomas
Subject: RE: YEC / Mayo A GS / KGS - Redevelopment Study / Francis Turbine+Generator Budget Price Request

Thank you very much for the budget pricing Gary. This is very useful.

I just have a few questions about this. What would the peak efficiency of the turbine be? You show a 2200 kW generator, but even at 90% turbine efficiency and 97.5% generator efficiency, I get an output slightly above 2200 kW. I am trying to firm up what the output would be to use in the economic analysis.

Also, would changing to a 6900 V generator change the cost significantly?

Regards,
Joel

From: Broadhurst Gary [mailto:Gary.Broadhurst@andritz.com]
Sent: Friday, April 01, 2016 6:23 PM
To: Joel Lambert; RDerksen@kgsgroup.com
Cc: Taylor Thomas
Subject: RE: YEC / Mayo A GS / KGS - Redevelopment Study / Francis Turbine+Generator Budget Price Request

Hi Joel & Rudy,

Andritz Hydro is pleased to provide you with our budget offer as requested for the Mayo A Redevelopment Study.

The turbine runner diameter is 986 mm. Setting elevation is 0.75 M above TWL. Generator would be 600 rpm; 2200 KW 4160 V.

Scope is:

- Vertical Francis turbine with steel spiral case and steel draft tube elbow
- 4160 V Synchronous generator with brushless excitation
- Turbine generator controls including governor function
- 5 KV metal clad switchgear
- DC power system
- 150 KVA Station Service transformer
- Installation advisor
- Commissioning and start-up

Budget price is $3,300,000 Taxes extra DDP site in the Yukon

Attached are the following documents:

- Preliminary turbine hydraulic outline
- Compact Francis Turbine brochure

Your assumption regarding the Andritz Hydro A CAT (Compact Axial Turbine) turbine is correct, as it would probably not be a good fit for the Mayo A GS Redevelopment concept of utilizing the existing powerhouse, because of the need for a deep setting with such a high head. In the event a completely new powerhouse would be considered then it might be applicable to consider our A CAT type turbines.

We trust this budget offer is of service to KGS in performing your Mayo A GS, Redevelopment Study. We'd appreciate if KGS could keep us abreast of developments of your study to YEC.

Kind regards,

Gary BROADHURST, PEng
Regional Sales Director, Western Canada

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Thank you.

From: Joel Lambert [mailto:JLambert@kgsgroup.com]
Sent: March-03-16 9:35 AM
To: Broadhurst Gary
Subject: RE: YEC / Mayo A GS / KGS - Redevelopment Study / Francis Turbine+Generator Budget Price Request

Hi Gary,

Here are a few drawings for the Mayo A Powerhouse and one of the site. Feel free to explore other options, but do not feel obliged to "optimize" at this stage. The deadlines are quite short so it doesn't leave much time.

I did not look at this in detail, but I would have thought that a Kaplan or your CAT turbines would have needed a much deeper setting than the existing substructure would allow. I strongly suspect that a francis machine will win out, but I have been wrong before.

Best regards,
Joel

From: Broadhurst Gary [mailto:Gary.Broadhurst@andritz.com]
Sent: Wednesday, March 02, 2016 10:45 AM
To: Joel Lambert
Cc: 'Michael Tilbrook'; Duflon Pierre
Subject: RE: YEC / Mayo A GS / KGS - Redevelopment Study / Francis Turbine+Generator Budget Price Request

Hi Joel,

We'd appreciate obtaining some of the existing Mayo A powerhouse drawings as we'd like to explore the possibility of other turbine types such as Kaplan or our Compact Axial Turbines (CAT).

Cheers,
Gary

Gary BROADHURST, PEng
Regional Sales Director, Western Canada

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gary.broadhurst@andritz.com
www.andritz.com

From: Broadhurst Gary
Sent: March-01-16 5:09 PM
To: 'Joel Lambert'
Cc: 'Michael Tilbrook'
Subject: RE: YEC / Mayo A GS / KGS - Redevelopment Study / Francis Turbine+Generator Budget Price Request

Hi Joel,

Thank-you for reaching out to Andritz Hydro regarding your Mayo A Redevelopment Study.

We'll endeavour to provide you with a budgetary estimate for a new vertical Francis turbine and generator for the Mayo A project. As you mentioned a horizontal Francis turbine & generator perhaps could be considered if we had more details regarding existing powerhouse.

I look forward meeting you during my next trip to Winnipeg or perhaps if you are coming thru / to Vancouver.

Kind regards,
Gary

Gary BROADHURST, PEng
Regional Sales Director, Western Canada

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gary.broadhurst@andritz.com
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Thank you.

From: Joel Lambert [mailto:JLambert@kgsgroup.com]
Sent: March-01-16 2:16 PM
To: Broadhurst Gary
Cc: 'Michael Tilbrook'
Subject: Mayo A - New unit pricing

Hi Gary,

As we discussed on the phone yesterday, I would like to get some pricing on a new for the Mayo A

facility at Yukon Energy. We are currently conducting a study to help YEC determine what to do with the facility (Replace, refurbish, remove, etc.). For various reasons, we are looking at removing the two existing units and installing a single unit.

Also, we have a very short timeline for this work, therefore, I would not have time for you to prepare a very detailed estimate, but any opinion on pricing that you could provide in the next two weeks would be very helpful.

The details of the installation is:

Arrangement: Vertical Francis. We could consider a horizontal arrangement, but that would require extensive concrete changes and I think it would be cost prohibitive.
Gross Head: 36.8 metres
Net Head: 34.6 metres
Max Q: 7.6 cms
Setting (centerline of distributor): 0.76 metres above TWL
Inertia constant (H): minimum of 2
All ancillary equipment (switchgear, transformers, cabling, etc.) will be replaced, therefore, use whatever generator voltage is optimal.
There is a surge chamber a short distance from the powerhouse. Existing water starting time is on the order of 1 second (assuming that both units react in tandem).

I mention the setting above as the hope is to reuse the same powerhouse substructure for both the "Replace" and the "Refurb" options. A report I have from about 15 years ago lists the spiral case as being in poor condition, so for this stage of the project, we will assume that the spiral case, stay ring, and discharge ring all need to be replaced.

If possible, I would be interested in pricing for a complete package, including:

- Turbine
- Generator
- TIV
- Governor/HPU
- Unit P&C

If certain items are not available, just let me know.

Best regards,
Joel Lambert, P.Eng.
Senior Mechanical Engineer
KGS Group
865 Waverley Street
Winnipeg, Manitoba, R3T 5P4
Phone: 204.896.1209 ext 245
Direct: 204.478.3245 Cell: 204.770.6411
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Thank You.

APPENDIX C

MAYO HYDRO DETAILED DIRECT COSTS

APPENDIX C: MAYO A DETAILED DIRECT COSTS
KGS PROJECT: 16-1404-002
MAYO HYDRO (MH0) FUTURE FACILITY OPTIONS
CONCEPT DESIGN REPORT
FINAL – REV 0

ITEMS	Unit	Unit Cost (2016 $)	OPTION 1: Replace		OPTION 2: Refurbish		OPTION 3: Greenfield		Option 4: Make Safe	
			Quantity	Cost (2016 $)	Quantity	Cost (2016 $)	Quantity	Cost (2016 $)	Quantity	Cost (2016 $)
SITEWORK				**$120,000**		**$120,000**		**$60,000**		**$60,000**
Clearing	-	-		-		-		-		-
- Misc.	ha	$20,000	0	$0	0	$0	0	$0	0	$0
Dewatering Allowance	months	$15,000	4	$60,000	4	$60,000	4	$60,000	4	$60,000
Access road maintenance	months	$5,000	12	$60,000	12	$60,000	0	$0	0	$0
SLOPE STABILIZATION				**$1,897,000**		**$1,897,000**		**$0**		**$0**
Powerhouse/Surge Slope										
- Phase 1: Mapping/Survey/Assessment	LS	$80,000	1	$80,000	1	$80,000	0	$0	0	$0
- Phase 2: Bench cut/ Flatten Top Slope / New Rock Support	LS	$1,700,000	1	$1,700,000	1	$1,700,000	0	$0	0	$0
Tailrace										
- Gabion Basket Repair	LS	$80,000	1	$80,000	1	$80,000	0	$0	0	$0
Access Road Alignment										
- Repair of the shoulder area where gully has formed near the sub-station	LS	$12,000	1	$12,000	1	$12,000	0	$0	0	$0
- Surface grading and minor granular fill placement	LS	$25,000	1	$25,000	1	$25,000	0	$0	0	$0
DECOMISSIONING AND DEMOLITION				**$799,000**		**$497,000**		**$1,040,000**		**$290,000**
Demo Mobilization/Demobilization	LS	$150,000	1	$150,000	1	$150,000	1	$150,000	0	$0
Powerhouse Superstructure Removal	LS	$250,000	1	$250,000	0	$0	1	$250,000	0	$0
Surge Tank Removal (includes improving access)	LS	$300,000	1	$300,000	1	$300,000	1	$300,000	0	$0
TG and Assoicated Equipment Removal	per unit	$60,000	2	$120,000	2	$120,000	2	$120,000	0	$0
Selected Concrete Demolition	m^3	$3,200	20	$64,000	10	$32,000	0	$0	0	$0
Blanking Plate	LS	$5,000	1	$5,000	1	$5,000	0	$0	0	$0
Plug Tunnel										
- Rock Excavation (from tunnel)	m^3	$1,000	0	$0	0	$0	10	$10,000	10	$10,000
- Rock Support	m^2	$260	0	$0	0	$0	25	$7,000	25	$7,000
- Concrete	m^3	$3,300	0	$0	0	$0	25	$83,000	25	$83,000
Backfill Powerhouse and Tailrace	m^3	$100	0	$0	0	$0	2000	$200,000	1500	$150,000
Secure Powerhouse (remove ladders, weld hatches)	LS	$10,000	0	$0	0	$0	0	$0	1	$10,000
Block Powerhouse Road and Signage	LS	$10,000	0	$0	0	$0	1	$10,000	1	$10,000
Hazardous Materials Disposal Allowance	LS	$10,000	6	$60,000	4	$40,000	6	$60,000	2	$20,000
REHABILITATION				**$1,014,000**		**$1,559,000**		**$0**		**$20,000**
New Roofing	LS	$106,000	0	$0	1	$106,000	0	$0	0	$0
Modernize Crane (allowance)	LS	$50,000	0	$0	1	$50,000	0	$0	0	$0
Concrete work for Generator / OWS Install	m^3	$3,300	40	$132,000	20	$66,000	0	$0	0	$0
Seismic Improvements										
- Anchoring Design and Install Allowance	LS	$800,000	1	$800,000	1	$800,000	0	$0	0	$0
- Bracing Design and Install Allowance	LS	$175,000	0	$0	1	$175,000	0	$0	0	$0
Lean Concrete Infill	m^3	$1,000	18	$18,000	18	$18,000	0	$0	0	$0
Asbestos Encapsulation (roof)	LS	$20,000	0	$0	1	$20,000	0	$0	1	$20,000
New Overhead Door	LS	$63,000	0	$0	1	$63,000	0	$0	0	$0
Concrete Remediation Allowance	LS	$53,000	1	$53,000	1	$53,000	0	$0	0	$0
Insulation Upgrade	LS	$160,000	0	$0	1	$160,000	0	$0	0	$0
Diving Inspection (Draft Tube Concrete / Guides)	LS	$11,000	1	$11,000	1	$11,000	0	$0	0	$0
Additional fall restraint measures	LS	$11,000	0	$0	1	$11,000	0	$0	0	$0
Repair Flashing, weather stripping, wall penetrations	LS	$10,625	0	$0	1	$11,000	0	$0	0	$0
Repoint Block Walls	LS	$15,000	0	$0	1	$15,000	0	$0	0	$0
NEW STRUCTURES				**$1,062,000**		**$266,000**		**$0**		**$0**
Powerhouse										
- Superstructure steel (based off building volume)	m^3	$120	1,450	$174,000	0	$0	0	$0	0	$0
- New Powerhouse Crane	LS	$100,000	1	$100,000	0	$0	0	$0	0	$0
- New Monorail Crane for Draft Tube Gates	LS	$30,000	1	$30,000	0	$0	0	$0	0	$0
- Steel Cladding	m^2	$450	670	$302,000	0	$0	0	$0	0	$0
- Architectural Finish	LS	$200,000	1	$200,000	0	$0	0	$0	0	$0
- Control Room	LS	$10,000	0	$0	1	$10,000	0	$0	0	$0
- Tailrace steel deck w/ guard rail	LS	$11,000	1	$11,000	1	$11,000	0	$0	0	$0
Surge Tank										
- Superstructure steel (based off tank volume)	m^3	$120	500	$60,000	500	$60,000	0	$0	0	$0
- Steel Cladding	m^2	$450	350	$158,000	350	$158,000	0	$0	0	$0
- Mechanical and Electrical	LS	$26,500	1	$27,000	1	$27,000	0	$0	0	$0
TURBINE AND GENERATOR				**$4,416,000**		**$3,142,000**		**$0**		**$0**
New Turbine, generator, governor, switchgear, DC system, SST (supply)	per unit	$3,550,000	1	$3,550,000		$0	0	$0	0	$0
New Turbine, generator, governor, switchgear, DC system, SST (Install)	per unit	$600,000	1	$600,000		$0	0	$0	0	$0
Refurbish Turbine	per unit	$492,000		$0	1	$492,000	0	$0	0	$0
New Generator (Includes Excitation and Install)	per unit	$2,100,000		$0	1	$2,100,000	0	$0	0	$0
New Turbine Inlet Valve (TIV)	per unit	$250,000	1	$250,000	1	$250,000	0	$0	0	$0
New Governor	Each	$209,000		$0	1	$209,000	0	$0	0	$0
Cooling Water Sediment Separator and Replace Shaft Seal	Each	$15,938	1	$16,000	1	$16,000	0	$0	0	$0
Sandblast, Inspect, Paint Stay Ring and Spiral Case	Each	$74,200		$0	1	$75,000	0	$0	0	$0
ELECTRICAL & MECHANICAL BALANCE OF PLANT				**$3,976,000**		**$4,389,000**		**$575,000**		**$575,000**
Mechanical Balance of Plant				$308,000		$327,000		$0		$0
Electrical Balance of Plant				$3,388,000		$3,782,000		$575,000		$575,000
TOTAL DIRECTS				**$13,284,000**		**$11,870,000**		**$1,675,000**		**$945,000**

APPENDIX D

ECONOMIC ASSESSMENTS

APPENDIX D: OPTION 1 ECONOMIC ASSESSMENT - NEW POWERHOUSE
KGS PROJECT: 16-1404-002
MAYO HYDRO (MH0) FUTURE - FACILITY OPTIONS - CONCEPT DESIGN REPORT - REV B

Assumptions:			
1	Capacity	2.3	MW
2	Annual Capacity Factor		
3	Annual Energy Production	10.43	GW.h
4	Annual Fuel Costs per MW.h	$0.00	
5	Annual O and M Costs per MW.h	$7.10	(Reference Project: Pehonan Estimated costs)
6	Annual CAPEX Costs per MW.h	$1.15	(Reference Project: Tazi Twé Estimated costs)
7	Capacity Cost	32,000	x1000$
8	Principal Payment	492	x1000$ (Using even principle payments method)
9	Project Life	65	Years
10	Nominal Interest Rate	5.45%	(From YEC)
11	Escalation Rate	2.0%	(From YEC)

Result Summary			
1	Total Energy Production	205,300	MW.h
2	Total Loan Payments	31,762	x1000$
3	Total Operating Cost (Fuel & O & M)	2,073	x1000$
4	Total CAPEX Cost (major maintaince)	335	x1000$
5	Total Cost	34,170	x1000$
6	Levelized Cost	16.64	Cents/KW.h
		166.44	Dollars/MW.h

Calculation Details

Year	Energy Production (MW.h)		Unpaid Balance	Loan Payments ($000) Current Value		Fuel & O & M ($000)	CAPEX ($000)	Total ($000)	
	Current Value	Present Value	Current Value	Principal	Interest	Current $ Value	Current $ Value	Current $ Value	Present $ Value
0									
1	8,797	8,342	31,508	492	1,731	64	10	2,297	2,178
2	11,759	10,575	31,015	492	1,704	87	14	2,297	2,066
3	13,338	11,375	30,523	492	1,677	100	16	2,286	1,950
4	13,599	10,998	30,031	492	1,650	105	17	2,264	1,831
5	13,832	10,609	29,538	492	1,623	108	18	2,242	1,719
6	14,064	10,229	29,046	492	1,596	112	18	2,219	1,614
7	14,194	9,790	28,554	492	1,570	116	19	2,196	1,515
8	14,307	9,358	28,062	492	1,543	119	19	2,173	1,422
9	14,420	8,944	27,569	492	1,516	122	20	2,150	1,334
10	14,537	8,551	27,077	492	1,489	126	20	2,128	1,251
11	14,588	8,137	26,585	492	1,462	129	21	2,104	1,174
12	12,962	6,857	26,092	492	1,435	117	19	2,063	1,091
13	11,784	5,911	25,600	492	1,409	108	18	2,027	1,017
14	11,776	5,602	25,108	492	1,382	110	18	2,002	953
15	11,625	5,244	24,615	492	1,355	111	18	1,976	892
16	11,488	4,915	24,123	492	1,328	112	18	1,951	834
17	9,614	3,900	23,631	492	1,301	96	15	1,905	773
18	9,614	3,699	23,138	492	1,274	97	16	1,880	723
19	9,614	3,508	22,646	492	1,248	99	16	1,855	677
20	9,614	3,326	22,154	492	1,221	101	16	1,831	633
21	9,614	3,154	21,662	492	1,194	103	17	1,806	593
22	9,614	2,991	21,169	492	1,167	106	17	1,782	554
23	9,614	2,837	20,677	492	1,140	108	17	1,758	519
24	9,614	2,690	20,185	492	1,113	110	18	1,733	485
25	9,614	2,551	19,692	492	1,087	112	18	1,709	454
26	9,614	2,419	19,200	492	1,060	114	18	1,685	424
27	9,614	2,294	18,708	492	1,033	117	19	1,661	396
28	9,614	2,176	18,215	492	1,006	119	19	1,637	370
29	9,614	2,063	17,723	492	979	121	20	1,612	346
30	9,614	1,957	17,231	492	952	124	20	1,588	323
31	9,614	1,855	16,738	492	926	126	20	1,564	302
32	9,614	1,760	16,246	492	899	129	21	1,541	282
33	9,614	1,669	15,754	492	872	131	21	1,517	263
34	9,614	1,582	15,262	492	845	134	22	1,493	246
35	9,614	1,501	14,769	492	818	137	22	1,469	229
36	9,614	1,423	14,277	492	792	139	23	1,446	214
37	9,614	1,349	13,785	492	765	142	23	1,422	200
38	9,614	1,280	13,292	492	738	145	23	1,398	186
39	9,614	1,214	12,800	492	711	148	24	1,375	174
40	9,614	1,151	12,308	492	684	151	24	1,352	162
41	9,614	1,091	11,815	492	657	154	25	1,328	151
42	9,614	1,035	11,323	492	631	157	25	1,305	140
43	9,614	981	10,831	492	604	160	26	1,282	131
44	9,614	931	10,338	492	577	163	26	1,259	122
45	9,614	883	9,846	492	550	166	27	1,236	113
46	9,614	837	9,354	492	523	170	27	1,213	106
47	9,614	794	8,862	492	496	173	28	1,190	98
48	9,614	753	8,369	492	470	177	29	1,167	91
49	9,614	714	7,877	492	443	180	29	1,144	85
50	9,614	677	7,385	492	416	184	30	1,122	79
51	9,614	642	6,892	492	389	187	30	1,099	73
52	9,614	609	6,400	492	362	191	31	1,077	68
53	9,614	577	5,908	492	335	195	32	1,054	63
54	9,614	547	5,415	492	309	199	32	1,032	59
55	9,614	519	4,923	492	282	203	33	1,010	55
56	9,614	492	4,431	492	255	207	33	988	51
57	9,614	467	3,938	492	228	211	34	966	47
58	9,614	443	3,446	492	201	215	35	944	43
59	9,614	420	2,954	492	174	220	36	922	40
60	9,614	398	2,462	492	148	224	36	900	37
61	9,614	378	1,969	492	121	228	37	878	35
62	9,614	358	1,477	492	94	233	38	857	32
63	9,614	340	985	492	67	238	38	835	30
64	9,614	322	492	492	40	242	39	814	27
65	9,614	305	0	492	13	247	40	793	25

APPENDIX D: OPTION 2 ECONOMIC ASSESSMENT - REFURBISHED POWERHOUSE
KGS PROJECT: 16-1404-002
MAYO HYDRO (MH0) FUTURE FACILITY OPTIONS
CONCEPT DESIGN REPORT
FINAL - REV 0

Assumptions:			
1	Capacity	2.3	MW
2	Annual Energy Production	10.43	GW.h
3	Annual Fuel Costs per MW.h	$0.00	
4	Annual O and M Costs per MW.h	$7.10	(Reference Project: Pehonan Estimated costs)
5	Annual CAPEX Costs per MW.h	$1.15	(Reference Project: Tazi Twé Estimated costs)
6	Capacity Cost	28,600	x1000$ (2011 Est. Cost with Contingencies)
7	Principal Payment	440	x1000$ (Using even principle payments method)
8	Project Life	65	Years
9	Nominal Interest Rate	5.45%	(From YEC)
10	Escalation Rate	2.0%	(From YEC)

Result Summary			
1	Total Energy Production	205,300	MW.h
2	Total Capital Cost	28,387	x1000$
3	Total Operating Cost (Fuel & O & M)	2,073	x1000$
4	Total CAPEX Cost (major maintaince)	335	x1000$
5	Total Cost	30,795	x1000$
6	Levelized Cost	15.00	Cents/KW.h
		150.00	Dollars/MW.h

Calculation Details

Year	Energy Production (MW.h)		Unpaid Balance	Loan Payments ($000) Current Value		Fuel & O & M ($000)	CAPEX ($000)	Total ($000)	
	Current Value	Present Value	Current Value	Principal	Interest	Current $ Value	Current $ Value	Current $ Value	Present $ Value
0									
1	8,797	8,342	28,160	440	1,547	64	10	2,061	1,954
2	11,759	10,575	27,720	440	1,523	87	14	2,064	1,856
3	13,338	11,375	27,280	440	1,499	100	16	2,056	1,753
4	13,599	10,998	26,840	440	1,475	105	17	2,036	1,647
5	13,832	10,609	26,400	440	1,451	108	18	2,017	1,547
6	14,064	10,229	25,960	440	1,427	112	18	1,997	1,453
7	14,194	9,790	25,520	440	1,403	116	19	1,977	1,364
8	14,307	9,358	25,080	440	1,379	119	19	1,957	1,280
9	14,420	8,944	24,640	440	1,355	122	20	1,937	1,201
10	14,537	8,551	24,200	440	1,331	126	20	1,917	1,128
11	14,588	8,137	23,760	440	1,307	129	21	1,897	1,058
12	12,962	6,857	23,320	440	1,283	117	19	1,859	983
13	11,784	5,911	22,880	440	1,259	108	18	1,825	915
14	11,776	5,602	22,440	440	1,235	110	18	1,803	858
15	11,625	5,244	22,000	440	1,211	111	18	1,780	803
16	11,488	4,915	21,560	440	1,187	112	18	1,757	752
17	9,614	3,900	21,120	440	1,163	96	15	1,714	695
18	9,614	3,699	20,680	440	1,139	97	16	1,692	651
19	9,614	3,508	20,240	440	1,115	99	16	1,671	610
20	9,614	3,326	19,800	440	1,091	101	16	1,649	571
21	9,614	3,154	19,360	440	1,067	103	17	1,627	534
22	9,614	2,991	18,920	440	1,043	106	17	1,606	500
23	9,614	2,837	18,480	440	1,019	108	17	1,584	467
24	9,614	2,690	18,040	440	995	110	18	1,563	437
25	9,614	2,551	17,600	440	971	112	18	1,541	409
26	9,614	2,419	17,160	440	947	114	18	1,520	382
27	9,614	2,294	16,720	440	923	117	19	1,499	358
28	9,614	2,176	16,280	440	899	119	19	1,477	334
29	9,614	2,063	15,840	440	875	121	20	1,456	312
30	9,614	1,957	15,400	440	851	124	20	1,435	292
31	9,614	1,855	14,960	440	827	126	20	1,414	273
32	9,614	1,760	14,520	440	803	129	21	1,393	255
33	9,614	1,669	14,080	440	779	131	21	1,372	238
34	9,614	1,582	13,640	440	755	134	22	1,351	222
35	9,614	1,501	13,200	440	731	137	22	1,330	208
36	9,614	1,423	12,760	440	707	139	23	1,309	194
37	9,614	1,349	12,320	440	683	142	23	1,288	181
38	9,614	1,280	11,880	440	659	145	23	1,268	169
39	9,614	1,214	11,440	440	635	148	24	1,247	157
40	9,614	1,151	11,000	440	611	151	24	1,227	147
41	9,614	1,091	10,560	440	588	154	25	1,206	137
42	9,614	1,035	10,120	440	564	157	25	1,186	128
43	9,614	981	9,680	440	540	160	26	1,165	119
44	9,614	931	9,240	440	516	163	26	1,145	111
45	9,614	883	8,800	440	492	166	27	1,125	103
46	9,614	837	8,360	440	468	170	27	1,105	96
47	9,614	794	7,920	440	444	173	28	1,085	90
48	9,614	753	7,480	440	420	177	29	1,065	83
49	9,614	714	7,040	440	396	180	29	1,045	78
50	9,614	677	6,600	440	372	184	30	1,025	72
51	9,614	642	6,160	440	348	187	30	1,005	67
52	9,614	609	5,720	440	324	191	31	986	62
53	9,614	577	5,280	440	300	195	32	966	58
54	9,614	547	4,840	440	276	199	32	947	54
55	9,614	519	4,400	440	252	203	33	927	50
56	9,614	492	3,960	440	228	207	33	908	47
57	9,614	467	3,520	440	204	211	34	889	43
58	9,614	443	3,080	440	180	215	35	870	40
59	9,614	420	2,640	440	156	220	36	851	37
60	9,614	398	2,200	440	132	224	36	832	34
61	9,614	378	1,760	440	108	228	37	813	32
62	9,614	358	1,320	440	84	233	38	795	30
63	9,614	340	880	440	60	238	38	776	27
64	9,614	322	440	440	36	242	39	758	25
65	9,614	305	0	440	12	247	40	739	23

APPENDIX D: OPTION 3 AND 4 ECONOMIC ASSESSMENT - DEMOLITION AND RETURN TO GREENFIELD/ABANDON IN SITU
KGS PROJECT: 16-1404-002
MAYO HYDRO (MH0) FUTURE FACILITY OPTIONS
CONCEPT DESIGN REPORT
FINAL – REV 0

Assumptions:			
1	Capacity	2.3	MW
2	Annual Energy Production	7.18	GW.h
3	Annual Fuel Costs per MW.h	$0.00	
4	Annual O and M Costs per MW.h	$7.10	(Reference Project: Pehonan Estimated costs)
5	Annual CAPEX Costs per MW.h	$0.00	
6	Project Life	10	Years
7	Nominal Interest Rate	0	(From YEC)
8	Escalation Rate	0	(From YEC)

Option 3 - Demolition and Return to Greenfield

Result Summary			
1	Total Energy Production	57,278	MW.h
2	Total Capital Cost	4,000	x1000$
3	Total Operating Cost (Fuel & O & M)	458	x1000$
4	Total CAPEX Cost (major maintaince)	0	x1000$
5	Total Cost	4,458	x1000$

Option 4 - Abandon in Situ

Result Summary			
1	Total Energy Production	57,278	MW.h
2	Total Capital Cost	2,300	x1000$
3	Total Operating Cost (Fuel & O & M)	458	x1000$
4	Total CAPEX Cost (major maintaince)	0	x1000$
5	Total Cost	2,758	x1000$

Calculation Details

Year	Energy Production (MW.h)		Capital ($000)		Operating ($000) (Fuel & O & M)		CAPEX ($000) (Major Maintaince)		Total ($000)	
	Current Value	Present Value	Current $ Value	Present $ Value	Current $ Value	Present $ Value	Current $ Value	Present $ Value	Current $ Value	Present $ Value
0										
1	4,539	4,304			33	31			33	31
2	4,722	4,246			35	31			35	31
3	4,999	4,264			38	32			38	32
4	6,038	4,884			46	38			46	38
5	8,277	6,348			65	50			65	50
6	9,697	7,052			78	56			78	56
7	9,949	6,862			81	56			81	56
8	10,179	6,658			85	55			85	55
9	10,412	6,458			88	55			88	55
10	10,544	6,202			91	54			91	54

APPENDIX E

EMAIL: AISHIHIK RERATE STUDY (APRIL 13, 2015)

The following correspondence from Yukon Energy Corporation was used as a basis for a Present Value analysis of the Mayo A Future Options. The attached email contains assumptions provided by Yukon Energy Corporation to analyze the benefit of an increase in capacity ($/MW), and the benefit of an increase in annual energy ($/GWh). The information was provided for the Aishihik Rerate and Assessment Project and is assumed to be applicable to the analysis of Mayo A.

Ariane Adriano

From: Hector Campbell <Hector.Campbell@yec.yk.ca>
Sent: April-13-15 11:45 AM
To: Ron Gee
Cc: Joel Lambert; Goran Sreckovic; Lawrence Joudry; Bill Haydock; Guy Morgan
Subject: RE: Aishihik rerate study,
Attachments: TAB-2012-05-08-Business Case Templates.xlsm

Joel,
You should assume the following:
1/ benefit of an increase in capacity - $2.5M per MW based on avoided capital cost of new natural gas generation.
2/ benefit of an increase an annual energy - $200,000 per GWh based on avoided operating (i.e. variable cost) cost of natural gas.

It would be worthwhile doing some sensitivity analysis based on capacity benefits of between $1M (high speed diesel gensets) and $10M (wind or higher cost new hydro).
Similarly for energy benefit going from $100,000 (best possible natural gas operating cost) to $300,000 (diesel operating cost).

For paybacks longer than 5 years, we use discounted payback – see attached economic spreadsheets – use 5.2% as YEC's discount rate.

Note that both of the larger turbines (AH1 and AH2) at Aishihik have had their generators rewound in the 1990's that would allow a modest increase in capacity to be an option or part of an option (combination of capacity and efficiency gains) with rerunnering.
The units were rewound in different years by different vendors resulting with different ratings on the new insulation. I can't recall the final revised generator ratings. I believe one was increased to about 16 MVA and the other one to about 16.5 MVA from their original 15.5 MVA ratings.

Goran/Lawrence/Bill/Guy – any comments?

Hector Campbell P. Eng., M.B.A.
Director, Resource Planning & Regulatory Affairs
Telephone: 867-393-5331 | Mobile: 867-334-7070
YUKON ENERGY
your needs power what we do

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SM-YEC-20141008

From: Ron Gee
Sent: April-10-15 3:51 PM

To: Hector Campbell
Cc: Joel Lambert
Subject: FW: Aishihik rerate study,

Hector,
I am away for a couple weeks starting Monday. I was wondering if could respond to the question below by sending any answer you have to Joel Lambert of KGS. Please copy me so that I can stay in the loop.

Thanks.

Ron Gee P. Eng.
Hydrological & Civil Engineer
Telephone: 867-393-5305 | Mobile: 867-334-6908
your needs power what we do

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SM-YEC-20141008MYEC-20141008

From: Ron Gee
Sent: April-09-15 9:17 AM
To: hector.campbell@yec.yk.ca
Subject: FW: Aishihik rerate study,

Hector,
Would you be able to answer the question below. It pertains to a study being performed on the potential rerunnering of the Aishihik turbines.

From: Joel Lambert [mailto:JLambert@kgsgroup.com]
Sent: April-09-15 9:14 AM
To: Ron Gee
Subject: FW: Aishihik rerate study,

Hi Ron,

The original question I sent is below. This is the value that YEC assigns to the additional energy produced by the new runner.

Say for example that the upgrade costs $1,000,000 and that the uprated machine produces an additional 2 GWhr/year. If the value of energy is $300,000 / GWhr, the simple payback would be 3.3 years. The value of energy may depend greatly if it reduces diesel consumption or not. Presumably it will since Aishihik has a lot of storage.

If it helps, we can have a call to discuss further. If so, I would likely include someone else from KGS that has a lot of experience in these matters.

Regards,
Joel

From: Joel Lambert [mailto:JLambert@kgsgroup.com]
Sent: March-31-15 2:26 PM
To: 'Ronald Gee (ron.gee@yec.yk.ca)'
Subject: Aishihik rerate study,

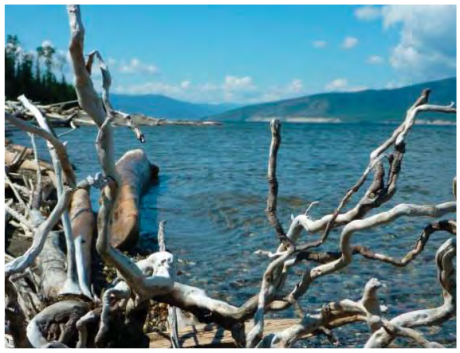
Hi Ron,

What value of energy should we be using in our payback calculations for the Aishihik Rerate Study? Presumably this would be a $/GW-h value.

Regards,
Joel Lambert, P.Eng.
Senior Mechanical Engineer
KGS Group
865 Waverley Street
Winnipeg, Manitoba, R3T 5P4
Phone: 204.896.1209 Cell: 204.770.6411
Fax: 204.896.0754

Appendix 5.7
Small Hydro Screening Assessment
(Knight Piesold 2016)

YUKON ENERGY CORPORATION
SMALL HYDROELECTRIC PROJECTS



SCREENING ASSESSMENT

PREPARED FOR:

Yukon Energy Corporation
#2 Miles Canyon Road Box 5920
Whitehorse, Yukon
Y1A 6S7

PREPARED BY:

Knight Piésold Ltd.
Suite 1400 – 750 West Pender Street
Vancouver, BC V6C 2T8 Canada
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VA103-556/2-2
Rev 0
October 7, 2016

Knight Piésold CONSULTING
www.knightpiesold.com

bsi. ISO 9001 ISO 14001 OHSAS 18001
FS 64925
EMS 550121
OHS 550122

YUKON ENERGY CORPORATION
SMALL HYDROELECTRIC PROJECTS

SCREENING ASSESSMENT
VA103-556/2-2

Rev	Description	Date
0	Issued in Final	October 7, 2016

Knight Piésold Ltd.
Suite 1400
750 West Pender Street
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Knight Piésold CONSULTING

EXECUTIVE SUMMARY

Yukon Energy Corporation (YEC) commissioned Knight Piésold Ltd. (KP) to conduct a desktop review of potential small hydroelectric projects in the Yukon and northern British Columbia. The objectives of the study were to compare technical and economic development criteria and to establish a ranking that provides YEC with the basis for further studies.

This study utilized a four stage screening process to identify the best development options from a list of forty five sites:

- Screen 1: Removal of Redundant Sites and Sites Located in Parks (44 reduced to 40 Sites)
- Screen 2: Removal of Sites with Excessive Transmission Lengths (40 reduced to 23 Sites)
- Screen 3: Unit Cost of Energy Screening (23 reduced to 5 Sites), and
- Screen 4: Focused Assessment of Preferred Options (Top 5 Sites).

The screening process yielded the following results:

- The most attractive (preferred) projects, based on a desktop level assessment of location, project layout, site characteristics, capacity, energy, and cost, are Drury Lake, Finlayson River, Anvil Creek, Tutshi – Windy Arm, and Wolf River.
- The Levelized Cost of Capacity (LCOC) for the preferred sites ranges from $700 to $1,200/kW-yr at the YEC real interest rate of 3.38 percent.
- The Levelized Cost of Energy (LCOE) for the preferred sites ranges from $0.13 to $0.21/kWh at the YEC real interest rate of 3.38 percent.
- Based on a stand-alone assessment of hydropower development and interconnection to the closest existing or proposed transmission line, the most attractive small hydro sites are the Finlayson River, Wolf River, and Tutshi – Windy Arm. Drury Lake and Anvil Creek appear to be more expensive on a cost of energy basis.
- The optimal installed capacities for the Finlayson River, Tutshi – Windy Arm, and Wolf River Projects are likely in the order of double those used in the present study. 20 MW was the upper bound cap for this study based on the purpose set out in the RFP (to evaluate sites of 20 MW or less).
- The Tutshi – Windy Arm Project has the additional benefit of increasing the winter generation at the Yukon Generating Station downstream.
- If the Moon Lake – Tutshi Lake pumped storage project is developed, it may have material synergies with development of the Tutshi – Windy Arm small hydro project.

The optimal small hydro site will depend on a number of factors, including capital costs, desired capacity, development of proposed transmission lines, environmental impacts, and social conditions. Further evaluation of the preferred sites is recommended to improve the understanding of engineering, economic, environmental, and social factors impacting project development. Should such assessment indicate that there are no technical or environmental showstoppers, further evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

The table below summarizes the key financial and technical attributes for the five preferred sites.

ATTRIBUTES	Drury Creek	Finlayson River	Anvil Creek	Tutshi - Windy Arm	Wolf River
TECHNICAL:					
Installed Capacity (MW)	8.1	17.6	9.8	7.2	20.0
Net Annual Generation (GWh)	31.7	138.9	41.3	56.6	95.6
Mean Annual Discharge (m^3/s)	4.9	16.5	4.1	16.1	40.3
Design Flow - Qd (m^3/s)	9.3	13.3	8.2	15.0	37.7
Gross Head (m)	99	150	135	54	60
Transmission Line Length (km)	1	5	11	1	23
FINANCIAL:					
Estimated Capital Cost	$ 97,250,000	$ 265,990,000	$ 109,210,000	$ 125,400,000	$ 220,170,000
O&M Costs - Fixed ($/yr)	$ 1,945,000	$ 5,320,000	$ 2,184,000	$ 2,508,000	$ 4,403,000
O&M Costs - Variable ($/yr)	$ 158,000	$ 695,000	$ 207,000	$ 283,000	$ 478,000
YEC Rate Scenario (3.38%)					
Levelized Cost of Energy ($/kWh)	$ 0.19	$ 0.12	$ 0.17	$ 0.14	$ 0.14
Levelized Cost of Capacity ($/kW-yr)	$ 700	$ 1,000	$ 700	$ 1,100	$ 700
IPP Rate Scenario (4.61%)					
Levelized Cost of Energy ($/kWh)	$ 0.23	$ 0.14	$ 0.20	$ 0.17	$ 0.17
Levelized Cost of Capacity ($/kW-yr)	$ 900	$ 1,100	$ 800	$ 1,300	$ 800
High Interest Rate Scenario (8.82%)					
Levelized Cost of Energy ($/kWh)	$ 0.24	$ 0.15	$ 0.21	$ 0.18	$ 0.18
Levelized Cost of Capacity ($/kW-yr)	$ 900	$ 1,200	$ 900	$ 1,400	$ 900

TABLE OF CONTENTS

PAGE

EXECUTIVE SUMMARY I

TABLE OF CONTENTS i

1 – GENERAL 1
- 1.1 INTRODUCTION 1
- 1.2 SCOPE 1
- 1.3 METHODOLOGY 1
- 1.4 OVERVIEW OF HYDROELEC POWER GENERATION 2
- 1.5 YUKON'S ELECTRICITY SYSTEM 4
  - 1.5.1 Current Capacity 4
  - 1.5.2 Power Grid 4
  - 1.5.3 Proposed Transmission Lines 5
- 1.6 INITIAL SITE LIST 6
- 1.7 SMALL HYDRO SITE LOCATIONS 6

2 – INFORMATION REVIEW AND PRELIMINARY SCREENING 9
- 2.1 RECONCILIATION OF EXISTING INFORMATION 9
- 2.2 PRELIMINARY EVALUATION – SCREEN 1 9
  - 2.2.1 Redundant Sites 9
  - 2.2.2 Sites Located in Parks 9
  - 2.2.3 Sites Passing Screen 1 9
- 2.3 TRANSMISSION LINE LENGTH – SCREEN 2 10
  - 2.3.1 Distance to Existing and Proposed Transmission Lines 10
  - 2.3.2 Sites Passing Screen 2 12

3 – COST TO BENEFIT ASSESSMENT - SCREEN 3 13
- 3.1 GENERAL 13
- 3.2 HYDROLOGY 13
  - 3.2.1 Regional Hydrology 13
  - 3.2.2 Discharge 13
  - 3.2.3 Hydrographs 14
  - 3.2.4 Dependable Capacity (Flow) 15
- 3.3 RUN OF RIVER PROJECTS 16
  - 3.3.1 Design Basis 16
  - 3.3.2 Energy Models 17
  - 3.3.3 Indicative Costs 17
  - 3.3.4 Cost to Benefit Analysis 17
- 3.4 SMALL HYDRO WITH STORAGE PROJECTS 19
  - 3.4.1 Design Basis 19
  - 3.4.2 Reservoir Flooded Areas 19
  - 3.4.3 Cost to Benefit Analysis 20
- 3.5 SHORTLIST OF PREFERRED SITES 22

4 – EVALUATION OF PREFERRED SITES 23
4.1 PROJECT LAYOUTS 23
4.1.1 Drury Lake 23
4.1.2 Finlayson River 25
4.1.3 Anvil Creek 27
4.1.4 Tutshi – Windy Arm 29
4.1.5 Wolf River 31
4.2 TURBINE SELECTION 33
4.3 CAPITAL COST EVALUATION 33
4.4 FINANCIAL EVALUATION 36
4.5 OTHER CONSIDERATIONS 38
4.5.1 Benefits to Downstream Generation 38
4.5.2 Benefits from Pumped-Storage Development 38
4.6 DEVELOPMENT SCHEDULE 39

5 – CONCLUSIONS AND RECOMMENDATIONS 41
5.1 CONCLUSIONS 41
5.2 RECOMMENDATIONS 43

6 – REFERENCES 44

7 – CERTIFICATION 46

TABLES

Table 1.1 Initial Site List 7
Table 2.1 Sites Passing Screen 1 10
Table 2.2 Distance (km) to Existing and Proposed Transmission Lines 11
Table 2.3 Sites Passing Screen 2 12
Table 3.1 Unit Runoff and Discharge 14
Table 3.2 Run of River Screen 3 Summary Table 18
Table 3.3 Storage Hydro Reservoir Characteristics 20
Table 3.4 Small Hydro with Storage Screen 3 Summary Table 21
Table 3.5 Shortlist of Preferred Sites 22
Table 4.1 Capital Cost Estimate - Preferred Sites 35
Table 4.2 Project Financial Attributes - Preferred Sites 37
Table 5.1 Summary of Financial and Technical Attributes – Preferred Sites 42

FIGURES

Figure 1.1 Conceptual Hydropower Project Layouts 3
Figure 1.2 Yukon Electricity Network (YEC, 2016) 5
Figure 1.3 Site Locations Overview Map 8
Figure 3.1 Typical Hydrograph 15
Figure 3.2 Normal Distribution 16

Figure 4.1 Drury Lake Project General Arrangement 24
Figure 4.2 Finlayson River Project General Arrangement 26
Figure 4.3 Anvil Creek Project General Arrangement 28
Figure 4.4 Tutshi – Windy Arm Project General Arrangement 30
Figure 4.5 Wolf River Project General Arrangement 32
Figure 4.6 Turbine Selection Guideline 33
Figure 4.7 Indicative T-tap Interconnection Arrangement 34
Figure 4.8 Minimum Development Schedule 40

APPENDICES

Appendix A Preliminary Capacity & Energy

ABBREVIATIONS

C	loaded capital cost
CFRD	Concrete Faced Rockfill Dam
DFO	Fisheries and Oceans Canada
EPCM	Engineering, Procurement and Construction Management
GWh	gigawatt hour
IFR	Instream Flow Requirement
km	kilometre
KP	Knight Piesold Ltd.
LC	levelized capital cost per year
LCOC	Levelized Cost of Capital
LCOE	Levelized Cost of Energy
m	metre
m^3	cubic metre
Mm^3	million cubic metre
m^3/s	cubic metre per second
MAD	Mean Annual Discharge
MAUD	Mean Annual Unit Discharge
MW	megawatt
MWh	megawatt hour
Q_d	design flow
WAF	Whitehorse – Aishihik – Faro (transmission grid)
WSC	Water Survey of Canada
YDC	Yukon Development Corporation
YEC	Yukon Energy Corporation
YECL	Yukon Electrical Company Ltd.
yr	year

1 – GENERAL

1.1 INTRODUCTION

Yukon Energy Corporation (YEC) commissioned Knight Piésold Ltd. (KP) to conduct a desktop review of potential small hydroelectric projects in the Yukon and northern British Columbia. The objectives of the study were to compare technical and economic development criteria and to establish a ranking that provides YEC with the basis to plan further studies on the more favorable sites.

1.2 SCOPE

This study was undertaken in response to a two part Request for Proposals (RFP) issued by YEC, to identify potential pumped-storage sites within a 25 km radius of existing or proposed transmission infrastructure and to review a number of previously identified small hydro resources with capacities of 20 MW or less. The intention was to compare the cost of energy and installed capacity with other potential fossil fuel and renewable options that may be available to YEC, including wind, diesel and natural gas-fired generation.

The requirements for the small hydro study, as stated in the RFP, were:

- Review existing information for the various sites
- Update existing cost estimates
- Update power generation profiles
- Evaluate size of reservoirs and inundation areas for small hydro sites with storage, and
- Evaluate potential hydro sites against financial and technical attributes.

This desktop assessment covered proposed sites and reports dating back more than fifty years. Previous studies have varied in scopes and objectives, and not all existing information was available to KP for this review. No new geotechnical or physical data has been collected, and the assessment does not weigh environmental and societal impacts or the regulatory permitting process, with the exception that projects located in parks have been eliminated due to perceived regulatory barriers. The assessment is high level in nature and relies upon data, mapping, and project information from various sources with variable quality.

1.3 METHODOLOGY

This study utilized a four stage screening process to determine the preferred run of river and storage hydroelectric projects within the scope of this study:

- Screen 1: Removal of Redundant Sites and Sites Located in Parks
- Screen 2: Removal of Sites with Excessive Transmission Lengths and Associated Costs
- Screen 3: Unit Cost of Energy Screening, and
- Screen 4: Focused Assessment of Preferred Options (Top 5 Sites).

Each screening stage is detailed in subsequent sections of this report. The process has been developed to eliminate sites that are indeterminate, fundamentally flawed, and comparatively expensive or technically unviable, with the overriding objective of providing a focus for future studies on the better development options.

1.4 OVERVIEW OF HYDROELEC POWER GENERATION

Conventional hydroelectric power stations utilize the water in a river and the elevation drop in its channel (often at rapids and waterfalls) to generate electrical energy, which is transmitted to domestic and/or industrial consumers using powerlines. Hydropower is a renewable source of energy with a low carbon footprint. It is a long standing, proven technology that is prevalent worldwide and particularly in regions with high annual precipitation and mountainous terrain.

Conventional hydroelectric power projects can be subdivided into two general types:

- Run of River Hydro

Run of river hydroelectric plants utilize the available flow in a river at any given time, with minimal upstream headpond/reservoir storage. Water is typically diverted at a weir into a water conveyance system (canal, tunnel, and/or penstock), to a powerhouse, and then back into the natural river channel. Very little alteration is made to the natural hydrograph downstream of a run of river project.

Electric output is a function of short term (hourly or daily) river discharge, varying daily and seasonally in parallel with the river discharge hydrograph. In the Yukon, run of river generating potential occurs predominantly from May until August, during spring freshet and summer glacial melt.

- Storage Hydro

Storage hydroelectric plants utilize an upstream lake or reservoir to store water and to control the outflow and energy output on a daily, monthly, or seasonal basis. This allows for load shaping and winter generation, a time at which run of river generation is very low.

Storage hydropower configurations vary, from lake/reservoir controlled run of river style projects (with configurations as described above), to large dams with built in generating units where all elevation head is derived from the dam itself, to a combination of both.

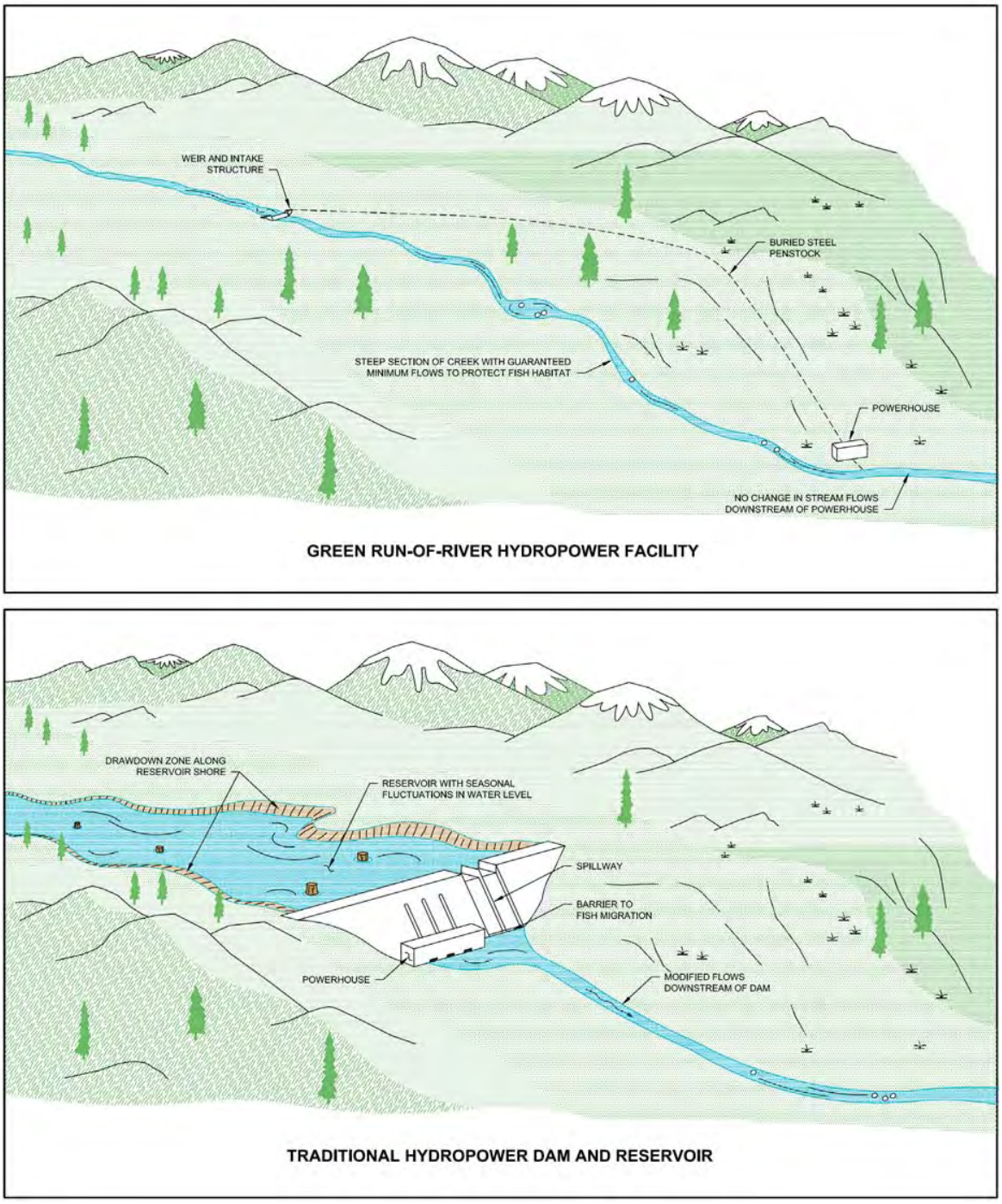


Figure 1.1 Conceptual Hydropower Project Layouts

1.5 YUKON'S ELECTRICITY SYSTEM

1.5.1 Current Capacity

YEC currently owns and operates approximately 131 MW of installed capacity, consisting of 92 MW of hydro, 0.8 MW of wind, and 37.8 MW of thermal (diesel and natural gas). Yukon Electrical Company Ltd. (YECL), owned by ATCO, supplies approximately 1.3 MW of hydroelectricity and 6.8 MW of diesel power.

YEC's hydroelectric generating capacity is comprised of:

- 37 MW Aishihik Generating Station, 150 km west of Whitehorse
- 15 MW Mayo Generating Station, 450 km north of Whitehorse
- 40 MW Whitehorse Generating Station, located on the Yukon River at Whitehorse, and
- 1.3 MW Fish Lake Generating Station (YECL).

1.5.2 Power Grid

The Yukon power grid is shown on Figure 1.2 and comprises the following major components:

- 138 kV Whitehorse / Aishihik / Faro (WAF) grid
- 69 kV Mayo / Dawson transmission line, and
- 138 kV Carmacks / Stewart transmission line, connecting the WAF grid and the Mayo / Dawson transmission line.

The Yukon electricity network is an isolated grid, with no connection to other jurisdictions (BC, Alaska or Northwest Territory). The Yukon grid currently services all Yukon communities except for Watson Lake, Burwash Landing/Destruction Bay, Beaver Creek, and Old Crow [YDC, 2015].

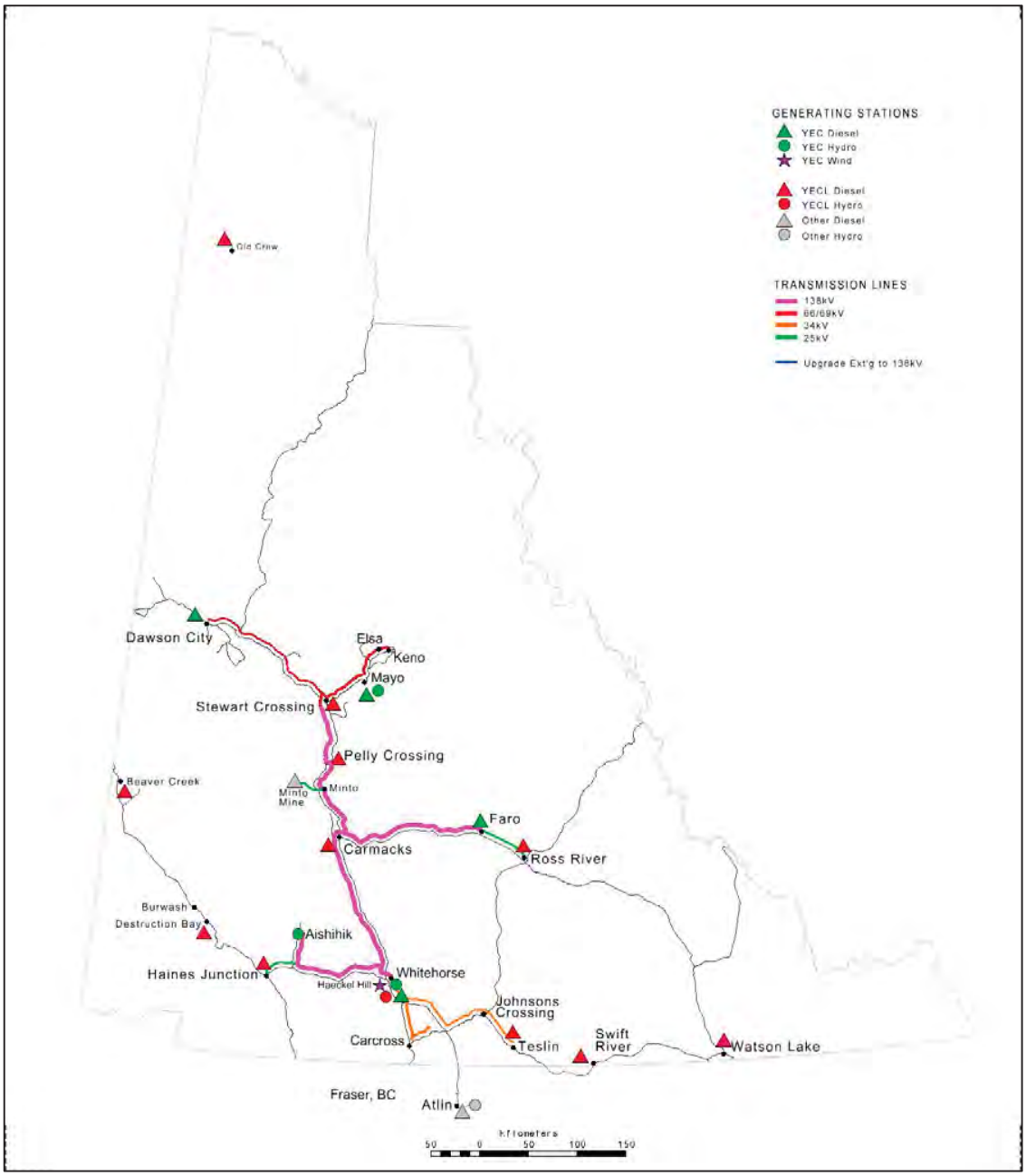


Figure 1.2 Yukon Electricity Network (YEC, 2016)

1.5.3 Proposed Transmission Lines

The following major transmission line extensions have also been considered by YEC:

- Aishihik to Destruction Bay
- Skagway (AK) to Whitehorse
- Atlin (BC) to Whitehorse, and
- Faro to Watson Lake, to connect Watson Lake to the Yukon grid.

1.6 INITIAL SITE LIST

In the RFP, forty nine projects were listed for review under the scope of the small hydro study. Upon project award, YEC requested that five sites be removed from the list. Table 1.1 provides a full listing of the forty four projects included in this study, along with their previously considered installed capacities and annual energy outputs as provided by YEC.

1.7 SMALL HYDRO SITE LOCATIONS

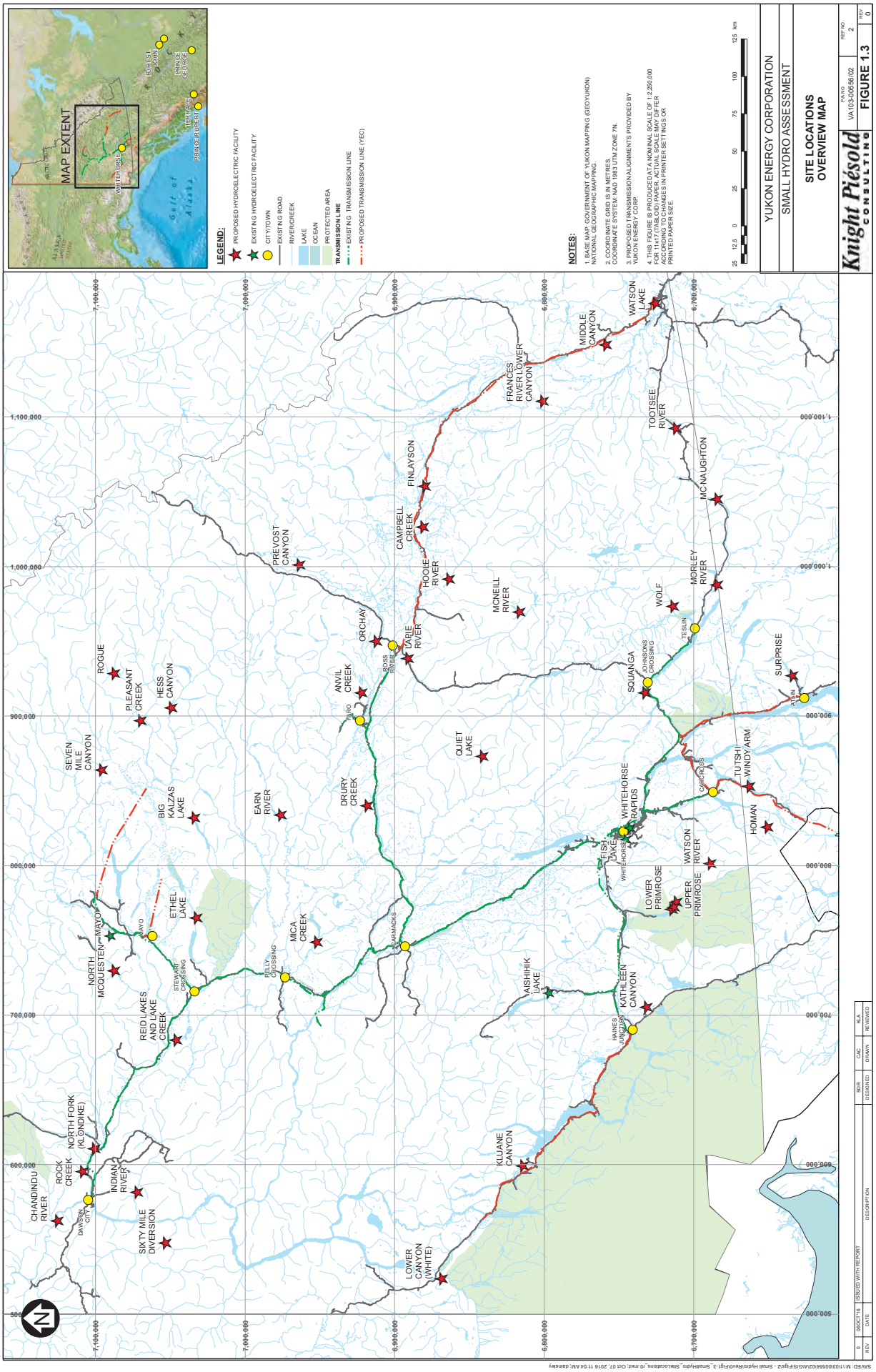
Figure 1.3 shows the location of the forty five sites, as well as existing and proposed transmission lines, communities, and existing hydropower plants.

Table 1.1 Initial Site List

Site #	Project	Type	Capacity [MW]	Energy [GWh]
1	Anvil Creek	Hydro with Storage	10.7	74
2	Big Kalzas Lake	Hydro with Storage	17	89.4
3	Campbell Creek	Hydro with Storage	20	105.1
4	Chandindu River	Run-of- River	3	15.9
5	Drury	Hydro with Storage	2.4	19.8
6	Earn	Hydro with Storage	7	36.8
7	Ethel Lake	Hydro with Storage	2	13.5
8	Finlayson	Hydro with Storage	17	128.9
9	Frances River (Lower Canyon)	Hydro with Storage	12.7	66.7
10	Hess Canyon	Hydro with Storage	18	94.6
11	Homan Lake	Hydro with Storage	4.2	26
12	Hoole River	Hydro with Storage	15	
13	Indian	Hydro with Storage	6	47.3
14	Kathleen Canyon	Run-of- River	2	
15	Kluane Canyon	Hydro with Storage	17	74.5
16	Kluane Canyon	Hydro with Storage	12	63.1
17	Lapie	Run-of-River	2	11.2
18	Lower Canyon on the White River	Hydro with Storage	16	84.1
20	McNaughton Cr.	Hydro with Storage	9.5	76
21	McNeil	Hydro with Storage	10	52.6
22	Mica Creek	Hydro with Storage	10	52.6
23	Middle Canyon (Small)	Hydro with Storage	14	
24	Morley River	Run-of- River	4	22.1
25	North Fork Klondike River	Run-of-River	2	12.3
26	North McQuesten	Hydro with Storage	5	26.3
27	Orchay	Hydro with Storage	4	35
28	Pleasant Creek	Hydro with Storage	5	26.3
29	Pleasant Creek with Rogue Diversion	Hydro with Storage	7	
30	Prevost Canyon	Hydro with Storage	11	60
31	Quiet Lake and Rose River Diversions	Hydro with Storage	15	78.8
32	Quiet Lake Diversion	Hydro with Storage	7	
33	Reid Lakes and Lake Creek	Hydro with Storage	4	22.1
34	Rock Creek	Run of River	1	5.1
35	Rogue	Hydro with Storage	12	63.1
36	Rose Lake to Kusawa Lake	Hydro with Storage	17	
37	Seven Mile Canyon	Hydro with Storage	10	52.6
38	Sixty Mile River Diversion	Hydro with Storage	18	94.6
39	Squanga Creek	Run of River	1.75	8.3
41	Tootsee River	Hydro with Storage	4	23
43	Tutshi-Windy Arm	Hydro with Storage	5.9	39.4
44	Upper and Lower Primrose	Hydro with Storage	16.1	92
47	Watson Lake & McDonald	Hydro with Storage	1	6
48	Watson River	Hydro with Storage	3	
49	Wolf River	Run of River	4.8	41.7

NOTES:

1. Site # is shown per YEC's description; initial list includes a total of 44 sites.


MAP EXTENT
LEGEND:
PROPOSED HYDROELECTRIC FACILITY
EXISTING HYDROELECTRIC FACILITY
CITY/TOWN
EXISTING ROAD
RIVER/CREEK
LAKE
OCEAN
PROTECTED AREA
TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE (YEC)
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:2,250,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
SITE LOCATIONS OVERVIEW MAP
Knight Piésold CONSULTING
PA NO. VA103-00556/02
REF NO. 2
FIGURE 1.3
REV 0
WHITEHORSE
DAWSON CITY
MAYO
WATSON LAKE
FRANCES RIVER LOWER CANYON
MIDDLE CANYON
TOOTSEE RIVER
MCNAUGHTON
FINLAYSON
CAMPBELL CREEK
HOOLIE RIVER
PREVOST CANYON
MCNEILL RIVER
MORLEY RIVER
WOLF
TESLIN
SQUANGA
JOHNSONS CROSSING
SURPRISE
ORCHAY
LAPIE RIVER
ROSS RIVER
ANVIL CREEK
QUIET LAKE
ROGUE
PLEASANT CREEK
HESS CANYON
SEVEN MILE CANYON
BIG KALZAS LAKE
EARN RIVER
DRURY CREEK
TUTSHI
WINDY ARM
CARCROSS
HOMAN
WHITEHORSE RAPIDS
FISH LAKE
WATSON RIVER
LOWER PRIMROSE
UPPER PRIMROSE
ETHEL LAKE
MICA CREEK
STEWART CROSSING
KLONDIKE HIGHWAY
NORTH MCQUESTEN
REID LAKES AND LAKE CREEK
AISHIHIK LAKE
HAINES JUNCTION
KATHLEEN CANYON
KLUANE CANYON
LOWER CANYON (WHITE)
CHANDINDU RIVER
ROCK CREEK
NORTH FORK (KLONDIKE)
INDIAN RIVER
SIXTY MILE DIVERSION
7,100,000
7,000,000
6,900,000
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6,700,000
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2 – INFORMATION REVIEW AND PRELIMINARY SCREENING

2.1 RECONCILIATION OF EXISTING INFORMATION

Many hydro studies have been completed for YEC, Yukon Electrical Company Ltd. (YECL), Yukon Development Corporation (YDC), and other entities in the Yukon, dating back over fifty years. The initial phase of this study was to review these reports and to compile project information.

The level of detail and quality in the available information was highly variable, with some sites having been studied numerous times, and others only having been identified as potential resources. Studies have varied, from desktop studies and high level reconnaissance to site investigations and feasibility designs.

A complete listing of the reports that were reviewed for the small hydro study, either having been provided to KP directly by YEC or found online through public sources, is provided in Section 6. It should be noted that this information was not comprehensive, and a number of historic reports were missing or otherwise unavailable for this study.

2.2 PRELIMINARY EVALUATION – SCREEN 1

The first screen targeted the removal of redundant projects and sites located in national or territorial parks. This level of screening resulted in the elimination of five sites.

2.2.1 Redundant Sites

From the information review, it appears that the site list included the following redundancies:

- Sites 15 and 16: Kluane Canyon – Although recorded with a different installed capacity, both sites are in the same location and represent only one resource potential (regardless, Kluane Canyon is located in a national park and is eliminated in Section 2.2.2).
- Site 23: Middle Canyon (Small) – Documentation revealed that the Lower Canyon on the Frances River (Site 9) is also known as Middle Canyon, and mapping investigations confirmed these sites to be interchangeable.

2.2.2 Sites Located in Parks

A review of project locations identified the following sites to be located in national or territorial parks:

- Sites 15 and 16: Kluane Canyon
- Site 36: Rose Lake to Kusawa Lake, and
- Site 44: Upper and Lower Primrose.

2.2.3 Sites Passing Screen 1

Table 2.1 provides the site list after Screen 1. Thirty nine sites were successful in progressing to the Screen 2 evaluation.

Table 2.1 Sites Passing Screen 1

Site #	Project	Site #	Project
1	Anvil Creek	25	North Fork Klondike River
2	Big Kalzas Lake	26	North McQuesten
3	Campbell Creek	27	Orchay
4	Chandindu River	28	Pleasant Creek
5	Drury	29	Pleasant Cr with Rogue
6	Earn	30	Prevost Canyon
7	Ethel Lake	31	Quiet Lake and Rose River Diversions
8	Finlayson	32	Quiet Lake Diversion
9	Frances River (Lower Canyon)	33	Reid Lakes and Lake Creek
10	Hess Canyon	34	Rock Creek
11	Homan Lake	35	Rogue
12	Hoole River	37	Seven Mile Canyon
13	Indian	38	Sixty Mile River Diversion
14	Kathleen Canyon	39	Squanga Creek
17	Lapie	41	Tootsee River
18	Lower Canyon White	43	Tutshi-Windy Arm
20	McNaughton Cr.	47	Watson Lake & McDonald
21	McNeil	48	Watson River
22	Mica Creek	49	Wolf River
24	Morley River		

NOTES:
1. Site # is shown per YEC's description; initial list included a total of 44 sites.

2.3 TRANSMISSION LINE LENGTH – SCREEN 2

Transmission line length and the associated costs of interconnection, along with access road lengths and costs, are significant factors impacting the viability of hydroelectric project development. With transmission costs estimated in the order of $500,000/km to $1,000,000/km, the economics of small hydro projects can be substantially eroded as transmission distance increases.

For this assessment, transmission lengths exceeding 25 km to an existing or proposed future transmission line were considered to be too great, and these projects were eliminated from further consideration at this time. Future grid expansions may warrant further consideration of sites outside of the 25 km buffer used in this study.

Project clustering may significantly improve the economics of more distant project groupings if they are developed concurrently, and this may render some of the more distant projects viable. However, it is outside the scope of this study to consider project clusters.

2.3.1 Distance to Existing and Proposed Transmission Lines

Table 2.2 provides a summary of the estimated shortest linear length to interconnect to existing and proposed future transmission lines. This table only includes the thirty nine sites passing Screen 1.

Table 2.2 Distance (km) to Existing and Proposed Transmission Lines

Site #	Project	Distance to Existing Transmission	Distance to Proposed Transmission
1	Anvil Creek	6.7	
2	Big Kalzas Lake	83.9	37.3
3	Campbell Creek	77	0.5
4	Chandindu River	29.2	
5	Drury	0.5	
6	Earn	62.9	
7	Ethel Lake	32.5	28.1
8	Finlayson	155.3	5.1
9	Frances River (Lower Canyon)	193.2	23.6
10	Hess Canyon	113.9	56.1
11	Homan Lake	43.3	15.3
12	Hoole River	46.8	15.0
13	Indian	29.2	
14	Kathleen Canyon	6.1	
17	Lapie	7.3	6.1
18	Lower Canyon on the White River	186.4	47.7
20	McNaughton Cr.	132.3	88.9
21	McNeil	93	72.3
22	Mica Creek	7.2	
24	Morley River	81.1	33.9
25	North Fork Klondike River	1.3	
26	North McQuesten	25.0	
27	Orchay	13.1	
28	Pleasant Creek	89.8	10.3
29	Pleasant Creek with Rogue Diversion	89.8	10.3
30	Prevost Canyon	81.6	78.5
31	Quiet Lake and Rose River Diversions	81.1	
32	Quiet Lake Diversion	81.1	
33	Reid Lakes and Lake Creek	4.6	
34	Rock Creek	3.9	
35	Rogue	149	79.5
37	Seven Mile Canyon	84.5	31.5
38	Sixty Mile River Diversion	58.4	
39	Squanga Creek	2.8	
41	Tootsee River	172.4	73.9
43	Tutshi-Windy Arm	24.8	0.5
47	Watson Lake & McDonald	254.7	1.9
48	Watson River	1.8	
49	Wolf	55.1	22.1

NOTES:

1. Site # is shown per YEC's description; initial list includes a total of 44 sites.

2.3.2 Sites Passing Screen 2

Table 2.3 provides the site list for projects within 25 km of existing or proposed transmission lines, along with the installed capacity and energy output values provided by YEC. Twenty two sites met the criteria and progressed to Screen 3.

Table 2.3 Sites Passing Screen 2

Site #	Project	Type	Capacity [MW]	Energy [GWh]
1	Anvil Creek	Hydro with Storage	10.7	74
3	Campbell Creek	Hydro with Storage	20	105.1
5	Drury	Hydro with Storage	2.4	19.8
8	Finlayson	Hydro with Storage	17	128.9
9	Frances River (Lower Canyon)	Hydro with Storage	12.7	66.7
11	Homan Lake	Hydro with Storage	4.2	26
12	Hoole River	Hydro with Storage	15	
14	Kathleen Canyon	Run-of- River	2	
17	Lapie	Run-of-River	2	11.2
22	Mica Creek	Hydro with Storage	10	52.6
25	North Fork Klondike River	Run-of-River	2	12.3
26	North McQuesten	Hydro with Storage	5	26.3
27	Orchay	Hydro with Storage	4	35
28	Pleasant Creek	Hydro with Storage	5	26.3
29	Pleasant Creek with Rogue Diversion	Hydro with Storage	7	
33	Reid Lakes and Lake Creek	Hydro with Storage	4	22.1
34	Rock Creek	Run-of- River	1	5.1
39	Squanga Creek	Run-of- River	1.75	8.3
43	Tutshi-Windy Arm	Hydro with Storage	5.9	39.4
47	Watson Lake & McDonald	Hydro with Storage	1	6
48	Watson River	Hydro with Storage	3	
49	Wolf River	Hydro with Storage	4.8	41.7

NOTES:
1. Site # is shown per YEC's description; initial list included a total of 44 sites.

3 – COST TO BENEFIT ASSESSMENT - SCREEN 3

3.1 GENERAL

The Screen 3 evaluation was based on consideration of capital costs, capacity, and the energy potential of each site. Six run of river and sixteen small hydro with storage sites underwent the following sequence of tasks:

- Hydrology review and assessment
- Review of project layouts
- Energy Modelling
- Indicative cost estimating, and
- Cost to benefit analyses (Unit Cost of Energy, Unit Cost of Capacity).

3.2 HYDROLOGY

A hydrology review was conducted on all sites passing Screen 2. The purpose of this review was to determine the suitability of hydrological values previously developed for various projects, and to develop hydrological estimates for those sites where no historically reported information could be obtained.

3.2.1 Regional Hydrology

Data from a total of forty six Water Survey of Canada (WSC) gauges with catchment areas between 10 km^2 and 7,000 km^2 were reviewed to develop an understanding of regional trends in measured runoff for catchments of varying sizes and regions. The data were used to develop estimates of Mean Annual Discharge (MAD) and Mean Annual Unit Discharge (MAUD) at all project sites that passed Screen 2. The data were also used to produce typical hydrographs to estimate the distribution of flow throughout the year.

3.2.2 Discharge

Table 3.1 provides the estimated MAUD and MAD values for all sites passing Screen 2. Where no previous hydrology information could be obtained, KP developed estimates on the basis of the MAUD values from the WSC gauges in the region. These gauges are dispersed across the majority of the Yukon and provide a reasonable means of assessing hydrologic patterns throughout the region. Some of the basic trends evident in the data are as follows:

- MAUD appears to decrease in a south-westerly direction along the border between the Yukon and the Northwest Territories, with lower unit discharge values evident in the dry, lower relief interior zones versus the mountainous terrain along the eastern provincial border.
- In the south-western corner of the Yukon, MAUD appears to be relatively high due to the onshore movement of moist maritime air from the Pacific Coast. The effects of this moisture influx extends slightly beyond the Coastal Mountain Range, and then drops off markedly due to a ‘precipitation shadow’ effect that results in a progressive reduction in MAUD moving east.

MAUD values were selected for the project sites on the basis of proximity and similarity of catchment size to the WSC stations. Commonly, there are two to three local gauge stations that provide a basis for estimating unit discharge. Where applicable, consideration was also given to the MAUD values reported for various project sites.

Additional regional considerations when determining a site's MAUD included:

- Glaciers in a watershed, which generally increase MAUD due to melt during the warm summer months
- Lakes in a watershed, which generally decrease MAUD due to greater evaporation, and
- The local relief, with higher elevation watersheds generally having higher precipitation and correspondingly higher MAUD.

Table 3.1 Unit Runoff and Discharge

Site #	Project	Catchment Area (km^2)	MAUD, Reported ($L/s/km^2$)	MAUD, KP Estimate ($L/s/km^2$)	MAD (m^3/s)
1	Anvil Creek	513		8.0	4.1
3	Campbell Creek	611		9.0	5.5
5	Drury	550	9.0		4.9
8	Finlayson	1,542	10.7		16.5
9	Frances River (Lower Canyon)	12,969		7.5	97.3
11	Homan Lake	150		12.0	1.8
12	Hoole River	738		9.0	6.6
14	Kathleen Canyon	904		15.5	14.0
17	Lapie	1,293	10.1		13.1
22	Mica Creek	543		4.5	2.4
25	North Fork Klondike River	1,100	12.6		13.9
26	North McQuesten	2,010		7.5	15.1
27	Orchay	390	7.5		2.9
28	Pleasant Creek	843		9.0	7.6
29	Pleasant Cr with Rogue	3,272		9.0	29.4
33	Reid Lakes and Lake Creek	1,024	5.4		5.5
34	Rock Creek	424	12.6		5.3
39	Squanga Creek	838	3.6		3.0
43	Tutshi-Windy Arm	992	16.2		16.1
47	Watson Lake & McDonald	330	3.4		1.1
48	Watson River	97		9.0	0.9
49	Wolf River	3,500		11.5	40.3

3.2.3 Hydrographs

Using the available WSC gauge data, hydrographs were generated and grouped according to watershed size in an effort to determine if any consistent and pronounced differences in annual hydrograph shape could be related to catchment size in the Yukon. The catchment sizes of the forty six WSC gauges that were considered range from 10 km^2 to 7,000 km^2. A variety of size groupings were plotted for comparison purposes and it appeared that there are two basic groups of hydrographs of similar shape: those for areas less than 500 km^2 and those for areas greater than 500 km^2. There does not appear to be sufficient variation in hydrograph shape to merit further division by basin size. The two basic hydrograph shapes, which were delineated according to the average monthly values for the indicated basin sizes, are shown on Figure 3.1.

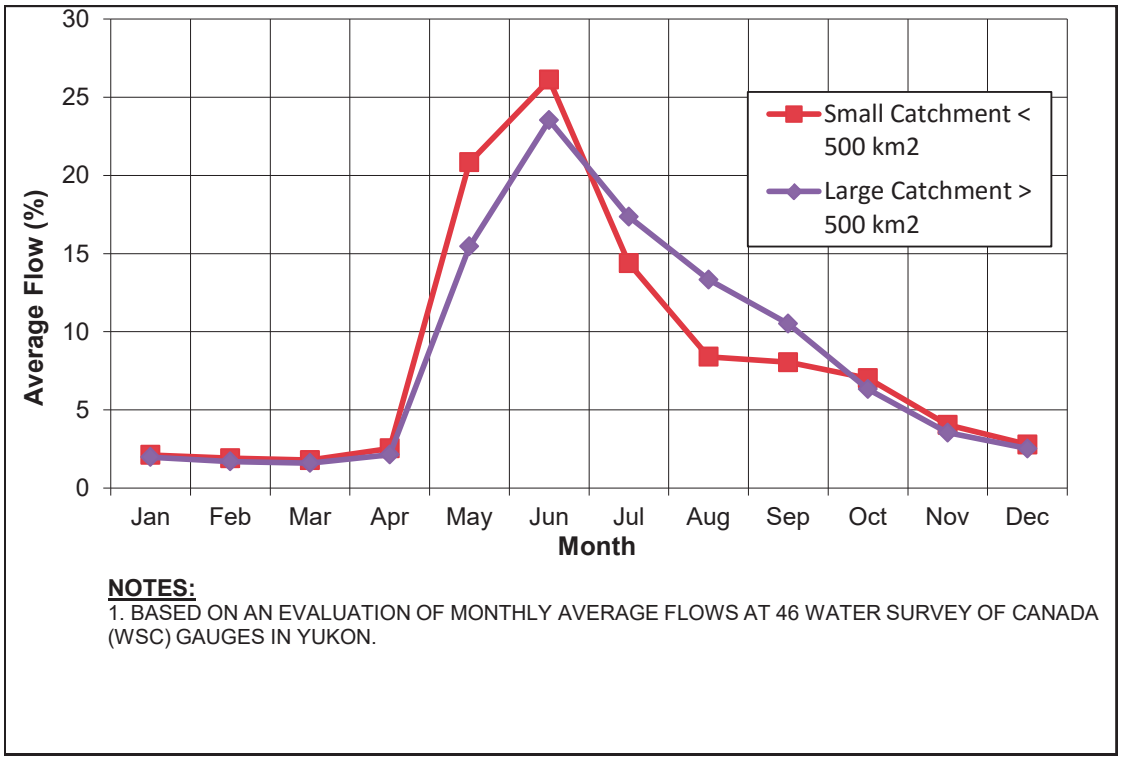

Figure 3.1 Typical Hydrograph

For relatively small basins, the peak freshet flow period is more pronounced but of shorter duration than for large basins, which tend to sustain flows at higher levels through the summer months. This pattern is consistent with the tighter elevation range characteristic of smaller basins (with snowmelt occurring more rapidly and more consistently throughout the basin) and the higher likelihood of glacier content in the large basins (which supply late summer flows through melting).

3.2.4 Dependable Capacity (Flow)

Dependable Capacity is defined by BC Hydro to be the maximum capacity that a generating station can reliably produce when required, with an 85 percent level of confidence and assuming that all generating units are in service (BC Hydro, 2005). In the context of hydropower plants, capacity synonymous with availabile flow and storage upstream of the intake.

In line with the 85 percent confidence level described above, Dependable Flow is herein defined to be the monthly flow that will be available for a given month in 85 percent of calendar years (P85). P85 values will vary between different drainages and river systems based on site specific climate and hydrology conditions.

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The hydrological estimates described in Sections 3.2.1 – 3.2.3 screening level assessments based on regional climatic and hydrographic trends. The WSC gauge data that was reviewed represents average flow data (P50 conditions). Long term site specific data was not available and 'true' site specific percentile values, such as P85, were not determined. However to support YEC's assessment of potential small hydro resources relative other generation technologies, KP assessed select regional data to provide indicative P85 values for each project as follows.

Based on the assumption that annual discharge follows a normal distribution (example shown on Figure 3.2), the P85 Dependable Flow will occur approximately one standard deviation below the P50 level (-1σ). The size of the standard deviation is dependent on the spread of the data for any particular river system, which is influenced by catchment area, elevation, and regional climatic trends.

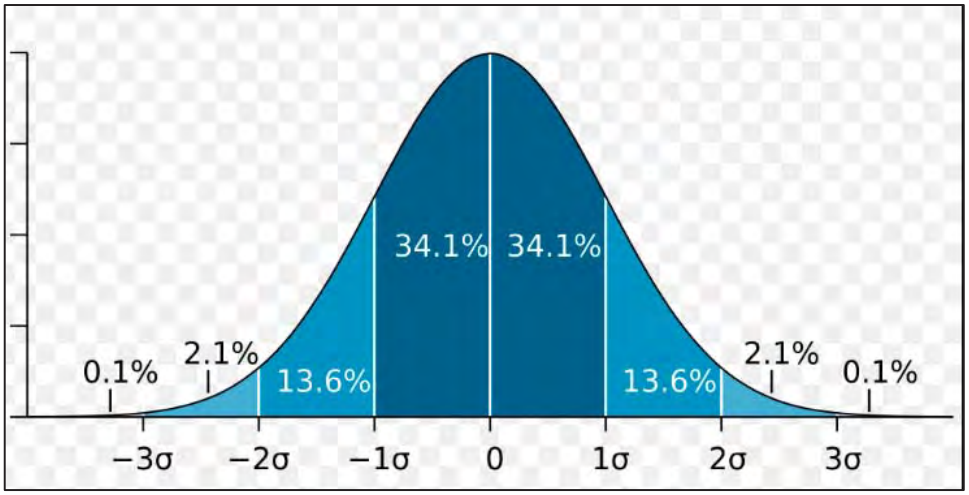


Figure 3.2 Normal Distribution

In order to provide YEC with a rough approximation of the dependable capacity for the small hydro sites, KP has reviewed the standard deviation and coefficient of variation observed in a small sample of long term WSC gauge data. This review indicates that the coefficient of variation is higher during the freshet and summer period than it is during the shoulder seasons and winter months. It also indicates that the coefficient of variation for smaller catchment areas is higher than that for larger catchments. Both of these observations align with expectation.

For the small hydro sites, and especially for sites that operate on a run of river basis, the Dependable Capacity will vary significantly from month to month, and during winter, dependable capacity is close to zero in some cases. The estimated indicative monthly dependable capacity and energy output values are included in Appendix A.

3.3 RUN OF RIVER PROJECTS

3.3.1 Design Basis

Run of river hydroelectric plants utilize the available flow in a river at any given time, with minimal headpond/reservoir storage, and electric output is a function of short term (hourly or daily) yield. The optimal installed capacity depends on numerous factors, including constructability, environmental requirements, and the need for and ability to sell seasonal power.

As illustrated in Figure 3.1, the majority of the electric generating potential for run of river projects in the Yukon occurs between May and August, from the onset of the spring freshet through summer as snow and glacial melt feed the river systems. Winter flows tend to be very low, as surface water is frozen and rivers are fed predominantly from lakes and groundwater sources. As such, run of river

projects do not offer good base load and are more beneficial for peak energy production in the spring and summer seasons.

Assuming that all energy output can be utilized, the optimal design flow for a run of river plant tends to be in the order of 2 times the Mean Annual Discharge (MAD). If peak power during the spring and summer is not desired and base load is more highly valued, a lower design flow and a correspondingly higher capacity factor should be targeted, such as 0.5 times MAD.

For the purpose of assessing and fairly comparing the run of river projects, it is assumed that all energy output can be utilized and, accordingly, design flow has been set at 2 times MAD. The exception is Site 49 – Wolf River, which is considered with a lower design flow to not exceed the 20 MW upper limit for this small hydro assessment. It appears that a much higher design flow for this site is an optimization worth considering in a future study.

3.3.2 Energy Models

Energy models were developed for the six run of river hydro sites evaluated in Screen 3. The energy models used the monthly hydrology data developed for this study and a number of assumptions:

- Instream Flow Requirements (IFR) equal to 5 percent of MAD.
- 10 percent head losses through intake and conveyance to the turbine, at maximum design flow, and a linear decrease in head loss with decreasing flow.
- Average efficiency of 90 percent from turbine to the point of sale, to account for turbine – generator losses, transformer losses, transmission losses, station usage, and outages.
- Turbine types auto selected for optimal performance according to design flow and head.

3.3.3 Indicative Costs

Basic indicative cost estimates were developed for each project using KP's in-house experience and cost estimating database for projects with comparable characteristics. Where the level of detail in the existing design was insufficient to permit an accurate assessment of site specific conditions, facility layouts, sizes, and costs were scaled according to head, flow, installed capacity, and other key project costing metrics. Cost estimates included the following major components:

- Task 100: Mobilization, Demobilization, Insurance, Bonds, Overheads, and Contractor's Profits
- Task 200: Access and Site Preparation
- Task 300: Intake, Forebay, Headrace, and Tailrace
- Task 400: Water Conveyance System
- Task 500: Powerhouse and Ancillary Services
- Task 600: Power Generation Equipment (Water to Wire)
- Task 700: Switchyard, Transmission, and Interconnection
- Task 800: Dam(s) and Reservoir(s)
- Engineering, Procurement, and Construction Management (EPCM): 8 %, and
- Contingency: 30 %.

3.3.4 Cost to Benefit Analysis

The fair evaluation of alternative hydropower development options requires an assessment of project costs and benefits. The Screen 3 assessment was based on the comparative values for two financial metrics, the Unit Cost of Capacity and the Unit Cost of Energy:

- ***Unit Cost of Capacity = Net Present Cost at Commissioning ($) / Installed Capacity (MW)***
  This unit of measurement can be useful for gauging project costs in relation to other proposed or existing power projects. For instance, YEC's Mayo B Hydroelectric Project was constructed for a cost of roughly $120 million, and added 10 MW of power to the Yukon's energy system (YEC, 2016), equating to a unit capacity cost of roughly $12 million/MW. The unit capacity cost of the better options in this study are in this order of magnitude, providing some confidence in the underlying quantities and unit rates that have been assumed.
  While unit capacity cost does have its usefulness, it is not a good measure of the overall project value since capacity is not directly correlated to energy production and revenues.
- ***Unit Cost of Energy = Net Present Cost at Commissioning ($) / Average Annual Energy Production (GWh/yr).***
  Unit energy cost is a useful financial metric for the determination of a project's value and relative ranking of sites with different installed capacities and hydrology characteristics. Provided that all energy can be sold, unit energy cost is directly correlated with revenue. The Screen 3 assessment and selection of preferred sites was based on the unit cost of energy.
  Unit energy costs in the order of $2.5 million/GWh/yr or less are considered to be favorable development costs and projects with this value may warrant further consideration.

Table 3.2 provides a summary of the major design outputs for the run of river projects, along with the estimated (indicative) costs and cost to benefit metrics. The values presented are based on a net present cost at commissioning that assumes a construction duration of 3 years and a real interest cost of 4.61 percent (IPP development rate provided by YEC).

Table 3.2 Run of River Screen 3 Summary Table

Site #	Name	Design Flow	Gross Head	Installed Capacity	Net Avg. Energy	Net Present Cost	Unit Capacity Cost	Unit Energy Cost
		m^3/s	m	MW	GWh/yr		$/MW	$/GWh/yr
14	Kathleen	28.0	15.0	3.7	12.6	$ 61,323,000	$ 16,537,000	$ 4,857,000
17	Lapie	26.2	36.0	8.3	29.6	$ 92,078,000	$ 11,057,000	$ 3,116,000
25	North Fork Klondike	27.8	69.0	16.9	60.0	$ 180,170,000	$ 10,638,000	$ 3,004,000
34	Rock Creek	10.6	40.0	3.7	12.6	$ 97,531,000	$ 26,053,000	$ 7,722,000
39	Squanga Creek	6.0	54.0	2.9	10.2	$ 30,248,000	$ 10,574,000	$ 2,980,000
49	Wolf River	28.3	80.0	20.0	104.9	$ 271,023,000	$ 13,559,000	$ 2,584,000

NOTES:
1. Net Average Energy is based on P50 hydrology estimates as described in Section 3.2.
2. Estimated monthly energy output values are provided in Appendix A.
3. Net Present Cost assumes a three year construction period and an interest rate of 4.61 percent.

3.4 SMALL HYDRO WITH STORAGE PROJECTS

3.4.1 Design Basis

Storage hydroelectric plants utilize an upstream lake or reservoir to store water and to control the outflow and energy output on a daily, monthly, or seasonal basis. This allows for load shaping and winter generation, provided the reservoir has sufficient storage in relation to MAD and the design flow of the plant. Storage capacity is of particular value during the low flow fall, winter, and early spring months, when run of river output is low and reliance on costly diesel power generation is high.

The available storage in an upstream reservoir is a significant factor to be considered in the sizing of storage hydro plants. While this study does not specifically address environmental considerations, lake level changes may impact the environment and private land, and technical constraints may further hinder the construction of high dams for large lake raises. The design basis for the storage hydro plants considered in this assessment was discussed with YEC during this study and was agreed as follows:

- For sites where storage is possible on a natural lake or lakes, lake level increases have been limited to 5 m.
- Where no upstream lake is available and/or where minimal viable elevation drop has been identified, a dam sized to store 20 m of water has been provided for both water storage and head (Site 9 – Frances River, Site 12 – Hoole River, Site 26 – North McQuesten River).

The selection of the optimal design flow and the corresponding installed capacity is a function of the reservoir storage capacity and MAD. The general approach used for the selection of design flow is:

- Where the available lake storage capacity exceeds the annual yield of a river system, reservoir size was reduced to roughly the volume of annual average yield, and the annualized flow through the plant was adjusted to match the man annual yield (flow approaches MAD, less IFR releases).
- Where the available lake storage capacity is substantially less than the annual yield of a river system, the design flow was set at 2 times MAD and the plant was assumed to operate as a run of river style project when the reservoir is near full, with the added benefit of an improved capacity factor due to reservoir draw down in the low flow months.

3.4.2 Reservoir Flooded Areas

Table 3.3 provides a summary of the reservoir storage characteristics for all of the small hydro with storage sites evaluated in Screen 3. These reservoir characteristics coupled with the hydrology conditions (Section 3.2) are the basis for the Screen 3 energy and cost estimating for the small hydro with storage sites.

For each of the options listed in Table 3.3, the area upstream of the dam that will be inundated when the dam is filled has been estimated using the available topography and a standard depth – area interpolation. Flooded areas are calculated as the estimated new lake area minus the natural lake area. These are best guess values based on the coarse mapping interval that was available.

Table 3.3 Storage Hydro Reservoir Characteristics

Site #	Project	Natural Lake Area (km^2)	Lake Level Increase (m)	New Lake Area (km^2)	Estimated Available Storage (m^3)
1	Anvil Creek	5.3	5.0	5.9	27,875,000
3	Campbell Creek	2.5	5.0	3.2	14,250,000
5	Drury Lake	26.0	5.0	27.9	134,750,000
8	Finlayson (Wolverine Lake)	8.2	5.0	10.6	47,000,000
8	Finlayson (Finlayson Lake)	20.0	5.0	23.0	107,500,000
9	Frances River (Lower Canyon)	2.8	20.0	15.5	70,625,000
11	Homan Lake	5.2	5.0	7.1	30,625,000
12	Hoole River	0.0	20.0	2.3	10,063,000
22	Mica Creek	32.6	2.0	35.0	71,400,000
26	North McQuesten	0.0	20.0	9.0	38,375,000
27	Orchay (Lake B)	0.7	5.0	0.9	3,875,000
27	Orchay (Orchay Lake)	5.5	5.0	6.3	29,375,000
28, 29	Pleasant Creek	10.0	5.0	13.5	58,750,000
33	Reid Lakes and Lake Creek	20.3	5.0	31.7	129,875,000
43	Tutshi Lake	51.9	5.0	55.0	267,125,000
47	Watson Lake	13.9	2.5	14.5	35,438,000
48	Watson River	0.2	5.0	0.6	2,000,000

3.4.3 Cost to Benefit Analysis

Energy models were developed for each small hydro with storage site, using the design basis described in Section 3.4.1 and the energy model assumptions described in Section 3.3.2. Indicative cost estimates were developed as described in Section 3.3.3.

Table 3.4 provides a summary of the major design outputs for the small hydro with storage projects, along with the estimated (indicative) costs and cost to benefit metrics. The values presented are based on a net present cost at commissioning, assuming a construction duration of 3 years and a real interest cost of capital of 4.61 percent (IPP development rate provided by YEC).

Table 3.4 Small Hydro with Storage Screen 3 Summary Table

Site #	Name	Design Flow	Gross Head	Installed Capacity	Net Avg. Energy	Net Present Cost	Unit Capacity Cost	Unit Energy Cost
		m^3/s	m	MW	GWh/yr		$/MW	$/GWh/yr
1	Anvil	8.2	135.0	9.8	41.3	$ 120,502,000	$ 12,329,000	$ 2,918,000
3	Campbell	11.0	77.0	7.5	29.0	$ 145,101,000	$ 19,403,000	$ 5,010,000
5	Drury	9.3	99.0	8.1	31.7	$ 84,993,000	$ 10,484,000	$ 2,682,000
8	Finlayson	13.3	150.0	17.6	138.9	$ 280,698,000	$ 15,932,000	$ 2,021,000
9	Frances	129.5	17.5	20.0	88.7	$ 281,896,000	$ 14,089,000	$ 3,178,000
11	Homan	3.6	77.0	2.4	13.5	$ 84,507,000	$ 34,529,000	$ 6,277,000
12	Hoole	13.2	17.5	2.0	7.7	$ 145,368,000	$ 71,276,000	$ 18,982,000
22	Mica	4.6	35.0	1.4	5.6	$ 123,257,000	$ 86,654,000	$ 22,165,000
26	North McQuesten	30.2	17.5	4.7	18.0	$ 156,324,000	$ 33,502,000	$ 8,675,000
27	Orchay	2.7	132.0	3.1	24.6	$ 89,740,000	$ 28,798,000	$ 3,653,000
28	Pleasant	5.4	40.0	1.9	14.9	$ 154,622,000	$ 81,554,000	$ 10,344,000
29	Pleasant & Rogue	56.7	40.0	20.0	77.9	$ 536,734,000	$ 26,804,000	$ 6,889,000
33	Reid Lakes & Lake Creek	5.2	90.0	4.1	32.4	$ 163,807,000	$ 39,830,000	$ 5,052,000
43	Tutshi - Windy Arm	15.0	51.0	6.8	53.4	$ 136,411,000	$ 20,141,000	$ 2,555,000
47	Watson Lake & McDonald	2.1	60.0	1.1	4.4	$ 56,326,000	$ 49,947,000	$ 12,776,000
48	Watson River	1.8	50.0	0.8	2.9	$ 28,593,000	$ 35,984,000	$ 10,009,000

NOTES:

1. Net Average Energy is based on P50 hydrology estimates as described in Section 3.2.
2. Additional capacity and energy values are provided in Appendix A; average capacity and average energy, and dependable capacity and firm energy.
3. Net Present Cost assumes a three year construction period and an interest rate of 4.61 percent.

3.5 SHORTLIST OF PREFERRED SITES

The five preferred sites were selected based on the lowest unit energy costs presented in Tables 3.2 and 3.4. Table 3.5 presents a summary of the shortlisted sites; which include one (1) run of river project (Wolf River) and four (4) small hydro with storage projects.

Table 3.5 Shortlist of Preferred Sites

Site #	Name	Design Flow	Gross Head	Installed Capacity	Net Avg. Energy	Net Present Cost	Unit Capacity Cost	Unit Energy Cost
		m^3/s	m	MW	GWh/yr	$	$/MW	$/GWh/yr
1	Anvil	8.2	135.0	9.8	41.3	$ 120,502,000	$ 12,329,000	$ 2,918,000
5	Drury	9.3	99.0	8.1	31.7	$ 84,993,000	$ 10,484,000	$ 2,682,000
8	Finlayson	13.3	150.0	17.6	138.9	$ 280,698,000	$ 15,932,000	$ 2,021,000
43	Tutshi - Windy Arm	15.0	51.0	6.8	53.4	$ 136,411,000	$ 20,141,000	$ 2,555,000
49	Wolf River	28.3	80.0	20.0	104.9	$ 271,023,000	$ 13,559,000	$ 2,584,000

It should be noted that, while the costs and costing metrics were assessed in an unbiased manner, a significant variable is accuracy of project reference information and quality of data for each sites; which induces inaccuracy into the assessment model. With more comprehensive site specific data (i.e. hydrology, topography and foundation conditions) the economics of preferred projects could deteriorate while other sites could improve, and therefore the comparative rankings would change.

Four (4) additional sites ranked closely to the five preferred sites and may warrant further consideration when site specific is available, including:

- Squanga Creek $M 2.980/GWh/yr
- North Fork Klondike River: $M 3.004/GWh/yr
- Lapie River $M 3.116/GWh/yr, and
- Frances River $M 3.178/GWh/yr/.

4 – EVALUATION OF PREFERRED SITES

4.1 PROJECT LAYOUTS

For the preferred sites, reference information and project layouts were reviewed in finer detail than was possible for the full list of sites evaluated in Screen 3. This involved detailed reconnaissance of historic reports, old and current mapping, and other pertinent site specific considerations.

4.1.1 Drury Lake

Reference Reports: *1989, 1990, 1991 Hydro Investigations* [S. Demers], *Assessment of Potential Hydro Sites* [KGS Group, 2008]

The Drury Lake Project is located on Drury Creek between Drury Lake and Little Salmon Lake, in the Yukon River watershed. The site is approximately 170 km north of Whitehorse and is situated within 1 km of the Robert Campbell Highway and the existing WAF transmission line.

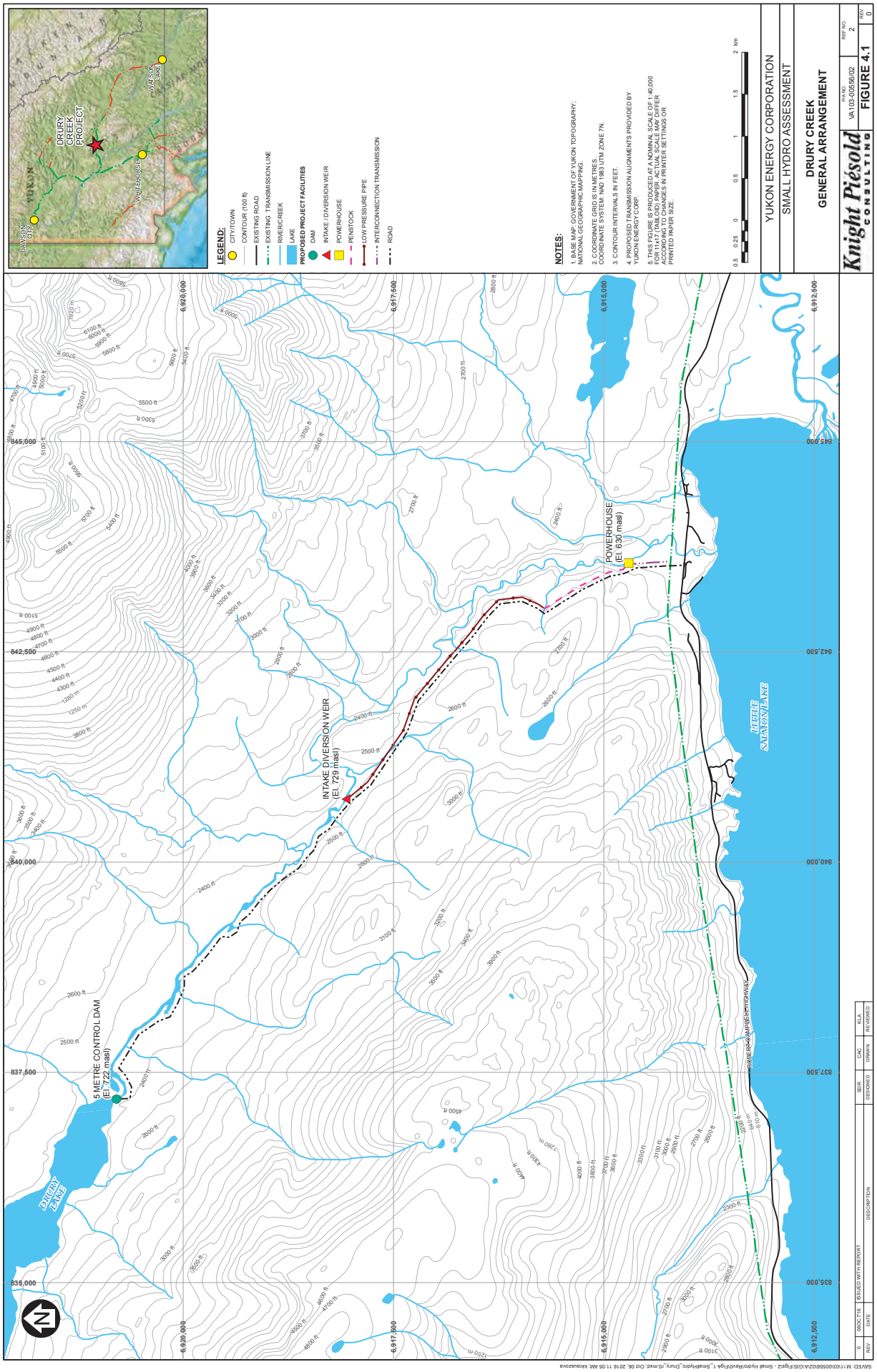
A variety of studies have previously been commissioned, including high level reconnaissance, geotechnical investigations, and design studies, and these have resulted in a number of alternative design concepts. The most recent study was completed by KGS in 2008 and provides basic site layouts, design and geotechnical considerations, and cost estimates for different options.

While earlier studies considered a low gradient canal and a short penstock, geotechnical risk and the presence of permafrost were noted by KGS. At this desktop level, the conveyance alignment and specific constructability concerns cannot be addressed in any detail beyond that reported by KGS, and so the selection of a buried low pressure penstock instead of a canal has been adopted by KP.

A preliminary general arrangement of the project layout is shown on Figure 4.1. Key project parameters and characteristics for this layout are as follows:

- Q_d = 9.3 m^3/s.
- Gross Head = 99 m.
- Installed Capacity = 8.1 MW.
- 5.3 km of access roads from the Robert Campbell Highway to the powerhouse, along the water conveyance, and upstream to the outlet of Drury Lake.
- Concrete Faced Rockfill Dam (CFRD) or earthfill control dam at the outlet of Drury Lake to provide 5 m of storage (operating storage of 135 Mm^3). The dam would be constructed with an IFR discharge system and a spillway to Drury Creek for flood water management.
- Intake weir across Drury Creek, approximately 4 km downstream of the lake outlet (El. 729 masl)
- 4.8 km penstock located on the south side of Drury Creek (alignment as previously indicated by KGS), comprising 3.6 km of low pressure pipe (LPP) and 1.2 km of high pressure pipe (HPP).
- Powerhouse (El. 630 masl) and substation at the edge of Drury Creek, upstream of the Robert Campbell Highway and the river mouth at Little Salmon Lake.
- 0.5 km transmission line, with t-tap interconnection to the existing WAF grid.

There does not appear to be much value in increasing the capacity of the Drury Lake Project. As designed, all available water (after IFR) on an average annual basis would be used for six months of reservoir filling and six months of generation; such that an increased capacity would only decrease the generating period.


DRURY CREEK PROJECT
DAWSON CITY
YUKON
WHITEHORSE
WATSON LAKE
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
EXISTING ROAD
EXISTING TRANSMISSION LINE
RIVER/CREEK
LAKE
PROPOSED PROJECT FACILITIES
DAM
INTAKE / DIVERSION WEIR
POWERHOUSE
PENSTOCK
LOW PRESSURE PIPE
INTERCONNECTION TRANSMISSION
ROAD
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:40,000 FOR 11"x17" (TABLOID) PAPER SIZE. IT MAY BE PLOTTED ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
0.5 0.25 0 0.5 1 1.5 2 km
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
DRURY CREEK
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
P/A NO. VA103-00556/02
REF NO. 2
REV 0
FIGURE 4.1
POWERHOUSE (El. 630 masl)
INTAKE DIVERSION WEIR (El. 729 masl)
5 METRE CONTROL DAM (El. 722 masl)
DRURY LAKE
LITTLE SALMON LAKE
SILVER TRAIL HIGHWAY
REV DESCRIPTION ISSUED WITH REPORT
0 06OCT16
DESIGNED BJR
DRAWN CAC
REVIEWED KLA

4.1.2 Finlayson River

Reference Reports: *1990 Hydro Investigations* [S. Demers, 1990]

The Finlayson River is a major tributary to Frances Lake and the Frances River, in the Liard River watershed. The Finlayson River Project is located adjacent to the Robert Campbell Highway and just upstream of Frances Lake, approximately 300 km to the northeast of Whitehorse.

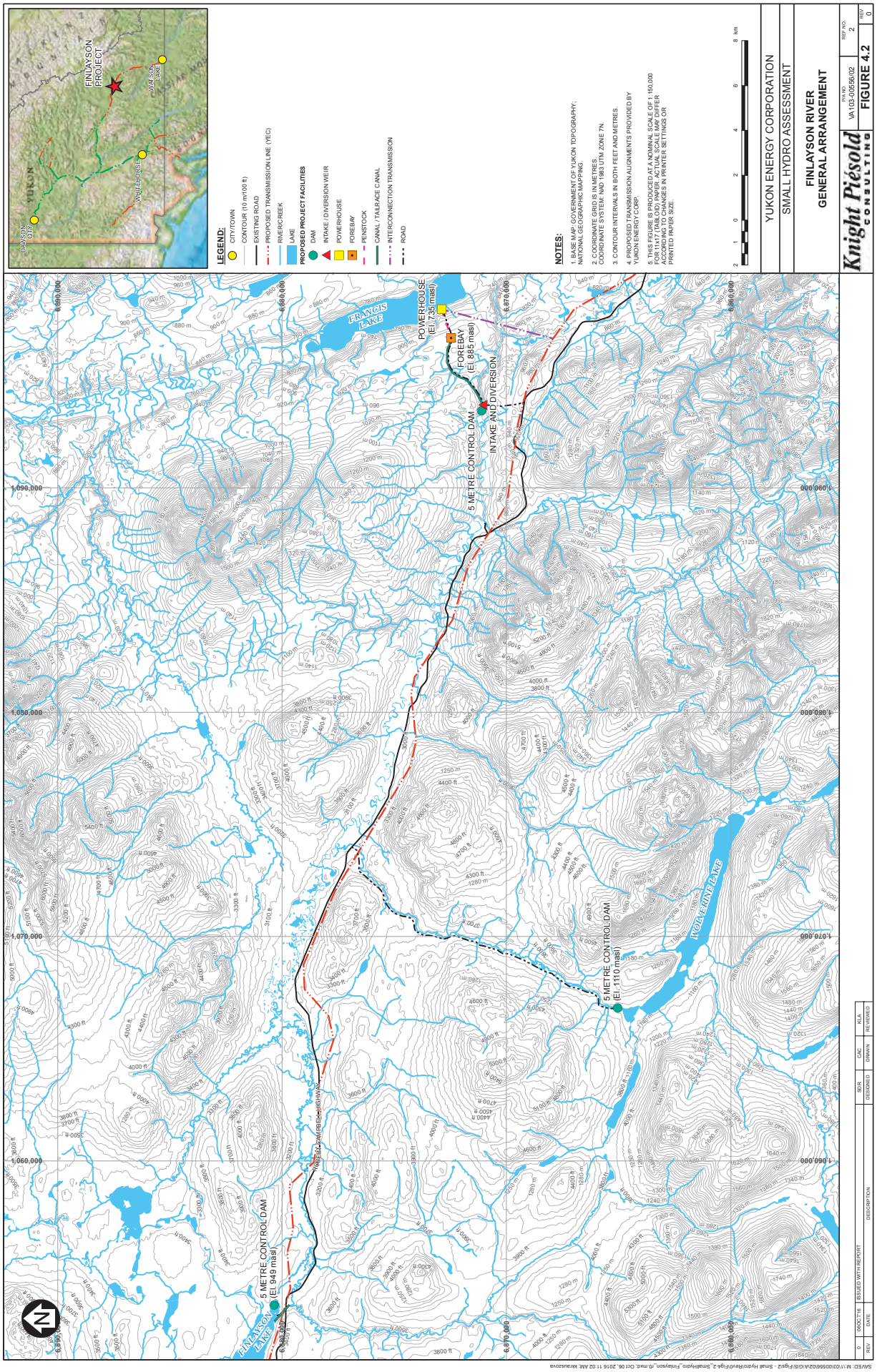
The only available study for this project was the 1990 Hydro Investigations by S. Demers. This study is outdated and high level in nature, and little is known of site specific geotechnical conditions. However, it is assumed that the locations of the intake dam, canal, penstock, and powerhouse are the most suitable and have therefore been used for this desktop level study.

The design concept involves lake storage and flow regulation on Finlayson Lake and Wolverine Lake, and an intake diversion dam on Finlayson River downstream of the Wolverine River confluence. In its previously envisioned configuration, the intake dam on Finlayson River would be 66 m high at the head of a canyon, and reservoir flooding would require rerouting approximately 3 km of the Robert Campbell Highway. The highway is gravel, and the anticipated costs and technicalities of rerouting this highway are not anticipated to be difficult. However, should rerouting of the highway be impractical for permitting or other reasons, it is likely that a smaller dam and a modified water conveyance alignment could be found.

A basic general arrangement for the proposed project layout is shown on Figure 4.2.Key project parameters for this layout are as follows:

- Q_d = 13.3 m^3/s.
- Gross Head = 150 m.
- Installed Capacity = 17.6 MW.
- 17 km of access roads, to reach the outlets of Wolverine and Finlayson Lakes, the intake diversion dam, water conveyance and powerhouse.
- Relocation of 3 km of the Robert Campbell Highway (due to dam flooding).
- Control dams at the outlets of Wolverine and Finlayson Lakes to provide 5 m of lake storage (combined operating storage of 155 Mm^3). The dams would be constructed with IFR release systems and spillways for flood water management.
- 66 m high CFRD or structured earthfill intake diversion dam located at the head of a canyon on the Finlayson River, upstream of Frances Lake.
- Spillway at the south abutment to route flood flows safely downstream to Finlayson River.
- Water conveyance canal at the north abutment, extending 4.7 km to a forebay (El. 885 masl).
- 1.35 km penstock.
- Powerhouse and substation, located at the shore of Frances Lake (El. 735 masl).
- 5.1 km transmission line, with t-tap interconnection to the proposed Ross River – Watson Lake transmission line paralleling the Robert Campbell Highway.

In its present configuration, the Finlayson River Project is sized for firm power of 17.6 MW, operating at a 100 percent capacity factor all year. It is anticipated that the optimal project in terms of a cost to benefit assessment would be much larger, perhaps in the order of 40 to 45 MW. Site investigations and a more detailed review of site specific data would be required to confirm project viability.


FINLAYSON PROJECT
WATSON LAKE
WHITEHORSE
DAWSON CITY
YUKON
LEGEND:
CITY/TOWN
CONTOUR (10 m/100 ft)
EXISTING ROAD
PROPOSED TRANSMISSION LINE (YEC)
RIVER/CREEK
LAKE
PROPOSED PROJECT FACILITIES
DAM
INTAKE / DIVERSION WEIR
POWERHOUSE
FOREBAY
PENSTOCK
CANAL / TAILRACE CANAL
INTERCONNECTION TRANSMISSION
ROAD
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN BOTH FEET AND METRES.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:150,000 FOR A 11"X17" PRINTED PAPER SIZE. IT MAY BE PLOTTED AT OTHER SCALES ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
2 0 1 2 4 6 8 km
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
FINLAYSON RIVER
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
PA NO. VA103-00556/02
REF NO. 2
FIGURE 4.2
REV 0
FRANCIS LAKE
POWERHOUSE (El. 735 masl)
FOREBAY (El. 885 masl)
INTAKE AND DIVERSION
5 METRE CONTROL DAM
5 METRE CONTROL DAM (El. 1110 masl)
WOLF CREEK
5 METRE CONTROL DAM (El. 949 masl)
FINLAYSON LAKE
REV 0 DOC TYPE ISSUED WITH REPORT DESCRIPTION BY CHECKED CAC DRAWN KLA REVIEWED
SAVED: M:\1\00\00556\02\A\GIS\Figs\ - Small Hydro\Rev0\Fig-2_Smallhydro_Finlayson_r0.mxd, Oct 06, 2016 11:02 AM, kkrauszova

4.1.3 Anvil Creek

Reference Reports: *Nil*.

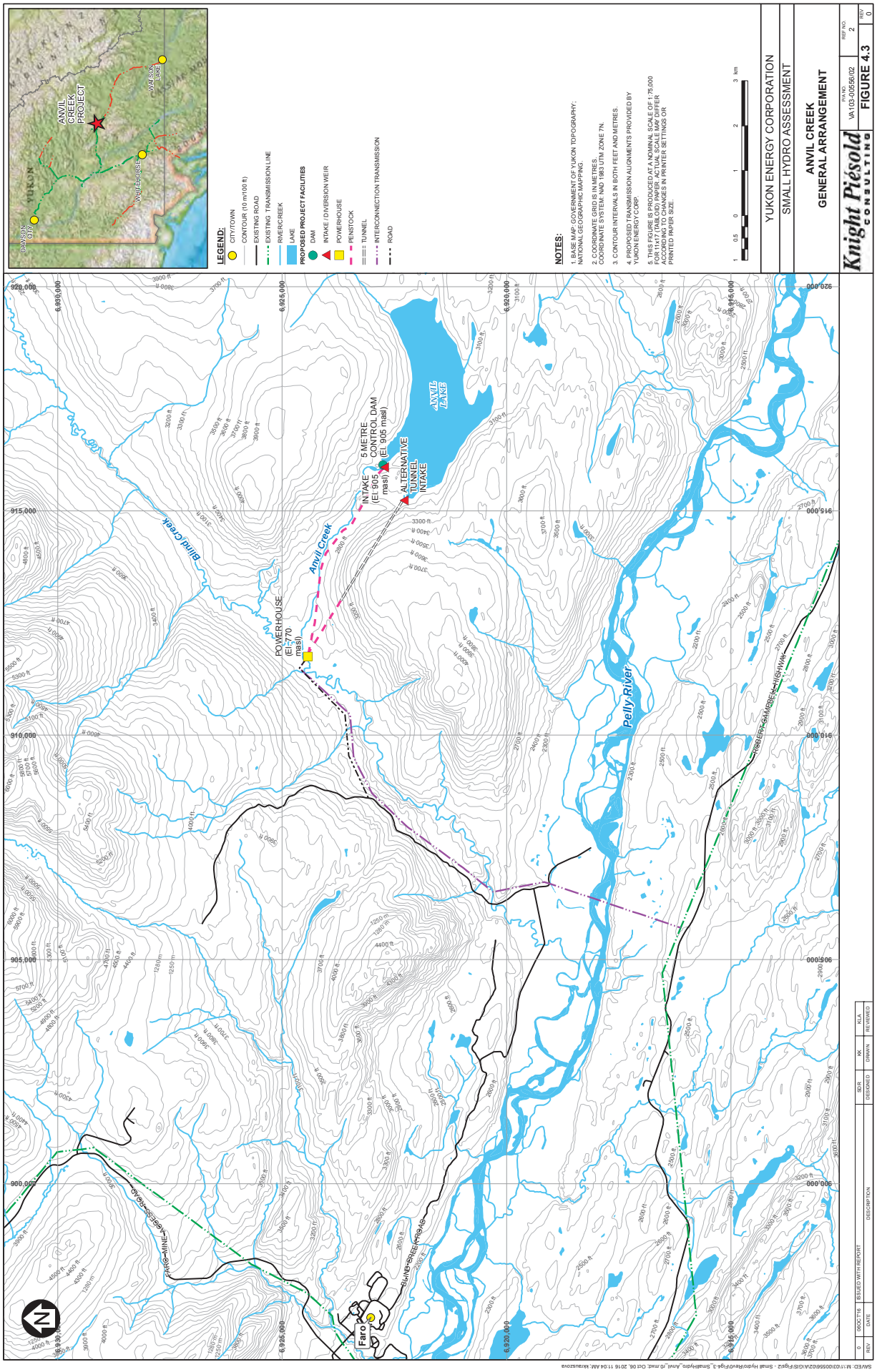
The Anvil Creek Project is located on Anvil Creek, approximately 205 km northeast of Whitehorse and 16 km east of Faro. The project is located in the Pelly River watershed, a tributary to the Yukon River. Very little previous information could be obtained for the data review of this site.

The KP concept involves lake storage and flow regulation on Anvil Lake and a buried penstock following the Anvil Creek valley to a powerhouse location upstream of the Anvil Creek – Blind Creek confluence. An alternative configuration involves a tunnel and penstock combination that offers a shorter overall water conveyance length. This option is envisioned to be more costly than the full penstock option, however should surficial conditions prove difficult in the Anvil Creek valley, it may become a viable alternative.

A basic general arrangement for the proposed project layout is shown on Figure 4.3, including both water conveyance options. Key project parameters for this layout are assumed as follows:

- Q_d = 8.2 m^3/s.
- Gross Head = 135 m.
- Installed Capacity = 9.8 MW.
- 3.5 km of new access road to access the powerhouse site from the Blind Creek Road. An allowance of 5 km of existing road upgrades for the Blind Creek access road have been allotted.
- 11 km of transmission line service access roads.
- Concrete Faced Rockfill Dam (CFRD) or earthfill control dam at the outlet of Anvil Lake to provide 5 m of storage (operating storage of 27.9 Mm^3). The dam would be constructed with an IFR discharge system and a spillway to Anvil Creek for flood water management.
- Intake weir at the dam and lake outlet (El. 905 masl)
- 4.7 km penstock located adjacent to Anvil Creek.
- Powerhouse (El. 770 masl) and substation at the edge of Anvil Creek.
- 11 km transmission line crossing the Pelly River and interconnecting to the WAF grid at the Robert Campbell Highway (Highway 16).

Very limited reference information was available for the Anvil Creek hydropower site. The project layout was developed using Google Earth and publicly available mapping on the Yukon Government website (GeoYukon). Site characterisation of terrain hazards, bedrock and surficial geology, access, and technical viability of the project should be determined through site visits and acquisition of topographic data and aerial photos.


LEGEND:
CITY/TOWN
CONTOUR (10 m/100 ft)
EXISTING ROAD
EXISTING TRANSMISSION LINE
RIVER/CREEK
LAKE
PROPOSED PROJECT FACILITIES
DAM
INTAKE / DIVERSION WEIR
POWERHOUSE
PENSTOCK
TUNNEL
INTERCONNECTION TRANSMISSION
ROAD
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN BOTH FEET AND METRES.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75,000 FOR LETTER SIZE PAPER AND 1:50,000 FOR TABLOID PAPER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
ANVIL CREEK
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
P/A NO. VA103-00556/02
REF NO. 2
REV 0
FIGURE 4.3
ANVIL CREEK PROJECT
WATSON LAKE
VANGORDA
DAWSON CITY
YUKON
ANVIL LAKE
5 METRE CONTROL DAM (El. 905 masl)
INTAKE (El 905 masl)
ALTERNATIVE TUNNEL INTAKE
Anvil Creek
Blind Creek
POWERHOUSE (El. 770 masl)
Pelly River
ROBERT CAMPBELL HIGHWAY
CANOL ROAD
FARO MINE-GRANUM ROAD
Faro
REV
DESCRIPTION
ISSUED WITH REPORT
DATE
DESIGNED
DRAWN
REVIEWED
BJH
KK
KLA

4.1.4 Tutshi – Windy Arm

Reference Reports: *1990, 1991 Hydro Investigations* [S. Demers, 1990, 1991], *Assessment of Potential Hydro Sites* [KGS Group, 2008].

The Tutshi – Windy Arm Project is a proposed storage hydropower development located between Tutshi Lake and Windy Arm of Tagish Lake in northern British Columbia. Tutshi and Tagish Lakes are tributaries to the Yukon River. The project site is approximately 45 km to the south of Carcross, Yukon, and the proposed powerhouse location is within 1 km to the east of the Klondike Highway.

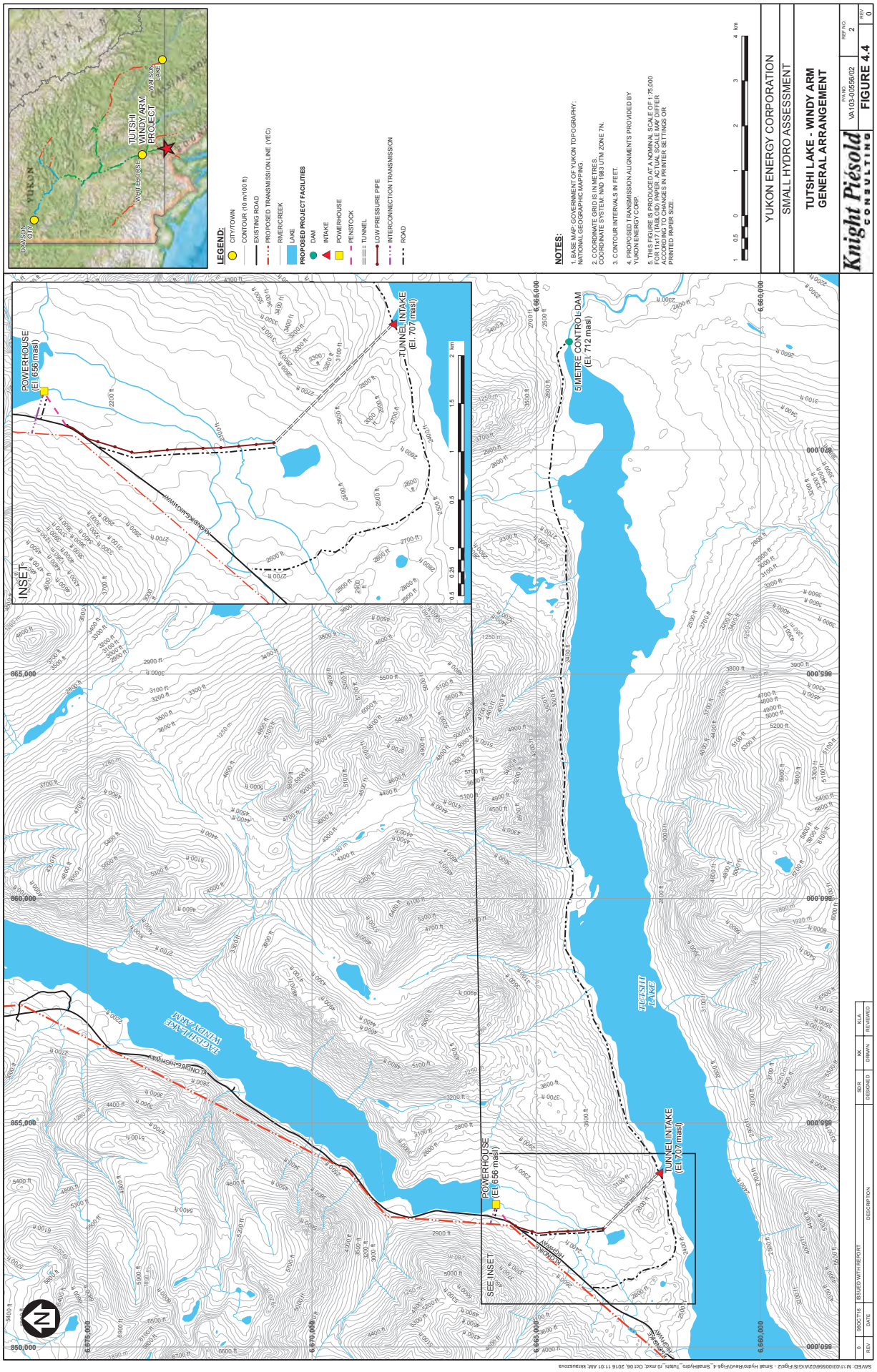
A number of studies have previously been completed for this site, including geotechnical investigations, design, and cost estimates, resulting in a number of alternative design concepts. This desktop study is based on the most current concepts, presented in the 2008 KGS report.

A basic arrangement for the proposed project layout is shown on Figure 4.4. Key project parameters for this layout are as follows:

- Q_d = 15.0 m^3/s.
- Gross Head = 54 m.
- Installed Capacity = 7.2 MW.
- 23.5 km of access roads, to reach the powerhouse, surface conveyance, tunnel intake, and outlet control dam on Tutshi Lake.
- Tutshi Lake outlet control dam to provide 5 m of lake storage (operating storage of 267 Mm^3), equipped with IFR release system and spillway for flood water management.
- Tunnel intake and 1.7 km tunnel through the hill separating the north end of Tutshi Lake from Windy Arm of Tagish Lake (Intake El. 707 masl).
- 2.7 km long penstock.
- Powerhouse on the south shore of Windy Arm, Tagish Lake (El. 656 masl).
- Substation and 0.5 km long transmission line, with t-tap interconnection to the proposed transmission line alongside the Klondike Highway.

In its present configuration, the Tutshi – Windy Arm Project is sized for firm power of 7.2 MW, operating at a 100 percent capacity factor all year. It is anticipated that the optimal project in terms of a cost to benefit assessment would be larger, perhaps in the order of 15 MW. At this larger installed capacity and higher design flow (Q_d = 30 – 32 m^3/s), the project would utilize more of the annual inflow to Tutshi Lake that would be spilled for a smaller project.

Site investigations and a more detailed review of site specific data would be required to confirm project viability and the optimal project size.


TUTSHI WINDY ARM PROJECT
YUKON
DAWSON CITY
WHITEHORSE
WATSON LAKE
LEGEND:
CITY/TOWN
CONTOUR (10 m/100 ft)
EXISTING ROAD
PROPOSED TRANSMISSION LINE (YEC)
RIVER/CREEK
LAKE
PROPOSED PROJECT FACILITIES
DAM
INTAKE
POWERHOUSE
PENSTOCK
TUNNEL
LOW PRESSURE PIPE
INTERCONNECTION TRANSMISSION
ROAD
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75,000 FOR A 11"x17" (TABLOID) PAPER SIZE. IT MAY BE PLOTTED ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
TUTSHI LAKE - WINDY ARM
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
P/A NO. VA103-00556/02
REF NO. 2
FIGURE 4.4
REV 0
INSET
POWERHOUSE (El. 656 masl)
TUNNEL INTAKE (El. 707 masl)
6 METRE CONTROL DAM (El. 712 masl)
TUTSHI LAKE
WINDY ARM
SEE INSET
TUNNEL/HIGHWAY
REV | DATE | DESCRIPTION | BY | CK | CLA
0 | DEC 7/16 | ISSUED WITH REPORT | DESIGNED | DRAWN | REVIEWED
SAVED: M:\1\03\00556\02\A\GIS\Figs\Figure 4 - Small Hydro\Rev0\Fig4-4_SmallHydro_Tutshi_rb.mxd: Oct 06, 2016 11:01 AM: kkrauszova

4.1.5 Wolf River

Reference Reports: *1990, 19911 Hydro Investigations* [S. Demers, 1990, 1991].

The Wolf River is a tributary of the Nisutlin River upstream of Teslin Lake, in the headwaters of the Yukon River. The Wolf River Project site is located near the river mouth and approximately 22 km to the northeast of the community of Teslin and the Alaska Highway.

The only available studies for this project were the 1990 and 1991 Hydro Investigations by S. Demers. Little is known of site specific geotechnical conditions and cannot be confirmed at the desktop level. It is assumed for the purpose of this study that the location of the powerhouse, penstock, and conveyance alignment was the most suitable based on the site visit by S. Demers.

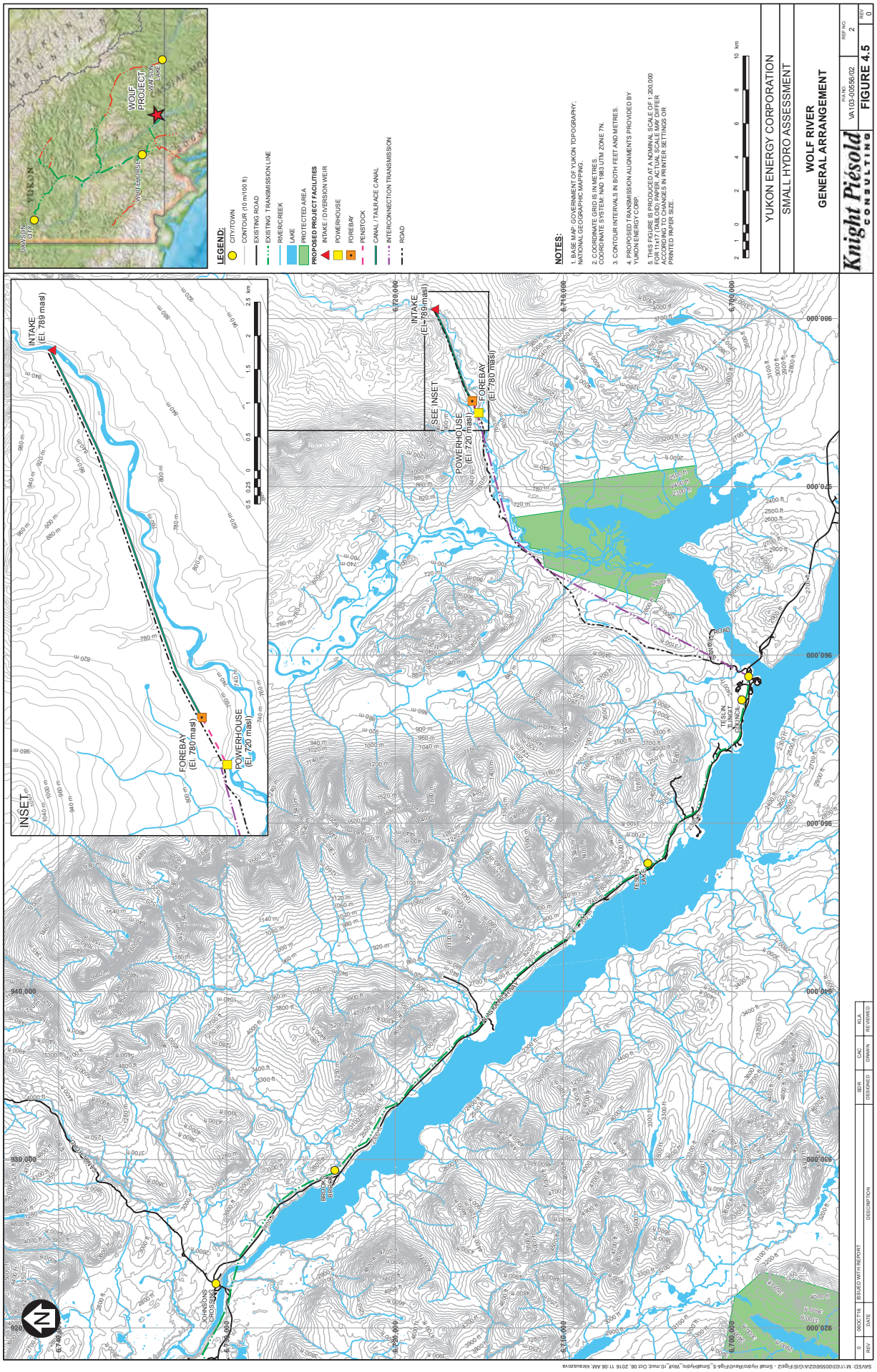
The project was envisioned to comprise a water conveyance approximately 11 kilometres in length. A review of Google Earth and regional mapping have led to a decision to move the intake further downstream, shortening the conveyance without a significant reduction in head. However, actual head will need to be confirmed with more accurate mapping.

A basic general arrangement for the proposed project layout is shown on Figure 4.5. Key project parameters for this layout are as follows:

- Q_d = 37.7 m^3/s.
- Gross Head = 60 m.
- Installed Capacity = 20 MW.
- 23 km of access roads to reach the project facilities.
- An intake diversion weir across Wolf River, diverting water to a 5.9 km long canal on the north side of the river (Intake El. 789 masl).
- Forebay (El. 780 masl) and 800 m long penstock.
- Powerhouse (El. 720 masl) and short tailrace channel to Wolf River.
- Substation and 23 km transmission line to Teslin, with a t-tap interconnection to the YEC proposed upgraded transmission line to Teslin.

This project has good power generating potential, and there may be an opportunity to target a higher installed capacity, in the order of 40 to 45 MW, for optimal project economics. However, for this study, an upper bound capacity of 20 MW was set as a cap for small hydro, in line with the scope described in the RFP.

The 1991 study also noted the potential opportunity for storage in Wolf Lake, which could improve winter generation and the plant capacity factor. This has not been considered in this study but may be a worthwhile design consideration in the future.


YUKON
DAWSON CITY
WHITEHORSE
WOLF PROJECT
WATSON LAKE
LEGEND:
CITY/TOWN
CONTOUR (10 m/100 ft)
EXISTING ROAD
EXISTING TRANSMISSION LINE
RIVER/CREEK
LAKE
PROTECTED AREA
PROPOSED PROJECT FACILITIES
INTAKE / DIVERSION WEIR
POWERHOUSE
FOREBAY
PENSTOCK
CANAL / TAILRACE CANAL
INTERCONNECTION TRANSMISSION
ROAD
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN BOTH FEET AND METRES.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:200,000 FOR LETTER SIZE PAPER AND 1:100,000 FOR TABLOID PAPER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
INSET
INTAKE (El. 789 masl)
FOREBAY (El. 780 masl)
POWERHOUSE (El. 720 masl)
SEE INSET
TESLIN
TLINGIT
BRIDGE
JOHNSON CROSSING
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
WOLF RIVER
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
PA NO. VA103-00556/02
REF NO. 2
FIGURE 4.5
REV 0
REV | DATE | DESCRIPTION | ISSUED WITH REPORT | BY/R | CHK'D | CAC | DWN | K.L.A | REVIEWED
0 | 06OCT16

4.2 TURBINE SELECTION

The selection of the optimal turbine and major equipment type and configuration is a function of design flows, installed capacities, and operating criteria. Conceptual turbine selections for the preferred sites described in this section generally conform to the typical equipment operating ranges illustrated on Figure 4.6. The preliminary turbine selections for the preferred sites are:

- Drury Creek: Francis
- Finlayson River: Pelton
- Anvil Creek: Pelton
- Tutshi-Windy Arm: Francis, and
- Wolf River: Francis.

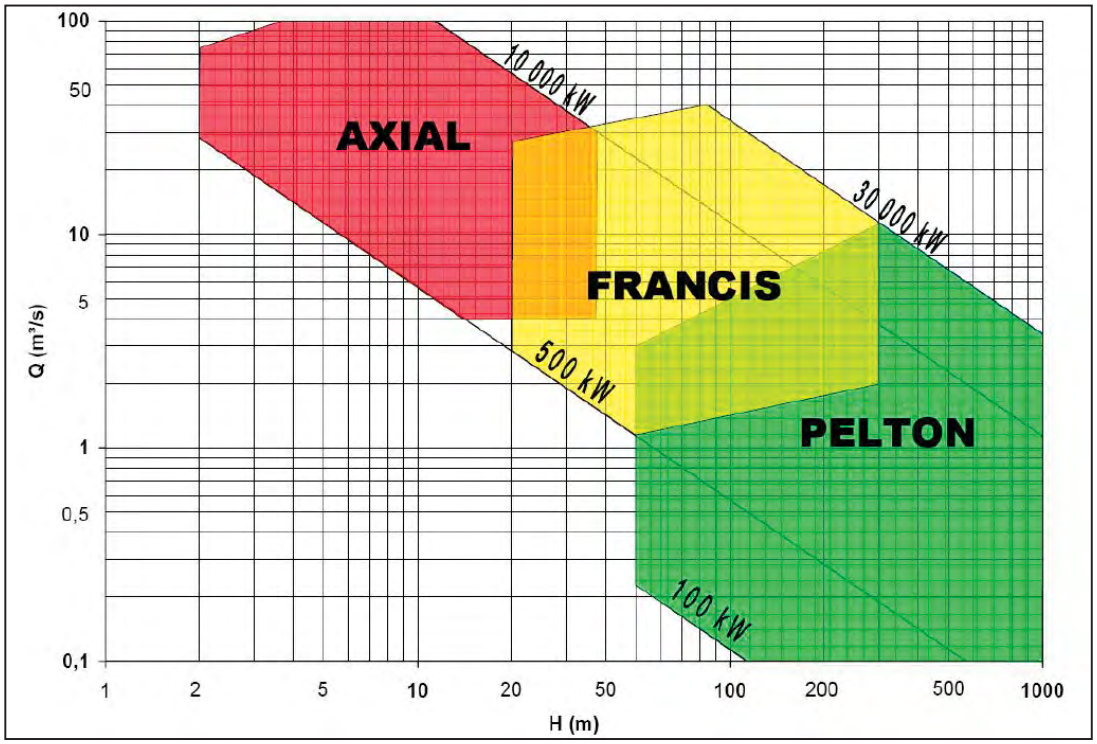


Figure 4.6 Turbine Selection Guideline

4.3 CAPITAL COST EVALUATION

Capital cost estimates have been developed based on the project configurations outlined in Section 4.1. Site specific data were used to establish project size, quantities and constructability. These attributes were used to estimate approximate material volumes for excavation, backfill, embankment material and reinforced concrete. Electrical and mechanical equipment requirements were estimated based on empirical data from KP's prior projects and published in industry technical reports.

The capital cost estimate includes an allowance for the Contractor's preliminary and general costs (overheads, insurance, bonus and profit etc.), an allowance for EPCM costs, and contingency.

Unit rates for material production, equipment procurement and installation costs relied on KP's internal costing database including recent, relevant experience with similar sized hydroelectric

projects in Western Canada and the Yukon. KP's hydro project cost database also offered an order of magnitude check of total estimated costs for individual facility components and complete facilities, based on projects with comparable characteristics such as design flow, penstock pipe characteristics (length, diameter, pressure rating), gross head, generating capacity, powerhouse area, excavation quantities, reinforced concrete volumes, backfill quantities, switchyard capacity and transmission line capacity and length. Where a project interconnection is via "Tee-Tap" type interconnection it is assumed the transmission line interconnects to the closest possible point along an existing or future proposed transmission line; requiring expensive substation and/or switching station infrastructure. There may be sites where a cheaper option exists to extend the transmission line slightly further to interconnect at an existing substation. In this case the avoided costs of building a new substation or switching station could outweigh the cost of extending the transmission line. This was not considered in this study, but should be in the next level of study. An indicative interconnection arrangement is depicted in Figure 4.7 below:

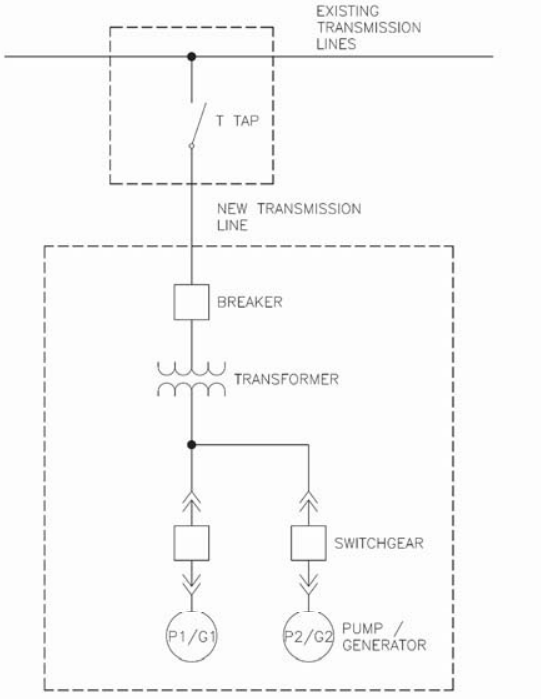


Figure 4.7 Indicative T-tap Interconnection Arrangement

Generating equipment costs were based on installed capacity, head and flow, while switchyard costs were estimated based on installed capacity. Adjustments to reflect the higher construction costs in the Yukon were included where appropriate. All dollars are shown in 2015 Canadian Dollars (CAD).

Capital costs were considered at a screening level, and costs will vary as more site specific assessments are undertaken and project designs are refined. The estimates have been prepared with sufficient detail for a preliminary AACE Class 5 estimate (±50%). These costs should be used as comparison of sites rather than as a reliable indication of the actual construction costs for any single project.

The overall estimated costs for the preferred sites are shown in Table 4.1.

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TABLE 4.1

YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT

CAPITAL COST ESTIMATE
PREFERRED SITES

10/6/2016 19:22

ITEM	DESCRIPTION	Drury Creek	Finlayson River	Anvil Creek	Tutshi - Windy Arm	Wolf River
100	MOB, DEMOB, INSURANCE, BONDS, OVERHEADS, CONTRACTOR'S PROFIT	$ 16,263,000	$ 44,480,000	$ 18,263,000	$ 20,970,000	$ 36,818,000
200	ACCESS AND SITE PREPARATION	$ 3,548,000	$ 8,650,000	$ 6,636,000	$ 7,216,000	$ 8,934,000
300	INTAKE, FOREBAY, HEADRACE AND TAILRACE	$ 2,318,000	$ 4,224,000	$ 2,036,000	$ 4,509,000	$ 11,137,000
400	WATER CONVEYANCE SYSTEM	$ 30,790,000	$ 27,253,000	$ 20,732,000	$ 39,901,000	$ 49,115,000
500	POWERHOUSE AND ANCILLARY SERVICES	$ 5,328,000	$ 11,236,000	$ 6,274,000	$ 5,057,000	$ 13,868,000
600	POWER GENERATION EQUIPMENT (WATER TO WIRE)	$ 5,675,000	$ 12,333,000	$ 6,842,000	$ 5,022,000	$ 13,980,000
700	SWITCHYARD, TRANSMISSION AND INTERCONNECTION	$ 3,161,000	$ 7,332,000	$ 8,677,000	$ 3,067,000	$ 20,097,120
800	DAM(S) AND RESERVOIR(S)	$ 3,391,000	$ 77,239,000	$ 9,680,000	$ 5,128,000	$ 5,595,000
	SUB-TOTAL (CONSTRUCTION COSTS)	**$ 70,474,000**	**$ 192,747,000**	**$ 79,140,000**	**$ 90,870,000**	**$ 159,544,120**
	EPCM ENGINEERING COST (8% of CONSTRUCTION COST)	$ 5,638,000	$ 15,420,000	$ 6,331,000	$ 7,270,000	$ 12,764,000
	CONTINGENCY (30 % of CONSTRUCTION COST)	$ 21,142,000	$ 57,824,000	$ 23,742,000	$ 27,261,000	$ 47,863,000
	TOTAL ESTIMATED CAPITAL COST	**$ 97,250,000**	**$ 265,990,000**	**$ 109,210,000**	**$ 125,400,000**	**$ 220,170,000**

M:\1\03\00556\02\A\Report\2 - Small Hydro\Rev 0\Tables\[Preferred Sites Rev0.xlsx]Table 4.1

NOTES:

1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

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0	6OCT'16	ISSUED WITH REPORT VA103-556/2-2	SDR	KLA

4.4 FINANCIAL EVALUATION

KP has developed a financial model to assess the Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC) for the five preferred sites. The basic parameters used in the financial model include:

- Capital Cost Estimate — Varies by alternative
- Fixed Operating Costs — 2.0% of initial capital cost per year
- Variable Operating Costs — $0.005/kWh for power generation
- Net Annual Generation — Varies by option
- Construction Period — 3 years, and
- Project Life — 65 years.

No escalation/inflation is included in the financial evaluation. Interest rates are assumed for the real cost of capital as provided by YEC:

- YEC resource options — 3.38%
- IPP resource options — 4.61%, and
- High interest scenario — 8.82%.

The loaded capital cost, or net present cost at Commercial Operation Date (COD) is accounts interest accrued during construction, using the following formula:

$$C = \sum_{\mathrm{yr}=0}^{\mathrm{n}} \mathrm{c}(1+i)^{\mathrm{n-yr}}$$

Where:

$$C = loaded\ capital\ cost$$
$$c = construction\ cost\ in\ given\ year\ of\ interest$$
$$yr = construction\ year\ of\ interest$$
$$n = total\ number\ of\ years\ of\ construction\ (4)$$
$$i = interest\ rate$$

Next, the levelized capital cost per year is calculated using the capital recovery factor formula:

$$LC = \frac{iC(1+i)^N}{(1+i)^N - 1}$$

Where:

$$LC = levelized\ capital\ cost\ per\ year$$
$$N = total\ project\ life$$

A summary of the project financial attributes for the preferred sites is included in Table 4.2. The summary provides levelized cost results for the YEC development real cost of capital rate, IPP rate, and high interest scenario rates provided by YEC.

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TABLE 4.2

YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT

PROJECT FINANCIAL ATTRIBUTES - PREFERRED SITES

10/6/2016 19:25

ITEM	Site # / Rate	5 Drury Creek	8 Finlayson River	40 Anvil Creek	43 Tutshi - Windy Arm	49 Wolf River
Project Life (Yrs)	65					
Real Cost of Capital (YEC)	3.38%					
Real Cost of Capital (IPP)	4.61%					
Real Cost of Capital - High Rate Scenario	8.82%					
Installed Capacity (MW)		8.1	17.6	9.8	7.2	20.0
Net Annual Generation (GWh)		31.7	138.9	41.3	56.6	95.6
Overnight Capital Cost ($)		**$97,250,000**	**$265,990,000**	**$109,210,000**	**$125,400,000**	**$220,170,000**
Construction Cost, Yr. 1	20%	$19,450,000	$53,198,000	$21,842,000	$25,080,000	$44,034,000
Construction Cost, Yr. 2	40%	$38,900,000	$106,396,000	$43,684,000	$50,160,000	$88,068,000
Construction Cost, Yr. 3	40%	$38,900,000	$106,396,000	$43,684,000	$50,160,000	$88,068,000
Fixed O&M Costs (% of Capital)	2.0%	$1,945,000	$5,320,000	$2,184,000	$2,508,000	$4,403,000
Variable Costs, Generation	0.5c/kWh	$158,000	$695,000	$207,000	$283,000	$478,000
YEC Rate Scenario						
Interest During Construction	3.38%	$6,030,000	$16,490,000	$6,770,000	$7,800,000	$13,650,000
Loaded Capital Cost, at End of Construction Period ($)		**$103,280,000**	**$282,480,000**	**$115,980,000**	**$133,200,000**	**$233,820,000**
Levelized Capital Cost		$3,946,000	$10,792,000	$4,431,000	$5,089,000	$8,933,000
Levelized Annual Cost		$6,049,000	$16,807,000	$6,822,000	$7,880,000	$13,814,000
Capital Cost of Energy Output	$/MWh	$3,300	$2,000	$2,800	$2,400	$2,400
Capital Cost of Capacity	$/kW-yr	$12,700	$16,000	$11,900	$18,600	$11,700
Levelized Cost of Energy	**$/kWh**	**$0.19**	**$0.12**	**$0.17**	**$0.14**	**$0.14**
Levelized Cost of Capacity	**$/kW-yr**	**$700**	**$1,000**	**$700**	**$1,100**	**$700**
IPP Rate Scenario						
Interest During Construction	4.61%	$8,280,000	$22,640,000	$9,300,000	$10,670,000	$18,740,000
Loaded Capital Cost, at End of Construction Period ($)		**$105,530,000**	**$288,630,000**	**$118,510,000**	**$136,070,000**	**$238,910,000**
Levelized Capital Cost		$5,140,000	$14,057,000	$5,772,000	$6,627,000	$11,635,000
Levelized Annual Cost		$7,243,000	$20,072,000	$8,163,000	$9,418,000	$16,516,000
Capital Cost of Energy Storage	$/MWh	$3,300	$2,100	$2,900	$2,400	$2,500
Capital Cost of Capacity	$/kW-yr	$13,000	$16,400	$12,100	$19,000	$12,000
Levelized Cost of Energy	**$/kWh**	**$0.23**	**$0.14**	**$0.20**	**$0.17**	**$0.17**
Levelized Cost of Capacity	**$/kW-yr**	**$900**	**$1,100**	**$800**	**$1,300**	**$800**
High Interest Rate Scenario						
Interest During Construction	8.82%	$16,210,000	$44,330,000	$18,200,000	$20,900,000	$36,700,000
Loaded Capital Cost, at End of Construction Period ($)		**$113,460,000**	**$310,320,000**	**$127,410,000**	**$146,300,000**	**$256,870,000**
Levelized Capital Cost		$5,526,000	$15,113,000	$6,205,000	$7,125,000	$12,510,000
Levelized Annual Cost		$7,629,000	$21,128,000	$8,596,000	$9,916,000	$17,391,000
Capital Cost of Energy Storage	$/MWh	$3,600	$2,200	$3,100	$2,600	$2,700
Capital Cost of Capacity	$/kW-yr	$14,000	$17,600	$13,000	$20,400	$12,900
Levelized Cost of Energy	**$/kWh**	**$0.24**	**$0.15**	**$0.21**	**$0.18**	**$0.18**
Levelized Cost of Capacity	**$/kW-yr**	**$900**	**$1,200**	**$900**	**$1,400**	**$900**

M:\1\03\00556\02\A\Report\2 - Small Hydro\Rev 0\Tables\[Preferred Sites Rev0.xlsx]Table 4.2

NOTES:

1. DISCOUNT RATES ARE REAL COST OF CAPITAL AS PROVIDED BY YEC. NOMINAL RATES HAVE NOT BEEN INCLUDED.
2. TIME VALUE OF MONEY HAS NOTE BEEN ASSESSED.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
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4.5 OTHER CONSIDERATIONS

The cost estimates and financial attributes described in Section 4.2 and 4.3 are appropriate for a stand-alone approach to project evaluation. Two additional potential synergies have been identified: benefits to downstream generation at other hydroelectric facilities, and benefits from potential pumped-storage developments. These benefits are described below.

4.5.1 Benefits to Downstream Generation

In the KGS 2008 study, it was noted that the Tutshi – Windy Arm Project would offer potential increases in winter generation at the Whitehorse Generating Station, due to the increased available winter flows in the Yukon River that will result from attenuation of the Tutshi Lake outflows. In the KGS study, the estimated magnitude of the increase was 6 GWh/yr.

This is an advantage that should improve the economics and relative merit of developing the Tutshi – Windy Arm Project. No other preferred site will improve the winter generation of the Whitehorse Generating Station or the three other existing hydropower facilities in the Yukon.

4.5.2 Benefits from Pumped-Storage Development

In parallel with this study, KP also completed an assessment of potential pumped-storage hydropower sites that could provide winter power to the Yukon. The study (KP Reference VA103-556/2-1) investigated a number of sites, many of which are located within the same watersheds as the small hydro sites considered in this report.

Of particular note, the best pumped-storage site for all scenarios assessed is located between Moon Lake and Tutshi Lake. Development of both the pumped-storage scheme and the Tutshi – Windy Arm small hydro project could have significant advantages, including shared cost of access to the Tutshi Lake outlet control dam, and additional flow control on Tutshi Lake, with the potential for compounded increases in winter generation. Additionally, it may provide significant logistical and construction related advantages if both sites were to be developed concurrently or in sequence.

The optimal project configuration for the combined Moon Lake – Tutshi Lake pumped-storage project and Tutshi – Windy Arm small hydro project would require a more detailed study encompassing both of these projects.

4.6 DEVELOPMENT SCHEDULE

A high level development schedule has been created to illustrate the relative timelines for completing critical tasks associated with developing small hydro projects in the Yukon. The relative timelines for completing the major development tasks is similar for each option described above, and this schedule should be considered as generic and indicative only. The major development tasks and timelines are listed below.

1. Feasibility Study – 1 year
   - Will require detailed mapping and site specific hydrology data for a minimum of one year of data collection
2. Environmental Assessment (Permitting and Baseline Studies) – 2 years (will start concurrent with Feasibility Study)
   - Will include fisheries, hydrological and wildlife/terrestrial studies that will be inputs to the Environmental Assessment for each project
   - First Nations and stakeholder consultation will also be included in this stage
3. EPC Tendering Process – 1 year
   - EPC tender design can start immediately after Feasibility Study
4. Construction – 3 years
   - Will commence once Environmental Assessment Certificate is received and EPC contractor is selected
5. Commissioning – 4-6 months
   - Commences after Construction
6. Operations – 65 years

The best case scenario for duration of project development is 5.5 years; from the start of the Feasibility Studies through to the end of Commissioning. Actual project development schedules are site specific and may be influenced environmental baselines studies, consultation with first nations and broader public opposition to development of the project.

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FIGURE 4.6

YUKON ENERGY CORPORATION
SMALL HYDROELECTRIC PROJECTS
DEVELOPMENT SCHEDULE - MAJOR TASKS

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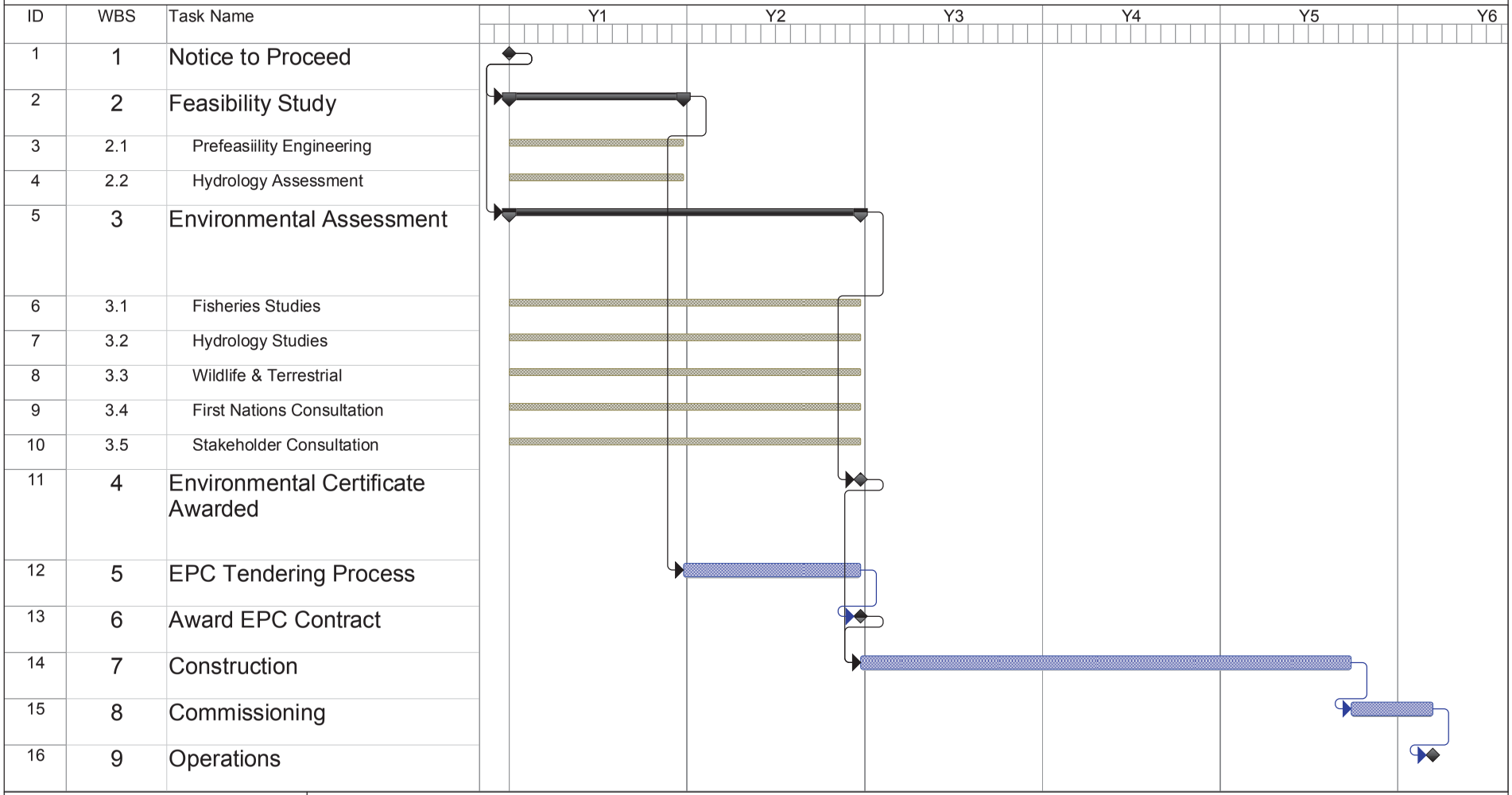

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Date: Thu 6/23/16
By: Daniel Rohn

Task
Milestone
Task with Subtask(s)
Subtask

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5 – CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

A screening assessment of previously identified small hydro sites in the Yukon was completed to identify the better development options for future studies. A total of forty-four potential sites were assessed in a multi-stage screening process.

The most attractive (preferred) projects, based on a desktop level assessment of location, project layout, site characteristics, capacity, energy, and costs, are Drury Lake, Finlayson River, Anvil Creek, Tutshi – Windy Arm, and Wolf River. Summary of results for preferred sites is as follows:

- LCOC ranges from $700 to $1,200/kW-yr at the YEC real interest rate of 3.38 percent.
- LCOE ranges from $0.13 to $0.21/kWh at the YEC real interest rate of 3.38 percent.
- Based on a stand-alone assessment of hydropower development, the most attractive small hydro sites are the Finlayson River, Wolf River, and Tutshi – Windy Arm. Whereas, Drury Lake and Anvil Creek appear to be more expensive on a cost of energy basis.
- The optimal installed capacities for Finlayson River, Tutshi – Windy Arm, and Wolf River Projects are likely higher than reported in the present design and should be explored further. The purpose of this study was to evaluate sites of 20 MW or less based on the requirements, as such the optimal installed capacities were not determined.
- The Tutshi – Windy Arm project has the added benefit of increasing potential winter generation at the Yukon Generating Station downstream.
- If the Moon Lake – Tutshi Lake pumped storage project is developed, it may have material synergies with development of the Tutshi – Windy Arm small hydro project.

A summary of the Financial and Technical attributes of the preferred sites is presented in Table 5.1 below:

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TABLE 5.1

YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT

SUMMARY OF TECHNICAL & FINANCIAL ATTRIBUTES
PREFERRED SITES

10/6/2016 19:25

ATTRIBUTES	Drury Creek	Finlayson River	Anvil Creek	Tutshi - Windy Arm	Wolf River
TECHNICAL:					
Installed Capacity (MW)	8.1	17.6	9.8	7.2	20.0
Net Annual Generation (GWh)	31.7	138.9	41.3	56.6	95.6
Mean Annual Discharge (m^3/s)	4.9	16.5	4.1	16.1	40.3
Design Flow - Qd (m^3/s)	9.3	13.3	8.2	15.0	37.7
Gross Head (m)	99	150	135	54	60
Transmission Line Length (km)	1	5	11	1	23
FINANCIAL:					
Estimated Capital Cost	$ 97,250,000	$ 265,990,000	$ 109,210,000	$ 125,400,000	$ 220,170,000
O&M Costs - Fixed ($/yr)	$ 1,945,000	$ 5,320,000	$ 2,184,000	$ 2,508,000	$ 4,403,000
O&M Costs - Variable ($/yr)	$ 158,000	$ 695,000	$ 207,000	$ 283,000	$ 478,000
YEC Rate Scenario (3.38%)					
Levelized Cost of Energy ($/kWh)	$ 0.19	$ 0.12	$ 0.17	$ 0.14	$ 0.14
Levelized Cost of Capacity ($/kW-yr)	$ 700	$ 1,000	$ 700	$ 1,100	$ 700
IPP Rate Scenario (4.61%)					
Levelized Cost of Energy ($/kWh)	$ 0.23	$ 0.14	$ 0.20	$ 0.17	$ 0.17
Levelized Cost of Capacity ($/kW-yr)	$ 900	$ 1,100	$ 800	$ 1,300	$ 800
High Interest Rate Scenario (8.82%)					
Levelized Cost of Energy ($/kWh)	$ 0.24	$ 0.15	$ 0.21	$ 0.18	$ 0.18
Levelized Cost of Capacity ($/kW-yr)	$ 900	$ 1,200	$ 900	$ 1,400	$ 900

M:\1\03\00556\02\A\Report\2 - Small Hydro\Rev 0\Tables\[Preferred Sites Rev0.xlsx]Table 4.2

NOTES:

1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

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To determine the optimal small hydro site will require further assessment of a number of factors, including desired capacity, development of proposed transmission lines, environmental impacts, political/societal conditions and capital cost estimates based on site quantities. Consideration of these factors, in conjunction with detailed site investigations and engineering studies on the preferred sites, will be required.

5.2 RECOMMENDATIONS

Further evaluation of the preferred sites is recommended, to improve the design basis, project configurations, and understanding of hydrological and geotechnical conditions. The following activities are recommended:

- Preliminary site visits to the following projects to further evaluate technical viability:
  - Drury Lake
  - Finlayson River
  - Anvil Creek
  - Tutshi – Windy Arm, and
  - Wolf River.
- Obtain accurate mapping (such as PhotoSat satellite topography) for the proposed project areas to confirm project configurations and details including dam sizes, water conveyance routings, powerhouse locations, access roads, and transmission lines.
- Implement hydrological data collection programs at the preferred sites.
- Update energy estimates based on hydrology data and accurate depth-area-capacity curves for reservoirs.
- Update quantity and cost estimates.
- Undertake a screening assessment of social and environmental permitting constraints at each of the five preferred sites.

Should the above assessment indicate that there are no technical or environmental showstoppers, detailed evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

6 – REFERENCES

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7 – CERTIFICATION

This report was prepared and reviewed by the undersigned.

Prepared:

Scott Rees, P.Eng.
Project Engineer

Reviewed:

Travis Brown, P.Eng.
Senior Engineer

PROFESSIONAL ENGINEER
7 October 2016
YUKON TERRITORY
TRAVIS JESS BROWN

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Approval that this document adheres to Knight Piésold Quality Systems: SRM

APPENDIX A

PRELIMINARY CAPACITY & ENERGY

(Pages A-1 to A-4)

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TABLE A1

YUKON ENERGY CORP.
SMALL HYDRO STUDY

SMALL HYDRO SITES
ESTIMATED AVERAGE CAPACITY

Site #	Name	Estimated Power at Turbine [1] (MW)												Power Summary (GWhr)	
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Minimum Monthly	Average Monthly
1	Anvil Creek	3.1	3.1	2.8	3.3	9.8	9.8	8.6	5.2	5.0	4.1	4.4	3.5	2.8	5.2
3	Campbell Creek	1.4	1.3	1.2	1.5	6.7	7.5	7.5	5.8	4.6	2.8	2.1	1.6	1.2	3.7
5	Drury Creek[3]	8.1	8.1	8.1	8.1	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	0.0	8.1
8	Finlayson River	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
9	Frances River	3.0	4.0	3.6	4.7	20.0	20.0	20.0	20.0	18.1	11.0	6.0	4.1	3.0	11.2
11	Homan Lake	1.0	1.0	0.9	1.1	2.7	2.7	2.4	2.2	2.1	1.9	1.4	1.1	0.9	1.7
12	Hoole River	0.4	0.3	0.3	0.4	1.8	2.0	2.0	1.6	1.3	0.8	0.4	0.3	0.3	1.0
14	Kathleen River	0.8	0.6	0.5	0.4	0.8	4.1	4.1	3.6	2.3	1.8	1.2	1.0	0.4	1.8
17	Lapie River	0.8	0.7	0.6	0.9	7.5	8.3	8.3	6.5	5.2	3.1	1.7	1.1	0.6	3.7
22	Mica Creek[3]	1.4	1.4	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	0.0	1.4
25	North Fork Klondike	1.7	1.4	1.3	1.9	15.1	16.9	16.8	13.2	10.5	6.3	3.4	2.3	1.3	7.6
26	North McQuesten	1.0	1.0	0.9	1.1	4.2	4.7	4.6	3.6	2.9	1.7	0.9	0.6	0.6	2.3
27	Orchay River	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
28	Pleasant Creek	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
29	Pleasant Cr with Rogue	3.4	3.2	2.9	3.6	18.6	20.0	20.0	16.2	12.9	7.7	5.5	4.1	2.9	9.8
33	Reid Lakes & Lake Creek	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
34	Rock Creek	0.4	0.3	0.3	0.5	3.7	3.7	3.3	2.0	1.9	1.6	0.9	0.6	0.3	1.6
39	Squanga Creek	0.3	0.2	0.2	0.3	2.6	2.9	2.9	2.2	1.8	1.1	0.6	0.4	0.2	1.3
43	Tutshi - Windy Arm	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
47	Watson Lake & McDonald Cr [3]	1.1	1.1	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.1	0.0	1.1
48	Watson River	0.1	0.2	0.2	0.2	0.8	0.8	0.7	0.4	0.4	0.3	0.2	0.1	0.1	0.4
49	Wolf River	4.3	3.5	3.2	4.7	20.0	20.0	20.0	20.0	20.0	15.2	8.3	5.7	3.2	12.1

\\KPL\VA-Prj$\1\03\00556\02\A\Data\Task 400 - Small Hydro\Energy\[Appendix A - Energy Summary Table.xlsx]A1

NOTES:
1. MONTHLY CAPACITY VALUES ARE PRELIMINARY ESTIMATES, CALCULATED USING THE ESTIMATED 50TH PERCENTILE HYDROLOGY VALUES FOR SMALL AND LARGE CATCHMENTS AS DETAILED IN REPORT SECTION 3.2.2.
2. INSTREAM FLOW REQUIREMENTS (ECOLOGICAL FLOWS ASSUMED TO BE 5 PERCENT OF MEAN ANNUAL DISCHARGE.
3. POWER VALUES DO NOT ACCOUNT FOR MINIMUM TURBINABLE FLOW (DEPENDENT ON NUMBER AND TYPE OF GENERATING UNITS).

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	28SEP'16	ISSUED WITH REPORT VA103-00556/2-2	SDR	TJB

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TABLE A2

YUKON ENERGY CORP.
SMALL HYDRO STUDY

SMALL HYDRO SITES
AVERAGE MONTHLY ENERGY ESTIMATES

Site #	Name	Estimated Net Energy Output [1] (GWhr)													Energy Summary (GWhr)	
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Energy Total	Minimum Monthly	Average Monthly
1	Anvil Creek	2.1	1.9	1.9	2.2	6.5	6.3	5.7	3.5	3.2	2.8	2.8	2.3	**41.3**	1.9	3.4
3	Campbell Creek	0.9	0.8	0.8	1.0	4.5	4.8	5.0	3.9	3.0	1.9	1.4	1.1	**29.0**	0.8	2.4
5	Drury Creek[3]	5.4	4.9	5.4	5.3	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.4	**31.7**	4.9	5.3
8	Finlayson River	11.8	10.7	11.8	11.4	11.8	11.4	11.8	11.8	11.4	11.8	11.4	11.8	**138.9**	10.7	11.6
9	Frances River	2.0	2.4	2.4	3.0	13.4	13.0	13.4	13.4	11.7	7.4	3.9	2.7	**88.7**	2.0	7.4
11	Homan Lake	0.7	0.6	0.6	0.7	1.8	1.8	1.6	1.4	1.4	1.2	0.9	0.7	**13.5**	0.6	1.1
12	Hoole River	0.2	0.2	0.2	0.2	1.2	1.3	1.4	1.1	0.8	0.5	0.3	0.2	**7.7**	0.2	0.6
14	Kathleen River	0.5	0.4	0.3	0.3	0.5	2.7	2.8	2.4	1.5	1.2	0.8	0.6	**12.6**	0.3	1.2
17	Lapie River	0.6	0.4	0.4	0.6	5.0	5.4	5.6	4.3	3.3	2.1	1.1	0.8	**29.6**	0.4	2.5
22	Mica Creek[3]	1.0	0.9	1.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.0	**5.6**	0.9	0.9
25	North Fork Klondike	1.1	0.8	0.9	1.2	10.1	11.0	11.3	8.8	6.8	4.2	2.2	1.5	**60.0**	0.8	5.0
26	North McQuesten	0.7	0.6	0.6	0.7	2.8	3.0	3.1	2.4	1.9	1.2	0.6	0.4	**18.0**	0.4	1.5
27	Orchay River	2.1	1.9	2.1	2.0	2.1	2.0	2.1	2.1	2.0	2.1	2.0	2.1	**24.6**	1.9	2.0
28	Pleasant Creek	1.3	1.1	1.3	1.2	1.3	1.2	1.3	1.3	1.2	1.3	1.2	1.3	**14.9**	1.1	1.2
29	Pleasant Cr with Rogue	2.3	1.9	1.9	2.4	12.4	13.0	13.4	10.8	8.3	5.2	3.6	2.8	**77.9**	1.9	6.5
33	Reid Lakes & Lake Creek	2.8	2.5	2.8	2.7	2.8	2.7	2.8	2.8	2.7	2.8	2.7	2.8	**32.4**	2.5	2.7
34	Rock Creek	0.3	0.2	0.2	0.3	2.5	2.4	2.2	1.3	1.2	1.1	0.6	0.4	**12.6**	0.2	1.1
39	Squanga Creek	0.2	0.1	0.1	0.2	1.7	1.9	1.9	1.5	1.1	0.7	0.4	0.3	**10.2**	0.1	0.8
43	Tutshi - Windy Arm	4.8	4.3	4.8	4.6	4.8	4.6	4.8	4.8	4.6	4.8	4.6	4.8	**56.6**	4.3	4.7
47	Watson Lake & McDonald Cr [3]	0.8	0.7	0.8	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.8	**4.4**	0.7	0.7
48	Watson River	0.1	0.1	0.1	0.2	0.5	0.5	0.5	0.3	0.3	0.2	0.1	0.1	**2.9**	0.1	0.2
49	Wolf River	2.8	2.1	2.2	3.0	13.4	12.9	13.4	13.4	12.9	10.2	5.4	3.8	**95.6**	2.1	8.0

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NOTES:
1. AVERAGE ENERGY VALUES ARE PRELIMINARY ESTIMATES, CALCULATED USING THE ESTIMATED 50TH PERCENTILE HYDROLOGY VALUES FOR SMALL AND LARGE CATCHMENTS AS DETAILED IN REPORT SECTION 3.2.2.
2. INSTREAM FLOW REQUIREMENTS (ECOLOGICAL FLOWS ASSUMED TO BE 5 PERCENT OF MEAN ANNUAL DISCHARGE.
3. ENERGY VALUES DO NOT ACCOUNT FOR MINIMUM TURBINABLE FLOW (DEPENDENT ON NUMBER AND TYPE OF GENERATING UNITS).

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	28SEP'18	ISSUED WITH REPORT VA103-00556/2-2	SDR	TJB

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TABLE A3

YUKON ENERGY CORP.
SMALL HYDRO STUDY

SMALL HYDRO SITES
PRELIMINARY ESTIMATED DEPENDABLE CAPACITY

Site #	Name	Estimated Power at Turbine[1] (MW)												Power Summary (GWhr)	
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Minimum Monthly	Average Monthly
1	Anvil Creek	2.7	2.8	2.5	2.9	6.5	8.7	5.1	3.0	3.5	2.9	3.7	3.0	2.5	3.9
3	Campbell Creek	1.1	1.1	1.0	1.2	4.4	6.5	4.9	3.8	3.5	2.1	1.7	1.3	1.0	2.7
5	Drury Creek[3]	8.1	8.1	8.1	8.1	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	0.0	8.1
8	Finlayson River	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
9	Frances River	2.1	3.2	2.9	3.7	17.0	20.0	19.0	14.8	13.9	8.3	4.4	2.9	2.1	9.3
11	Homan Lake	0.9	0.9	0.8	1.0	1.8	2.4	1.4	1.5	1.7	1.5	1.2	1.0	0.8	1.3
12	Hoole River	0.3	0.3	0.3	0.3	1.2	1.8	1.3	1.0	1.0	0.6	0.3	0.2	0.2	0.7
14	Kathleen River	0.6	0.4	0.4	0.3	0.5	3.0	3.9	2.3	1.8	1.4	0.9	0.7	0.3	1.3
17	Lapie River	0.6	0.5	0.4	0.6	4.9	7.3	5.5	4.2	3.9	2.3	1.2	0.8	0.4	2.7
22	Mica Creek[3]	1.4	1.4	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	0.0	1.4
25	North Fork Klondike	1.2	1.0	0.9	1.3	9.9	14.8	11.1	8.5	8.0	4.7	2.5	1.6	0.9	5.4
26	North McQuesten	0.9	0.9	0.8	0.9	2.7	4.1	3.0	2.4	2.2	1.3	0.7	0.5	0.5	1.7
27	Orchay River	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
28	Pleasant Creek	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
29	Pleasant Cr with Rogue	2.8	2.6	2.4	3.0	12.1	18.1	13.6	10.5	9.8	5.8	4.4	3.3	2.4	7.4
33	Reid Lakes & Lake Creek	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
34	Rock Creek	0.2	0.2	0.2	0.3	2.5	3.3	1.9	1.1	1.3	1.1	0.6	0.4	0.2	1.1
39	Squanga Creek	0.2	0.2	0.1	0.2	1.7	2.5	1.9	1.4	1.4	0.8	0.4	0.3	0.1	0.9
43	Tutshi - Windy Arm	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
47	Watson Lake & McDonald Cr [3]	1.1	1.1	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.1	0.0	1.1
48	Watson River	0.1	0.2	0.2	0.2	0.5	0.7	0.4	0.2	0.3	0.2	0.1	0.1	0.1	0.3
49	Wolf River	3.0	2.4	2.2	3.3	20.0	20.0	20.0	20.0	19.1	11.5	6.1	4.1	2.2	11.0

\\KPL\VA-Prj$\1\03\00556\02\A\Data\Task 400 - Small Hydro\Energy\[Appendix A - Energy Summary Table.xlsx]A3

NOTES:
1. DEPENDABLE CAPACITY VALUES ARE PRELIMINARY ESTIMATES, CALCULATED USING THE ESTIMATED 85TH PERCENTILE HYDROLOGY VALUES FOR SMALL AND LARGE CATCHMENTS AS DETAILED IN REPORT SECTION 3.2.4.
2. INSTREAM FLOW REQUIREMENTS (ECOLOGICAL FLOWS ASSUMED TO BE 5 PERCENT OF MEAN ANNUAL DISCHARGE.
3. POWER VALUES DO NOT ACCOUNT FOR MINIMUM TURBINABLE FLOW (DEPENDENT ON NUMBER AND TYPE OF GENERATING UNITS).

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	28SEP'16	ISSUED WITH REPORT VA103-00556/2-2	SDR	TJB

Knight Piésold CONSULTING

TABLE A4

YUKON ENERGY CORP.
SMALL HYDRO STUDY

SMALL HYDRO SITES
PRELIMINARY ESTIMATED FIRM ENERGY

Site #	Name	Estimated Net Dependable Energy Output [1] (GWhr)													Energy Summary (GWhr)	
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Energy Total	Minimum Monthly	Average Monthly
1	Anvil Creek	1.8	1.7	1.7	1.9	4.3	5.6	3.4	2.0	2.3	1.9	2.4	2.0	**31.0**	1.7	2.6
3	Campbell Creek	0.8	0.7	0.7	0.8	2.9	4.2	3.3	2.5	2.3	1.4	1.1	0.9	**21.6**	0.7	1.8
5	Drury Creek[3]	5.4	4.9	5.4	5.3	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.4	**31.7**	4.9	5.3
8	Finlayson River	11.8	10.7	11.8	11.4	11.8	11.4	11.8	11.8	11.4	11.8	11.4	11.8	**138.9**	10.7	11.6
9	Frances River	1.4	1.9	1.9	2.4	11.4	13.0	12.7	9.9	9.0	5.5	2.8	1.9	**74.0**	1.4	6.2
11	Homan Lake	0.6	0.6	0.6	0.6	1.2	1.6	0.9	1.0	1.1	1.0	0.8	0.7	**10.6**	0.6	0.9
12	Hoole River	0.2	0.2	0.2	0.2	0.8	1.2	0.9	0.7	0.6	0.4	0.2	0.1	**5.6**	0.1	0.5
14	Kathleen River	0.4	0.3	0.2	0.2	0.3	2.0	2.6	1.6	1.2	0.9	0.6	0.5	**9.6**	0.2	0.9
17	Lapie River	0.4	0.3	0.3	0.4	3.3	4.7	3.6	2.8	2.5	1.6	0.8	0.5	**21.3**	0.3	1.8
22	Mica Creek[3]	1.0	0.9	1.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.0	**5.6**	0.9	0.9
25	North Fork Klondike	0.8	0.6	0.6	0.9	6.6	9.6	7.4	5.7	5.2	3.2	1.6	1.1	**43.1**	0.6	3.6
26	North McQuesten	0.6	0.5	0.5	0.6	1.8	2.6	2.0	1.6	1.4	0.9	0.4	0.3	**13.4**	0.3	1.1
27	Orchay River	2.1	1.9	2.1	2.0	2.1	2.0	2.1	2.1	2.0	2.1	2.0	2.1	**24.6**	1.9	2.0
28	Pleasant Creek	1.3	1.1	1.3	1.2	1.3	1.2	1.3	1.3	1.2	1.3	1.2	1.3	**14.9**	1.1	1.2
29	Pleasant Cr with Rogue	1.8	1.6	1.6	1.9	8.1	11.7	9.1	7.0	6.4	3.9	2.8	2.2	**58.2**	1.6	4.8
33	Reid Lakes & Lake Creek	2.8	2.5	2.8	2.7	2.8	2.7	2.8	2.8	2.7	2.8	2.7	2.8	**32.4**	2.5	2.7
34	Rock Creek	0.2	0.1	0.1	0.2	1.7	2.2	1.3	0.8	0.9	0.7	0.4	0.2	**8.7**	0.1	0.7
39	Squanga Creek	0.1	0.1	0.1	0.1	1.1	1.6	1.3	1.0	0.9	0.5	0.3	0.2	**7.3**	0.1	0.6
43	Tutshi - Windy Arm	4.8	4.3	4.8	4.6	4.8	4.6	4.8	4.8	4.6	4.8	4.6	4.8	**56.6**	4.3	4.7
47	Watson Lake & McDonald Cr [3]	0.8	0.7	0.8	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.8	**4.4**	0.7	0.7
48	Watson River	0.0	0.1	0.1	0.1	0.3	0.4	0.3	0.2	0.2	0.2	0.1	0.1	**2.1**	0.0	0.2
49	Wolf River	2.0	1.4	1.5	2.1	13.4	12.9	13.4	13.4	12.4	7.7	4.0	2.7	**86.9**	1.4	7.2

\\KPL\VA-Prj$\1\03\00556\02\A\Data\Task 400 - Small Hydro\Energy\[Appendix A - Energy Summary Table.xlsx]A4

NOTES:
1. FIRM ENERGY VALUES ARE PRELIMINARY ESTIMATES, CALCULATED USING THE ESTIMATED 85TH PERCENTILE HYDROLOGY VALUES FOR SMALL AND LARGE CATCHMENTS AS DETAILED IN SECTIOIN 3.2.4 OF REPORT VA103-00556/2-2.
2. INSTREAM FLOW REQUIREMENTS (ECOLOGICAL FLOWS ASSUMED TO BE 5 PERCENT OF MEAN ANNUAL DISCHARGE.
3. ENERGY VALUES DO NOT ACCOUNT FOR MINIMUM TURBINABLE FLOW (DEPENDENT ON NUMBER AND TYPE OF GENERATING UNITS).

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	28SEP'18	ISSUED WITH REPORT VA103-00556/2-2	SDR	TJB

Appendix 5.8
Atlin Hydro Expansion Study

MORRISON HERSHFIELD

REPORT

Atlin Hydro Expansion

Pre-Feasibility Study

Atlin, British Columbia

Presented to:

Atlin Tlingit Economic Limited Partnership

Project No. 5151214 June 5, 2015

Revised: June 23, 2016

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MORRISON HERSHFIELD

June 23, 2016 MH ref. 5151214

Stuart Simpson, General Manager,
Atlin Tlingit Economic LP
PO Box 408,
Atlin, BC
V0W1A0

Dear Mr. Simpson:

Re: Prefeasibility Study for Atlin Hydro Expansion Project – 2016 Update

Morrison Hershfield is pleased to provide our report on the above noted project. This is an updated version of the prefeasibility report completed in 2015. This 2016 update now includes the transmission line options assessment for connection to the Yukon electrical system and addresses Yukon Energy Corporation's comments. It continues to be a privilege to work with ATELP on this exciting and interesting renewable energy project.

We look forward to any opportunity to support you and your team in developing this important project. In the meantime, if we can be of further service, please do not hesitate to contact me at (867) 456-4747.

Yours truly,
Morrison Hershfield Limited

Forest Pearson, P.Eng.,
Geological Engineer / Project Manager

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TABLE OF CONTENTS

		Page
1	**PROJECT OVERVIEW**	**1**
1.1	Background and Project Objective	1
1.2	Scope of Work	2
1.3	Previous Work and Available Data	3
2	**SITE VISIT & OBSERVATIONS**	**5**
3	**PROPOSED LAYOUT**	**12**
3.1	Project Components Overview	12
3.2	Lower Powerhouse Alternatives	13
4	**HYDROLOGICAL AND POWER STUDIES**	**18**
4.1	Hydrological Study	18
4.2	Power and Energy Simulations	29
4.3	Power Generation	32
4.4	Simulation results	35
4.5	Power Production Summary	38
5	**PRELIMINARY DESIGN**	**41**
5.1	Design Criteria and Assumptions	41
5.2	Surprise Lake Control Structure	42
5.3	Upper Power Plant Expansion	50
5.4	Lower Power Plant	59
6	**TRANSMISSION LINE OPTIONS ASSESSMENT**	**72**
6.1	Overview of Transmission Line Connection	72
6.2	Atlin to Jakes Corner Transmission Line: 69 kV and 138 kV Comparison	74
6.3	Yukon Connection Options Assessment	82
7	**COST ESTIMATE & CONSTRUCTION SCHEDULE**	**90**
7.1	Cost Estimate	90
7.2	Schedule	95
8	**SUMMARY AND RECOMMENDATIONS**	**98**
8.1	Summary	98
8.2	Recommendations for Future Work	99
9	**REFERENCES**	**102**

TABLE OF CONTENTS (Continued)

Page

LIST OF APPENDICES

APPENDIX A: Preliminary Design Drawings

APPENDIX B: Topographic Mapping

APPENDIX C: Site Visit Memorandum

APPENDIX D: Photo Log

APPENDIX E: Transmission Options Assessment Study

APPENDIX F: Atlin Substation Cost Estimate

APPENDIX G: Cost Estimate

LIST OF TABLES

Table 3-1: Lower Powerhouse & Penstock Alignment Options 15
Table 4-1: Summary of nearby Water Survey of Canada hydrometric gauging stations. 20
Table 4-2: Mean monthly inflows and outflows of Surprise Lake, 1963 to 1993 (unregulated). 25
Table 4-3: Contributing catchments for the Upper and Lower Power Plant. 27
Table 4-4: Summary of 7-day low flow analysis for 2, 5, 10 and 25 year return periods, based on the Surprise Lake synthetic inflow and outflow series. 27
Table 4-5: Summary of Flood Frequency Analysis for the Pine Creek catchment at the Surprise Lake control structure, Upper and Lower Intakes. 28
Table 4-6: Parameters of Surprise Lake Control Structure 29
Table 4-7: Mean monthly Surprise Lake water levels, inflows and outflows during the simulated period 31
Table 4-8: Design Parameters and Assumptions for the Upper and Lower Power Plant. 34
Table 4-9: Average monthly power and energy generation for the Upper and Lower plants (2.5 m storage) 36
Table 4-10: Average monthly power and energy generation for the Upper and Lower plants (2 m storage) 38
Table 5-1: Design flood flows 41
Table 6-1 Atlin to Jakes Corner Transmission Line Options Cost Summary (2016$) 75
Table 6-2. Indirect Costs as Percentage of Direct Costs 78
Table 6-3. Comparison of 69 kV and 138 kV options for Yukon to Atlin transmission line. 81
Table 6-4. Yukon electrical system connection options cost summary (2016$). 87
Table 6-5. Yukon system connection options assessment summary. 89
Table 7-1: Summary of Atlin Hydroelectric Expansion Project Estimated Construction Costs 94

LIST OF FIGURES

Figure 2-1: Project Overview 6
Figure 3-1: Lower Powerhouse & Penstock Alternatives 14
Figure 3-2: Upper powerhouse alternate arrangement 16
Figure 4-1: 1981 to 2010 climate normals for Atlin, BC (Environment Canada Station #1200560). 19
Figure 4-2: Mean daily unit flow comparison for selected regional WSC stations over the common period of record, 1966-1969. 21
Figure 4-3: Daily unit flows for the period-of-record, 1966-1969 22
Figure 4-4: Atlin Hydro Expansion Project contributing catchments 24

TABLE OF CONTENTS (Continued)

Page

Figure 4-5: Surprise Lake synthetic hydrology (unregulated) based on reverse-routing of scaled Gladys River (WSC 09AE004) 1963-1993 hydrometric record. 26
Figure 4-6: Average yearly Surprise Lake operations for the proposed 2.5 m operational range. 31
Figure 4-7: Simulated Surprise lake water levels under proposed 2.5 m operational range. 32
Figure 4-8: Flow duration curve for Upper and Lower Power Plant. 34
Figure 4-9: Upper and Lower Power Plant mean monthly power production (MW). 36
Figure 4-10: Total simulated annual power generation (GWh) from the Upper and Lower Power Plants. 37
Figure 4-11: Simulated average monthly generation for the Upper and Lower Power Plant. 39
Figure 4-12: Simulated minimum monthly generation for the Upper and Lower Power Plant. 40
Figure 5-1: Required Rip Rap D_{50} to Resist a Given Flow Velocity 42
Figure 5-2: Discharge capacity of low level outlet at full opening 47
Figure 5-3: Layout of Upper Powerhouse Expansion 53
Figure 5-4: New Switchyard Location 58
Figure 5-5: Discharge capacity curve of the overflow spillway of the lower head pond 62
Figure 5-6: Layout of Lower Powerhouse 66
Figure 5-7: Lower Powerhouse Surge Facility Location 69
Figure 6-1. Overview of Southern Lakes electrical system. 73
Figure 6-2. Southern Lakes monthly energy demand, 2013-2015. 74
Figure 6-3. Typical 69 kV Pole configuration for BC portion of transmission line. 77
Figure 6-4. Yukon system connection Option 2 - connect to a new 138 kV transmission line in the Carcross valley. 84
Figure 6-5. Yukon system connection Option 3 - connect to Whitehorse with new transmission line along Alaska Highway. 86
Figure 7-1: Overview Project Development Schedule 97

1 PROJECT OVERVIEW

1.1 Background and Project Objective

On April 1st, 2009 the 2.1MW Atlin Hydro Project began commercial power production. The hydropower facility is owned by Xeitl Limited Partnership which is 100% owned by Taku River Tlingit First Nation. The project is located on Pine Creek and is approximately 4 km east of the community of Atlin, BC. Atlin is an isolated community located approximately 50 km south of the Yukon-British Columbia border. Atlin is only road accessible from the Yukon Territory.

Atlin is not connected to a regional electrical power grid and therefore all electrical needs of the community are generated locally. Power created by the current Atlin hydro project is sold to BC Hydro on a 25-year energy purchase agreement. Under this agreement, Xeitl has an obligation to provide up to 8.3 GWh/yr by 2032. The Atlin hydro project now meets all of the community's electrical power needs and has additional unutilized generating capacity. Backup power in case of outage is provided by diesel electric generation owned and operated by BC Hydro.

The current hydropower project only develops a portion of the hydropower potential of the site. The existing project utilizes approximately 107 m of head (drop) on Pine Creek. There remains another 55 m of head between the current powerhouse (located at the confluence of Pine and Spruce Creeks) and Atlin Lake. There is also additional undeveloped head upstream of the current head pond. As such, the existing project only utilizes a portion of the flow available in Pine Creek. There is then significant additional energy potential on Pine Creek that could be developed.

The Yukon Territory has an isolated electrical system that is largely supplied by hydroelectricity. Atlin is not currently connected to the Yukon's electrical grid. The Yukon is nearing capacity of its renewable energy system. Most recently public available forecasts suggest that the Yukon will have a renewable energy shortfall of over 80 GWh/yr by 2030[1]. Shortfalls in renewable energy will be met with fossil-fuel based electrical generation (diesel or natural gas fired generation).

In summer of 2014 the Taku River Tlingit First Nation's economic development corporation, the Atlin Tlingit Economic Limited Partnership (ATELP), secured funding from the Aboriginal Affairs and Northern Development Canada's ecoENERGY for Aboriginal and Northern Communities Program to conduct a pre-feasibility study of expanding the hydropower project. The current study provides a preliminary assessment of increasing hydropower production for export to the Yukon electrical grid. This study has been updated in 2016 to include a transmission connection assessment.

The community of Atlin, British Columbia is located on the Yukon Plateau physiographic region of northern BC, just east of the Coast Mountains. Pine Creek originates from Surprise Lake and then flows westward approximately 20 km to discharge into Atlin Lake. Much of the creek has been extensively mined for placer gold since the 1900's. A road from Atlin to Surprise Lake parallels the creek. Surprise Lake (32 km^2) is the headwaters for the creek and provides storage for the hydropower project. The current hydropower project has developed 107.6 m of head by conveying water through a penstock

[1] Yukon Energy Corporation, 2013:Yukon Energy Corporation Application for an Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Whitehorse Diesel – Natural Gas Conversion Project. December 9, 2013.

over a distance of approximately 3.9 km around a set falls in a short canyon. The current powerhouse lies just upstream of the confluence with a significant tributary stream called Spruce Creek. Below the current powerhouse, Pine Creek flows another 4 km, dropping approximately 55 m before discharging to Atlin Lake.

The current study envisions expanding the current powerhouse with two additional turbines of 1.45MW each (bring the total powerhouse capacity to 5MW). A second, or lower, powerhouse could be developed on Atlin Lake, providing an additional 2.5 to 3MW of capacity. The capacity of the lower powerhouse is a function of available flows and head (see Section 4.3 of this report); the specific installed capacity will need to be refined during the next phase of study. A new transmission line of approximately 100 km would be required to connect the project with the Yukon Territory's electrical grid.

1.1.1 Project Objective

In general terms the goal of the project is twofold:

1. Estimate the scale of the hydropower opportunity readily available for development on Pine Creek. How much power could be generated if the full potential of the site was developed?

2. Is the expanded development of the site, for sale to the Yukon electrical grid, potentially economically viable?

The study is to determine the scale of the opportunity and if whether it is worthwhile to pursue. At this stage the development concepts have not taken into consideration environmental and social mitigations and only limited work has been done to optimize the project design. The design concepts presented in this study are preliminary in nature for the purpose of estimating project costs and are not necessarily representative of the ultimate design or layout of the project.

1.2 Scope of Work

The scope of work for the Atlin Hydro Expansion Project pre-feasibility study is as follows. The level of detail of the study is limited by the available budget; however the objective is to generate a preliminary project concept and a cost estimate at +/-30%. Power and energy estimates are evaluated based on available historical flow data on both Pine Creek and nearby rivers. The project work consists of two main phases:

1. Project conceptualization, to define the proposed layout and energy estimates:
    a. Project initiation, including review of previous work and previous studies and an initial site visit by the project team;
    b. Site definition including initial project layout concepts and acquisition of new 1-m contour mapping of the project study area;
    c. Hydrological and power studies including development of an updated synthetic flow series, power production estimates and a simplified flood frequency analysis.

2. Pre-feasibility engineering and design

    a. Preliminary design of the major works including dams, intake structures, control structures and spillways, water conveyance and powerhouse;

    b. Preparation of cost estimate (+/-30%) estimated from bill of quantities derived from the preliminary design drawings (class IV or better based on AACE framework). Also a preliminary construction schedule is presented.

    c. Completion of a transmission assessment to estimate electrical transmission and connection requirements to the Yukon's electrical system, including cost estimates.

    d. Preparation of this prefeasibility design report and a presentation.

Two other related phases of work are being conducted concurrently with this prefeasibility study:

a. A hydrometric monitoring program was established in late 2014 to determine actual water levels and stream flows in key water bodies relevant to the hydro expansion project. This consists of continuous monitoring of lake levels in Surprise Lake and flow in Pine and Spruce Creeks;

b. An environmental scoping is being completed consisting of an existing environmental data review, gap analysis and an assessment of regulatory approvals likely to be required.

1.3 Previous Work and Available Data

This study builds upon previous work and existing information. Some of the most relevant data includes:

- Surprise Lake Hydroelectric Project: Proposal for Supply of Electricity to BC Hydro at Atlin, prepared by Canadian Utilities, Limited, Synex Energy Resources Ltd and Yukon Development Corporation. 1990.
- Atlin Hydroelectric Project Hydrology Report. Prepared for Taku Land Corporation by Sigma Engineering Ltd. March, 2006.
- Stage-discharge data for Surprise Lake and Pine Creek. Spot flow and lake measurements collected between 1990 and 2005 for Yukon Energy Corporation.
- Stream flow data for Pine Creek collected at Water Survey of Canada (WSC) station (09AA008) which operated at the mouth of Pine Creek. This station has only 10 years of complete discharge data between 1956 and 1969 (1956-1961, 1966-1969).
- Presentation on Biological Assessment of the Atlin Small Hydro Project, Progress Report September 2005 prepared by Richard Erhardt for Taku Land Corp.
- Atlin Hydroelectric Project Environmental Impact Statement prepared by Taku Land Corporation August 2006.
- Atlin Hydroelectric Project As-Built Drawings by Sigma Engineering. Prepared for Taku Land Corporation, July 2009.

- Atlin BC to Yukon Interconnection Costing Study. Prepared by BBA Engineering for Yukon Energy Corporation. August 2011.
- BC Land Tenure from DataBC including: TANTALIS Crown Tenures, Crown Land Rights-of-way, Surveyed Parcels and Surveyed Right-of-way Parcels.
- Confidential construction data provided by Atlin Tlingit Economic Development Corporation for the existing hydroelectric project completed in 2009. This includes access to construction contracts and project cost details for the original project construction between 2007 and 2009.

1.3.1 Topographic Mapping

New 1-meter topographic mapping was obtained for the project and is used as the topographic base for the preliminary design. Underhill Geomatics of Whitehorse, Yukon was retained to generate the mapping. The mapping was created from 2010 1:20,000 scale aerial photography. The mapping includes 1 meter contour data, water bodies and an orthophoto. The extent of the mapping generally follows Pine Creek and extends from the current intake head pond down to Atlin Lake. Mapping data was provided digitally to ATELP in AutoCAD format and cartographic version of mapping is provided in Appendix B.

2 SITE VISIT & OBSERVATIONS

An initial site visit was conducted by the project team on September 24 and 25th, 2014. Forest Pearson (project manager / geological Engineer), David Morissette (hydrotechnical engineer) and Shaun Beatty (civil engineer) were part of the visit and were accompanied for portions of the visit by Stuart Simpson, ATELP General Manager. The site visit included a brief helicopter over flight of the potential project site followed by on the ground reconnaissance. A copy of the site visit memorandum is provided in Appendix C and a representative photo log is provided in Appendix D. The location of features described herein are shown on Figure 2-1.

The site visit included:

- Ground inspection of the Surprise Lake outlet and control structure with access via Surprise Lake road;
- Ground inspection of the existing Pine Creek intake structure. This included a brief visual reconnaissance of Spruce Creek for consideration of diversion into the existing head pond;
- Visual reconnaissance of the existing penstock and associated right of way;
- Site visit to the inside and outside of the existing powerhouse. This also included the bridge and potential new headpond area downstream of the existing powerhouse;
- A detailed on the ground reconnaissance of a potential lower powerhouse location on Atlin Lake, just south of the Monarch Mountain Trail parking lot. The hill-slope above this site was also inspected for ground and terrain conditions for the penstock route;
- A road-based reconnaissance from both the Art Centre Road and South Pine Drive of a potential higher penstock alignment to Atlin Lake;
- A ground traverse of the upper 1.5 km of the lower penstock alignment to assess potential intake locations, ground conditions and to determine topographic constraints to a penstock alignment.

The following main conclusions were gathered from the site visit:

Surprise Lake Control Structure

- The control structure at Surprise Lake can be readily modified to increase storage range on the lake by raising the existing sheet pile and rock fill control weir (see Photo 1). Work will need to be done to assess the suitability of the current outlet structure and fish way under higher and lower lake conditions.
- The channel between the lake and the control structure appears to be relatively shallow. It is likely the channel would need to be deepened to extract water from the lake at lower lake levels.

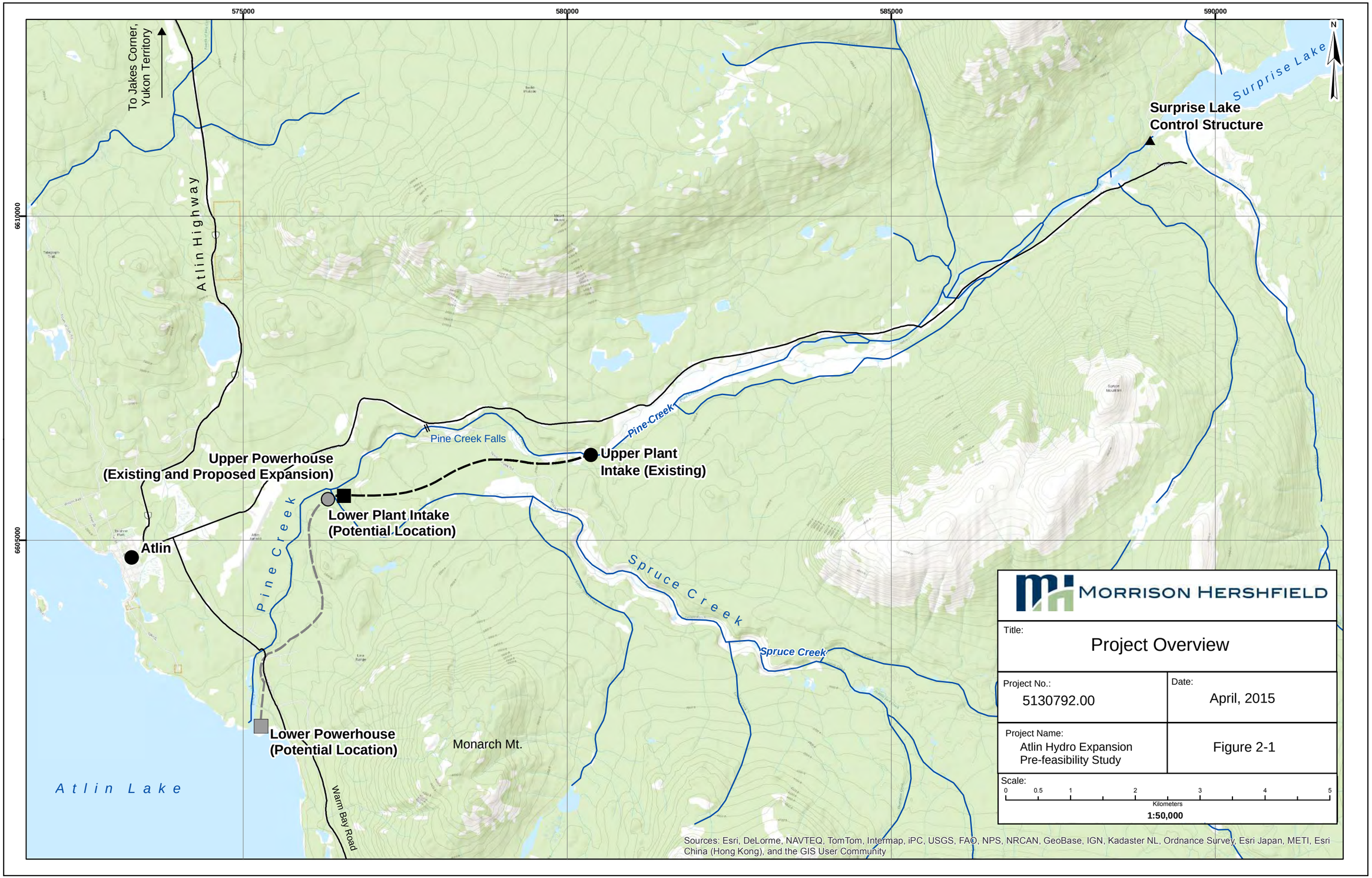

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Photo 1: Surprise Lake control structure with rock fill and sheet pile weir on the right.

Existing (Upper) Power Plant

- There appears to be adequate space at the existing head pond to accommodate a second intake structure to feed the powerplant expansion. The head pond is contained by bedrock outcrops on both sides of the creek (see Photo 2).
- The head pond itself is created by a concrete weir founded on bedrock. The weir appears to be in good condition, however has some minor leaks through the south abutment. These leaks do not appear to be problematic at this time.
- The head pond is reported to have issues with frazil ice accumulation in the winter. It is thought that this problem may be compounded by the presence of a submerged rockfill berm between the main pond area and the intake. This creates a depositional area that may exacerbate the accumulation of frazil ice. Furthermore, there is a reach of rapids on the creek immediately upstream of the head pond. These rapids not only limit the size of the head pond but are also likely to increase frazil ice generation in this reach..
- The existing clearing for the penstock is quite wide and should be able to accommodate a second penstock for most of the alignment with any further clearing. Ground conditions appear

to be glaciofluvial gravel for most of the route which is suitable for excavation and installation of a penstock (see Photo 4).

- Expanding the existing powerhouse appears reasonable. There is adequate space on the south side assuming some excavation of the hill side. Soils at the powerhouse are primarily sand and gravel with no bedrock outcrops anticipated near surface (see Photo 3).
- Sand and course gravel is abundant throughout the area and is readily available due to the extensive placer gold mining of the creeks.

Photo 2: Existing head pond and intake structure, looking west.

Photo 4. Existing penstock right of way, looking downstream (west). Penstock in on the left, service road on the right side of the clearing.

Photo 3. Existing powerhouse looking south towards Spruce Creek. Pine Creek is in foreground.

Lower Power Plant

- No obvious or natural containment for a head pond was identified. Topography is fairly flat and no deep natural pools near the desired intake location were observed. In the absence of any natural features, it is proposed that an excavated head pond be created immediately downstream of the existing powerhouse access road bridge (see Photo 3). Potential for tail water effects from a lower head pond on the existing powerhouse will need to be considered. Soils at this location are coarse alluvial gravel with no bedrock in the vicinity. This suggests that soils will be fairly porous should an impoundment be created in this area.
- The alignment for the lower penstock is significantly more complicated that the upper alignment. This is due to steep side slopes, varying terrain conditions (bedrock outcrops, wetland areas) and topographic constraints (see Photo 5).
- The upper 1.5 km of the potential penstock alignment is primarily alluvial sand and gravel terraces. A saddle between the mountain side and a bedrock hill was located and provide a convenient topographic feature for the penstock alignment approximately 1.5 km south of the head pond area.

Photo 5. View of lower penstock alignment terrain conditions looking north towards existing powerhouse.

- There are a number of titled properties along the lower segment of the potential penstock alignment (within the first kilometer upstream of the powerhouse). These are located along Warm Bay Road, Arts Centre road and either side of Pine Creek at the bridge. These properties conflict with some potential penstock routes.
- There appears to be adequate space for a powerhouse on the shore of Atlin Lake. Pine Creek itself has created a large alluvial fan extending out into Atlin Lake. The shallow gravel deposits extend out into the lake making the lake quite shallow near the mouth of the creek. The lake drops off more quickly from the shoreline south of the fan (see Photo 6). Sediment disposition from the creek affecting the potential tailrace should be considered.
- The hillside above the potential powerhouse location rises steeply to the east of the Warm Bay Road. The hillside is open rolling bedrock outcrop with very little tree cover.

Photo 6. View of potential lower powerhouse locations on Altin Lake. Pine Creek fan is on the left. Note exposed bedrock hillside above Warm Bay road.

3 PROPOSED LAYOUT

3.1 Project Components Overview

Multiple new hydro project components are required to maximize power production at Pine Creek. For the purposes of this study, the hydro expansion project layout is assumed to consist of the followings (see Figure 2-1):

1. Increased water storage range on Surprise Lake to increase water storage for seasonal power production. It will require modifications to the existing Surprise Lake control structure and weir.
2. Expanding the upper power house with additional generating capacity. It will require an additional penstock and intake structure to convey the additional water to the added turbine(s). It is not anticipated that the existing head pond will require modification other than the addition of a second intake structure for the new penstock. Modifications to help prevent frazil ice accumulation in the head pond are however warranted, especially with the proposed increase in winter flows.
3. A new powerhouse on or near Atlin Lake. It will require a new conveyance (penstock) and associated head pond and intake structure downstream of the existing powerhouse.
4. A transmission line from Atlin to the Yukon Territory's electrical grid. It has been assumed that the new transmission line would terminate at Jakes Corner based in the preliminary transmission options assessment completed as part of this study.

3.1.1 Spruce Creek Diversion

Spruce Creek is the largest tributary to Pine Creek. It joins Pine Creek immediately below the current powerhouse. Like Pine Creek, Spruce Creek has been extensively modified and affected by placer gold mining over the past century. Placer mining on both creeks continues to occur.

Flows from Spruce Creek can be utilized for power production at either the new lower power project or potentially by both power plants if the creek was diverted into the upper (existing) head pond. The current head pond has a normal water elevation of about 832.5 m. Diverting Spruce Creek would require intercepting the creek at approximately elevation 835 m and approximately 1.7 km of conveyance (ditch or pipe) to convey the water to the head pond. Given this topography there are a number of considerations that make diverting Spruce Creek into the upper head pond challenging:

- Construction of the conveyance may be challenging due to steep side-slope topography at the required intake elevation.
- Soils are very permeable gravels which would make a diversion ditch relatively porous and may even require a liner.
- An intake structure on Spruce Creek may be challenging due to high sediment load and frequent floods and variable flows resulting from upstream placer mining operations.

Preliminary estimates suggest that diverting Spruce Creek into the upper head pond could create an additional 2 to 3 GWh/yr of summer energy. Summer energy is of limited to low value to Yukon. Therefore the economic case for an upper diversion of Spruce Creek is difficult to envision at this time under conventional development approaches.

For the purposes of this study, it will be assumed that Spruce Creek will be utilized for the lower power plant only. A small diversion ditch will divert Spruce Creek into the new lower headpond just upstream up the mouth of the creek into Pine Creek.

3.2 Lower Powerhouse Alternatives

Several layout alternatives for the lower power plant were considered to determine the optimal arrangement and to address the physical constraints of the site. Specifically lower powerhouse locations and associated penstock alignment options were evaluated. The potential layout alternatives were developed based on on-site observations, topographic mapping and land ownership. Five potential powerhouse locations were identified jointly by the project team and ATELP. These options are shown on Figure 3-1.

Table 3-1 provides a qualitative evaluation of the project layout options for the lower power plant for a number of considerations. Location “E”, located on the Pine Creek fan near the Monarch Mountain trail parking lot was selected for preliminary design. This location was selected for the following reasons:

- Develops the maximum head for the site (maximize power potential)
- Penstock alignment largely avoids land tenure conflicts and powerhouse location largely avoids other potential land use conflicts.
- Site appears to be technically suitable from a construction perspective
- The hillside above the selected site provides opportunity for development of the required surge facility.

Figure 3-1: Lower Powerhouse & Penstock Alternatives

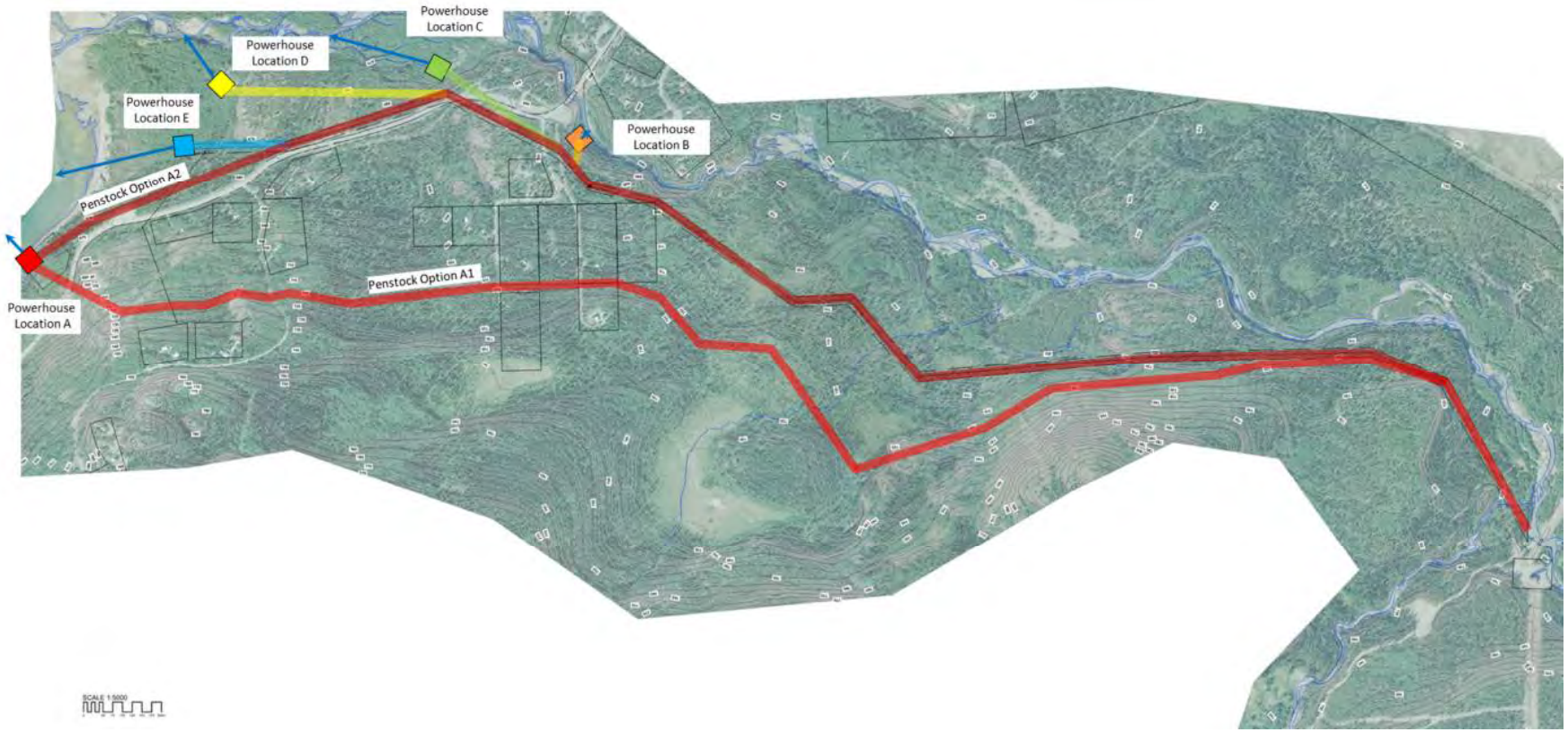

Table 3-1: Lower Powerhouse & Penstock Alignment Options

Green indicates Best for parameter, Red indicates Worst for parameter. **Bold** indicates preferred option.

Powerhouse Location	A. Atlin Lake		B. Pine Creek Above Bridge	C. Pine Creek Below Bridge	D. Upper Pine Creek Fan	E. Lower Pine Cr. Fan
Penstock Alignment	A1. Upper Alignment	A2. Lower Alignment along Warm Bay Road	B. Lower Alignment to Pine Creek Bridge	C. Lower Alignment to below Campground.	D. Lower Alignment to Pine Cr. fan	**E. Lower Alignment to Pine Cr. fan**
Penstock Length	4.4 km	4.4 km	3.0 km	3.4 km	3.8 km	**4.0 km**
Penstock Constructability	• Greatest length of potentially poorly drained/swampy soil • Significant lengths of side hill construction in rock • Significant rock work at end of alignment (Monarch Mt. Trail area)	• Less side hill & rock construction • Less poorly swampy areas crossed • Requires construction of 1.0 km along Warm Bay Road (either in ditch or under road surface)	• Less side hill & rock construction • Less poorly swampy areas crossed. • Does not cross Warm Bay Rd.	• Less side hill & rock construction • Less poorly swampy areas crossed.	• Less side hill & rock construction • Less poorly swampy areas crossed.	• **Less side hill & rock construction** • **Less poorly swampy areas crossed.**
Penstock Alignment Land Ownership	Likely land conflicts both at S. Pine Creek Drive and potentially along Art Centre Rd.	Avoids land conflicts – route pass below (north) of S. Pine Creek Dr. properties. Possible issues with constructing in Warm Bay Rd. right of way.	Avoids land conflicts – route pass below (north) of S. Pine Creek Dr. properties	Avoids land conflicts – route pass below (north) of S. Pine Creek Dr. properties	Avoids land conflicts – route pass below (north) of S. Pine Creek Dr. properties	**Avoids land conflicts – route pass below (north) of S. Pine Creek Dr. properties**
Gross Head	57.5 m (Lake elev. 667.5)		42 m (Creek elev. 683)	47.5 m (land surface elev. 676.5)	52.5 m (land surface elev. 671.5)	**56m (land surface elev. 669)**
Powerhouse Constructability	Hillside, sand and gravel over bedrock. Site is small but likely adequate.		Site is very small and difficult to access. Will likely require building powerhouse into hillside and bedrock excavation	Adequate space, extensive sand and gravel, well drained. Possible near-surface bedrock at base of hill.	Adequate space, extensive sand and gravel, well drained. No bedrock. May require creek deflection berm to prevent migration of creek into powerhouse area.	**Adequate space, extensive sand and gravel, well drained.** **Possible near-surface bedrock at base of hill.**
Tailrace Considerations	Excavation of tailrace in lake required (to accommodate lake level fluctuations		Negligible – direct discharge to creek	Requires 270 m long excavated tailrace in sand and gravel to Pine Creek.	Requires 100 m long excavated tailrace in sand and gravel to Pine Creek.	**Requires 200 m long excavated tailrace in sand and gravel to Atlin Lake**
Proximity of Private Property	Nearest residence: 400m.		160 m to campground and 110m nearest residence on S. Pine Drive and	100 m to campground. 320 m to nearest residence on Pine Dr. and S. Pine Dr.	330 m to nearest residence on Warm Bay Rd. 680 m to campground.	**220 m to nearest residence on Warm Bay Rd.**
Recreational Impacts	Likely conflicts/issues with crossing Monarch Mt. Trail		Potential construction noise/visual impacts to campground & neighbors	Potential construction noise/visual impacts to campground	No significant conflicts identified.	**Tailrace constructed through Pine Creek beach**

3.2.1.1 Upper Powerhouse Alternate Arrangement

There is a set of rapids on Pine Creek immediately upstream of the current head pond. Further upstream of the rapids, Pine Creek has been heavily disturbed and flows through approximately 5 km of placer gold mine workings. Between the upper end of the placer mining area and the existing head pond, the creek drops approximately 65 m. Therefore additional head potential exists upstream of the current plant. An alternative arrangement for the upper powerhouse has been identified as described below, but this option has not been assessed in detail as part of the current study. Generally, components of this alternate arrangement are described as follows:

There is an old diversion canal that at some time in the last century intercepted Pine Creek upstream (east) of the placer mining area and diverted the creek around the mines. Remnants of the diversion channel are clearly visible on the south side of the valley and the former canal comes within 1.5 km of the current head pond.

An alternative arrangement could be developed that would utilize the additional 65 m of head. This alternative arrangement could consist of intercepting Pine Creek upstream of the placer mines, building a 7.5 km long power canal following the old canal, plus a new 4.3 km penstock from the end of the power canal to the existing powerhouse (see Figure 3-2). This arrangement would require an entirely new penstock (the existing penstock could not be used due to higher pressures associated with the additional head) plus entirely new turbines to utilize the full flow and higher head. This would result in the existing infrastructure (head pond, penstock and powerhouse) being largely un-utilized.

Figure 3-2: Upper powerhouse alternate arrangement

There are two advantages to the alternate arrangement:

1. Increased annual energy production—depending on the specific installed capacity, it could produce on the order of an additional 17 GWh/yr of energy (on top of the energy production of the proposed layout); and
2. A potential reduction in frazil-ice related issues by avoiding the set of rapid upstream of the current head pond. It is suspected that this reach is generating most of the frazil ice that reaches the existing upper headpond.

The drawback of this alternate arrangement is the existing investment would not be well utilized. The existing plant would only be used for limited generation during late summer/fall months if there is surplus water in the creek and if there are outages on the new power plant.

The costs and technical challenges of this alternate arrangement, plus financial implications should be assessed at the next phase of study before advancing the final scheme for the hydro expansion project to feasibility level study.

4 HYDROLOGICAL AND POWER STUDIES

This section presents an analysis of the hydrology of Pine Creek watershed for the purpose of expanding hydroelectric generation in Pine Creek. The goal of the project is to increase energy generation by (1) developing additional head below the existing powerhouse (including the Spruce Creek catchment), and (2) optimize storage in Surprise Lake to maximize winter energy generation that is highly valuable to the Yukon.

The Atlin Tlingit Economic Limited Partnership (ATELP) currently owns and operates a 2.1 MW hydroelectric generation facility that utilizes flows in Pine Creek. The Atlin Hydro Expansion Project considers the possibility of increasing power generation on Pine Creek by developing additional head, expanding the existing facility and optimizing the storage in Surprise Lake to maximize winter generation. Surplus energy would be delivered to Yukon via a transmission line connecting Atlin to Jakes Corner.

The outflows of Surprise Lake are controlled by an overflow rock fill weir and a low level outlet operated with a slide gate. Water from Surprise Lake seasonally overtops the weir at the outlet. Otherwise, minimum flows are maintained in Pine Creek year-round with a fishway.

4.1 Hydrological Study

4.1.1 Geographic Setting and Climate

Pine Creek is located near Atlin in north western British Columbia. The regional climate of the catchment spans three different Biogeoclimatic Zones (Boreal White and Black Spruce, Spruce-Willow-Birch and Alpine Tundra). The nearest and continuously active meteorological station is located in Atlin (Environment Canada Station #1200560). This station is located approximately 7 km from the Pine Creek catchment at an elevation of 673.6 m ASL.

The Atlin station has records of daily temperature and precipitation beginning in August, 1905 to the present day. According to the 1980-2010 Canadian Climate normal set by Environment Canada, the station receives 365 mm of annual precipitation, with 201 mm falling as rain. Mean monthly temperatures fluctuate seasonally between -12.8°C (January) to 13.4°C (July) with a mean annual temperature of 1.1°C. The total monthly precipitation and mean temperature for Atlin are shown in Figure 4-1.

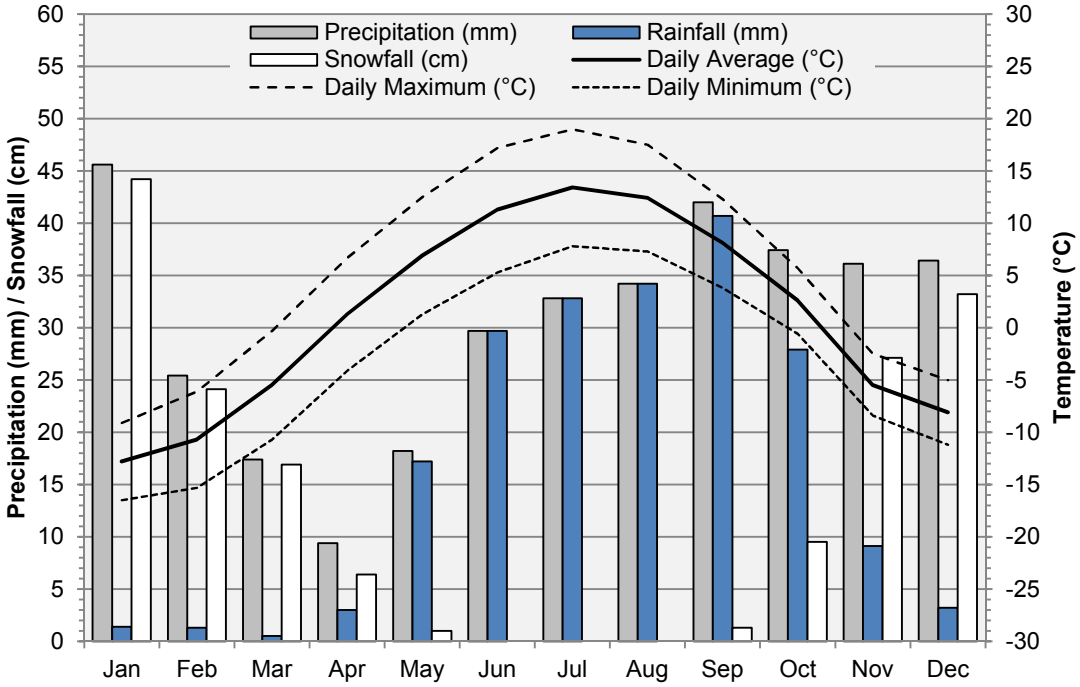

Figure 4-1: 1981 to 2010 climate normals for Atlin, BC (Environment Canada Station #1200560).

4.1.2 Previous Studies

A hydrological study was completed by PO Sjoman Hydrotech Consulting in 2003. This report was referenced in Sigma Engineering Hydrology Report (2006). The findings of this report were the basis for selecting the Gladys River WSC station as a representative data set for developing a long-term synthetic flow series for Pine Creek for the purpose of estimating the power potential of the existing power plant. This study included an assessment of eight Water Survey of Canada (WSC) stations proximal to the region. Due to an inability to retrieve PO Sjoman report, the report was not reviewed or evaluated as part of this assessment.

Sigma Engineering Ltd. completed a Hydrology Report for the Atlin Hydroelectric Project (2006). This report used a comparison of common period of record flows at the Gladys River and Pine Creek to determine a 'calibration factor' of 0.97. This was used to convert flows measured at the Gladys River to flows on Pine Creek at selected points within the catchment. The ratio of average annual unit discharge was used to synthesize flows at the intake location and outlet of Surprise Lake using a scaling factor based on the size of each catchment area. Using this data, the mean annual flow (MAF) was estimated at 4.06 m^3/s at the existing upper intake and 3.4 m^3/s at the outlet of Surprise Lake.

The flow series used by Sigma to estimate the power and energy potential of the site could not be retrieved. Verifications were made in the current study to confirm the selection of Glady's River as the reference hydrometric station to develop a flow series for Pine Creek.

4.1.3 Regional Stations

Five Water Survey of Canada (WSC) stations in proximity of Pine Creek were evaluated for suitability as surrogate flow records of Pine Creek. The catchment areas had to be no greater than four times that of Pine Creek, to be considered representative to develop a long term flow series. Table 4-1 summarizes the WSC stations considered, along with the number of complete years of record, mean annual flows and unit flows. Unit flows per square kilometer provides a way to compare watersheds of different sizes, by comparing flows on a common basis (over one kilometer square). A general description of each WSC station considered in this assessment and its ability to represent flow in Pine Creek is presented hereafter.

Table 4-1: Summary of nearby Water Survey of Canada hydrometric gauging stations.

Station	Name	Drainage Area (km^2)	Period	Complete years of record	Mean yearly flows (m^3/s)	Unit flows ($m^3/s/km^2$)
09AA008	Pine Creek near Atlin	697	1956-1969	10	5.1	0.0074
09AE004	Gladys River at outlet of Gladys Lake	1,910	1961-1993	32	14.8	0.0078
09AA012	Wheaton River near Carcross	864	1966-2011	41	7.9	0.0091
09AA009	Watson River near Carcross	1,150	1956-1973	9	5.1	0.0044
09AB008	McClintock River near Whitehorse	1,700	1957-1994	28	9.8	0.0058

Pine Creek

The Pine Creek station (09AA008) has a catchment area of 697 km^2 and operated near the mouth of Pine Creek on Atlin Lake from 1956 to 1969. There is 10 years of complete data between 1956-1961 and 1966-1969. Daily discharge records from this station represent all flows that originate within the project area. Daily mean discharges were selected from complete-year records and used as the basis for evaluating the ability of other regional stations to represent flows within this catchment. Mean annual discharge for the complete-year record is 5.1 m^3/s, representing an area-unit flow of 0.0074 $m^3/s/km^2$.

Gladys River

The Gladys River station (09AE004) is the catchment located immediately to the east of the Pine Creek basin. The record from this gauge location extends from 1961 to 1993 and contains 30 years of complete daily records. The station is located near the outlet of Gladys Lake and has mean annual flow of 14.8 m^3/s, with a unit flow of 0.0078 $m^3/s/km^2$. The Gladys River's catchment contains a similar percentage of surface water area as Pine Creek.

Wheaton River

The Wheaton River station (09AA012) is located approximately 90 km to the northwest of Atlin. Continuous daily flow measurement began at this station in 1966 and continues to the present. The station has a drainage area of 864 km^2 comprised primarily of high elevation terrain. Annual

discharge at this gauge is dominated by snowmelt and rain events during the spring. No lakes, ponds or other surface water features that provide storage are present within the Wheaton River catchment.

Watson River

Also located to the northwest of Atlin, the record from the Watson River station (09AA009) spans 20 years between 1956 and 1973. This station represents a drainage area of 1,150 km^2 and has a mean annual discharge of 5.1 m^3/s. Similar to the Wheaton River, the Watson river catchment is dominated by upper elevation terrain but represents a much larger catchment area.

McClintock River

The McClintock River is located approximately 92 km to the north of Atlin, BC, with daily flow data collected between 1957 and 1994. The station represents a drainage area of 1,700 km^2 and has a mean annual flow of 9.8 m^3/s. This station was primarily considered as an alternative to represent flows from parts of the Pine Creek catchment that are not affected by the storage of Surprise Lake. This includes the areas that drain into Spruce Creek and the inflows into Surprise Lake.

A comparison was made between the five gauging stations over the common period of record from 1966 to 1969. Unit hydrographs averaged over the four years were plotted to compare the behavior of each catchment over the year.

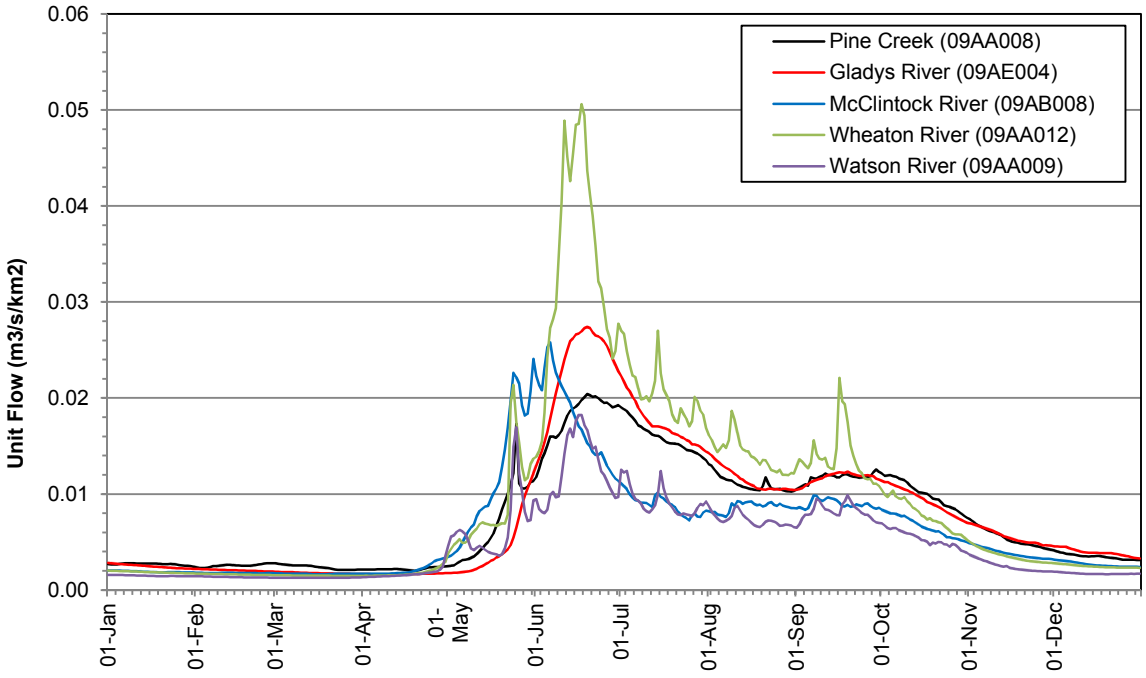

Figure 4-2: Mean daily unit flow comparison for selected regional WSC stations over the common period of record, 1966-1969.

The McClintock and Watson Rivers were rejected since their unit flow is significantly lower than the reference Pine Creek station's unit flow. A comparison of the Wheaton River flows with the Pine

Creek and Gladys River flows was made to determine if it is a suitable reference station for the inflows to Surprise Lake (i.e. un-routed flows to the lake). Figure 4-3 shows the unit yearly hydrographs for the three stations over the common period of record.

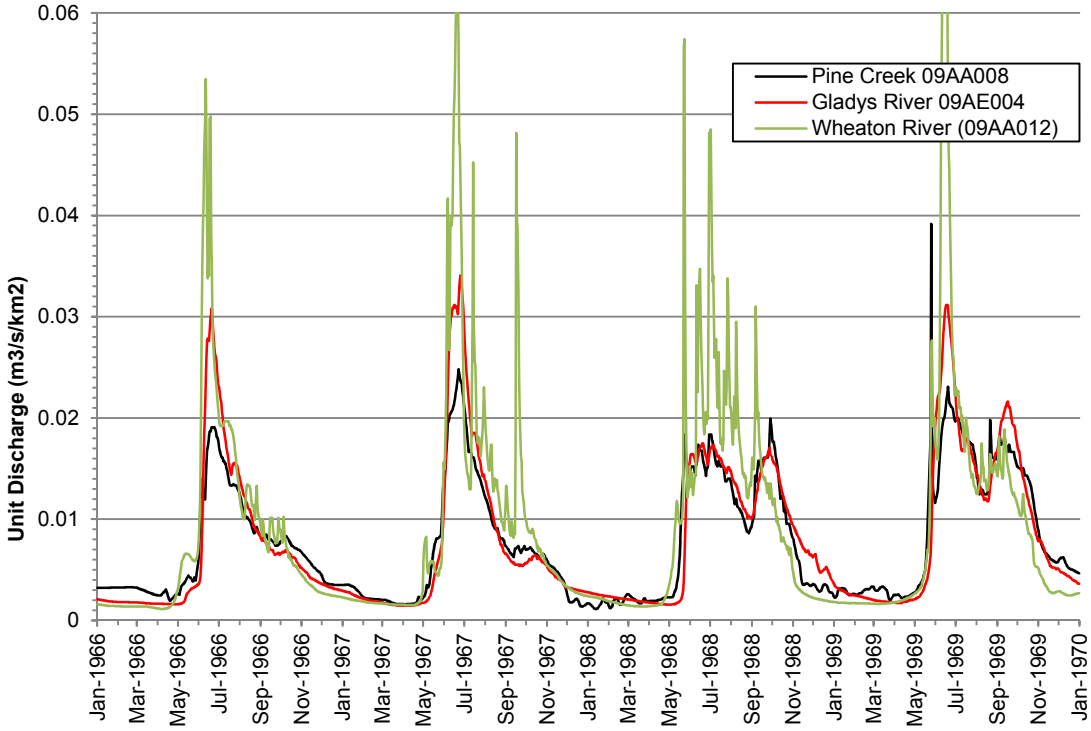

Figure 4-3: Daily unit flows for the period-of-record, 1966-1969

The Gladys River station is considered the most suitable station to develop long-term synthetic flow series in Pine Creek. Although the Wheaton River could also have been suitable to develop and inflow series to Surprise Lake based on the previous comparison, the Gladys River is retained for the following reasons:

- Use of Gladys River in previous hydrometric assessment for the purposes of electrical generation;
- Similarity of unit flows for Pine Creek and Gladys River (see Table 4-1);
- Both Gladys River and Pine Creek gauging stations capture water discharging from large surface water body at a similar elevation (Surprise Lake and Gladys Lake);
- Gladys River catchment is located adjacent to Pine Creek with the gauging stations located approximately 60 km from one another. Each station also demonstrates a similar timing of freshet and response to regional precipitation events.

4.1.4 Development of the flow series

A long-term flow series for Pine Creek was developed using the Gladys River flow record as described above. Flows from Gladys River were transferred directly to the various sub catchments of Pine Creek based on a ratio of catchment areas. Gladys River has generally higher summer flows

than Pine Creek over the 4 years of common record (Figure 4-3) while flows during the fall and winter are generally lower. This is likely due to the larger percentage of the catchment that Surprise Lake represents compared to Gladys Lake, thus providing more significant routing of inflows. Continuous flow gauging on Pine Creek will allow to improve the quality of the inflow series and firm up power estimates. Overall Gladys River has a unit flow per kilometer square that is about 5% higher than Pine Creek. The Gladys River flow record is however more recent thus may capture better the potential effects of climate change on the catchment. At this stage of study and based on the available data, Gladys River represents the best proxy station to use to determin the power and energy potential of the Atlin Hydro Expansion Project.

Inflows to Surprise Lake were first determined, following by inflows from the different intermediate sub-catchments. This approach is consistent with the one taken in previous hydrological studies of the Pine Creek catchment.

The proposed layout of the Atlin Hydro Expansion Project is presented in detail in Sections 3 and 5, as well as on the drawings in Appendix A. Based on the proposed layout, flows were determined at the following locations along Pine Creek to simulate the power and energy generation potential of the project:

- Surprise Lake at its outlet;
- Upper head pond/intake (existing, for the upper power plant);
- Lower head pond/intake (new, for the lower power plant);

Figure 4-4 illustrates the contributing catchments to each location. Inflows to Surprise Lake will be regulated based on the selected management scheme, while flows originating downstream of Surprise Lake will be unregulated. Both head ponds have minimal storage capacity and as a result is neglected in the power generation analysis.

The total catchment area at the outlet of Surprise Lake is 470 km^2. The upper and lower plants respectively have catchment areas of 553 and 678 km^2 at their intake

570000
585000
600000
615000
6625000
6610000
6595000
N

Surprise Lake
Catchment 469km²

Surprise Lake
32km²

Surprise Lake
Control Structure

Lower Intake Intermedate
Catchment 18.7km²

Upper Intake Intermedate
Catchment 83.2km²

Upper Power Plant
(Existing and Proposed)

Upper Plant
Intake (Existing)

Atlin

Lower Plant Intake
(Potential Location)

Lower Plant
(Potential Location)

Atlin Lake

Spruce Creek
Catchment 106km²

Legend

- Lower Plant Intake (Potential Location)
- Lower Plant (Potential Location)
- Surprise Lake Control Structure
- Upper Plant Intake (Existing)
- Upper Power Plant (Exisiting)
- Atlin
- Catchment Areas

Coordinate System: NUTM08
Projection: Transverse Mercator
Datum: North American 1983
Units: Meter

MORRISON HERSHFIELD

Scale: 0 1 2 4 6 8 10
Kilometers
1:175,000

Title:
Atlin Hydro Expansion Project
Contributing Catchments

Project No.:	Date:
5143079200	March 2015
Project Name: Atlin Hydro Expansion Prefeasibility Study	Figure 4-4

Sources: Esri, DeLorme, NAVTEQ, TomTom, Intermap, iPC, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), and the GIS User Community

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Surprise Lake

Synthetic flow records of Pine Creek at the outlet of Surprise Lake were determined by scaling daily flows in the Gladys River between 1963 to 1993 (complete years only) to the Surprise Lake catchment area (470 km^2). This data was then reverse-routed through Surprise to determine an inflow series to Surprise Lake this is used to simulate reservoir operations. The reverse routing exercise was based on methods described by Zoppou (1999) for reverse routing of flows through a surface water body. Corresponding Surprise Lake elevations were determined by a stage-discharge relationship for the outlet of Surprise Lake that is based on measurements made by Yukon Energy Corporation (YEC) at the lake outlet between 1990 and 2006 (by Monty Alfred). Daily inflow volumes were determined by subtracting the outflows from changes in Surprise Lake storage (estimated area of 32 km^2). Daily inflow flow series to Surprise Lake were then routed through Surprise Lake to develop an outflow series. The two outflow series (synthetic and routed) compared well.

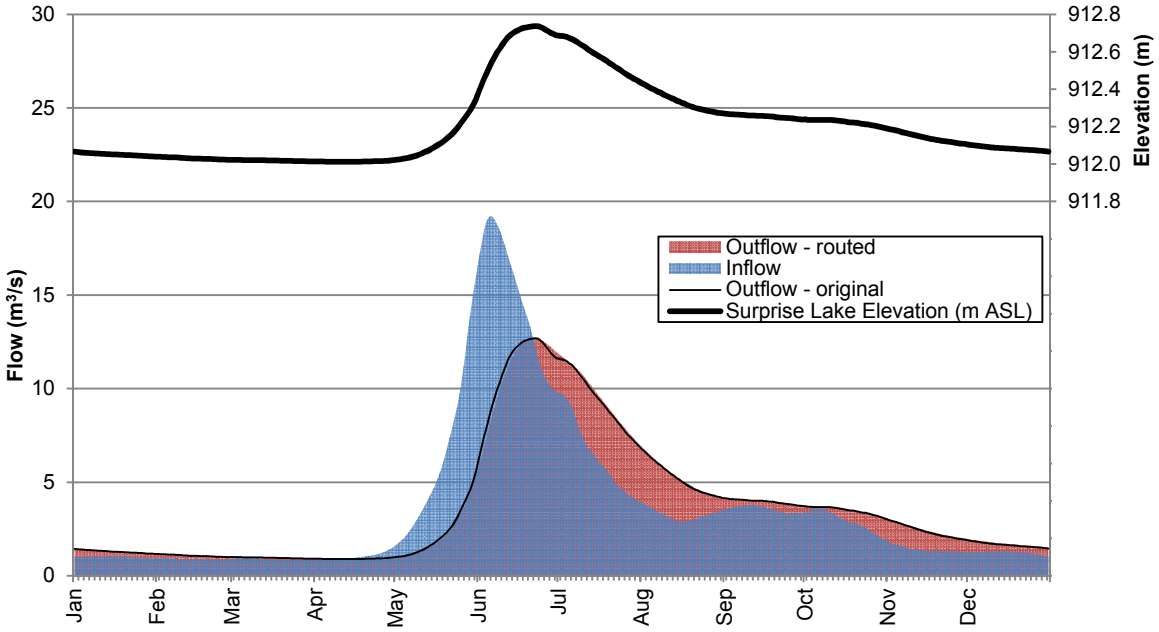
The resulting Surprise Lake inflow series does not reflect the effect of storage in the lake and is therefore considered representative of flows in other reaches of the Pine Creek catchment (i.e. Spruce Creek and intermediate catchment between the different structures) not affected by surface water bodies.

The average monthly inflows and outflows of Surprise Lake are presented in Figure 4-2. Average monthly inflows were calculated from daily inflows to Surprise Lake as a result of the reverse-routing exercise. Surprise Lake outflows were calculated from daily average inflows routed through Surprise Lake considering a natural outlet (without any outlet structure) for verification purposes. A graphical presentation of unregulated average daily flows and Surprise Lake water levels is shown in Figure 4-5.

Table 4-2: Mean monthly inflows and outflows of Surprise Lake, 1963 to 1993 (unregulated).

Month	Inflow (m^3/s)	Outflow (m^3/s)
January	1.1	1.4
February	1.0	1.2
March	1.0	1.1
April	1.1	1.0
May	6.4	2.3
June	14.9	11.0
July	6.4	9.5
August	3.3	5.2
September	3.6	4.0
October	2.9	3.5
November	1.5	2.5
December	1.3	1.7
Annual Mean	**3.7**	**3.7**

Figure 4-5: Surprise Lake synthetic hydrology (unregulated) based on reverse-routing of scaled Gladys River (WSC 09AE004) 1963-1993 hydrometric record.



Intermediate catchments below Surprise Lake

Flow series from the various intermediate sub-catchments below Surprise Lake were determined by scaling the synthetic inflow series to Surprise Lake to each of those catchments. The basin area for the intermediate catchments are presented in Table 4-3 below.

The intermediate catchment of Pine Creek between the Surprise Lake outlet and the upper head pond has a surface area of 83.2 km^2. The resulting average yearly inflows is estimated at 0.7 m³/s, resulting in a total average yearly inflow of 4.4 m³/s at the upper power plant intake.

Average yearly flows in Spruce Creek (catchment area of 107 km^2) were estimated at 0.8 m³/s. Flows were also calculated for the intermediate catchment of Pine Creek between the existing intake and the mouth of Spruce Creek (catchment area of 19 km²), yielded an average yearly flow of 0.2 m³/s. The resulting total flow at the lower power plant intake is then of 5.4 m³/s.

Table 4-3: Contributing catchments for the Upper and Lower Power Plant.

	Catchment	Basin area (km²)	Mean flow (m³/s)
Upper Plant	Surprise Lake	470	3.7
	Intermediate catchment above upper intake on Pine Creek	83	0.7
	Total	**553**	**4.4**
Lower Plant	Intermediate catchment below upper intake on Pine Creek	19	0.2
	Spruce Creek	107	0.8
	Total	**678**	**5.4**

4.1.5 Low Flow Analysis

Minimum flows occur in the late winter and are associated with base flow in the channel. A 7-day low flow analysis of the 2, 5, 10, and 25-year return periods was calculated for the synthetic Surprise Lake inflow and outflow (unregulated) series. This analysis is based on fitting the annual minimum flows for any seven consecutive days to a Log-normal Pearson Type III distribution function. This function is then solved for the associated recurrence probability (0.5, 0.2, and 0.1, 0.05, respectively) to estimate the 7-day low flows. Table 4-4 presents the low flows for Surprise Lake inflows, Pine creek at the outlet of Surprise Lake, Spruce Creek and Intake structures.

The 7-day low flows for the upper intake are slightly greater than previously reported by Sigma Engineering Ltd. (2006). Sigma estimated 1.1 m^3/s, 0.93 m^3/s, 0.85 m^3/s and 0.78 m^3/s for 2, 5, 10 and 25-year return periods using a slightly different methodology. It is expected that differences with the results presented in this report are a function of the different methods applied.

Table 4-4: Summary of 7-day low flow analysis for 2, 5, 10 and 25 year return periods, based on the Surprise Lake synthetic inflow and outflow series.

Return Period (years)		Empirical Probability	Surprise Lake Inflow (m³/s)	Surprise Lake Outlet (m³/s)	Upper Intake (m³/s)	Spruce Creek (m³/s)	Lower Intake (m³/s)
7Q2	2	50 %	1.3	1.0	1.2	0.3	1.6
7Q5	5	20 %	1.1	0.9	1.1	0.25	1.4
7Q10	10	10 %	0.9	0.9	1.1	0.22	1.3
7Q25	25	4 %	0.8	0.9	1.0	0.20	1.3

4.1.6 Flood Analysis

A simplified flood frequency analysis of Pine Creek was conducted to determine floods of different return period at various key locations for the project. Floods were determined at the following locations:

- Surprise Lake control structure (lake outlet)
- Upper head pond/intake
- Lower head pond/intake

The maximum flows at the outlet of Surprise Lake are dependent on the water level management scheme. Two sets of maximum daily annual flows over the duration of the flow series were retrieved: one from the synthetic Surprise Lake inflows and a second from the simulated outflows from Surprise Lake which occur prior to controlled releases from the reservoir (maximum flow between early May and end of October). Each set of maximum annual flows were fit to a Gumbel, Log Normal and Log-Pearson III type probability model. The average flow predicted by all three distribution models was taken as a representative flood flow for the respective return periods.

The flood frequency developed for the Surprise lake inflow series was scaled to the Spruce Creek and intermediate segments of the catchment below Surprise Lake using the respective catchment area ratios. Flood flows from the outlet of Surprise Lake were then combined with intermediate catchment and Spruce Creek flows to determine flood sizes at the Upper and Lower Intakes. The size, probability and return periods of flood flows are summarized in Table 4-5.

The 1: 100 year flood at the Surprise Lake outlet is estimated at 16.4 m^3/s. This flood translates to a 25.5 m^3/s and 39.3 m^3/s flow at the Upper and Lower Intakes, respectively. A number of similarly-sized flows (i.e. 0.8 m^3/s) at the outlet of Surprise Lake were excluded from the analysis since these values more strongly reflect the reservoir management scheme rather than actual peak flood flows at the Surprise Lake outlet.

Table 4-5: Summary of Flood Frequency Analysis for the Pine Creek catchment at the Surprise Lake control structure, Upper and Lower Intakes.

Return Period (years)	**Surprise Lake Control Structure** (*m^3/s*)	**Upper Intake** (m^3/s)	**Lower Intake** (m^3/s)
2	5	9	15
10	10	17	26
20	12	19	30
50	15	23	35
100	16	26	39
200	18	28	43
1000	22	34	53

4.2 Power and Energy Simulations

Simulations were run to estimate the long-term power and energy potential of the Atlin Hydro Expansion Project. The proposed layout of the project is discussed in more detail in Section 3 and 5. The layout is composed of two power plants:

1) The ***upper power plant,*** which includes the existing 2.1 MW facility augmented with a new 2.9 MW plant for a total installed capacity of 5 MW. The upper plant operates under a gross head of 107.6 m.

2) The ***lower power plant*** has an installed capacity of 2.8 MW. It operates under a gross head of 55.5 m. Its head pond is located approximately 200 m downstream of the tailrace of the upper plant.

4.2.1 Surprise Lake Storage

Surprise Lake is the reservoir for the existing power plant on Pine Creek and is currently managed within a 1.05 m operating range. The Atlin Hydro Expansion Project considers an increase in the storage range at Surprise Lake in order to increase and maximize winter energy generation from the system.

It is proposed to increase the Surprise Lake storage range to 2.5 m. Based on an approximate surface area of 32 km^2 for Surprise Lake, it would provide up to 80 Mm^3 of storage. This volumes stores most of the inflows to the lake (except for the summer releases for power generation and for minimum flow requirements), which were estimated to be on average 132 Mm^3 per year over the duration of the flow series.

Modifications to the Surprise Lake Control Structure would be required to accommodate the increase in storage range (discussed in Section 5.1). Table 4-6 summarizes the configuration of the existing and proposed control structure at the outlet of Surprise Lake.

Table 4-6: Parameters of Surprise Lake Control Structure

	Existing Configuration	Proposed Configuration
Overflow weir crest elevation (m)	913.1	913.85
Weir crest width (m)	32	32
Outlet control structure	1.8 m diameter culvert	1.8 m diameter culvert
Full Pond Level (m)	913.15	913.85
Low Pond Level (m)	912.10	911.35
Operational Range	1.05	2.5

The power simulation considers two new power plants. The upper power plant will be located adjacent to the existing generating station and will utilize all of the water available for generating at that site. The location of the lower power plant will be near Atlin Lake and utilize flows from the Pine Creek catchment below the upper Intake and outflows from the upper power plant. The location and layout of the proposed power plants are illustrated in Drawings 01 to 03 in Appendix A. Contributing catchment areas to each plant are presented on Figure 4-4 in Section 4.1.4.

Consideration was also given to a 2 m storage option (911.85 m to 913.85 m) in Surprise Lake for the power simulations. Results for this option are presented for the purpose of evaluating the benefits and environmental challenges of the 2.5 m storage range. The detail methodology for the 2 m storage option is not presented in the report, but similar operation rules as the 2.5 m storage range apply.

4.2.2 Surprise Lake Management

A model was created to simulate the management of Surprise Lake. The following rules and assumptions were incorporated into the model:

1) Maximize winter generation, where the majority of freshet and summer inflows are stored in Surprise Lake and released later in the winter for hydro generation. Summer releases are only to meet the Atlin electrical load (baseline taken as the 20 years forecast) and minimum flow requirements. The Atlin electrical load can be met with power production at both power plants (existing and expansion to upper power plant and new lower power plant). Unregulated inflows from the intermediate sub-catchments below Surprise Lake also provide additional water to both power plants during the summer months;

2) Regulated flow releases for the winter begin on November 1st and last until May 10th. Releases are kept as constant as possible during the winter period, except during the spring when power demand from the Yukon is expected to be lower. The objective is to discharge flows of approximately 6 m³/s on average from Surprise Lake.

   The objective of the schedule of releases is to draw down Surprise Lake as close as possible to the LSL without going below this level in any of the simulated years. Gate operation rules were developed based on the water level in the lake to meet that objectives. The following gate openings are retained (in % opening):

Lake Elevation > than	% Open
913.85 m	*55 %*
913.60 m	*60 %*
912.10 m	70 %
911.45 m	80 %
911.35 m	25 %

3) The gate opening is set at a 10 % (18 cm) when the reservoir fills in the summer and fall. This opening maintains a minimum flow in Pine Creek of a least 10% of the mean annual discharge (MAD) of 3.7 m³/s at the outlet of Surprise Lake. Inflows from the intermediate catchment areas below Surprise Lake and above the intake structures contribute additional flow to Pine Creek.

4) Floods are managed as close as possible to the full pond level by opening the low level outlet gate when the water level is above 913.75 m in Surprise Lake (10 cm below the full

pond level). Most floods can be managed without exceeding the full pond level by more than 10 cm.

Surprise lake water levels were simulated for the 2.5 m operational range as a result of the regulated flow releases for 30 years of synthetic flow records (1963 to 1993). Figure 4-6 and Table 4-7 presents the average yearly Surprises Lake water levels, inflows and outflows over the duration of the flow series. Maximum storage occurs in late October. The lake is drawn down to within 10 cm of the low pond level typically in early May, prior to lake infilling. Surprise Lake water levels for the entire simulation period are illustrated in Figure 4-7.

Surprise Lake reaches the full pond level in 23 of the 31 years of simulation. In the years when lake levels do not reach the full pond level, they are at least within 0.2 m with the exception of 1978 (the driest year). Management of Surprise Lake causes water levels to be drawn down in the spring to a level close to the low pond level and varies between 911.35 m and 911.5 m, depending on the timing of the start of reservoir infilling during the freshet. Water spills above the crest of overflow weir during the late summer and early fall in approximately one-half of the simulated years. This is a result of Surprise Lake reaching the proposed full supply elevation of 913.85 m.

Figure 4-6: Average yearly Surprise Lake operations for the proposed 2.5 m operational range.

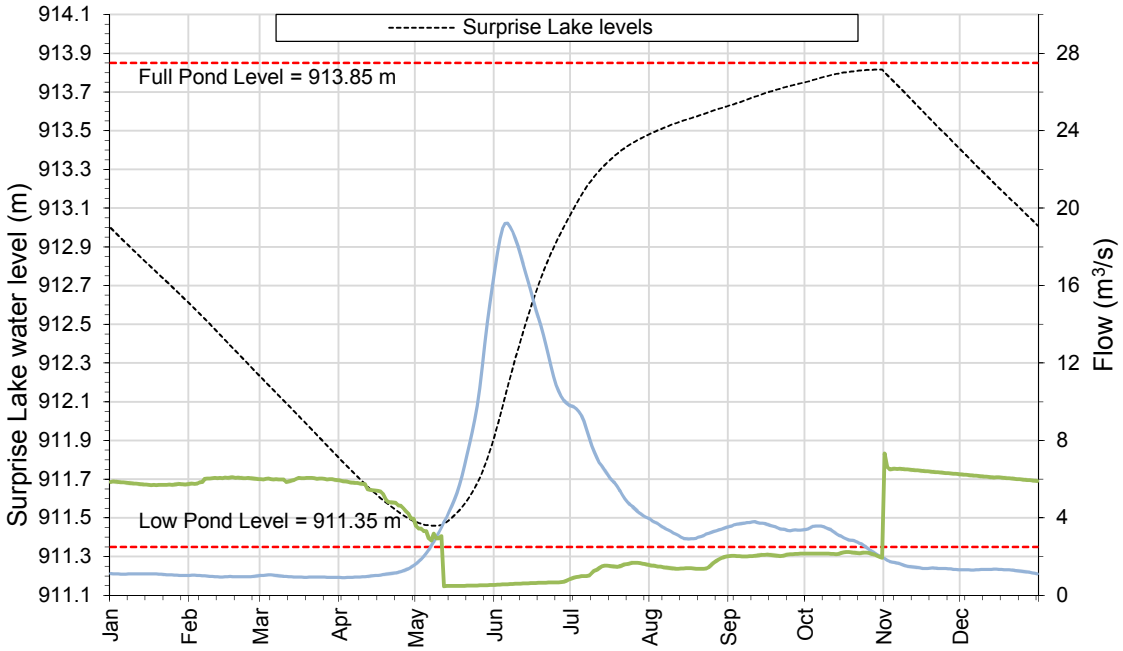
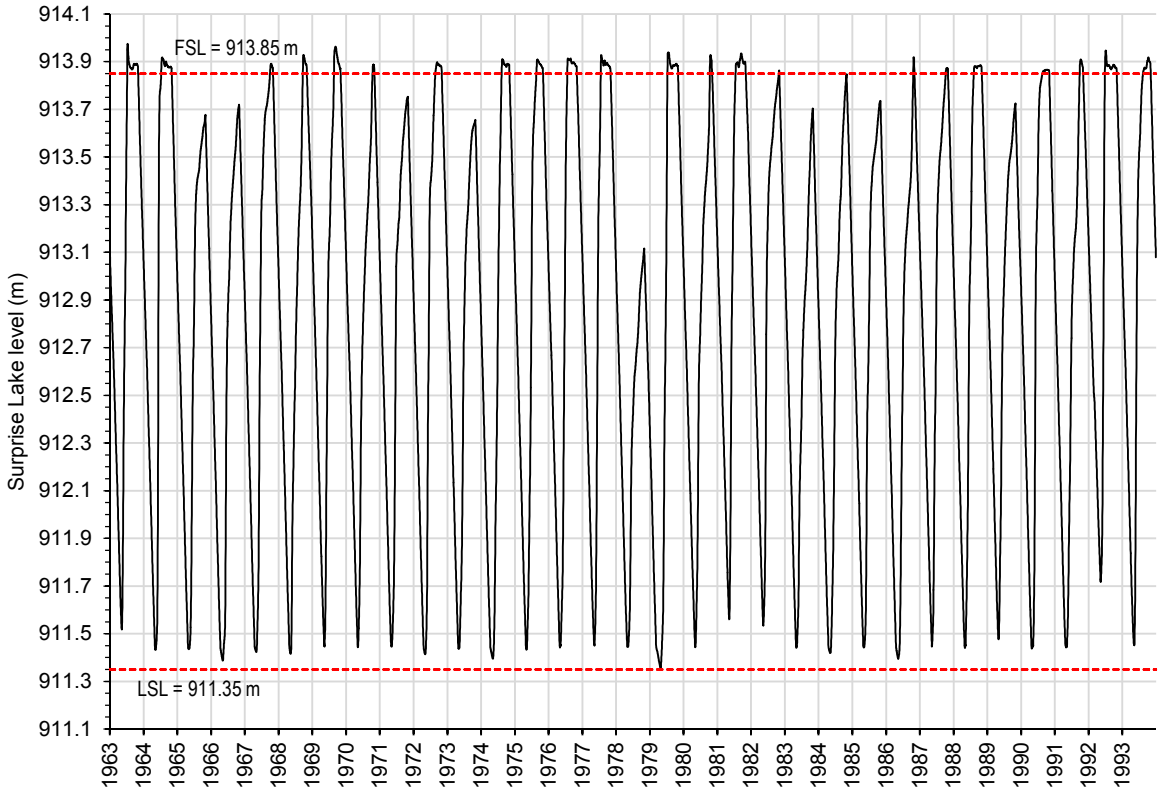


Table 4-7: Mean monthly Surprise Lake water levels, inflows and outflows during the simulated period

Month	Surprise Lake Level (m)	Inflows (m³/s)	Outflows (m³/s)
January	912.8	1.1	5.8
February	912.4	1.0	6.0
March	912.0	1.0	6.0
April	911.6	1.1	5.2
May	911.6	6.4	1.4
June	912.6	14.9	0.6
July	913.3	6.4	1.4
August	913.6	3.3	1.5

September	913.7	3.6	2.1
October	913.8	2.9	2.2
November	913.6	1.5	6.4
December	913.2	1.3	6.1

Figure 4-7: Simulated Surprise lake water levels under proposed 2.5 m operational range.



4.3 Power Generation

A power generation model was created to estimate the power and energy potential of the Atlin Hydro Expansion Project. The results that are presented in this section are for the total installed capacity on Pine Creek, including the existing 2.1 MW power plant.

Upper power plant

The existing 2.1 MW power plant is located approximately 10 km downstream of Surprise Lake on Pine Creek. The upper power plant has a gross head of 107.6 m and bypasses a reach of Pine Creek with a steep gradient containing several waterfalls. The proposed development is to construct an additional power plant adjacent to the existing 2.1 MW plant. A new penstock will convey water from the existing upper head pond to the new power plant adjacent to the existing plant and will operate under the same head. A new intake structure will be constructed in the existing upper head pond.

The power simulations for the upper plant include the operation of the existing and proposed power generation facilities. The power simulation of the upper power plant is a function of the synthetic

flow series and management of the reservoir (Surprise Lake), with an additional contribution from the intermediate catchment between the outlet of Surprise Lake and the Upper Power Plant intake. The average yearly inflow to the upper intake is estimated at 4.4 m^3/s. A flow duration curve is also presented in Figure 4-8.

The existing plant is currently operated with a 1.22 m (48 inches) diameter high-density polyethylene (HDPE) diameter penstock that conveys water to the 2.1 MW power plant that operates under a turbine flow of 2.45 m^3/s. Based on the flow duration, a total turbine flow of 6 m^3/s is selected for the upper plant (existing and new plant combined) which corresponds to a flow with approximately 30% exceedance. The new upper plant will then have a turbine flow of 3.55 m^3/s which leads to an installed capacity of 2.9 MW. A new 1.52 m (60 inch) diameter HDPE penstock will convey water from the upper head pond to the new upper plant. Head losses were estimated for both friction along the penstock and at various singularities along the system. A Manning's coefficient of 0.010 was selected for the HDPE penstock.

A conservative constant 85% turbine efficiency was used for the power simulations. Higher turbine efficiency can however be achieved under optimal operating flows especially for Francis and Pelton turbines. The proposed Turgo turbines for the upper power plant expansion will however have a slightly lower efficiency. Detail turbine efficiency curves will be obtained from suppliers in the feasibility study and power simulations will be conducted with varying efficiency based on the operating flows to firm up the power estimates.

Power production simulation parameters and assumptions for the upper power plant are summarized in Table 4-8.

Lower power plant

The lower power plant will have a new intake constructed approximately 200 m downstream of the upper power plant tailrace. It will capture the inflows coming from Spruce Creek through a small diversion of the creek into the new lower head pond. A new penstock will convey water approximately 4 km to the lower power plant located adjacent to Pine Creek approximately 200 m upstream of its mouth on Atlin Lake.

Power simulations for the lower power plant utilized the regulated flows from the upper power plant (turbine flow and residual spill), and the unregulated flows from the intermediate catchment between the upper head pond and Spruce Creek, and from Spruce Creek itself. The average yearly flow at the lower intake is estimated at 5.4 m^3/s. A flow duration curve for flows at the lower power plant intake is presented in Figure 4-8.

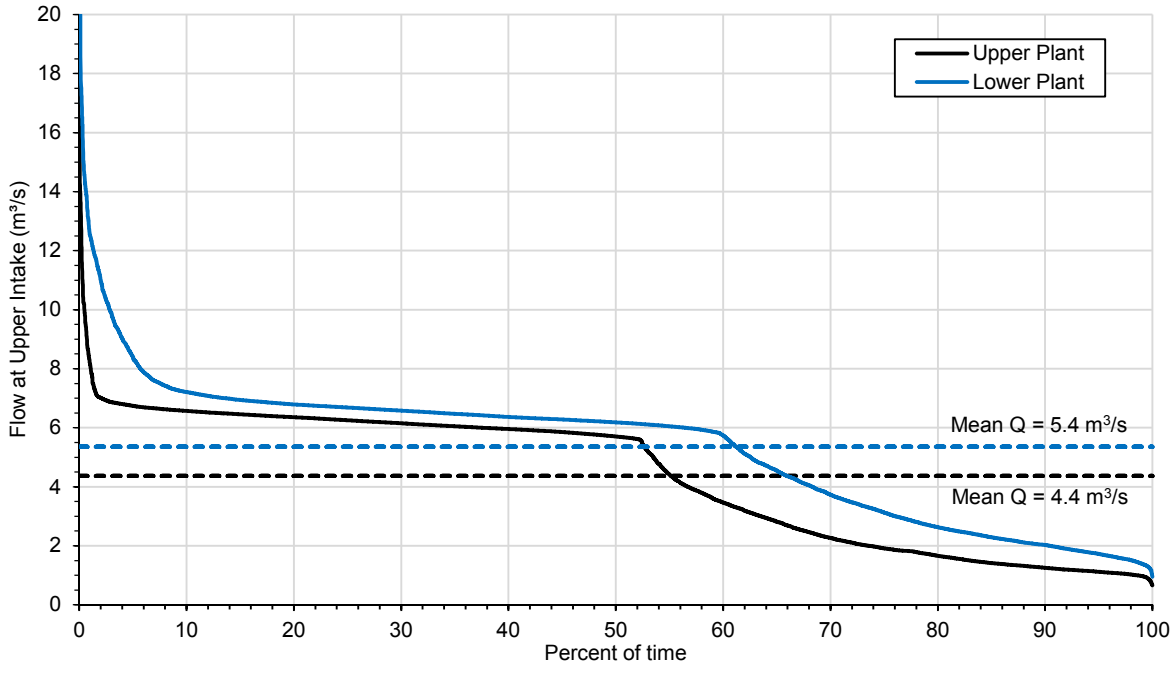
Based on the flow duration curve a turbine flow of 7 m^3/s is selected, which corresponds to a flow with approximately 20% exceedance. The new lower power plant will operate under a gross head of 55.5 m, which leads to an installed capacity of 2.8 MW. Two 1.52 m (60 inches) diameter HDPE penstock will convey water from the new lower head pond to the lower power plant. Head losses were estimated for both friction along the penstock and at various singularities along the system. A Manning's coefficient of 0.010 was selected for the HDPE penstock.

Power production simulation parameters and assumptions for the lower power plant are summarized in Table 4-8.

Table 4-8: Design Parameters and Assumptions for the Upper and Lower Power Plant.

Element	Upper Plant	Lower Plant
Gross Head	107.6 m	55.5 m
Penstock Size	1.5 m diameter (HDPE)	2 x 1.5 m diameter (HDPE)
Maximum Flow Velocity	2 m/s	2 m/s
Head Losses	Friction: 4.3 m Singularities: 3.0 m Total: 7.3 m	Friction: 4.2 m Singularities: 3.0 m Total: 7.2 m
Average yearly flow	4.4 m^3/s	5.4 m^3/s
Environmental Flow (10% MAF)	0.44 m^3/s	0.54 m^3/s
Turbine Flow	Existing Plant: 2.45 m^3/s New: 3.55 m^3/s Total: 6 m^3/s	New: 2 x 3.5 m^3/s Total: 7 m^3/s
Installed Capacity	Existing: 2.1 MW New: 2.9 MW Total: 5.0 MW	New: 2 x 1.4 MW Total: 2.8 MW
Turbine Efficiency	85%	85%

Figure 4-8: Flow duration curve for Upper and Lower Power Plant.



4.4 Simulation results

Power and energy generations were estimated on a daily basis at each power plant. A minimum flow of 10% of the mean annual flow at each plant is discharged from the head pond year-round. Monthly results were compiled for presentation in the report.

Figure 4-9 and Table 4-9 presents monthly power and energy generation for each plant. Figure 4-10 presents the total yearly generation over the duration of the 31-year synthetic flow series. This flow series does provide indication of the variability of power generation relative to the average power production. A low-flow assessment is also provided in Section 4.5 which gives indication of the firm power production. A more comprehensive percentile assessment of generation will be completed as part of the feasibility study and will be supported by flow data collected on Pine Creek since 2014.

Upper power plant

The mean annual power for the upper power plant is estimated 3.2 MW for an average capacity factor of 63%. The mean monthly capacity factor varies between close to 100% in November and December to as low as 30% in August. This corresponds with the timing and magnitude of controlled releases and infilling of the Surprise Lake reservoir.

Using the simulated flow series for Pine Creek (1963 to 1993), the total mean annual energy generation for the upper power plant is 28.2 GWh and varies between 23.7 GWh and 34.9 GWh over the simulated period.

Lower power plant.

The mean annual power for the lower power plant is 1.9 MW for an average capacity factor of 66%. The average monthly capacity factor varies on average between as high as 90% in November and December, and as low as 35% in August. The capacity factor of the lower plant is generally between 80% and 90% during the winter months.

The mean annual energy generation for the lower power plant is based on the synthetic flow records (1963 to 1993). Simulated mean annual energy generation for the Lower Power Plant is 16.3 GWh and varies between 13.6 and 20.3 GWh over the simulation period. Figure 4-10 presents the yearly total energy generation at the lower plant over the duration of the flow series. The spike in generation that is observed in June is a result of the freshet of the various intermediate sub-catchments below Surprise Lake (between power plants and Spruce Creek).

Figure 4-9: Upper and Lower Power Plant mean monthly power production (MW).

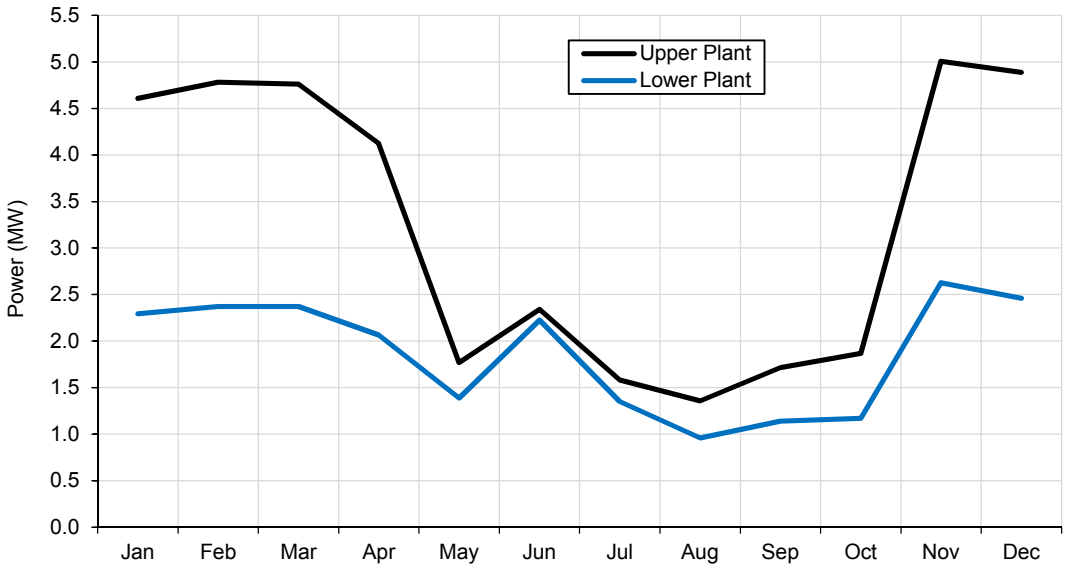
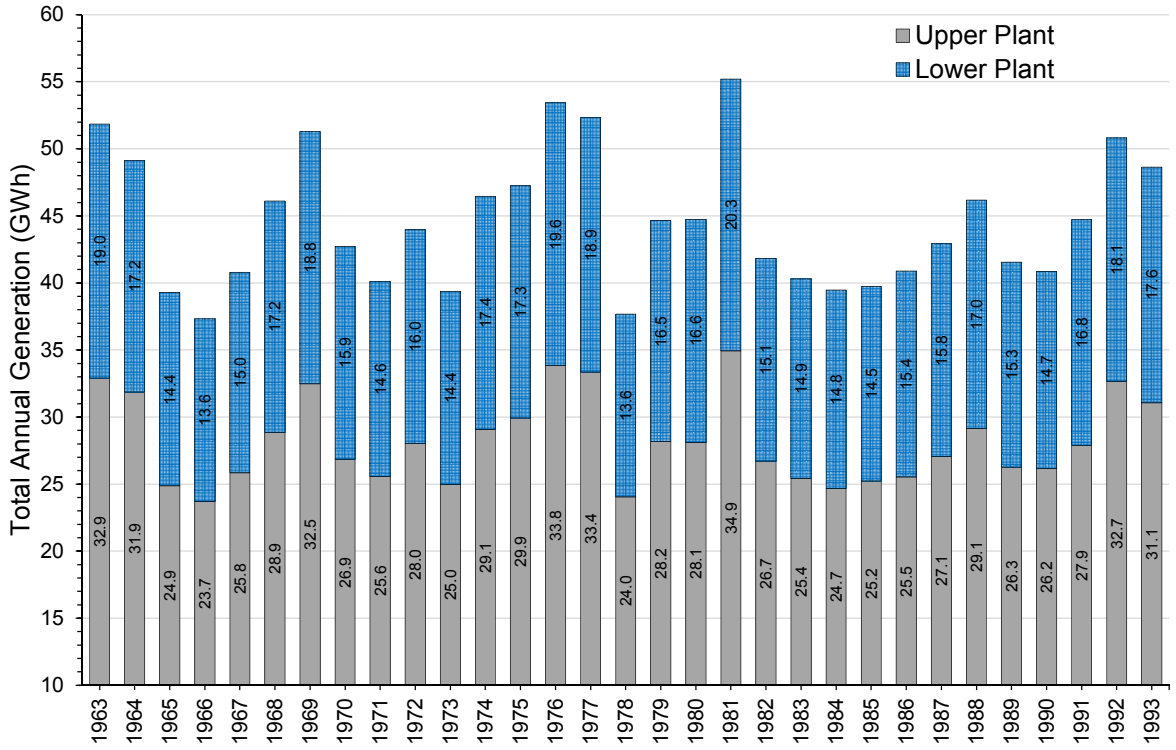


Table 4-9: Average monthly power and energy generation for the Upper and Lower plants (2.5 m storage)

Month	Upper Plant		Lower Plant		Total	
	MW	GWh	MW	GWh	MW	GWh
January	4.6	3.4	2.3	1.7	6.9	5.1
February	4.8	3.2	2.4	1.6	7.2	4.9
March	4.8	3.5	2.4	1.8	7.1	5.3
April	4.1	3.0	2.1	1.5	6.2	4.5
May	1.8	1.3	1.4	1.0	3.2	2.4
June	2.3	1.7	2.2	1.6	4.6	3.3
July	1.6	1.2	1.3	1.0	2.9	2.2
August	1.4	1.0	1.0	0.7	2.3	1.7
September	1.7	1.2	1.1	0.8	2.9	2.0
October	1.9	1.4	1.2	0.9	3.0	2.3
November	5.0	3.6	2.6	1.9	7.6	5.5
December	4.9	3.6	2.5	1.8	7.3	5.5
Annual Average	**3.2**	**28.2**	**1.9**	**16.3**	**5.1**	**44.6**

Figure 4-10: Total simulated annual power generation (GWh) from the Upper and Lower Power Plants.



Comparison with the 2 m storage option

The power and energy generation potential of the Atlin Hydro Expansion Project was estimated for a 2 m storage range in Surprise Lake as a potential alternative to the 2.5 m storage base case presented in this study. A 2 m storage range could either be implemented by raising the new proposed low pond level (thus reducing the required river excavation to accommodate the lower level) or by lowering the proposed new full pond level (thus reducing the increase in the overflow weir height and the increase in the maximum lake level). Average monthly energy generation for the 2 m storage range for both the upper and lower power plants is presented in Table 4-10. The difference in energy generation between the 2.5 m storage option is presented for comparison purposes.

Table 4-10: Average monthly power and energy generation for the Upper and Lower plants (2 m storage)

Month	Upper Plant			Lower Plant			Total		
	Power (MW)	Energy (GWh)	Diff. (GWh)	Power (MW)	Energy (GWh)	Diff. (GWh)	Power (MW)	Energy (GWh)	Diff. (GWh)
January	4.6	3.4	0	2.3	1.7	0	7.0	5.1	0
February	3.8	2.8	-0.4	1.8	1.2	-0.4	5.6	4.0	-0.8
March	3.4	2.5	-1.0	1.6	1.2	-0.5	5.0	3.8	-1.5
April	1.9	1.4	-1.6	1.0	0.7	-0.8	2.9	2.1	-2.4
May	1.6	1.2	-0.1	1.3	0.9	-0.1	2.9	2.1	-0.2
June	2.7	1.9	+0.2	2.2	1.6	0	4.9	3.5	+0.2
July	2.5	1.9	+0.7	1.7	1.2	+0.2	4.1	3.1	+0.9
August	2.0	1.5	+0.4	1.2	0.9	+0.2	3.2	2.4	+0.6
September	2.4	1.7	+0.5	1.4	1.0	+0.2	3.8	2.7	+0.7
October	2.5	1.8	+0.5	1.4	1.0	+0.2	3.9	2.9	+0.7
November	5.0	3.6	0	2.5	1.9	0	7.4	5.5	0
December	4.9	3.6	0	2.5	1.8	0	7.5	5.4	0
Average	**3.1**	**27.3**	**-0.9**	**1.7**	**15.3**	**-1.0**	**4.9**	**42.6**	**-1.9**

The 2 m storage range option in Surprise Lake produces on average 1.9 GWh less energy per year, which only represents a 4.5% drop in generation potential. The main effect of implementing a 2 m storage range compared to a 2.5 m storage range a reduction in the winter energy generation (when most needed by Yukon) and an increase summer generation. The reduction in winter energy is estimated at 4.7 GWh on average, being observed mostly from February to April based on the operation scheme that was defined for the purpose of the simulations.

Further optimization work should be done in the next project phase to determine the benefits of the additional winter energy associated with the 2.5 m operational range compared to the regulatory challenges that may result from a larger storage range on Surprise Lake.

4.5 Power Production Summary

The proposed Atlin Hydro Expansion Project power simulations are a function of synthetic flows developed for Pine Creek that are based on historical hydrometric records scaled from the Gladys River between 1963 and 1993. The simulation maximizes the storage available in Surprise Lake, optimizes generation potential at existing facilities and incorporates additional flows from Spruce Creek and intermediate catchments below the existing intake structures. Two additional power plants were incorporated into a power production simulation of the hydroelectric expansion. This resulted in a total 7.8 MW installed capacity on Pine Creek.

The storage range of 2.5 m in Surprise Lake is considered the most optimal range at this preliminary stage to maximize winter energy generation on Pine Creek. Such a range allows maximum storage of the inflows to the lake during an average hydrological year. The simulations were intended to

maximize winter energy generation for the purpose of distributing to Yukon Energy during periods of greater energy demand. Consequently, this operation mode reduces generation in the summer months during the reservoir infilling period. Minimum energy delivery obligation for the community of Atlin (forecast 2032 load) are still met every month of the year over the duration of the synthetic flow series.

Figure 4-11 illustrates the average total monthly generation for the project while Figure 4-12 illustrates the minimum total monthly generation from both power plants combined over the duration of the flow series. It is important to note that careful adjustment of flows from Surprise Lake can be performed to meet, at a minimum, the future energy delivery obligation. Maximum energy generation is achieved in winter months (November through March) and minimum generation occurs in summer months (May through October) during reservoir infilling.

Total average yearly energy generation for the upper and lower power plants combined amounts to approximately 44.6 GWh with an average capacity factor close to 65%. This power simulation represents represent the upper range of generation from Pine Creek.

Figure 4-11: Simulated average monthly generation for the Upper and Lower Power Plant.

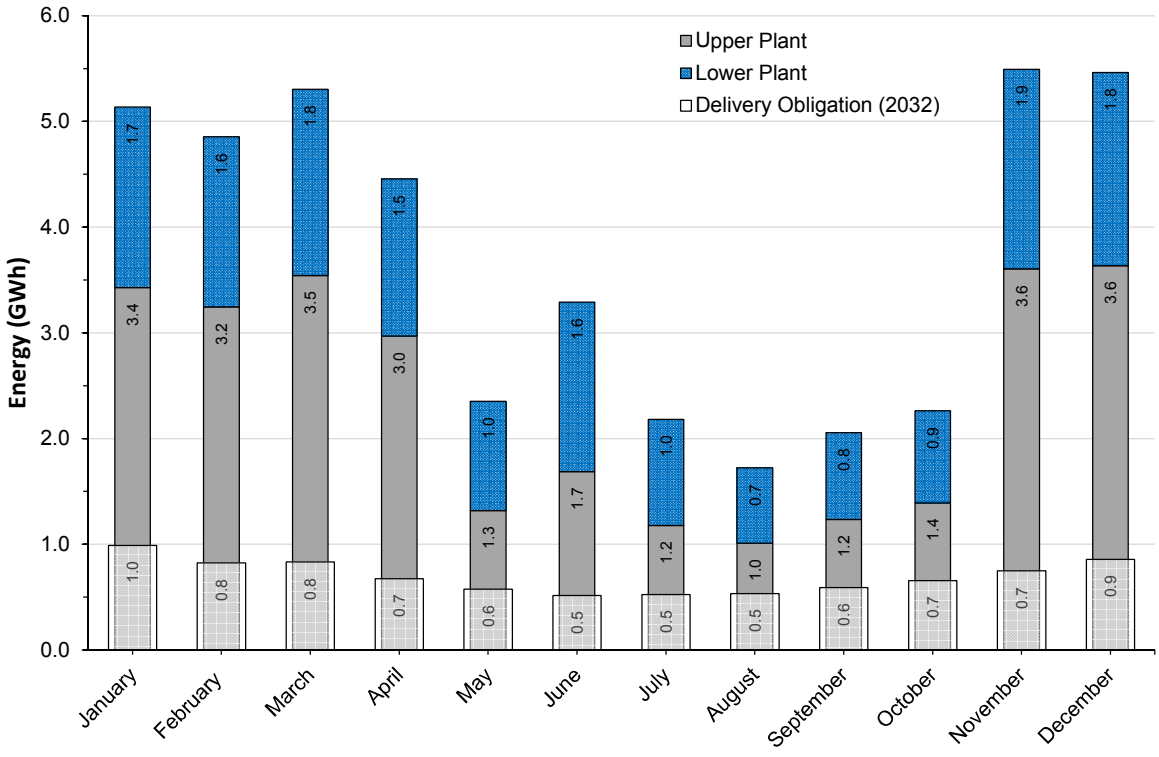
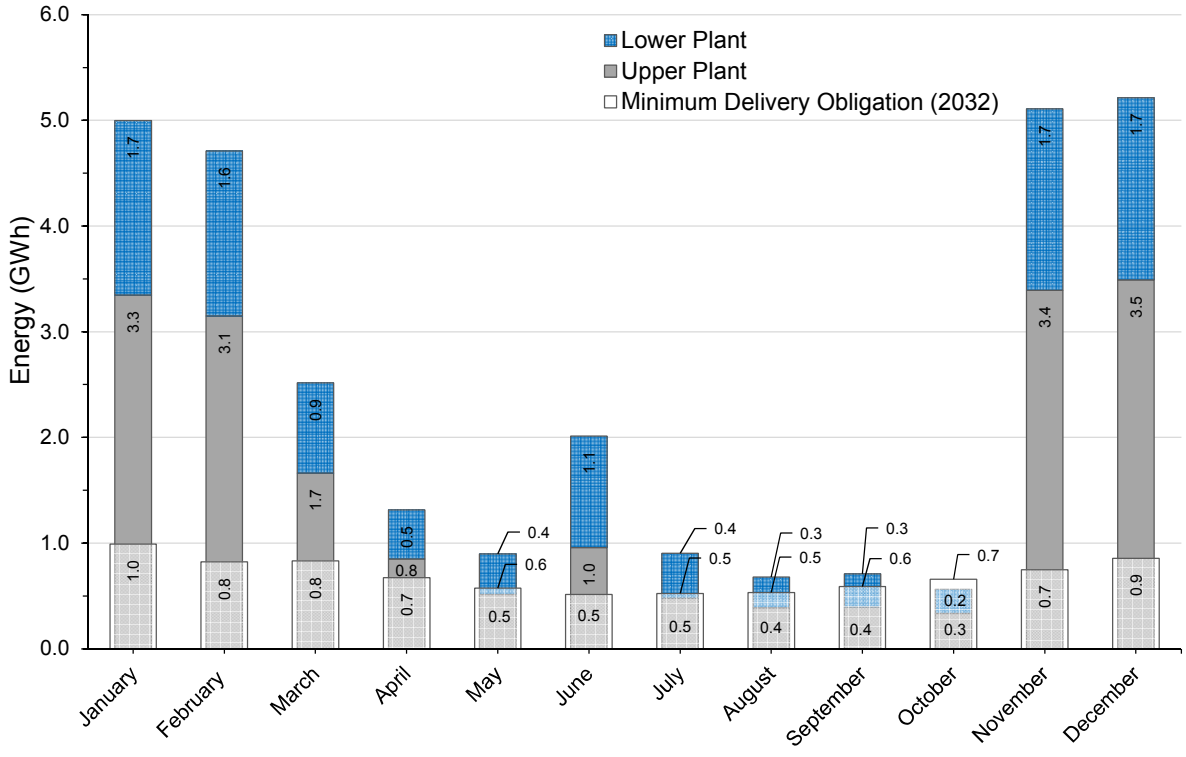


Figure 4-12: Simulated minimum monthly generation for the Upper and Lower Power Plant.



5 PRELIMINARY DESIGN

5.1 Design Criteria and Assumptions

The 1:100 years flood is selected as the design flood for the project at this stage. This corresponds to the inflow design flood recommended by the Canadian Dam Association for dams with a Low level of consequence in case of dam failure (no potential loss of life). Due to the small impoundment volume of both head ponds, it is expected that the effects of a potential dam break would be minimal and would dissipate rapidly as the flood wave migrates down river. This assumption will need to be confirmed in the feasibility study.

A preliminary flood study was conducted and is presented in detail in Section 4. The design flood flows retained for the hydraulic design of the spillway at each works are presented in Table 5-1.

Table 5-1: Design flood flows

Location	Design flow (m^3/s)
Surprise Lake control structure	16
Upper head pond	26
Lower head pond	39

It should be noted that the design flow at the Surprise Lake control structure represents the maximum outflow that can be expected at the lake outlet, considering the routing of inflows through the lake. Design flows for the upper and lower head pond are also based on the maximum outflows from Surprise Lake, with additional unregulated inflows coming from the various intermediate sub-catchments below Surprise Lake. If a smaller storage range at Surprise Lake was to be selected for the project, design flows would likely be increased due to increased spill at the Surprise Lake control structure resulting from the smaller storage volume being held in the lake.

Each of the three locations above will be designed to safely pass the inflow design flood.

Additional design criteria are selected for the water retaining structures.

- Minimum freeboard (embankment dam): 0.5 m (no wave action)
- Minimum freeboard (embankment dam): 1.0 m (potential wave action – Surprise Lake)
- Minimum freeboard (concrete dam): 0.5 m
- Minimum side slope (rock fill): 2H:1V

The Isbash equation was used to determine the appropriate size of rip rap/cobbles that is required to resist flow velocities, at different locations for the project (overflow weir at Surprise Lake control structure and lower head pond, stilling basin at lower head pond, Spruce Creek diversion ditch, etc.). Large quantities of cobbles are readily available near Pine Creek due to extensive placer mining that has taken place in the area. Cobbles can be used in location where fairly flat erosion protection is required. In sloped areas, riprap will need to be produced in order to stay in place. Cobbles would be at risk of rolling compared to angular rock.

The Isbash equation is widely used in engineering applications and relates the mean diameter of rip rap (D_{50} in mm) required to resist a given flow velocity:

$$D_{50} = \frac{V^2}{2g\,C^2\left(\frac{\gamma_r - \gamma_e}{\gamma_e}\right)\cos\alpha}$$

Where,

V is the flow velocity in m/s;
g is the gravitational constant of 9.81 m²/s;
C is the Isbash coefficient for turbulence (0.86 for low turbulence, up to 1.2 for high turbulence where hydraulic jumps form);
γ_r is the specific weight of rock, approximately equal to 2.65 x 9,810 N/m³;
γ_e is the specific weight of water, approximately equal to 1 x 9,810 N/m³;
α is the angle of repose of rip rap (based on side slope of channel).

Figure 5-1 presents curves for different turbulence coefficients for given velocities. A side slope of 2H:1V was used to determine the angle α, which is the slope proposed for the rip rap.

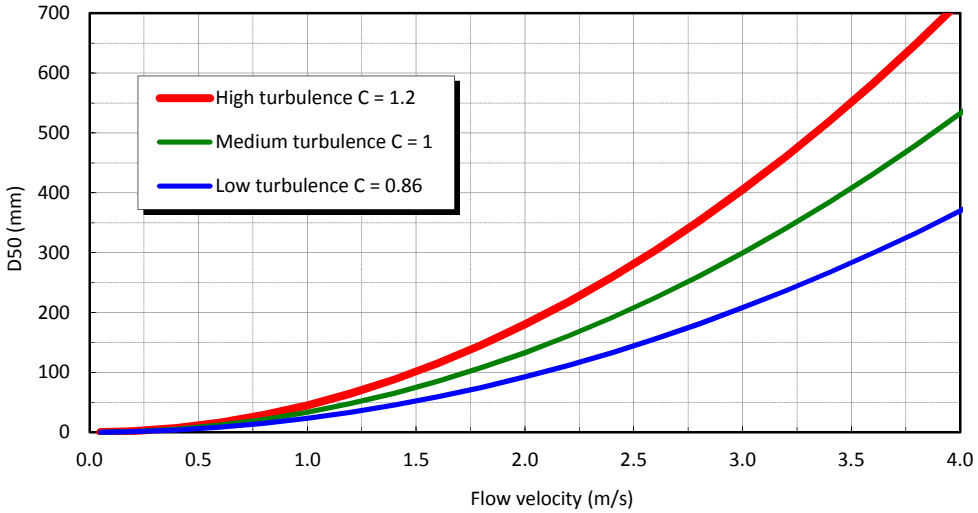


Figure 5-1: Required Rip Rap D_{50} to Resist a Given Flow Velocity

5.2 Surprise Lake Control Structure

The Surprise Lake control structure currently allows the management of water levels in the lake and to control outflows, especially during the winter period. Water is being stored during the summer and fall, and then being released during the winter months for power generation at the existing Upper Plant. The lake is currently managed between the following water levels:

- Existing full pond level: 913.15 m
- Existing low pond level: 912.10 m

1.05 m of storage is currently licensed in Surprise Lake, which is expected to be sufficient to meet the Atlin's electrical load for the next 20 years or more. The hydro project also currently includes a lake storage permits that allows flooding up to 913.85 m on Surprise Lake, which is not currently being fully utilized.

It should be noted that Surprise Lake uses a local datum derived from elevation on top of the concrete wall at the low level outlet intake (elevation of 913.75 m shown on Sigma Engineering as-built drawings). It is believed that this local datum was derived from old benchmarks left by Monty Alfred when doing water surveys more than a decade ago. For consistency between the existing works and operating water levels, it is decided to maintain the local datum at this stage. All licensed water levels refer to this local datum.

It was previously identified in Section 4 that a storage range of 2.5 m would provide an optimal storage range to maximize winter energy generation and store the vast majority of the yearly inflows. Based on a preliminary qualitative assessment of environmental constraints, it was decided to set the new pond level at the 913.85 m value that is current licensed and to develop additional top and bottom storage. The Lake Storage Permit will not require modification; only the Water License will need to be modified or appended to account for the larger storage volume that is being utilized.

The existing Surprise Lake control structure is composed of the following works:

- A ***rock fill overflow weir*** with a crest elevation of 913.15 m. A sheet pile cut-off wall and membrane provide seepage control for the structure. The weir is closed on each side with a higher secondary crest at elevation 914.15 m (1 m higher) than the main overflow section. Large riprap (D_{50} > 500 mm) is protecting the bridge abutments immediately downstream from the overflow weir;

Photo 7: Existing weir at Surprise Lake

- A ***low level outlet*** of 1.8 m diameter pipe on the left embankment, in the small head pond. It is closed with an Armtec vertical sliding gate (operated manually with a gearbox) mounted on a vertical concrete headwall of 0.5 m thickness and approximately 4 m in height. The headwall is founded on a concrete footing of 0.3 m thickness. The current invert elevation of the pipe is at elevation 909.80 m.

Photo 8: Existing outlet structure at Surprise Lake

- A ***fishway*** located on the left embankment, in the small head pond. The fishway is composed of a 1 m diameter culvert that travels under the road embankment. Downstream is a concrete fish passage structure with a total of six basins. Each basin is separated by a baffle that allows the fish to swim through each drop, which are estimated to have an approximate height of 20 to 30 cm. The culvert is permanently open but the fish passage concrete structure can be dewatered by closing the opening in the baffles and/or the downstream gate (operated with a hand wheel). The current invert elevation of the culvert is at elevation 911.10 m.

Photo 9: Existing fishway downstream of Surprise Lake control structure

The change in the full and low pond levels (increase in storage range in Surprise Lake) will require some modifications on the existing structures to effectively retain the water in the lake and discharge water downstream of the structure. The overflow weir will need to be raised, while the low-level outlet may require modification to be operational at higher and lower water levels. The fishway in its current state will remain operational for part of the year, when water levels in the lake vary between the existing storage limits. Additional studies will need to be done to determine the effectiveness of the fishway for higher and lower water levels and if it needs to be operational at all during that period. If required the fishway could be modified to accommodate the new operating water levels. Details about the proposed changes on each the structures are presented below and on Drawing 04 in Appendix A.

Overflow rockfill weir

It is proposed to raise the crest elevation of the rock fill weir from 913.15 m to 913.85 m (0.7 m increase). Additional class 1 riprap (D_{50} of 300 mm) will be placed on the downstream face of the weir while additional cobbles (D_{50} of 200 mm) will be placed on the upstream face of the weir, matching the materials of the existing structure. Class 1 riprap can resist flow velocities up to 3.5 m/s based on Isbash equation, which will be adequate under the inflow design flood scenario. The crest width of the overflow section will remain at 32 m and the longitudinal slopes will also remain the same as for the existing structure (4H:1V) downstream slope and 2.5H:1V upstream slope). To reduce seepage through the raised portion of the weir, it is proposed to extend the sheet-pile cut-off up to the new crest-elevation, by bolting on new sheet-pile onto the existing one. Additional membrane is not deemed necessary at this time. It was installed to prevent against internal erosion (piping) of the structure, and the small increase in the full pond level is not likely to modify significantly seepage flow under the structure.

Modifications to the overflow weir will take place in the dry as much as possible, with the flow being diverted through the low level outlet. Surprise Lake should be near its current low pond level at the time of construction.

Low level outlet

At this stage, it is assumed that the low level outlet will remain operational in its current configuration, with only a few minor modifications. The access catwalk will however need to be raised to accommodate the higher full pond level. The current gearbox will remain in place but will sit lower relative to the water level compared to current conditions but will still remain above the full pond level thus remaining operational.

A cursory verification of the existing vertical slide gate (Armtec) specifications was made. It was determined that the gate can adequately resist the increased pressure head (by up to 70 cm), and can operate adequately also under higher water levels.

The maximum hydraulic capacity of the low level outlet was estimated using the sluice gate equation to confirm that it can discharge the flows required for the project (on average 6 m^3/s during the winter season – see Section 4) for the range of operating water levels. Verification was made first to confirm that friction through the pipe was not controlling the discharge capacity of the low-level outlets. It is assumed that there is no downstream submergence effect at this stage. It will

likely require downstream excavation in Pine Creek to lower the downstream water level and ensure an adequate hydraulic capacity near the low pond level. The equation is as follow:

$$Q = C_d A\sqrt{2gH}$$

Where,

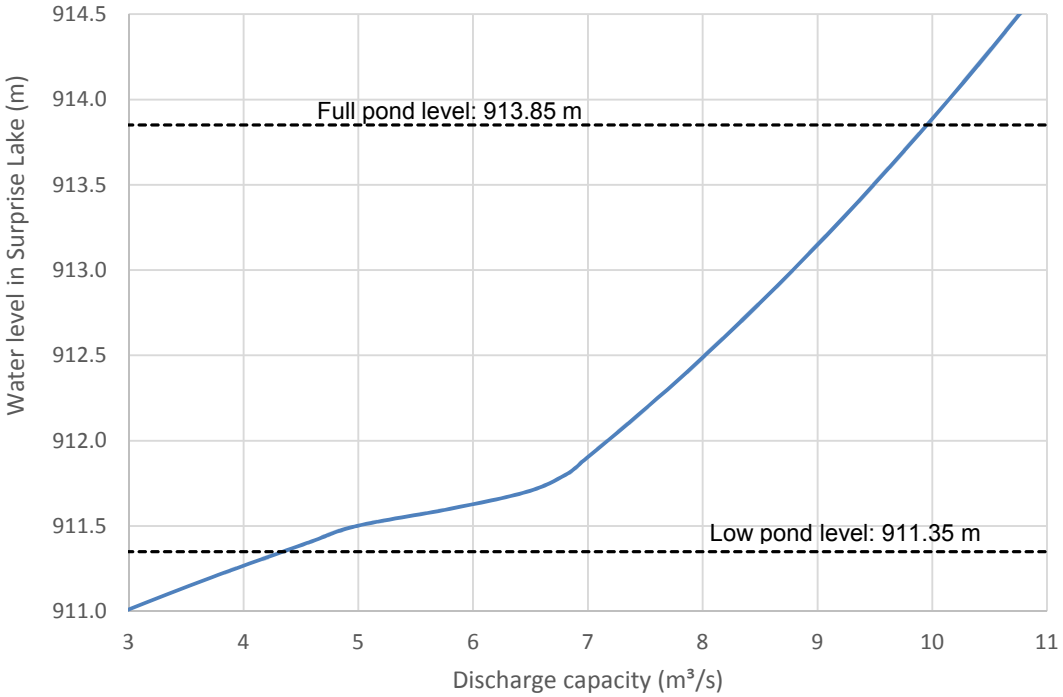
C_d is the discharge coefficient, taken as 0.5;
A is the cross-sectional area of the hydraulic passage;
g is the gravitational constant of 9.81 m²/s;
H is the head above the invert elevation of the low level outlets (equal to the water surface elevation minus the invert elevation).

Figure 5-2 presents the discharge capacity curve of the low level outlet at full-opening. It should be noted that when water levels dip below 911.6 m (top of culvert), the conduit becomes partially submerged and behaves as open channel flow.

At the full pond level of 913.85 m, the low level outlet has a discharge capacity of approximately 10 m³/s. Such a discharge capacity will allow for the effective management of floods near the full pond level with minimal increase in water level above the full pond level. With a design flow of 16 m³/s (1:100 years flood), it means that only 6 m³/s would pass over the rock fill weir assuming that the gate of the low-level outlet is fully open. This would translate to a maximum water level of approximately 914.1 m.

Near the low pond level of 911.35 m, approximately 4.5 m³/s could be discharged from the low level outlet assuming no submergence effects. This will require river excavations downstream from the structure. In this case, the low level outlet would be partially submerged and open channel flow equations do apply.

Figure 5-2: Discharge capacity of low level outlet at full opening



Fishway

It is expected that the fishway culvert will be partially dewatered from mid-March to early-June due the proposed new low pond levels (911.35 m, or 0.75 m lower than in current conditions). There will however always be water conveying through the fishway (minimum depth at entrance of 0.25 cm). The fishway would also experience higher discharge and flow velocities when the lake level is above the current full pond level of 913.15 m due to the increased head. Surprise Lake water levels are expected to be higher than this value from early July to early December on average, when the lake is filled to the new full pond level of 913.85 m

At this stage it is assumed that the fishway will remain operational with only a few minor changes to the existing geometry. Modifications of the cross-sectional area of the openings between the basins and/or of the height of the sills are proposed at this stage to improve the efficiency of the fishway. Additional studies will need to be completed to determine if further changes are warranted based on the operation water levels.

Channel excavation

In order to accommodate the new low pond level of 911.35 m, channel excavations will be required both upstream and downstream of the Surprise Lake outlet structure.

In the current configuration, it was reported by ATELP that there is a head difference between the water level in Surprise Lake and immediately upstream of the control structure, when the lake is near its current low pond level of 912.10 m. That head difference is believed to vary between 10 and 20 cm, suggesting that there is a hydraulic control upstream of the structure. This control occurs in

the shallow section that is easily seen from shore approximately 60 m upstream of the structure. Remnants and old wooden structure are also seen in the water at this location, contributing to the reduction in the conveyance capacity at this location at low water. The picture below shows this shallow section.

Photo 10: Remains of old wooden control structure at Surprise Lake outlet

An exploratory bathymetric survey was conducted by ATELP in the spring of 2015 to determine the elevation of the river bed at that location. Results showed that at numerous locations the water depth is on average only 0.8 to 1.0 m in the shallow sections (when the lake was approximately at elevation 912.80 m) thus suggesting that the river bed elevation is approximately 912.0-911.8 m. In order to adequately convey the flows in future conditions down to the low pond level of 911.35 m, it is recommended to excavate the lake outlet to elevation 910.35 m to provide a minimum of 1 m water depth. Excavation could take place mostly from shore. If a longer reach is required, either in-water excavation or access with a temporary rock fill berm is possible.

The following approximate ***upstream excavation*** dimensions are selected based on the available information:

- Length: 180 m
- Width: 10 m (assuming limited reach from the excavation equipment)
- Average depth: 2.0 m (1.5 m depth and 0.5 m additional excavation for erosion protection)

The riverbed is believed to be silty at this location such that protection against erosion will be warranted. Maximum flow velocities up to 1.5 m/s can be expected at that location under critical low water conditions. Cobbles with a minimum D_{50} of 100 mm will be adequate at this location. Such cobbles should be readily available in close proximity to the site.

It has also been identified that current water levels downstream of the structure will be too high in future conditions to accommodate the new low pond level. The current tailwater levels are believed to vary between 911.5 m and 912.0 m on average. It is expected water levels below 911.0 m are require to adequately discharge water from the lake when near the low pond level of 911.35 m. River excavations will be required downstream from the structure to lower the tailwater levels by up to 1 m. The picture below shows Pine Creek downstream of the outlet structure, with some riffles in the far end (approximately 100 m downstream of the structure).

Photo 11: Pine Creek looking downstream from Surprise Lake control structure

At this stage, the following preliminary ***downstream excavation*** dimensions are assumed for costing purposes.

- Length: 150 m
- Width: 10 m (assuming access from one shore or over-ice)
- Average depth: 1 m

As for the upstream excavation, erosion protection will be required for the downstream excavation if the river substrate following the excavations is too small. Maximum flow velocities between 2 and 2.5 m/s can be expected at this location, such that cobbles with a minimum D_{50} of 200 mm is required.

A bathymetric survey of Pine Creek below the structure will be required to further assess the downstream water levels at the control structure. Hydraulic modelling should be conducted to determine the extent of excavation that is required to adequately convey water out of the lake at the new low pond level. Environmental effects of river excavations on Pine Creek will also need to be assessed.

5.3 Upper Power Plant Expansion

The upper power plant expansion will be adjacent to the existing power plant. It will make use of the existing infrastructure, more specifically the headpond and clearing for the existing penstock and powerhouse. Details about the new infrastructures required for the expansion are described below.

5.3.1 Intake

A second concrete intake box is selected for the intake structure, located west of the current intake structure. The intake will utilize the existing head pond. The existing intake structure was assessed for suitability to supply both penstocks (existing and proposed new penstock) but was determined to have insufficient capacity. The proposed new intake structure will be identical to the current structure due to good reported operator experience with the existing structure. Furthermore using identical designs will facilitate ease of maintenance, parts and servicing of the two structures.

The proposed location is to take advantage of the former diversion channel that had been previously excavated through bedrock during the construction of the head pond weir (see Photo 12). It has since been backfilled. The new intake structure would be set back from the existing structure to allow for a small cofferdam/plug to remain, isolating the work area from the existing head pond and allow the head pond to remain operations during most of the construction.

Photo 12: Existing intake under construction with diversion channel to the right

The intake structure would be founded on bedrock. Its dimensions are approximately 2.1 m wide by 4m deep with an approximate height of 6 m. The walls and the floor of the structure will be 0.4 m thick, made of reinforced concrete.

The intake will be closed with a vertical sliding gate mounted on the upstream face of the wall of the intake box. The gate will be operated using a mechanical screw hoist. For winter operations a portable steam boiler can be used for potential de-icing operations, if required. Trashracks will be installed upstream of the gate, inside the intake box, to prevent debris from entering the penstock. Embedded steel guides in the concrete walls just downstream of the face of the structure will allow stoplogs to be inserted to dewater the intake box and remove debris when maintenance of the structure is required.

Concrete Wing Wall

A concrete wing wall is proposed to extend upstream from the east face of the new intake box. The wing wall can be constructed as part of the new intake box works. A sheet pile wall would then be installed connecting the wing wall to the west upstream end of the existing intake structure. The area between contained by these structures would then be backfilled to provide a work surface for mechanized removal of frazil ice from the vicinity of the intakes.

The concrete wing wall would be 0.8 m thick reinforced concrete with an approximate height of 6 m by 6 m long. The wall will be constructed on a concrete footing that will be founded on bedrock. Use of a sheet-pile retaining wall between the wing wall and the existing intake structure will allow the retaining wall to be installed without needing to dewater the headpond or existing intake.

A detail assessment of the frazil ice accumulation issue in the upper headpond will need to be conducted in the feasibility study. It will allow to determine potential mitigation solutions to reduce the accumulation of frazil ice in the headpond that currently require substantive maintenance activities each winter. The new proposed operational scheme at Surprise Lake will lead to higher winter flows in Pine Creek which could increase frazil ice generation.

5.3.2 Penstock

The proposed second penstock will parallel the existing penstock. It is proposed to install the penstock on the north side of the current penstock for ease of construction. As the current penstock is located on the southern half of the existing cleared right of way with a service road located on the north side. Installing the penstock on the north side will allow it to be installed without needing to routinely cross the existing penstock during construction.

A cross-over will be required near the powerhouse. Because there is insufficient space near the river to expand the existing powerhouse to the north. It is suggested that the new penstock cross the existing penstock where it is cut into the crest of the hill-slope above the powerhouse. This location allows the proposed new penstock to be readily installed above the existing pipe at this location.

The total length of the penstock is approximately 4 km with all but approximately 330 m (being sections for bedrock) running through sand and gravel. A trench will be excavated along the

proposed route between the access road and the existing penstock. A typical cross-section is proposed through overburden as presented on Drawing 02 of Appendix A.

The cross-section through overburden will be excavated with side slopes of 1.5H:1V with a minimum horizontal clearance of 0.4 m on each side to facilitate compaction of backfill. It is proposed to install the penstock over a minimum layer of 0.15 m thickness of granular fill to ensure good drainage at the bottom of the trench. The penstock will then be backfilled first with select granular fill around and over the penstock. A minimum of 0.7 m of random fill will then be placed above the granular fill to reduce risk of freezing of the penstock in case of extended winter shut-down. The random fill will be graded to cover the whole width of the trench and prevent ponding of water at surface. It is expected that a large portion of the overburden materials excavated from the penstock trench will be used as random fill.

Penstock Selection Considerations

For the proposed arrangement, approximately 4 km of penstock will be required to convey flows to the powerhouse from the intake structure at the head pond. Typical head losses within a conveyance system are usually in the order of 5 to 10% of the total gross head, with this value usually being more critical for sites with relatively low elevation changes. In order to minimize friction losses that will occur over the length of the penstock, flow velocities are typically kept between 1.8 and 2.4 m/s.

Based on the design flows for the upper powerhouse expansion, a nominal 5 ft. (1.52 m) inner diameter penstock size was selected as most appropriate. At this diameter penstock is available in steel or in high-pressure HDPE alternatives, while steel is the only high-pressure alternative at larger diameters (2 m or more). Both steel and HDPE penstock is available in lengths of up to 15 m. When comparing supply costs, HDPE is a more cost effective alternative than steel and has some installation advantages due to lighter weight for handling and flexibility during installation and welding. In general the installation methods are very similar in terms of backfill and connection requirements. On this basis, plus considering the existing owner's experience, HDPE penstock has been selected for the majority of the upper power plant conveyance system.

For the HDPE penstock option lighter wall weight would be used for the upper portion of the route, getting progressively thicker until the penstock elevation dropped to the point where transition to steel pipe would be required due to higher water pressures. Based on the existing penstock configuration, the following quantities of HDPE penstock are assumed (outside diameters are presented here):

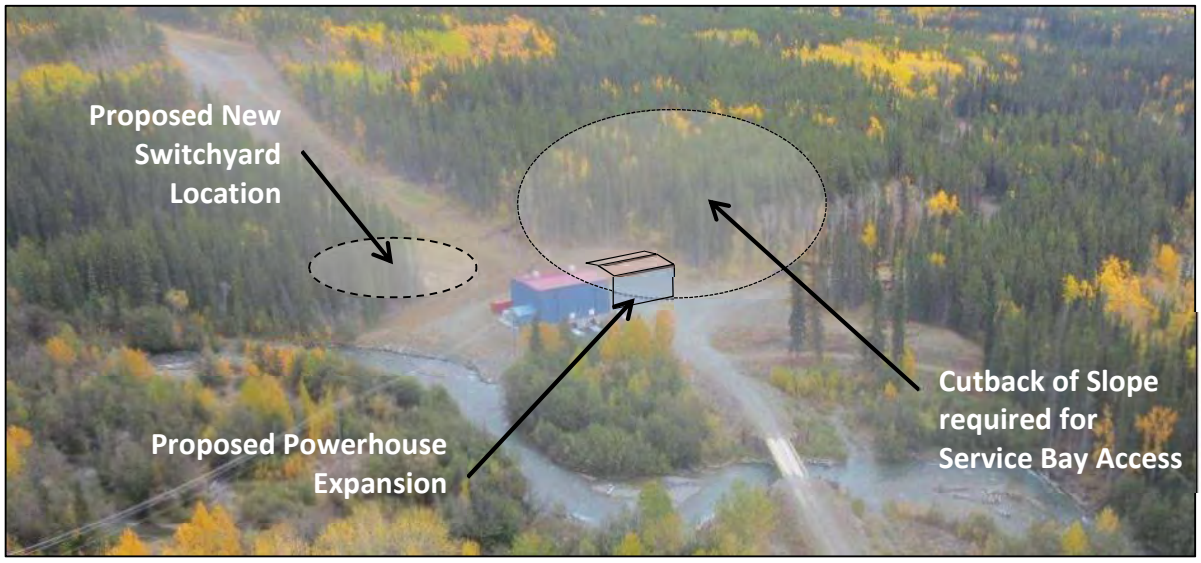
- 1,828 m of 63" DR41
- 256 m of 63" DR32.5 (50 PSI)
- 713 m of 63" DR26 (64 PSI)
- 768 m of 63" DR21(80 PSI)

As this site has 107 m of gross head, the lower 440 m of penstock would need to be steel pipe to resist the higher pressures. The steel penstock would then bifurcate to small steel pipes sections immediately upstream of the powerhouse expansion to feed the two new units.

5.3.3 Upper Powerhouse Expansion

The proposed powerhouse expansion will be located on the south side of the existing upper powerhouse and be constructed within the existing granular parking and turn around area. The powerhouse is expected to be constructed in the dry, with an overburden plug remaining within the tailrace to exclude the creek water from the foundation excavation during construction. This plug would be removed after the powerhouse had been completed, and the remainder of the tailrace would be completed in the wet. Limited inflows were experienced during the construction of the existing powerhouse. The powerhouse excavation was advanced to what was reported as a "hardpan" layer (likely glacial till). Based on this previous experience it is anticipated that only limited dewatering will be required. .

Figure 5-3: Layout of Upper Powerhouse Expansion



The powerhouse extension would be located on the south side of the existing powerhouse, as seen in the Figure 5-3 above and Drawing 06, and will require a cutback into the adjacent hill slopes to the southeast to facilitate adequate access into the service bay from the south side. The Pine Creek water elevation at this location will be regulated to approximately 723.5 m by the proposed lower headpond for the new lower power plant. The anticipated tailrace elevation would be approximately the same elevation as the creek with the existing tailrace channel widened to facilitate the increased flow.

The existing upstream head pond and intake structure maintains the forebay level at the penstock intake to approximately El. 832.5 m during normal operations, which provides a gross available head of approximately +/- 107 m for both the existing plant and the proposed expansion.

5.3.3.1 Foundation Considerations

Subsurface conditions at the proposed powerhouse extension are known with some confidence due to the construction of the previous powerhouse. Foundation conditions are expected to be course alluvial gravel similar to what can be observed at the surface in the area. The new powerhouse will

be marginally deeper than the existing structure at the location of the draft tube and it is not expected that bedrock will be encountered. Due to the existing proximity of the powerhouse to Pine Creek, foundation dewatering may become an issue during construction. Currently sheet pile retaining walls have been shown along the downstream side of the new powerhouse to either side of the draft tubes to prevent washout or movement of fill from beneath the structure into the tailrace. A sheet pile cut off wall may be required around the perimeter of the structure if groundwater conditions prove difficult. Further analysis will be required to determine the appropriate foundation design and soil parameters at the powerhouse location moving forward.

5.3.3.2 Turbine / Generator Equipment Considerations

Turbine Selection

At this level of study, turbine design flows are typically selected for an exceedance of approximately 25% to 35%, which corresponds to a flow of approximately 6.2 m^3/s. As the existing 2.1 MW plant currently uses up to 2.45 m^3/s, a design flow of 3.6 m^3/s was selected to maximize the plant capacity providing an additional 2.9 MW with a gross head of approximately 107 m. When accounting for riparian flows these design values correspond to an exceedance of approximately 25% which was desired to provide as much power as was reasonable possible from the powerhouse expansion alone. The selected design flow and capacity of the expansion would require further analysis and refinement at later stages of study in order to optimize the cost of annual energy generation.

Pelton and Francis units were initially considered for the powerhouse expansion due to their ability to efficiently operate with lower flows and medium to high gross head, and their typical use in small hydro developments. Turgo units were also considered for this application as they overlapped the operational ranges of Pelton and Francis units considered for this application.

Turgo units are very similar to Pelton units in that they are impulse type turbines with the advantage that they can operate at higher flows than a similarly sized Pelton machine. Similar to a Pelton unit, the impulse energy from jets of water are used to drive the turbine wheel, except that in a Turgo unit the jets comes in at an angle to the wheel instead of perpendicular to the axis of rotation. For the same power produced a Turgo unit will typically have a runner half the size of a comparable Pelton unit and therefore twice the specific speed, which will in turn require a smaller, less expensive generator. Similar to Pelton units, a Turgo unit uses deflectors to prevent upsurge on a load rejection therefore eliminating the need for surge facilities.

Francis units were discarded from the selection process as the remaining flow available from Surprise Lake did not allow for efficient operation year round at lower flow levels. Due to their slower rotation speed, Francis units would require much larger and more expensive generators than what would be required for Pelton or Turgo units. Additionally, the selection of Francis units would have required a surge facility which would be difficult and costly at this powerhouse location.

As expected, Turgo and Pelton units were both acceptable solutions given the relatively low design flows and medium to high gross head. The combination of operational flow and head at this site are near the lower limit of Pelton operation, but Turgo units are well suited to the site conditions and operate at higher RPM than a comparable Pelton unit, and therefore require a smaller and less costly generator. Pelton units considered would have had to incorporate multiple jets or conversely operate at a slower speed, increasing the cost for either the turbine and/or generator respectively.

The preferred option utilizes two Turgo units to reduce equipment size and cost, and allows the existing powerhouse crane at the upper plant to be utilized to carry out installation and repairs. Although not necessary given the existing plant contains two units, the addition of two Turgo units provides additional generation reliability and better plant efficiencies over a wider range of flows. Additional studies of greater detail should revisit and confirm the selection of dual Turgo units.

The selected unit parameters of the 1.45 MW Turgo Turbines proposed are summarized below:

- Normal Head Pond Level: 832.5 m
- Tailwater Level: 724.0 m to 723.5 m
- Rated head: 107 m
- Penstock: Single 1.52m I.D. diameter HDPE penstock with a bifurcation to 0.9 m diameter steel penstocks at the powerhouse.

Layout Considerations

The powerhouse has been located immediately adjacent to the existing powerhouse to facilitate use of the existing powerhouse crane for maintenance and repairs. The service bay has been located on the south side of the new structure similar to the existing powerhouse as it provides the best means of access without extending the proposed building further than necessary beyond the expanded tailrace.

5.3.3.3 Transient Analysis and Surge Facility

A surge facility is not required as the design of Turgo units utilizes deflectors to prevent upsurge on a load rejection and allows for the dissipation of surge pressures without damage to the units, which is similar to the Pelton units installed in the existing powerhouse.

5.3.3.4 Powerhouse Configuration

Details for the development scheme for the expanded powerhouse with two Turgo units have been provided in Drawings 06, 07 and 08. A service bay for the powerhouse would be constructed on the south (access) side of the powerhouse at ground level and contain the new electrical and mechanical systems associated with the plant within an insulated, metal clad steel superstructure. It has been assumed that the existing control room can be modified to allow for operation of the units; however, there is additional room available in the new service bay to include a new control room if necessary.

The service bay has been sized such that the generating equipment can be brought in to the powerhouse on flatbed trucks and unloaded using the existing overhead crane running on extensions of the existing rails and crane supports. There is also room to work on the major unit components in the service bay during the initial installation and for any future maintenance work. The existing 23 tonne overhead bridge crane will be retained as it is sufficient for the heaviest lift associated with the new turbines which is the generator assembly. The existing crane will perform loading, unloading, insertion and removal of the generator rotor or the assembled generator stator onto or from a truck.

The new superstructure for the powerhouse building will be designed to match the envelope of the existing structure with crane rails extended to cover the new portions of the powerhouse. Modifications to the existing pre-engineered building will be required, including the removal of the end column and bracing on the south side to facilitate the travel of the existing crane into the new building. Further study will be required to verify that modifications can be made to the existing pre-engineered structure without compromising its integrity as the designs of pre-engineered structures are typically highly efficient and leave little room for changes in loading or load path.

Immediately upstream of the powerhouse expansion the single HDPE penstock would bifurcate into two steel penstocks. Turbine flows would enter the concrete powerhouse substructure through short sections of steel penstock and then exit through individual draft tubes to the tailrace and then into Pine Creek. A turbine inlet valve (TIV) would be provided immediately upstream of each turbine as a means of shutting off the flow in an emergency and for use as an isolation device during maintenance activities, in addition to the intake structure slide gate.

Floor elevations have been selected based on the assumed tailwater level and the setting of the Turgo unit. The centerline of the penstock bifurcation is dictated by the turbine setting, with the lower powerhouse levels designed to provide adequate clearances around the turbine inlet valves immediately upstream of the units. The service bay elevation is set to match the existing powerhouse and the surrounding parking and turnaround area. Unit settings would need to be confirmed following detailed hydraulic analysis and turbine selection in the next project phase.

5.3.3.5 Electrical Equipment Considerations

General Configuration

The basic proposed configuration is a 2.9 MW, two unit plant expansion which is anticipated to require two 1.81 MVA generators. The two generating units will be of the synchronous type, with a nominal rating of 1.81 MVA at 0.8 power factor (pf).

The remainder of the electrical systems will generally follow the electrical configuration with the following main characteristics:

- Static excitation systems.
- One generator step up transformer (GSU) for the entire plant, with voltage and power ratings matching the generating units.
- 15kV class, vacuum generator circuit breakers and arc resistant switchgears.
- Redundant station service system.
- Energy would be sent to the proposed switchyard located adjacent to the expanded powerhouse which would then distribute power north through a 69 kV transmission system to the Yukon's electrical grid or have power stepped down for distribution to the community of Atlin.

Medium Voltage System

Each generating unit will have arc resistant switchgear that will feature draw out generator vacuum circuit breakers. As well, switchgear sections will house generator side Potential and Current

Transformers (PTs and CTs) and surge suppression equipment, tie off for the excitation system and GSU side PTs and CTs and will also include a tie off for the SSLC.

Interconnection between the generating units and the switchgear and between the switchgear and GSU will be by 15kV cable. The generator neutral leads will be connected to the neutral grounding equipment.

AC Station Services

Power for all auxiliary services and AC equipment required at each facility will be provided from the Powerhouse AC station service system.

Under normal operation, the station service power will be provided by the station's own generators. The station service system will allow power to be maintained during several types of equipment outages. The generator step-up transformer can energize the station service transformer from the high voltage network. The Generator circuit breaker will isolate the generator excitation transformers for this case.

If the units are shut down and power is not available from the HV network, the existing 50 kW generator that ATELP owns for the station service of the existing plant could be connected to the station service system. At this time we anticipate that a portable diesel generator would be available locally or from Whitehorse if needed, and the cost for purchasing one to keep at site has not been included in our estimates.

Dry-type transformers, switchgear line-ups, main breakers and tie breakers will be sized for the full load of the station.

The main incomings and tie-circuit breakers on each load center will be remotely controlled from the main control room and locally at the switchgear.

The AC distribution system will have a single 600V MCC, a single 600V panel, and a single 120/208V panel for both generating units and their auxiliaries, and at this time no redundancy has been provided.

Unit and GSU Protection

Generators and generator step up transformers will be protected by single multifunction digital relays. These relays, which will be powered by a single 125 VDC system, will provide the following minimum protections:

- Generator Reverse Power (32).
- Generator Thermal Protection (49).
- Inadvertent Energization (50/27).
- Breaker Failure Protection (50BF).
- Generator Turn Fault Protection (51SP).
- Generator Stator Ground Fault (59G).
- 100% Generator Stator Ground Fault (64S).
- Generator Field Ground (64F).
- Generator Under-frequency (81).
- Generator Differential (87G).

- Generator V/Hz (96G).
- Transformer Oil Temperature (26T).
- Transformer Winding Temperature (49WT).
- Transformer Overcurrent (50/51).
- Transformer Differential (87T).
- Transformer Restricted Ground Fault (87G).
- Transformer V/Hz (96T).

There will also be other standalone protection for mechanical generator or governor faults, such as overspeed and for GSU, such as oil level, oil temperature, etc.

Controls will be Programmable Logic Controller (PLC) based.

5.3.4 New Switchyard and Transmission

A new 4 km long 69 kV transmission system would be used to transmit energy from the proposed lower powerhouse to the new proposed switchyard located at the upper Atlin powerhouse. From this switchyard power would then be transmitted north to connect with the Yukon Territory's electrical grid or be stepped down for distribution to the community of Atlin. The new switchyard has been proposed to be located to the northeast of the upper powerhouse on slightly higher ground than the parking and turn around area adjacent to the upper powerhouse. A preliminary layout of the substation is provided in Appendix F.

Figure 5-4: New Switchyard Location

The generator step up transformers would be located in a switchyard adjacent to the Upper powerhouse. The high side voltage would be 69kV. A 69kV disconnects would also be located downstream of the transformer to provide isolation.

The switchyard would have a 69 kV SF6 circuit breaker and motorized disconnect with ground switches, potential transformers, current transformers and associated bus work and steel structures. This breaker would feed a single transmission line.

5.4 Lower Power Plant

5.4.1 Intake and Head Pond

An artificial head pond will need to be excavated for the intake structure of the lower powerhouse. A reconnaissance of lower Pine Creek (downstream of the existing powerhouse) was conducted both by air and foot to locate potential locations for the head pond. Pine Creek is mostly a shallow braided gravel-bed creek with some deeper pools that generally do not exceed 2 to 3 m in depth. The floodplain of the creek is also quite flat limiting the options to potentially raise the water level to form the head pond. It was determined that the optimal location to build the new head pond would be immediately downstream of the bridge located near the existing (upper) powerhouse. The following photo shows the location where it is proposed to excavate the lower head pond, as seen from the bridge when looking downstream.

Photo 13: Proposed location of lower head pond on Pine Creek, looking downstream

At this location, Pine Creek takes a sharp bend towards the north (to the right if looking downstream) and widens slightly over a short distance. Higher ground is located on the left bank (up to elevation 725 m) and the road closes the right bank at least to elevation 723.5 m. The headpond could then be naturally contained at least to elevation 723.5 m at this location, and

higher if needed with only small closing dam being required. Spruce Creek enters Pine Creek about 50 m downstream of that location such that a small diversion will be required to have Spruce Creek connecting with the head pond. The approximate dimension of the proposed head pond will be 50 m by 60 m, which is limited by the space available.

The following works will composed the head pond:

- A concrete intake structure located on the left side of the head pond;
- A concrete wingwall adjacent to the intake structure;
- A rock fill overflow spillway, located over the natural creek bed, to control the head pond water levels;
- An rock fill closing dam on either side of the overflow spillway;
- An excavated slope on the upstream end of the head pond;

Diversion of Pine Creek during construction of the head pond will take place with a diversion channel on the right side of the creek. The diversion channel will be excavated through the existing access road to the upper power plant. Crossing of the road (if deemed necessary for access from the north side of the creek) could either be done by installing culverts or by moving the existing bridge Since filling of Surprise Lake will occur during the construction period of the lower head pond (summer season) flows are expected to be low. Spruce Creek diversion will only be built once all other works of the head pond are completed. For the purpose of preliminary sizing of the diversion channel, a maximum diversion flow of 10 m^3/s was assumed. A diversion channel with a base width of 5 m and a maximum depth of 2 m (1.5 m flow depth and 0.5 m freeboard) is selected. The diversion channel will need to be protected with rock fill (or cobbles) with a D_{50} of at least 100 mm.

The depth of the head pond was determined based on the minimum submergence criteria for the intake. Two 1.52 m diameter penstocks are proposed for the lower plant (discussed in more detail in Section 5.4.2). The following parameters were estimated for each penstock:

- Maximum flow: 3.5 m^3/s (total turbine flow 7 m^3/s)
- Maximum flow velocity: 2 m/s

The minimal submergence of the intake was determined based on Gordon equation (1970) developed based on observations on numerous existing generating stations in Quebec.

$$S_{min} = CVd^{0.5}$$

Where,

S_{min} is the minimum submergence
C is a coefficient to account for approach flow conditions (0.55 for linear and 0.72 for asymmetric)
V is the flow velocity in the penstock (in m^3/s)
d is the penstock diameter (in m)

A C coefficient of 0.72 was selected since approach flow conditions at the intake are not linear, thus increasing the risk of vortex formation. The resulting minimal submergence was calculated as 1.8 m.

In order to establish the head pond depth and the invert elevation of the intake (for each penstock), a minimum pond level was set based on the topographical constraints as well as based on the proposed geometry for the spillway (discussed further). The objective is also to maximize the head at the site without adversely impacting tailwater levels at the upper plant. . A minimum pond level of 723.0 m was selected. With a 1.52 m inside diameter (I.D.) diameter penstock and a minimum submergence of 1.8 m, the invert elevation of the intake has to be at least 3.4 m below the minimum pond level. The invert elevation of the intake was set at elevation 719.2 m which provides an additional 0.4 m of safety margin against submergence against potential entrainment of debris and ice in the small head pond. The bottom of the head pond is set at elevation 718.2 m, which is 1 m below the invert of the intake. It will reduce sediments from filling the bottom up to the intake elevation.

Intake structure and concrete retaining wall

A concrete intake box for the intake structure will be located on the left side of the overflow spillway, adjacent to the concrete wingwall. Since no bedrock is present at the site, it will be founded on overburden materials, such that a concrete pad will be required. Its dimensions will be approximately 6 m wide by 4 m deep, with an approximate height of 7 m. The structure should extend up to elevation 725 m to close the head pond. The walls and the floor of the structure will be 0.4 m thick, made of reinforced concrete.

The intake will be closed with a vertical sliding gate mounted on the upstream face of the downstream wall of the intake box. At this stage, it is expected that the gates will be operated using a mechanical screw hoist. For winter operations, a portable gas generator and steam boiler can be used for potential de-icing operations, if required. Power could also be easily provided to the lower head pond since the existing upper powerhouse is located within 300 m of the site. Thrash\racks will be installed upstream of the gate, inside the intake box, to prevent debris from entering the penstock. Embedded steel guides in the concrete walls just downstream of the upstream face of the structure will allow the insertion of stop-logs to dewater the intake box to remove debris or if maintenance of the structure is required.

A concrete retaining wall will be built on the left side of the intake box to close the south end of the head pond. The retaining wall will allow mechanized equipment to operate adjacent to the intake structure for removal of frazil ice, if needed. The wall will be 0.8 m thick reinforced concrete with an approximate maximum height of 7 m. It will be approximately 18 m long. The wall will be constructed on a concrete footing that will be founded on overburden materials. Rock fill will be used to backfill the wall on the downstream side, where a parking/turn-around area for access will be established.

Overflow spillway

Due to the small size of the head pond and for ease of operations, an overflow spillway is selected to pass the design flood without the need for any gate operations. The overflow spillway will also allow maintaining the minimum pond level. Since the head pond is mostly excavated into the ground, the spillway will only have a maximum height of approximately 3 m. An overflow rock fill weir was selected with a sheet pile cut-off wall to reduce seepage through and under the structure. It is proposed to extend the cut-off wall at least 6 m below the bottom elevation of the head pond to prevent internal erosion and seepage.

Two different crest elevations are proposed:

1. A lower crest at elevation 723.0 m, with a width of 4.5 m. This crest will pass normal summer excess flows and provide the minimum environmental flow;
2. A higher crest at elevation 723.7 m, with a width of 15 m. This crest will allow the passage of larger floods.

Side slopes of 4H:1V are selected along the crest of the overflow weir to provide vehicle access on the crest for maintenance activities, including mechanized frazil ice removal and sediment removal in the head pond if required. A 5 m crest width is selected to accommodate potential machinery traffic.

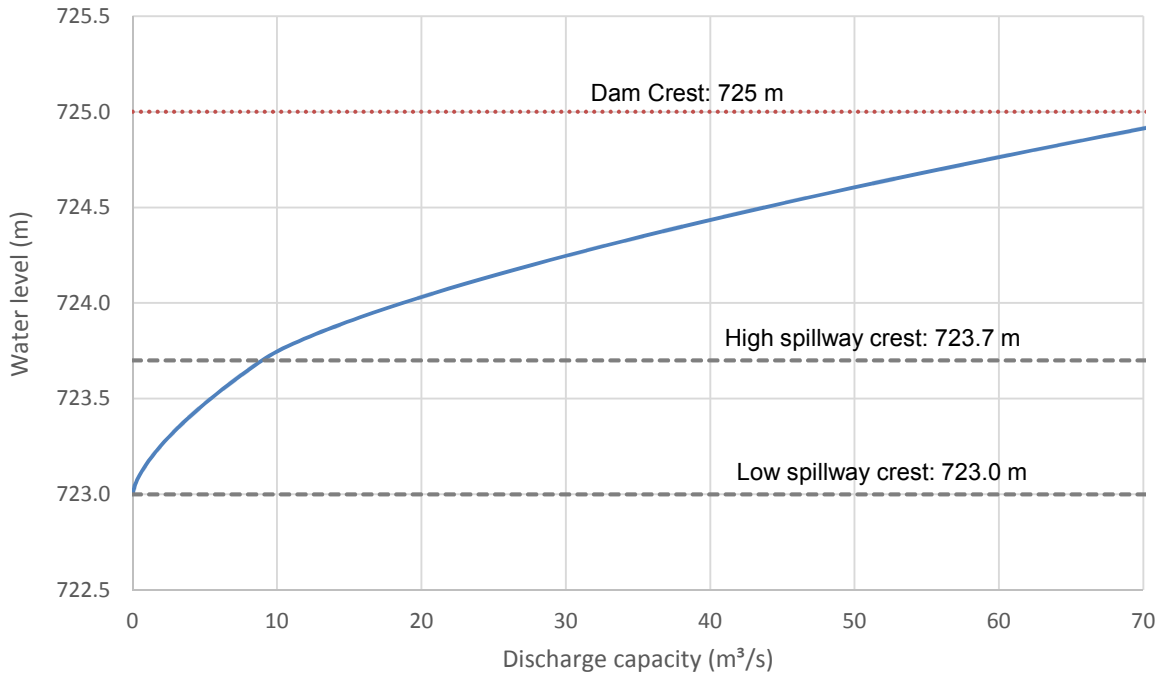
The overflow weir equation was used to determine the capacity of the proposed overflow spillway. A discharge capacity curve for the overflow spillway is presented below.

$$Q = C\sqrt{2g}LH^{3/2}$$

Where,

Q is the flow passing over the weir (in m^3/s)
C is the discharge coefficient, taken as 0.34 which is a conservative value for a long broad crested weir
g is the gravitational constant (9.81 m^2/s)
L is the crest width (in m)
H is the head above the crest (in m)

Figure 5-5: Discharge capacity curve of the overflow spillway of the lower head pond



The capacity of the low crest at the normal pond level of 723.5 m is estimated at 5.4 m³/s, while it increases to 9 m³/s up to the elevation of the higher crest (723.7 m). In the eventuality of the passage of the design flood (estimated at 39 m³/s), the water level in the head pond would reach 724.4 m. Based on this calculated value for the maximum flood level, the crest elevation of the closing dam adjacent to the spillway is set at 725.0 m to provide the minimum 0.5 m freeboard criteria.

Maximum flow velocities over the crest of the spillway are estimated at 2.5 m/s under the design flood scenario. Rip rap with a D_{50} of 300 mm is selected (class 1), which can resist flow velocities up to 3 m/s based on Figure 5-1. The downstream slope of the overflow spillway is set at 10H:1V. This will provide flow velocities of approximately 1 m/s on average, which may be adequate to provide fish passage under most hydraulic conditions through the low crest of the spillway. A small stilling basin will be constructed at the toe of the spillway. The stilling basin will be 15 m long and 0.5 m deep. This will protect the river bed against scour and will allow the formation of a hydraulic jump in a controlled location. The stilling basin will be protected with rip rap with a D_{50} of 300 mm also.

Closing dam

A closing dam will be required on each side of the overflow spillway. Since the headpond is mostly excavated into the ground the dam will be small with a maximum height of 3 m near the bridge. The sheet pile cut off wall will extend into the dam. On the upstream side of the lower head pond, a work terrace will be built at elevation 723.5 m (normal pond operating level) to provide access for maintenance, especially mechanized ice removal if needed. Rip rap (class 1 D_{50} of 300 mm) should be installed up to elevation 724.5 m (maximum flood level) to protect the banks of the head pond against erosion.

As a summary, the following elevations and design parameters are selected for the lower head pond:

- Bottom of head pond: 718.2 m
- Intake invert elevation: 719.2 m
- Spillway crest elevation: 723.0 m (4.5 m width) and 723.7 m (15 m width)
- Normal pond level: 723.5 m
- Minimum pond level: 723.0 m
- Maximum flood level: 724.5 m
- Closing dam crest elevation: 725.0 m
- Rip rap: class 1 – 200-450 mm (D_{50} 300 mm)
- Spillway downstream slope: 10H:1V

5.4.2 Penstock

A preliminary discussion of the selected penstock route was provided in Section 3.2. The final alignment of the lower penstock selected for this study is shown on Drawing 03. The route is dictated by topographical constraints and substantively avoiding privately owned land. The

alignment of the lower penstock traverses significantly more challenging terrain than the existing upper penstock.

The alignment is dictated by the following considerations:

1. Avoid crossing private land at South Pine Drive. The proposed alignment largely avoids this by skirting between the private land and Pine Creek's canyon above the Warm Bay Road Bridge. Crossing a small corner of private land may be unavoidable, but that will need to be determined in future studies.

2. Topographic constraints consisting of small bedrock hills at 2+000 and 2+900. The proposed alignment takes advantage of natural saddles between the hills and the side of Monarch Mountain. Alignment elevations were selected to minimize cut/fill requirements, especially of bedrock.

Over the length of the penstock, terrain and ground conditions vary as follows:

- Between 0+000 and 0+800 the penstock will follow the north side of Warm Bay Road. Soils are anticipated to be predominantly sand and gravel overburden with bedrock near surface.
- From 0+800 to 1+100 the alignment crosses a series of bedrock knobs.
- Terrain conditions from 1+100 to 2+000 are largely unknown, but are anticipated to be blanket of till over bedrock. Soils appear to be adequately drained along this hillside section.
- From 2+000 to 2+500 the alignment is anticipated to cross a challenging area of poorly drained soils. Organic and ice-rich soils (soil that have high ice content either as permafrost or are frozen for most of the year) may be present in this area.
- From 2+500 to 2+850 will be a side-cut into bedrock and talus slope.
- From 2+850 to 4+000 ground conditions are expected to be relatively more mild, consisting of glaciofluvial terraces/benches and alluvial plain materials with no significant bedrock outcrops. Soils appear to be predominantly sand and gravel and are well drained.

Of the total 4 km of the lower penstock, it is assumed a total of 500 m will be running through bedrock with the rest in overburden material. A typical cross section through overburden is presented on Drawing 03 in Appendix A.

The cross-section through overburden will be excavated with side slopes of 1.5H:1V with a minimum horizontal clearance on each side of 0.4 m to facilitate compaction of backfill. It is proposed to install the penstocks over a minimum layer of 0.15 m thickness of granular fill to ensure good drainage at the bottom of the trench. The penstocks will then be backfilled first with select granular fill around and over the penstock. A minimum of 0.7 m of random fill will then be placed above the granular fill to reduce risk of freezing of the penstock in case of extended winter shut-down. The random fill will be graded to cover the whole width of the trench and prevent ponding of water at surface. It is expected that a large portion of the overburden materials excavated from the penstock trench will be used as random fill.

Penstock Selection Considerations

Larger total design flows are required for the lower powerhouse because of the addition of flows from Spruce Creek for the proposed single turbine. A 2 m inside diameter penstock is required based on the considerations described previously in Section 5.3.2 (flow velocities between 1.8 and 2.4 m/s). At this diameter, steel pipe is the only readily available option.

The cost of the lower penstock is the largest cost item for the lower power plant. Therefore a preliminary cost optimization assessment was conducted to evaluate the potential for using two smaller diameter HDPE penstocks in lieu of a single large steel penstock. To meet the flow requirements for the lower power plant, twin 5 ft (1.52 m) I.D. penstocks would be required. The optimization included the costs of both excavation and backfill requirements in both overburden and bedrock sections of the alignment. The assessment concluded that twin HDPE penstocks would be approximately 10% lower material and installation cost with approximately equivalent excavation and backfill costs. However, it is believed that the HDPE option offers substantive constructability benefits as follows:

- Relatively shallower and wider excavations making excavations easier.
- Easier excavation due to typically more weathered and looser surface materials.
- Existing owner experience and comfort with using HDPE penstock.
- Easier handling, welding and installation of smaller diameter, more flexible HDPE pipe.
- Consistent material size with upper penstock may result in overall project savings and improved installation efficiency.

For the HDPE penstock alternative lighter wall weight would be used for the upper portion of the route, getting progressively thicker until the penstock elevation dropped to the point where transition to steel pipe would be required. Based on the elevations/pressures, the following quantities of HDPE penstock are assumed (outside diameters are presented here):

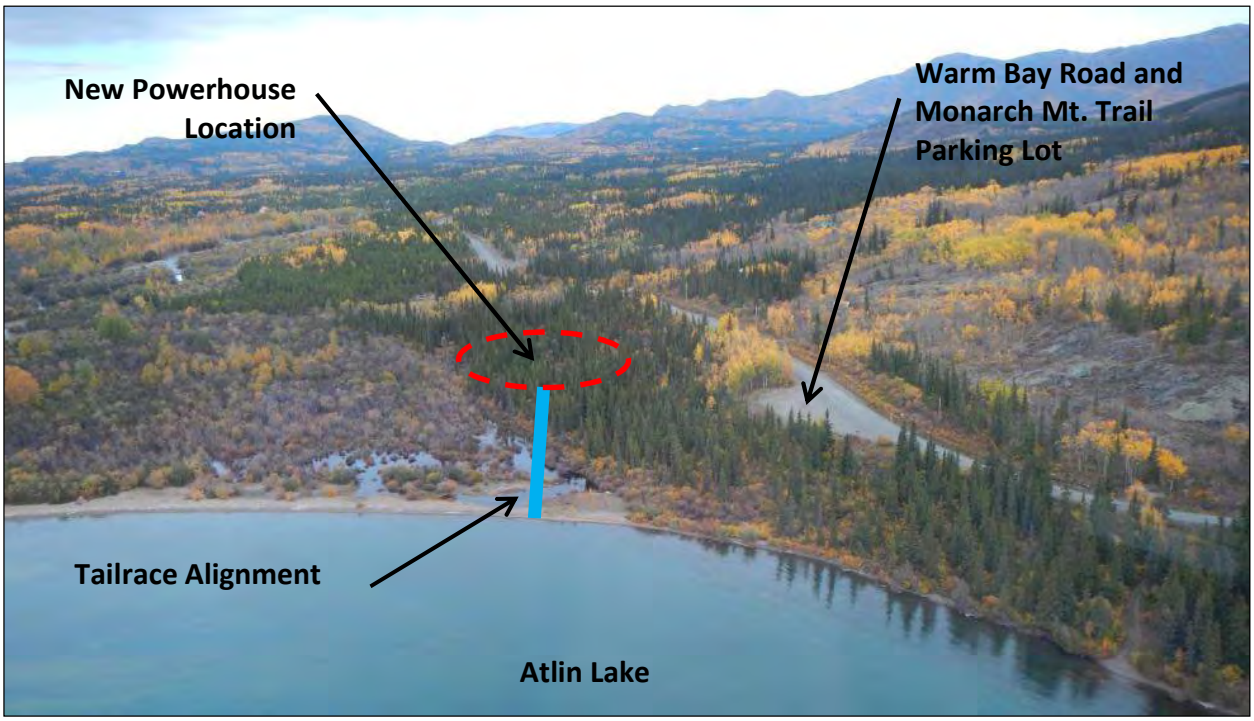
- 2x 3,025 m of 63” DR41
- 2x 375 m of 63” DR32.5 (50 PSI)

For the last 600 m it is assumed the penstock would transition to a 2 m diameter steel pipe. A reverse bifurcation would transition the twin HDPE penstocks to the larger diameter steel penstock.

5.4.3 Lower Powerhouse

The proposed new lower powerhouse will be located on the east side of Pine Creek, approximately 150 m north of Atlin Lake as shown on Drawing 11. The powerhouse would be constructed within the steeply sloped banks below Warm Bay Road in an effort to found the powerhouse in bedrock. The powerhouse will be constructed in the dry, with an overburden plug located within the tailrace to exclude lake water from the foundation excavation during construction. This plug would be removed after the powerhouse has been completed, and the remainder of the tailrace completed in the wet.

Figure 5-6: Layout of Lower Powerhouse



The powerhouse will be located west of Warm Bay Road as seen in the figure above, on the sloped hillside just north of the Monarch Mountain trail parking area. Atlin Lake levels vary through an approximate range from elevation 669.25 m to 666.85 m and the anticipated tailrace elevation would be approximately the same elevation since the tailrace channel would be designed to minimize head losses between the powerhouse and Atlin Lake.

For the preferred head pond and intake being considered, the head pond level would be maintained at approximately El. 723.5 m during normal operation, which would provide an assumed gross available head of approximately +/- 56 m.

5.4.3.1 Foundation Considerations

Subsurface conditions at the proposed powerhouse location are currently unknown. A visual inspection of the site shows significant areas of exposed bedrock immediately to the east of Warm Bay Road dipping down to the west and south underneath the road alignment. To the west of the road there is the Pine Creek alluvial fan which is likely to be composed of a saturated sand and gravel. The slopes west and below Warm Bay Road appear to be comprised at the surface of overburden (till) due to the significant tree cover. Due to the slope and proximity to large amounts of exposed bedrock it is expected that any overburden cover may be limited and has therefore been assumed to be approximately 2 m thick or less. Due to the depth of the structure and the amount of exposed bedrock present in close proximity it has been assumed that structures can be founded on bedrock in the chosen location, though design provisions could be made if there is no bedrock. Given the observed saturated sand and gravel condition of the alluvial fan, considerable groundwater inflow should be expected in any excavations in overburden at or below the lake level.

5.4.3.2 Turbine / Generator Equipment Considerations

Turbine Selection

At this level of study, hydroelectric design flows are typically selected at an exceedance of approximately 25% to 35%, which corresponds to a flow of approximately 6 to 7 m^3/s. On this basis a design flow of 7 m^3/s was selected to provide a maximum plant capacity of 2.8 MW with a gross head of approximately 56 m.

Pelton and Turgo units were also considered for the arrangement at the lower powerhouse location, but due to the relatively low gross head of 56 m for these types of units, an efficient or cost-effective turbine-generator arrangement was not possible. Operating speeds would be much slower and require a large and cost prohibitive generator. Due to this, Francis type units were determined to be the best solution. While two units are a viable option for providing the plant capacity of 2.8 MW and would provide increased reliability of station service power, the costs of providing two sets of turbines and generating equipment were considered to outweigh the potential benefits of a one unit solutions. Given the existing powerhouse upstream and its planned expansion, additional reliability for the community of Atlin was not deemed to have substantial value compared to the incremental cost of additional turbine and generator equipment.

Options with two units for this size of plant would also increase the complexity of electrical considerations and require a larger powerhouse footprint, which would increase the overall cost based on preliminary estimates even though the excavation depths for the smaller units are less than for a single large unit. The single unit's more compact footprint is desirable at this location due to the potential excavation required both into rock and the adjacent slope. While additional studies should be undertaken to confirm or optimize the number of units at the next level of study, a powerhouse with one unit has been selected at this time based on both the supply of equipment and potential construction costs.

The selected unit parameters of the 2.8 MW Horizontal Francis Turbine proposed is summarized below:

- Max headwater level: 724.0 m
- Full Supply Level (FSL): 723.0 m to 723.5 m
- Tailwater Range: 666.85 m to 669.25 m
- Rated head: 55.4 m
- Allowable upsurge: 40%
- Penstock: Dual 1.52 m I.D. diameter HDPE penstock with union to a single 2.0 m diameter steel penstock approximately 600 m upstream of the powerhouse.

Layout Considerations

For this size of Francis turbine, there are several equipment suppliers with vertical or horizontal shaft arrangements that would be suitable. In a comparison between vertical and horizontal arrangements for the chosen Francis turbines with such a diameter, we have reviewed the following considerations:

- A vertical shaft arrangement for Francis turbines would require a lower level under the generator floor for maintenance of the components in the turbine pit such as the distributor assembly, turbine bearings, servomotors, cooling water supply unit, and other facilities. The added lower floor will incur more civil cost which is not likely warranted for such a compact turbine.
- In comparison to a vertical unit, a horizontal shaft arrangement for a Francis turbine features: 1) fewer floors in the powerhouse; 2) decreased overall height of the powerhouse; 3) decreased depth of excavation; 4) decreased civil construction costs; and 5) is easier to monitor, maintain and overhaul the units.
- In general, common practice is to recommend using Francis turbines with a runner size less than 1.75 m diameter in a horizontal arrangement, and using a vertical arrangement for large capacity or large diameter Francis turbines. With a proposed runner diameter of 1.00 m this turbine falls well within the range of an acceptable horizontal unit size.
- On the basis of the considerations listed above, a single horizontal Francis unit has been selected for the proposed lower Atlin Powerhouse. For this type and size of unit, the centerline of the runner has been set approximately 1.7 m above the assumed tailwater level to obtain the correct submergence for the draft tube.

Transient Analysis and Surge Facility

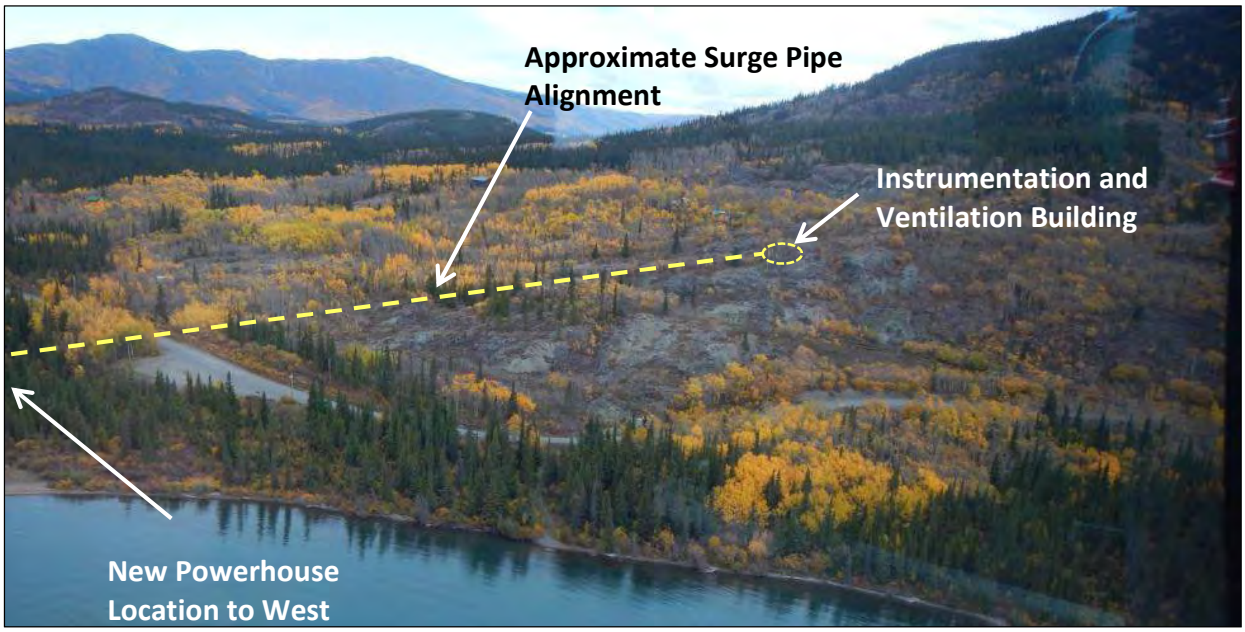
To avoid unnecessary complication with addressing the inclusion of a surge facility it has been assumed the surge connection to the penstock will be provided downstream of the union of the dual HDPE penstocks at a distance of approximately 30 m from the powerhouse. A preliminary transient analysis has considered the following variables: the penstock diameter at the powerhouse, the flow velocity of 2.2 m/s at the rated plant capacity, the preferred head pond and intake location and relatively long length of penstock (4 km). The results of the preliminary transient analysis have indicated that to achieve an acceptable combination of unit governability, gate times, maximum overspeed and maximum penstock pressure during plant operations, there will be a need for a surge facility.

Assuming the construction of a vertical surge tanklocated within approximately 50 m of the powerhouse, it would require a diameter of 6.5 m with an active zone between elevations 713 to 732 m. As finished ground elevation is 670 m at the proposed powerhouse and the adjacent slopes only extend to approximately 680 m, the required surge tank would between 55 and 65 m high, be difficult to construct and be extremely expensive. Alternatively, we have assumed that a surge facility will connect to the steel penstock approximately 30 m upstream of the powerhouse, where it will be possible to extend an approximately 400 m section of steel surge pipe up the bedrock slopes to the east of the powerhouse that quickly rises to the required active zone elevations. Based on the required surface area to meet unit stability criteria, the surge facility could consist of sections of 2.0 m diameter pipe installed at an incline matching the ground profile at this location through the active zone. Ventilation for the shaft and monitoring instrumentation will be provided at a small building at the end of the surge shaft on the eastern slope. The conceptual arrangement of this surge facility is shown in Figure 5-7 and on Drawing 11. The alignment shown was selected to avoid crossing of privately owned land.

Since a surge facility will be located in relative proximity to the powerhouse, the generator's natural inertia will suffice to provide stable operation and good unit response. The maximum overspeed

would be limited to approximately 60% of rated speed. While this is anticipated to be acceptable, a more detailed transient analysis would be required to confirm and optimize these values at the next stage of study.

Figure 5-7: Lower Powerhouse Surge Facility Location



Powerhouse Configuration

Details for the development scheme with a single horizontal Francis unit have been provided in Drawings 11, 12 and 13. A service bay for the powerhouse would be constructed on the east (access) side of the powerhouse at ground level, complete with a control room and overhead crane within an insulated, metal clad steel superstructure. A 30 tons overhead bridge crane with a span of approximately 10 meters will be needed for the selected unit, the heaviest component of which is the generator assembly. The selected crane will be able to perform loading, unloading, insertion and removal of the generator rotor or the assembled generator stator onto or from a truck.

The service bay has been sized such that the generating equipment can be brought in to the powerhouse on flatbed trucks and unloaded using the proposed overhead crane. There is also room to work on the major unit components in the service bay during the initial installation and for any future maintenance work.

Approximately 600 m upstream of the powerhouse the dual HDPE penstocks would transition to a single steel penstock supplying the Francis unit. Turbine flows would enter the concrete powerhouse substructure through a section of steel penstock and then exit through the draft tube to the tailrace and travel 150 m to Atlin Lake. A turbine inlet valve (TIV) would be provided immediately upstream of the turbine as a means of shutting off the flow in an emergency and for use as an isolation device during maintenance activities, in addition to the intake structure slide gate.

Floor elevations have been selected based on the assumed tailwater levels and the setting of the Francis unit. The centerline of the penstock is dictated by the turbine setting, with the lower powerhouse level designed to provide adequate clearances around the turbine inlet valves immediately upstream of the unit. The service bay elevation is set 1 m above the anticipated maximum tailwater level along with the surrounding parking and turnaround area, as shown on Drawing 13. The required elevations would need to be confirmed following subsequent surveys and detailed hydraulic analysis should this project proceed to later stages of study and development.

5.4.3.3 Electrical Equipment Considerations

General Configuration

The basic proposed configuration is a 2.8 MW, single unit plant which is anticipated to require one 3.5 MVA generator at 0.8 power factor (pf).

The remainder of the electrical systems will generally have the following main characteristics:

- Static excitation systems.
- One generator step up transformer (GSU) for the plant, with voltage and power ratings matching the generating unit.
- 15kV class, vacuum generator circuit breakers and arc resistant switchgears.
- Station service system.
- A 69 kV transmission system would be used to transport the energy to the proposed switchyard at the expanded upper Atlin Plant which would then transmit power north to connect with the Yukon's electrical grid or be stepped down for distribution to the community of Atlin.

Medium Voltage System

The generating unit will have arc resistant switchgear that will feature draw out generator vacuum circuit breakers. As well, switchgear sections will house generator side PTs, CTs and surge suppression equipment, tie off for the excitation system and GSU side PTs and CTs and will also include a tie off for the SSLC.

Interconnection between the generating units and the switchgear and between the switchgear and GSU will be by 15kV cable. The generator neutral leads will be connected to the neutral grounding equipment.

AC Station Services

Power for all auxiliary services and AC equipment required at the facility will be provided from the Powerhouse AC station service system. Under normal operation, the station service power will be provided by the station's own generators. The generator step-up transformer can energize its station service transformer from the high voltage network. The Generator circuit breaker will isolate the generator excitation transformers for this case. It has been assumed that a portable backup diesel generator will be available locally or from Whitehorse if required.

Dry-type transformers, switchgear line-ups, main breakers and tie breakers will be sized for the full load of the station.

The AC distribution system will have a single 600V MCC, a single 600V panel, and a single 120/208V panel for the generating unit and its auxiliaries.

Unit and GSU Protection

The Generator and generator step up transformer will be protected by single multifunction digital relays. These relays, which will be powered by a single 125 VDC system, will provide the following minimum protections:

- Generator Reverse Power (32).
- Generator Thermal Protection (49).
- Inadvertent Energization (50/27).
- Breaker Failure Protection (50BF).
- Generator Turn Fault Protection (51SP).
- Generator Stator Ground Fault (59G).
- 100% Generator Stator Ground Fault (64S).
- Generator Field Ground (64F).
- Generator Under-frequency (81).
- Generator Differential (87G).
- Generator V/Hz (96G).
- Transformer Oil Temperature (26T).
- Transformer Winding Temperature (49WT).
- Transformer Overcurrent (50/51).
- Transformer Differential (87T).
- Transformer Restricted Ground Fault (87G).
- Transformer V/Hz (96T).

There will also be other standalone protection for mechanical generator or governor faults, such as overspeed and for GSU, such as oil level, oil temperature, etc.

Controls will be PLC based.

6 TRANSMISSION LINE OPTIONS ASSESSMENT

A transmission line options assessment has been completed as follows to determine the technical requirements and associated costs to deliver power from the proposed Atlin Hydro Expansion project to the Yukon's electrical system. The transmission line options assessment consists of two components:

1. The line from the Atlin hydro facility to Jakes Corner, Yukon; and
2. The connection between the Atlin line and the Yukon electrical system, including new transmission line or upgrades required.

Work conducted as part of this assessment includes:

- the development of a cost estimate for a 69 kV transmission line (section 6.2);
- a system assessment study to determine interconnection/system upgrade needs (section 6.3) and
- development of a cost estimate for substations at either end of the transmission line (details provided in Appendix F).

Some of the options included consideration of 138 kV transmission line components. Costs for development of a 138 kV line were specified by Yukon Energy Corporation for the purposes of this study.

As part of this work a transmission options study was prepared by b7kennedy & Associates Inc. to assess electrical system requirements. This study is provided in Appendix E and provides a high-level assessment of transmission system needs and performance for connecting the Atlin hydro power project to the Yukon electrical system.

6.1 Overview of Transmission Line Connection

The new transmission line from Atlin is proposed to join the southern Yukon electrical system at Jakes Corner at the junction of the Alaska Highway and the Tagish Road. The existing Yukon system at this location is a 34.5 kV system owned primarily by ATCO Electric Yukon. The existing southern Yukon electrical system is illustrated schematically on Figure 6-1. Currently the line suppling power to the Southern Lakes area originates at Yukon Energy's substation S150 located at Whitehorse Rapid Generating Station (WRGS). This line is ATCO Electric Yukon's Southern Lakes distribution line (called line 9L). Substation S150 also provides power to three other ATCO Electric Yukon lines. Yukon Energy operates a 138 kV transmission system with a 138 kV bus at both S150 and the Riverside substation (S171) which is also at the WRGS. S171 is a ring bus to accommodate power generated from all YEC's generating assets (hydro and thermal plants)

Electrical load information for 2013 through late 2015 was provided by ATCO Electric Yukon for the Southern Lakes system. Peak loads are between 8 and 9 MW and occur in December, January and February. Peak loads by community are not known at this time, but ATCO staff have indicated that peak loads in Teslin are on the order of 1 MW. Annual energy consumption for this region has been

39.2 GWh and 38.8 GWh for 2013 and 2014 respectively. Figure 6-2 shows energy consumption in the Southern Lakes area on a monthly basis. Simulated electrical production from the Atlin Hydro Expansion project is shown as a dashed black line on Figure 6-2. See section 4.4 for a discussion of the simulated power production. As can be seen on this figure, the simulated generating profile of the Atlin Hydro Expansion project fits relatively well with the energy demand of the region. Because the generation during winter months is a function of reservoir (Surprise Lake) withdrawals, the operation can be optimized somewhat to match the loads on a seasonal basis.

Figure 6-1. Overview of Southern Lakes electrical system.

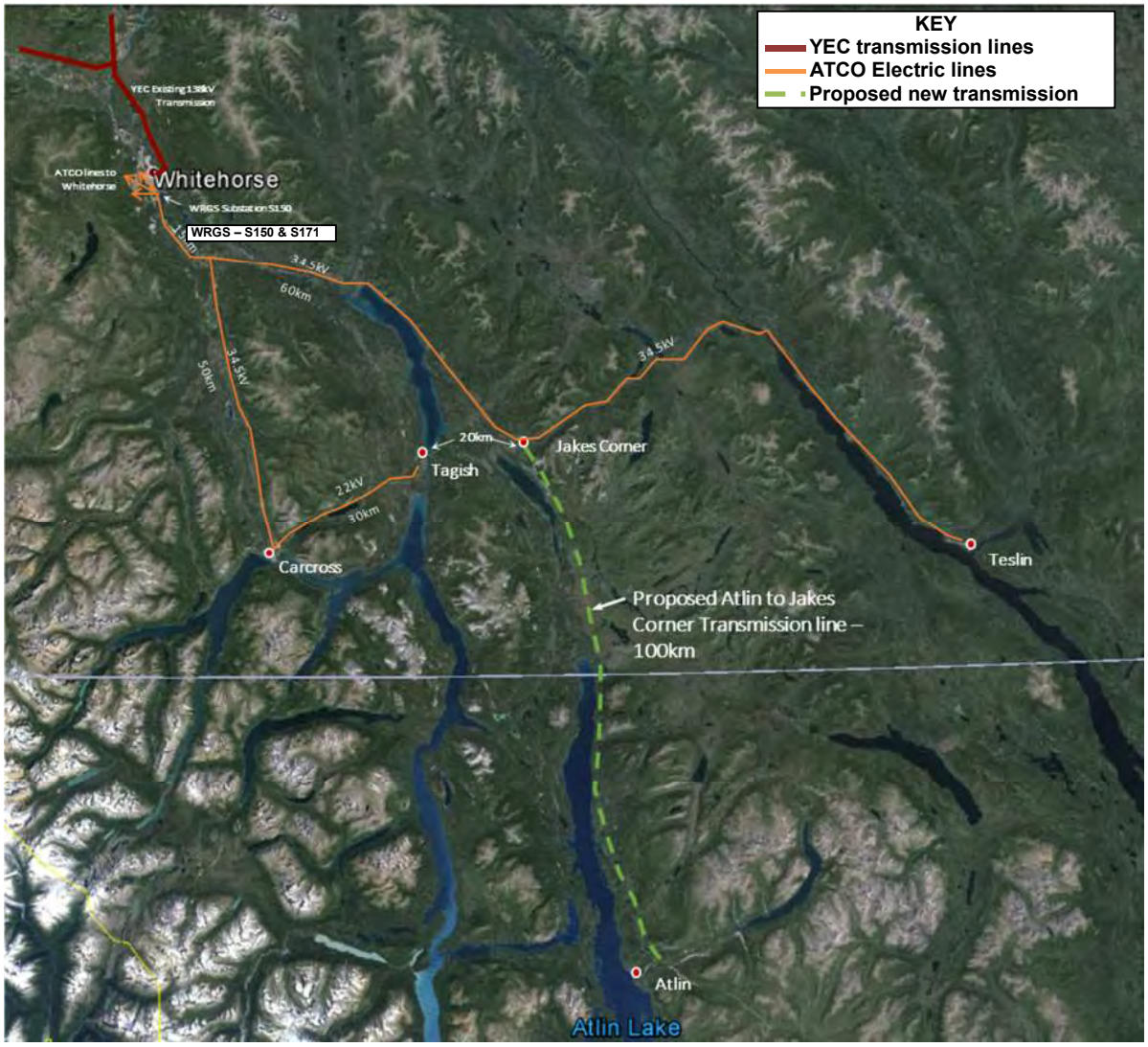
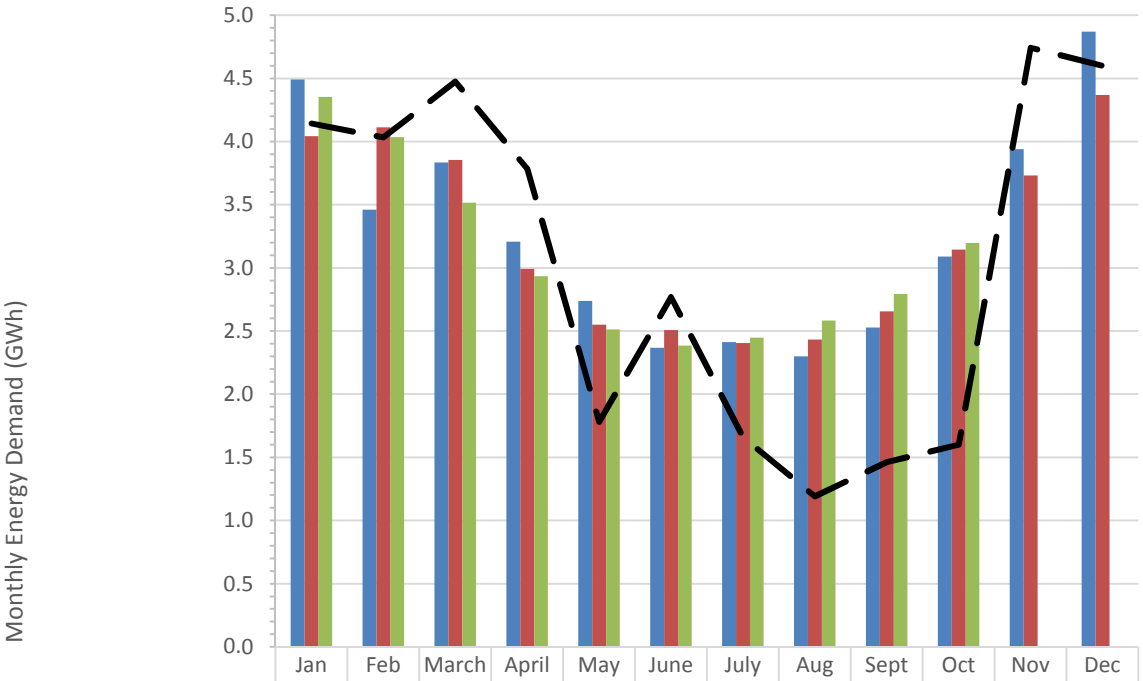


Figure 6-2. Southern Lakes monthly energy demand, 2013-2015.



	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
2013	4.5	3.5	3.8	3.2	2.7	2.4	2.4	2.3	2.5	3.1	3.9	4.9
2014	4.0	4.1	3.9	3.0	2.6	2.5	2.4	2.4	2.7	3.1	3.7	4.4
2015	4.4	4.0	3.5	2.9	2.5	2.4	2.4	2.6	2.8	3.2		
•Atlin Hydro Gen.	4.1	4.0	4.5	3.8	1.8	2.8	1.7	1.2	1.5	1.6	4.7	4.6

6.2 Atlin to Jakes Corner Transmission Line: 69 kV and 138 kV Comparison

The base case assumption for the Atlin transmission line is a line at 69 kV. As an alternative, 138 kV has also been considered. The Transmission Options Assessment study by b7kennedy & Associates (Appendix E) confirmed that 69 kV performs adequately for the power being transferred over the line (on the order of 7 MW). At full-load, line losses for the 69 kV transmission line are estimated at 2.2%, or 0.16 MW; losses less than 5% are considered acceptable.

6.2.1 Construction Cost Estimates

Table 6-1 below provides a construction cost estimates for the 69 kV line and 138 kV alternative. The Atlin to Jakes Corner line length is assumed to be nominally 100 km with 50 km in BC and Yukon respectively. Further details on how these cost estimates were prepared are provided in the following sections.

Table 6-1 Atlin to Jakes Corner Transmission Line Options Cost Summary (2016$)

Transmission Line Cost Item	69 kV ($000 CAD)	138 kV ($000 CAD)
Line Construction (inc. OPGW)	21,319	33,444*
Clearing and Access	1,380	4,284
Subtotal Direct Costs	**22,699**	**37,728**
Planning	681	1,132
Property Acquisition & Permitting	1,589	2,641
Survey & Structure Staking	454	755
Engineering	1,816	3,018
Project Management	1,589	2,641
Construction Management	1,135	1,886
Owner's Costs	1,135	1,886
Subtotal Indirect Costs	**8,399**	**13,959**
Transmission Line	31,098	51,687
Overhead & Interest (0.95%)	295	491
Contingency (25%)	7,774	12,922
Total Cost	**39,167**	**65,100**

** Based on YEC provided 138 kV transmission line cost estimate, including optical ground wire (OPGW)*

6.2.1.1 69 kV Transmission Line Construction Cost Estimate

A cost estimate has been prepared for the transmission line component of the Atlin Hydro Expansion Project. This is expected to include the portion of the line between Atlin and Jake's Corner, as well as 69 kV options for other portions of the line towards Whitehorse (discussed further in Section 6.3). A cost estimate at +/- 30% level is presented, which is the level of precision that is typically achieved at a pre-feasibility study level, with no site-specific geotechnical investigations and limited opportunity for detailed project optimization. The cost estimate includes all direct construction costs, as well as indirect, lodging and travel, engineering and permitting studies, construction supervision and Owner's costs. The cost estimate values are presented in Canadian dollars, based on 2016 costs with no escalation for future work. A contingency of 25% was added to all project costs, including Owner's costs.

Further cost estimate details and assumptions for a 69 kV transmission line are presented below.

Line Design Assumptions

Preliminary assumptions were made regarding the technical details of the transmission line design in order to prepare the cost estimate. These assumptions were based on industry standard practices and historical information from a number of 69 kV projects completed by MH for BC Hydro over the past five years. These technical details are not intended to be the basis for future engineering design efforts; they are solely used for cost estimating purposes. The actual aspects of the transmission line design will need to be determined when the engineering for the project begins.

Structures and Framing

The 69 kV transmission line support structures are expected to be single wood poles. Fifty-five foot Class 2 Western Red Cedar poles were assumed as the basis for the estimate. The poles are expected to be direct-embedded into native soil, with standard embedment depths. The framing includes a single timber cross-arm in a triangular configuration. The conductors are expected to be supported by standard porcelain clamp insulators. A standard span length of 100 m between poles has been used for the estimate. For sections of the 69 kV circuit with a distribution underbuild, the pole has been changed to a 65 ft Class 1 Western Red Cedar at 90 m spans. Future work should give consideration for allowing for distribution underbuild at the north end of the transmission line (Jakes Corner to Little Atlin Lake area).

Detailed engineering design has not been performed on the poles, however basic preliminary assessments of the suitability for the poles to support the applied loads and meet vertical clearance requirements has been considered. The structural loading and clearance requirements were taken from CSA Standard C22.3 No.1-10 Overhead Systems.

Conductors

The conductor for the 69 kV circuit is assumed to be 397 kcmil “Ibis” ACSR. There would be three conductors in a triangular configuration on the wood poles. A fibre optic cable underbuild has also been included. The selected cable is a self-supporting optical ground wire (OPGW) attached to the pole below the conductor crossarm.

Terrain Considerations

For the purposes of this cost estimate, average terrain conditions (being typical rolling terrain with well-drained soil with limited areas of bedrock outcrop) were assumed for the length of the circuit. The portion of the line from Atlin to Jake’s corner is expected to generally follow Atlin Road (BC Highway #7) along the relatively low terrain adjacent to Atlin Lake. The route is expected to avoid the more rugged mountainous terrain further to the east of the highway. The highway follows relatively gradual rolling hills, and in general not particularly steep, so major excavation and blasting are not expected.

The soil conditions along the route are anticipated to be primarily well-drained till (unsorted glacially derived sediments) or sand and gravel. There will be underlying bedrock that is exposed at some locations. In the area adjacent to Atlin Road, there is expected to be adequate overburden for direct-embedment of wood poles for the majority of the route, without the need for rock extensive foundations. Detailed geotechnical information was not available at the time of the cost estimate, so these assumptions will need to be confirmed.

A right-of-way for the poles will need to be cleared, generally following the east side of Atlin Road. The right-of-way is assumed to be generally contiguous with the cleared road allowance. The clearing is expected to include light brush and small trees for most of the route, with little to no heavy timber. A 15 metre wide machine cleared right-of-way for the 69 kV circuit has been assumed for the cost estimate which is similar to ATCO's contemporary clearing practice in Yukon. The required total ROW required has not been determined at this time. The Atlin Road in BC has a 200 ft (61 m) total right-of-way of which approximately 24 m total width has been cleared (9.0 m road width plus 7.5 m cleared right of way on either side), as shown on Figure 6-3. According to BC Ministry of Transportation and Highways Technical Circular T-03/14 (2014), transmission lines can be accommodated in the road right-of-way subject to approved design. Similarly in the Yukon the transmission line can be placed in the road ROW (Government of Yukon, Transportation Engineering Branch, Utility Line Guideline, 2005)

It is assumed the poles will be placed 9 m from the road shoulder. This cleared area is assumed to be required for 100% of the circuit route in BC, and 25% of the route in the Yukon because the Yukon portion of the road has significantly wider existing clearing due to recent re-construction of the road in Yukon. The poles are assumed to be directly accessible from the Atlin Road. No separate access road has been included for the circuit.

There are no significant water crossings expected along Atlin Road. There are multiple small creeks (the specific number has not been determined in this stage of study) that will be accommodated by the typical span length of the wood poles. Similarly, no significant avalanche areas were identified along the route.

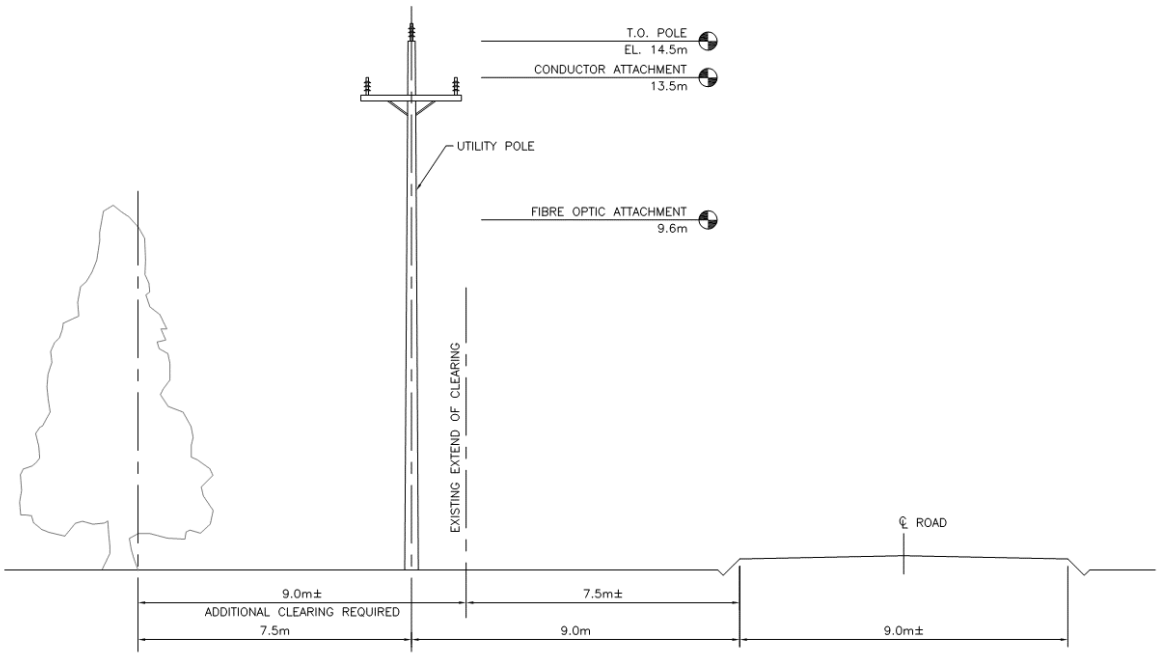


Figure 6-3. Typical 69 kV Pole configuration for BC portion of transmission line.

Indirect Costs

Indirect costs for the project include planning, property acquisition, permitting, survey and structure staking, engineering, project management, construction management, and owners' costs. Where more accurate data is not available these costs are based on historical values for similar transmission line projects in Yukon and British Columbia. Indirect costs are calculated as a percentage of the direct capital costs, and these are presented in Table 6-2 below.

Table 6-2. Indirect Costs as Percentage of Direct Costs

Indirect Cost	Percentage of Direct Costs
Planning	3%
Property Acquisition & Permitting	7%
Survey & Structure Staking	2%
Engineering	8%
Project Management	7%
Construction Management	5%
Owners' Costs	5%

Overhead, Interest and Contingency

The overhead and interest costs are based on historical values for similar transmission line projects in Yukon and British Columbia. They are taken to be 0.95% of the direct and indirect project costs. A 25% contingency has been applied to project components, including the transmission line, to account for unforeseen costs and additional items to be determined in the feasibility study.

6.2.1.2 138 kV Transmission Line Construction Cost Estimate

The cost of developing a 138 kV transmission line was provided by Yukon Energy Corporation (YEC) based on their previous work. In 2014 YEC completed an internal cost estimate for development of a 138 kV transmission line. This line assumes unit direct cost of $327,882 / km including optical ground wire (OPGW) for communication. The same indirect percentages as the 69 kV option were assumed.

The 138 kV line assume the standard wood-H pole design that is used in the Yukon. This requires a cleared right-of-way 30 m wide. In Yukon transmission lines of this size must be separate from the road right-of-way. For the purposes of this assessment it is assumed that the 138 kV transmission line would occupy a separately cleared 30 m right of way separated from the road by a vegetative (tree cover) barrier in both BC and Yukon.

6.2.1.3 Sources of Information

The estimates used data from the following sources:

- Information supplied by the YEC, including recent cost estimated completed for the 138 kV Stewart to Keno transmission line.
- Information contained in the Atlin BC to Yukon Interconnection Costing Study, August 9, 2011, prepared by BBA Engineering.
- Labour productivity values have been based on published data from the National Electrical Contractors Association (NECA) Manual of Labour Units. Factors have been applied to labour hours based on craft skill, worker availability, local conditions, potential winter work, rugged terrain, and complex work.
- RSMeans CostWorks 2015 cost estimating software and database
- Current in-house data and historical project data, available to Morrison Hershfield. This includes materials costs and contractor labour cost rates, typical for British Columbia and the Yukon.

6.2.1.4 Exclusions

- Applicable taxes
- Construction All Risk Insurance, liability insurance, or any other insurance types relevant to a construction project of this type
- Financing costs
- Fees and royalties
- Business development costs
- Removal of hazardous materials
- Public information forums
- Inspections and permits
- Allowance for funds used during construction (AFUDC)
- Overall site security, health and safety
- Ambulances and medical facilities
- Currency fluctuations beyond those specified in this Estimate
- Allowances for scope changes
- Event-driven risk
- Cost Escalations
- Escalation related to Owner's cost.
- Operating and Maintenance costs

6.2.2 Regulatory Considerations

As per Schedule 1, Part 4, Section 1 of the *Yukon Environmental and Socio-Economic Assessment Act* (YESAA) Assessable Activities, Exceptions and Executive Committee Projects Regulations, a 69 kV line of 50 km or less is subject to a Designated Office Evaluation. Under this assessment there is a requirement for an environmental and socio-economic impact assessment as per the Project

Proposal Form (provided by the Yukon Environmental Assessment Board (YESAB)). The form is submitted and subject to a three phase review process: Adequacy, Evaluation, and Recommendation.

Based on the criteria defined in Schedule 3 of the YESAA Regulations, a 138 kV line is anticipated to trigger an Executive Committee Review as the line is not likely to be contiguous to an existing right-of-way for its entire length. As per Schedule 3 of the Assessable Activities, Exceptions and Executive Committee Project Regulations, an Executive Committee Screening is required for the *"Construction or installation of a power line with a voltage of 138 kV or more or of a length of more than 50 km if the power line is not on a right of way developed for a power line, pipeline, railway line or road nor on a right of way contiguous to, for its whole length, a right of way developed for a power line, pipeline, railway line or road."*

Irrespective of whether a 69 kV or 138 kV line is selected, neither option would trigger environmental assessment requirements under the *British Columbia Environmental Assessment Act* (BCEAA), nor the *Canadian Environmental Assessment Act* (CEAA 2012).

Permitting requirements in British Columbia and Yukon are similar between the 69 kV and 138 kV options (additional permits for work within an existing right-of-way will be required for the 69 kV line, whereas the 138 kV will require other permits for development of a new utility right-of-way). With the larger disturbance footprint and separate right-of-way associated with the 138 kV line and Executive Committee level review, it should be expected that the permitting process will be more complicated and take more time than that expected for the 69 kV line.

6.2.3 Comparison Summary

As noted previously a 69 kV transmission line between Jakes Corner and Atlin is adequate for transferring the power from the Atlin Hydro Expansion project to the Yukon electrical system. 138 kV is a voltage that could be used for this line and is thought that this option could provide some benefits.

Advantages and disadvantages of the two options are summarized in Table 3 below.

Table 6-3. Comparison of 69 kV and 138 kV options for Yukon to Atlin transmission line.

Atlin to Jakes Corner Transmission Line Voltage	Advantages	Disadvantages
69 kV	• Lower cost; • Adequate capacity and acceptable line losses; • Can be accommodated in road right-of-way; • Relatively less clearing requirements; • Overall smaller project that has lower impact and simpler to maintain and operate. • Less complicated permitting, assessment and land acquisition requirements	• Requires a 69 kV to 34.5 kV or 138 kV substation in Yukon (either at Jakes Corner or Carcross).
138 kV	• Slightly lower line losses; • Potentially avoids a substation at Jakes Corner or Carcross, potentially saving $3,000,000; however increases substation cost in Atlin. • Significant additional transmission capacity (but is not likely to be required)	• Higher cost; • Requires separate right-of-way; • More complicated permitting & assessment requirements; • Twice as large clearing requirements and project footprint • Likely more complex and difficult to operate and maintain due to higher voltages.

The 69 kV line option is adequate for the proposed project needs and the advantages of the higher voltage option do not appear to outweigh the challenges and costs it possess. Therefore no further consideration of the a 138 kV line from Jakes Corner to Atlin is warranted at this time unless there are significant changes to power demands and supply in the Atlin region.

6.3 Yukon Connection Options Assessment

A set of three options for delivery and transmission of power from the Atlin Hydro Expansion project to the Yukon's electrical system have been considered. For the purposes of this assessment, each of these three options assumes a 69 kV transmission line from Atlin to Jakes Corner is required; therefore costs associated with this line (as presented in Section 1.2 above) are common to all options and not considered further in this assessment. The three primary options are:

1. connect to the existing ATCO's existing southern Yukon system at Jakes Corner;
2. connect to a new 138 kV transmission line in the Carcross valley; or
3. connect to a new transmission line along the Alaska Highway at Jakes Corner.

Each of the three options has two sub-options, described further in Sections 6.3.1to 6.3.3.

To assess these options, a high-level system study was completed by b7kennedy & Associates Inc. This report is provided in Appendix E. Substation costs for these options were prepared by Magna IV Engineering and can be found in Appendix F.

6.3.1 Option 1. Connect to Existing Electrical System

Option 1 looks to supply power to the southern Yukon making maximum utilization of the existing electrical infrastructure. The two sub-options are:

a) Connect to ATCO's line SL622 at Jakes Corner serving the Southern Lakes load as isolated. This assumes there is no interconnection to the existing Yukon electrical system at S150.

b) Connect to ATCO's line SL622 at Jakes Corner serving the Southern Lakes and is interconnected to the Yukon's electrical system via the 34.5kV line 9L to S150 in Whitehorse.

These options include the following new infrastructure (see Figure 6-1):

- A new substation with 69 kV bus at the upper Atlin hydro generating station;
- A 100 km long 69 kV transmission line to Jakes Corner; and
- A 69/34.5 kV substation at Jakes Corner.

The system study concludes that Option 1a) is not recommended because the Atlin Hydro Expansion project is not able to supply the entire Southern Lakes load under peak load conditions. Option 1b) which includes connection to the rest of the Yukon system at S150 is considered feasible and provides acceptable results from the point of view of voltage regulation and losses. Line losses to Jakes Corner at full generation (7.1 MW sent from Atlin) are estimated at 0.157 MW, or 2.2%. If it is assumed there is no load on the Southern Lakes system and all of the Atlin output is absorbed at Whitehorse, then line losses to Whitehorse would be at most 0.403 MW.

From a regulatory perspective, Option 1 is the simplest of the three options assessed, as it does not require any additional transmission infrastructure other than the Atlin to Jakes Corner transmission line itself.

Option 1b) is the simplest and lowest cost option because it does not require additional new transmission infrastructure other than the Atlin to Jakes Corner line and associated substations.

6.3.2 Option 2: Connect to a New 138 kV Transmission Line in Carcross Valley

Option 2 assumes connection to a new (future) 138 kV transmission line developed by Yukon Energy from their substation S171 in Whitehorse to Carcross. The two sub-options are:

a) The 69 kV interconnection to Jakes Corner is extended to Carcross and connected to the 138 kV system via a 138/69 kV substation in Carcross.

b) Extend the 138 kV line from Carcross to Jakes Corner and connect to the 138 kV system via a 138/69 kV substation in Jakes Corner.

These options include the following new infrastructure (Figure 6-4):

- A new substation with 69 kV bus at the upper Atlin hydro generating station;
- A 100 km long 69 kV transmission line to Jakes Corner;
- For Option 2a), a 69/34.5 kV substation at Jakes Corner; for Option 2b), a 69/34.5 kV substation and 69/138 kV substation at Jakes Corner;
- A 50 km long transmission line to Carcross at 69 kV for Option 2a), and 138 kV for Option 2b). The 69 kV assumes a distribution underbuild along the Tagish Road between Carcross and Tagish; and
- A 138 kV tap at an assumed pre-existing substation at Carcross.

Options 2a) and 2b) assume that a 138 kV line has previously been built from Whitehorse (S171) to Carcross.

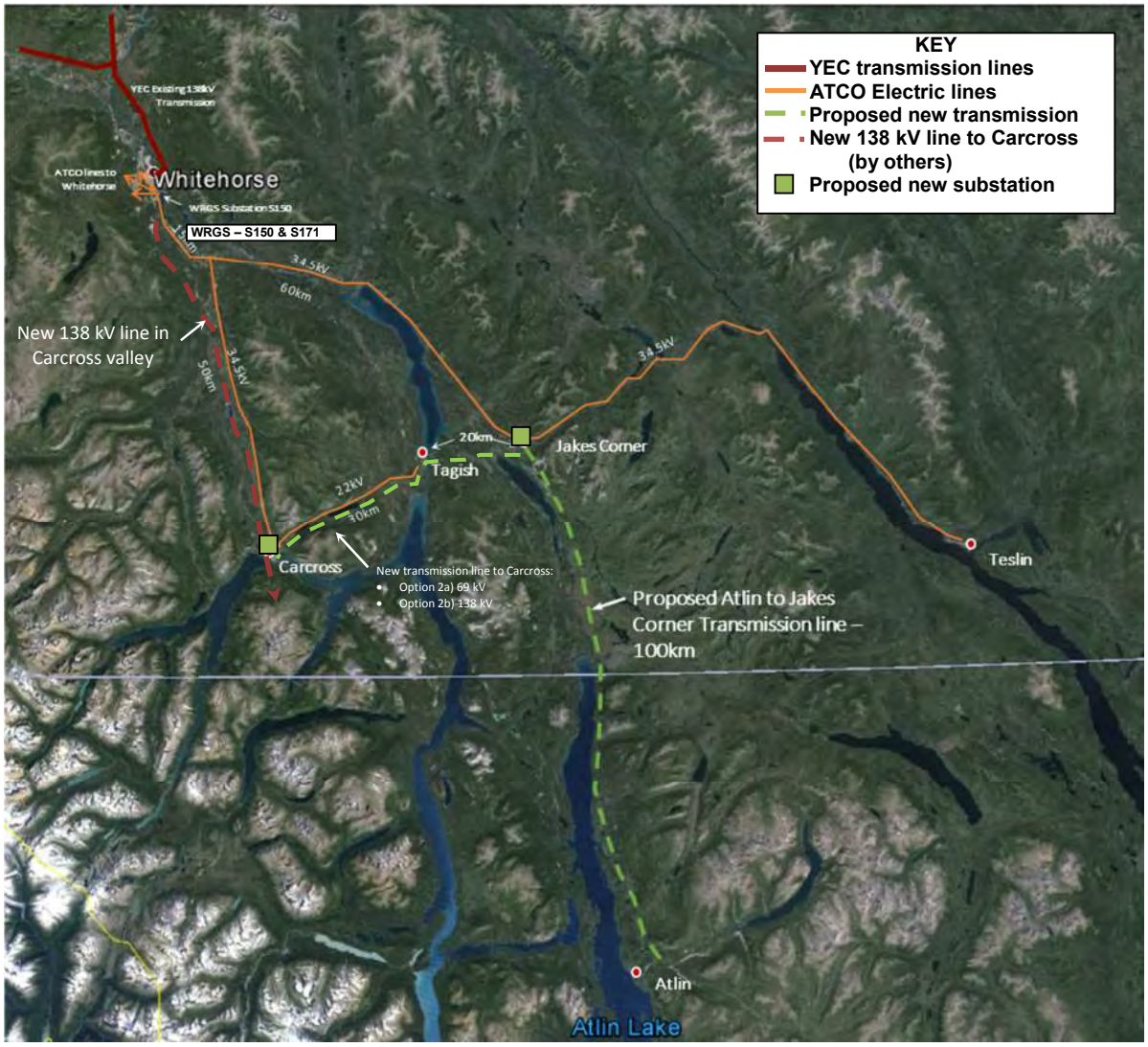
These options provide a connection both at Jakes Corner to ATCO's line SL622 and a connection of the future Carcross valley 138 kV line. It is assumed that the load is split between Jakes Corner and Carcross. Voltage regulation and line losses at full Atlin generation are similar to Option 1b), however with the split loads additional shunt compensation is required. From a performance perspective, Option 2 does not appear to provide any significant advantage, however there could be some system redundancy provided by connecting to the Yukon system at two points.

Assuming the 69 kV line would run within or contiguous to an existing right-of-way for its entire length, Option 2a) would be subject to a Designated Office Evaluation under YESAA. Conversely, it is assumed that a new 138 kV line would be in a separate right-of-way and therefore Option 2b) would be subject to an Executive Committee Screening. With respect to other permitting requirements, both Option 2a) and 2b) would have additional complexity relative to Option 1. Option 2a) would

require permitting and development of an additional 20 km of new 69 kV line between Tagish and Jakes Corner, plus the replacement of 30 km of existing distribution line between Carcross and Tagish. The new line would require a 15 m wide cleared right-of-way and it is assumed the replacement line would occupy the same right-of-way as the existing distribution line. A more involved permitting process is anticipated for Option 2b) when compared with Option 2a) given the larger footprint associated with an additional substation as well as 50 km of new 138 kV transmission line, which includes a 30 m wide cleared right-of-way. This would be separate from the existing distribution infrastructure.

If it is assumed there is no load on the Southern Lakes system and all of the Atlin output is absorbed at Whitehorse, then total line losses to Whitehorse would be at most 0.261 MW and 0.246 MW for Options 2a) and 2b) respectively.

Figure 6-4. Yukon system connection Option 2 - connect to a new 138 kV transmission line in the Carcross valley.



6.3.3 Option 3: Connect to Whitehorse with New Transmission Line along Alaska Highway

Option 3 assumes a new transmission line from Jakes Corner directly to Yukon Energy's Riverside substation (S171) in Whitehorse. This additional line would be in total 75 km long and paralleling the Alaska Highway. The two sub-options are:

a) A new 69 kV transmission line from Jakes Corner to S171. At S171 a 138/69 kV transformer is installed.

b) A new 138 kV transmission line from Jakes Corner to S171. At Jakes Corner a 138/69 kV substation is established.

These options include the following new infrastructure (see Figure 6-5);

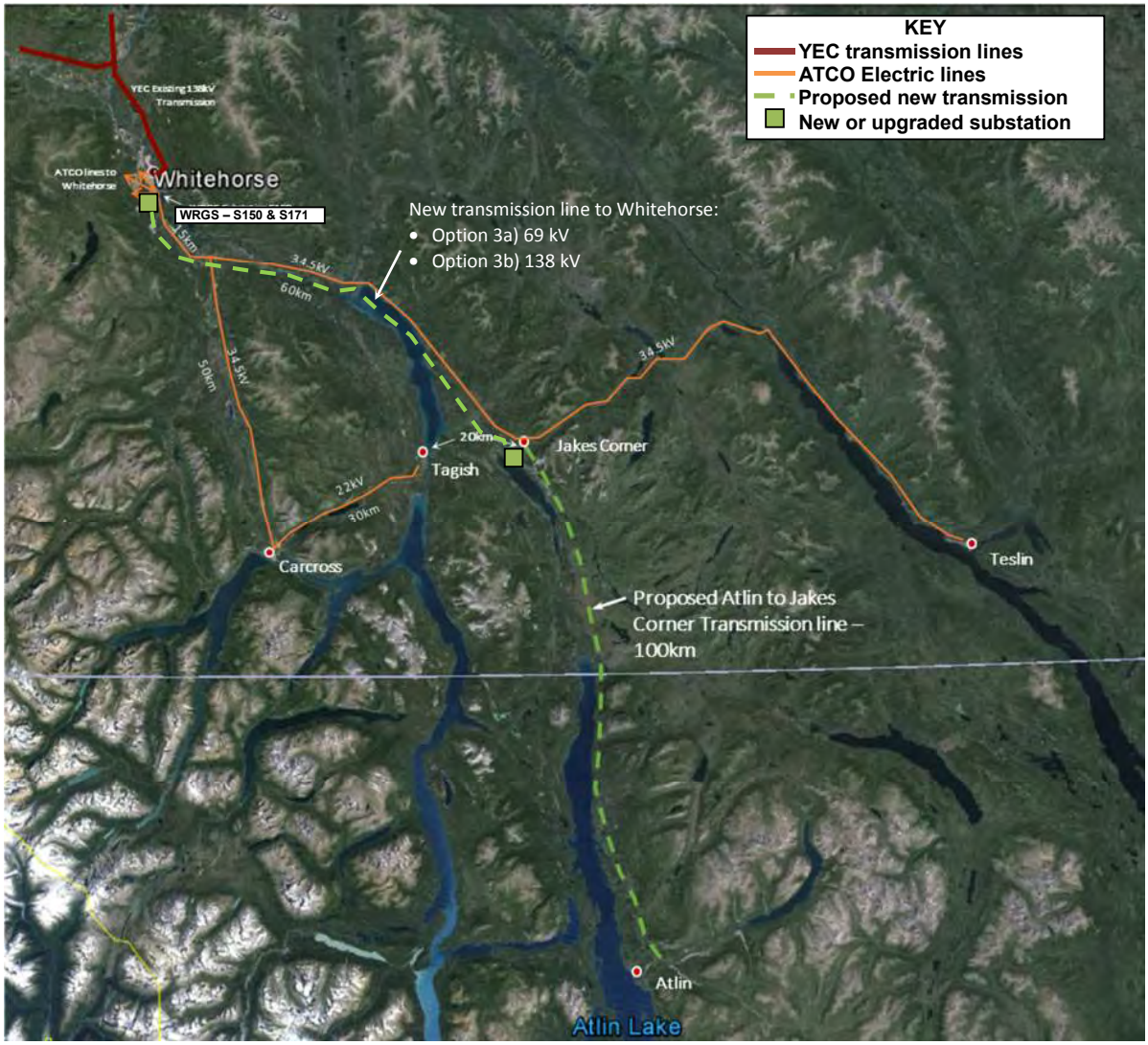
- A new substation with 69 kV bus at the upper Atlin hydro generating station;
- A 100 km long 69 kV transmission line to from Atlin to Jakes Corner;
- For Option 3a), a 69/34.5 kV substation at Jakes Corner; for Option 3b), a 69/34.5 kV substation and 69/138 kV substation at Jakes Corner;
- A 75 km long transmission line to Whitehorse at 69kV for Option 3a) and 138 kV for Option 3b). The 69kV assumes a distribution underbuild along the Alaska Highway between Jakes Corner and Whitehorse; and
- A 138 kV tap at S171 in Whitehorse.

These options provide a connection both at Jakes Corner to ATCO's line SL622 and a connection to S171 in Whitehorse. Shunt compensation is required at Jakes Corner for voltage support. Voltage regulation and line losses at full Atlin generation are similar to Option 1b). From a performance perspective, Option 3 does not appear to provide any significant advantage. Option 3a) assumes replacement of ATCO's aging distribution (34.5 kV) infrastructure along the Alaska Highway between Whitehorse and Jakes Corner. This may provide some infrastructure renewal benefit. Option 3b) does not replace ATCO's existing distribution infrastructure because it is assumed the new 138 kV line would be separate.

Assuming the 69 kV line would run within or contiguous to an existing right-of-way for its entire length, Option 3a) would be subject to a Designated Office Evaluation under YESAA. Conversely, it is assumed that a new 138 kV line would be in a separate right-of-way and therefore Option 3b) would be subject to an Executive Committee Screening. With respect to other permitting requirements, Option 3 would have additional complexity relative to Option 1. Option 3a) would require permitting and replacement of 75 km of existing distribution line between Jakes Corner and Whitehorse. The new line would require a 15 m wide cleared right-of-way and it is assumed the replacement line would occupy the same right-of-way as the existing distribution line. A more involved permitting process is anticipated for Option 3b) when compared with Option 3a) given the larger disturbance footprint associated with an additional substation as well as 75 km of new 138 kV transmission line, which includes a 30 m wide cleared right-of-way. This would be separate from the existing distribution infrastructure.

If it is assumed there is no load on the Southern Lakes system and all of the Atlin output is absorbed at Whitehorse, then total line losses to Whitehorse would be at most 0.275 MW and 0.187 MW for Options 3a) and 3b) respectively.

Figure 6-5. Yukon system connection Option 3 - connect to Whitehorse with new transmission line along Alaska Highway.



6.3.4 Yukon System Connection Options: Cost Estimate Summary

Table 6-4 below provides a summary of the estimated costs for the various options for connecting to the Yukon electrical system. This table details additional costs associated with the connection beyond the Atlin to Jakes Corner transmission line itself. Basis for transmission line cost estimates are provided in Sections 6.2.1.1 and 6.2.1.2 above. Substation costs were developed by Magna IV Engineering and details are provided in Appendix F.

Table 6-4. Yukon electrical system connection options cost summary (2016$).

Connection Cost Item	Option 1a ($000 CAD)	Option 1b ($000 CAD)	Option 2a ($000 CAD)	Option 2b ($000 CAD)	Option 3a [b] ($000 CAD)	Option 3b [b] ($000 CAD)
Additional Line Length	None	None	50 km	50 km	75 km	75 km
Additional Line Voltage	n/a	n/a	69 kV	138 kV	69 kV	138 kV
Direct Cost						
Additional Line Construction	Option not recommended	0 [c]	12,608	17,050	20,733	26,886
Clearing and Access		0	756	2,184	861	3,444
Subtotal Direct Costs		**0**	**13,364**	**19,234**	**21,594**	**30,330**
Indirect Cost						
Planning		0	401	577	648	910
Property Acquisition & Permitting		0	936	1,346	1,512	2,123
Survey & Structure Staking		0	267	385	432	607
Engineering		0	1,069	1,539	1,728	2,426
Project Management		0	936	1,346	1,512	2,123
Construction Management		0	668	962	1,080	1,517
Owner's Costs		0	668	962	1,080	1,517
Subtotal Indirect Costs		**0**	**4,945**	**7,117**	**7,990**	**11,222**
TOTALS						
Additional Transmission Line		0	18,309	26,350	29,584	41,553
Substation		1,446	2,690 [a]	2,501 [a]	2,690	2,501
Overhead & Interest (0.95%)		14	199	250	281	395
Contingency (25%)		362	5,250	7,213	8,068	11,013
Total Yukon Connection Cost	**n/a**	**1,821**	**26,449**	**36,315**	**40,623**	**55,462**

Notes: [a] this options assumes expanding an existing substation in Carcross or Whitehorse

[b] Option 3 assumes same substation costs as Option 2, but Carcross substation is located in Whitehorse.

[c] Option 1 does not require any additional transmission line beyond the primary Atlin to Jakes Corner line.

6.3.4.1 Yukon System Connection Options Conclusions

A summary of the various attributes for the six options are provided in Table 6-5. Based on this work, Option 1b) appears to be the most viable option. Connecting to the existing infrastructure at Jakes Corner is technically viable and should result in acceptable system performance. This option is the lowest cost and simplest to implement. The high-level system study has not identified significant upgrades to the existing grid required for this option beyond those costs presented herein.

Adding additional transmission infrastructure from Jakes Corner to Carcross or Whitehorse does not significantly improve transmission performance or reduce transmission losses from the Atlin Hydro Expansion project. Development of the additional transmission lines may have other benefits to the Yukon's electrical transmission system and the utilities; however they do not appear to be required for the Atlin Hydro project to deliver electricity to the Yukon.

Table 6-5. Yukon system connection options assessment summary.

Yukon System Connection Option	Option 1a) Jakes Corner Southern Lakes, isolated	Option 1b) – Jakes Corner Southern Lakes connected	Option 2a) – Carcross 138 kV 69 kV Jakes Corner to Carcross	Option 2b) – Carcross 138 kV 138 kV Jakes Corner to Carcross	Option 3a) – Whitehorse 69 kV Jakes Corner to Whitehorse	Option 3b) – Whitehorse 138 kV Jakes Corner to Whitehorse
High-level capital cost of connection (total include contingency (25%) & overhead)	n/a	No additional line req'd Substation Only: $1,446,000 Total $1,821,000	Additional line: $18,309,000 Substations: $2,690,000 Total: $26,449,000	Additional line: $26,350,000 Substations: $2,501,000 Total: $36,315,000	Additional line: $29,584,000 Substations[2]: $2,690,000 Total: $40,623,000	Additional line: $41,553,000 Substations[2]: $2,501,000 Total: $55,462,000
Technical feasibility	No Peak loads of Southern Lakes cannot be met	Yes Voltage regulation and losses are within acceptable ranges.	Yes Voltage regulation and losses are within acceptable ranges.	Yes Voltage regulation and losses are within acceptable ranges.	Yes Voltage regulation and losses are within acceptable ranges.	Yes Voltage regulation and losses are within acceptable ranges.
Transmission losses (at full generation of 7 MW sent)[1]	n/a	0.157 to 0.403 MW	0.157 to 0.261 MW	0.156 to 0.246 MW	0.157 to 0.275 MW	0.158 to 0.187 MW
System benefits	n/a	No additional benefits other than generation provided to Southern Lakes at Jakes Corner.	• Atlin hydro generation supplied at both Jakes Corner and Carcross. • Replaces 30 km Carcross to Tagish distribution line with new infrastructure.	• Atlin hydro generation supplied at both Jakes Corner and Carcross. • Extends higher-voltage transmission infrastructure to Jakes Corner.	• Replaces 75 km Whitehorse to Jakes Corner distribution line with new infrastructure[3].	• Extends higher-voltage transmission infrastructure to Jakes Corner[3].
Regulatory & environmental considerations	n/a	• No additional considerations other than Atlin to Jakes Corner transmission line. • YESAB Designated Office Evaluation assumed (69 kV and line ≤ 50 km) for Atlin to Jakes Corner transmission line.	• YESAB Designated Office Evaluation if line is within or contiguous with an existing right-of-way for its entire length. • Option assumes a 138 kV line exists to Carcross. • Requires development of 20 km of new line plus re-construction of 30 km of existing line. • Additional project footprint is assumed to be 15 m x 20 km = 30 ha.	• YESAB Executive Committee Screening, as line is not likely to be contiguous with an existing right-of-way for its entire length. • Option assumes a 138 kV line exists to Carcross • Requires development of 50 km of new line in a separate right-of-way. • Routing could be challenging due to extensive land ownership in Tagish area. • Additional project footprint is assumed to be 30 m x 50 km = 150 ha.	• YESAB Designated Office Evaluation if line is within or contiguous with an existing right-of-way for its entire length • Requires re-construction of 75 km of existing line.	• YESAB Executive Committee Screening, as line is not likely to be contiguous with an existing right-of-way for its entire length. • Requires development of 75 km of new line in a separate right-of-way. • Routing could be challenging due to terrain and land ownership constraints at the north end of Marsh Lake. • Additional project footprint is assumed to be 30 m x 50 km = 225 ha.

Notes [1] Higher line loss value assumes all of Atlin hydro output is absorbed at Whitehorse and all loads at Jakes Corner/Teslin and Carcross are switched off.

[2] For Option 3, substation costs are assumed to be the same as Option 2 but the substation is located in Whitehorse, not Carcross.

[3] ATCO Electric Yukon has indicated that by putting new transmission between Whitehorse and Carcross they could contribute financially to the project's capital cost because they would avoid the upcoming replacement cost of their 34 kV "transmission" infrastructure. Presumably the same would hold true for the Whitehorse to Jakes Corner leg as well. However, this consideration will not be included in the assessment at this time.

7 COST ESTIMATE & CONSTRUCTION SCHEDULE

7.1 Cost Estimate

A cost estimate has been prepared for the Atlin Hydro Expansion Project. A cost estimate at +/- 30% level is presented, which is the level of precision that is typically achieved at a pre-feasibility study level, with no site-specific geotechnical investigations and limited opportunity for detailed project optimization. The cost estimate is considered to be at a class 4 level based on the AACE framework. Quotes were however obtained for some key items of the project such as the turbines providing a slightly higher level of precision than AACE recommends for a class 4 cost estimate. The cost estimate includes all direct construction costs, indirect, lodging and travel, engineering and permitting studies, construction supervision and Owner's costs. A contingency of 25% was added to all project costs, including Owner's costs. Details for the cost basis is presented below while the complete cost estimate is presented in Appendix G.

Unit prices were selected to include both direct and indirect costs (man power, equipment, camp, travel, etc). Unit costs were derived from recent experience by the project team on similar project and ATELP actual costs from 2007 to 2009 for building the existing power plant. It should be noted that the hydropower industry has experienced considerable cost escalation in the last five years. Project experience has shown costs have been escalating faster than inflation and have been on the order of 25% increase since 2009.

Some of the reference projects costs have been provided by KGS based on their recent relevant project experience, including:

New Post Creek (OPG)

- 28 MW plant in north-eastern Ontario with two horizontal Francis turbines
- Preliminary design and tender documents by KGS, currently acting as Owner's Engineer
- Currently negotiating final pricing with design-build contractor (detailed tender cost breakdowns have been provided for KGS review)

Tazi Twé (formerly Elizabeth Falls, SaskPower)

- 50 MW, 4-unit plant in northern Saskatchewan
- Currently proceeding with final design, in Alliance-style partnership with SaskPower and Contractor
- Assisting SaskPower negotiate final project pricing with Contractor (detailed bid price cost breakdowns provided for review)

Mayo B (Yukon Energy Corporation)

- 10 MW, two horizontal Francis units, first power in December 2011
- KGS completed final design and were contact administrators
- Involved in initial negotiations with contractor, administered the open-book construction contract (contractor invoices included details on direct unit prices, quantities, employee hours, indirects, overhead, travel, camp costs, and profit markups)

Wawaitin (OPG)

- 8 MW plant with two Francis units, first power in 2010
- KGS assisted design-build contractor with initial bid, completed final design

Northern Hydro Study (SaskPower)

- KGS conducting pre-feasibility study of 8 potential hydro sites in northern Saskatchewan (near Northwest Territories border) ranging from 5 to 25 MW
- Turbine suppliers solicited for bid pricing
- Contractor with extensive hydroelectric construction experience were retained to review and confirm direct unit prices, indirects, and other markups carried in study cost estimates

Sechelt (Conwest, now Regional Power)

- 16 MW plant in BC with two Pelton units, first power in 1997
- KGS completed final design, contract admin and site supervision

KGS Group has also been involved in several larger hydroelectric construction projects (200 MW +) for Manitoba Hydro, both ongoing and in recent years. They have conducted similar work in northern Canada for repair and construction of water-retaining structures, from conceptual studies to detailed design. From these projects KGS has an extensive and up-to-date cost database, from detailed unit price and equipment costs through to final project costs for various structures and sizes of generating stations. Additional cost information was also obtained from similar local projects from Yukon Government (Highways and Community Services) as well at ATCO Electric Yukon (transmission line costs and Fish Lake Hydro upgrade project).

The following key unit costs were used for the main cost items of the project. Specifics of some of the quantity assumptions are stated in Appendix E. Various components were estimated as lump sum items due to the lack of design information available at this time. For example, the majority of the powerhouse mechanical and electrical balance-of-plant components were estimated as lump sum items based on ratios established on previous construction projects. A total cost allowance of $500,000 was also included for potential environment mitigation works associated with the lower power plant (not including fishways). The specific cost basis for key items is as follows:

Land clearing

Assumed $20,000/ha based on recent construction cost estimate in central Yukon. Actual costs for existing Atlin hydro project could have been lower, but actual unit prices could not be determined at this time.

Access roads (permanent)

$100,000/km based on actual mining resource road costs in Keno, Yukon has been used. Other hydro projects have experienced access road costs as high as $350,000/km.

General Excavation (dry)

$11.25/m^3$ has been used based on 25% cost escalation of actual general excavation costs paid in 2009 as part of the Atlin hydro construction. Other projects have experienced general excavation costs ranging from $20 to $35/$m^3$. The relatively low cost for general excavation assumed in this estimate is probably reasonable due to abundance of earthmoving capability in the Atlin area as a result of the placer mining industry.

General Excavation (rock)

$100/m^3$ has been used based input from ATELP and their actual experience with the previous hydro project. Other projects have experienced rock excavation costs in the order of $125/$m^3$

Rip rap (produce, haul & place)

$112.50/m^3$ has been used based on 25% cost escalation of actual rip rap costs paid in 2007 as part of the Atlin hydro's Surprise Lake control structure. At that time ATELP paid $27/$m^3$ for produce rip rap plus $63/$m^3$ to haul and place rip rap, including geotextile. Other projects have experienced rip rap costs ranging from $120 to $140/$m^3$.

Granular fill (supply and place)

$81.25/m^3$ has been used based on 25% cost escalation of actual supply and placement of drain rock costs paid in 2008 as part of the Atlin hydro construction ($65/$m^3$ in 2008).

Random backfill (supply and place)

$37.50/m^3$ has been used based on 25% cost escalation of actual supply and placement of drain rock costs paid in 2008 as part of the Atlin hydro construction ($65/$m^3$ in 2008).

Sheet Pile Cutoff Wall

$295.10/m^2$ has been used based on 25% cost escalation of actual sheet pile costs paid in 2007 as part of the Atlin hydro's Surprise Lake control structure. At that time ATELP paid $227/$m^3$ for supply and install of the Surprise Lake weir sheet pile wall. Other projects have experienced sheet pile costs up to $840/$m^2$.

1.52 m Ø I.D. HDPE Penstock

Penstock pricing was obtained from two suppliers: Uponor Infra Ltd of Mississauga Ontario and Wolseley Industrial of Langley BC. The latter was the HDPE penstock pipe supplier in 2009. Price for supply of pipe and freight to Atlin from Wolseley is (outside diameters are presented here):

63" DR41	$249.00/ft ($817/m)
63" DR32.5 (50 PSI)	$287.00/ft ($942/m)
63" DR26 (64 PSI)	$332.00/ft ($1089/m)
63" DR21(80 PSI)	$385.00/ft ($1263/m)

Plus installation costs:

- Joint welding = $3670 per day for 4 joints;
- Pipe haul and placement = Assumed $100/15 m using reduced price from Mayo-B;
- Indirect factor 1.25;
- Overhead and profit factor 1.12;

1.52 m Ø I.D. Steel Penstock

A price of $2,350/m for 3/8" coated steel pipe was used. This is based on the Mayo-B Hydro Project penstock prices which were $4.7/kg ($2016 using 5% escalation). This is for coated pipe, interior and exterior. This price is representative of the supply and installation of the pipe including welding and touch-up of the coating. The price does not include any excavation or filing. By way of comparison, in 2011 Mayo-B supply-only pipe was $2.5/kg which is $3.42/kg after escalation. However more current pricing for New Post hydro project is actually $7/kg supply and install, no backfill or excavation, no indirects or overhead and profit, however it is for a larger size pipe than was used in Mayo-B. Indirect factor of 1.25 plus overhead and profit factor of 1.12 have been added to the supply and install cost.

2.0 m Ø Steel Penstock

A price of $3,100/m for 3/8" coated steel pipe was used as per the considerations described for the 1.52 m penstock.

Volumes for penstock excavation and backfill were determined by using a typical cross section times the applicable length. Excavation and volume estimates for the lower head pond, dam and weir were determined using the preliminary design drawings as well as Civil 3D. Other excavation volumes were estimated based on the footprint of the proposed works and the assumed depths. Additional notes regarding the quantities estimated are presented with the detailed cost estimate in Appendix F.

Transmission line and substation costs were estimated for the 2016 report update and are provided in Section 6 of this report. A 2% inflation factor was applied to convert 2015 to 2016 prices.

Additional owner's costs were added to the total project costs on a percentage basis of the direct/indirect costs. The following costs were included, with the percentage value that was used:

- Feasibility study: 1.5%
- Final design & procurement: 5%
- Assessment & licensing (including environmental studies): 3%
- Site assistance & quality assurance: 5%
- Other owner's costs (including legal and financing): 4%

Table 7-1 presents a summary of the construction cost estimate of the Atlin Hydro Expansion Project. The hydroelectric generation project alone, without transmission is estimated at **79.7M$.** A total project cost of **120.7M$** is estimated including transmission required to connect with the Yukon's electrical grid at Jakes Corner.

A financial assessment was completed based on the project capital cost estimate. The total expanded Atlin Hydro project is estimated to produce on average 44.6 GWh/yr, of which between 6.2 and 8.3 GWh/yr is committed to BC Hydro by 2032. Therefore it is assumed the project will deliver 36.3 GWh/yr of energy to the Yukon's electrical grid (net of 2.2% line losses).

Table 7-1: Summary of Atlin Hydroelectric Expansion Project Estimated Construction Costs

Item		Cost (M 2016$)
SURPRISE LAKE CONTROL STRUCTURE UPGRADE		
1.	Site work	0.08
2.	Structures & Excavation	0.14
3.	Environmental & Mitigations	0.07
	Sub-total (1)	**0.3**
UPPER POWER PLANT EXPANSION		
1	Site Work	0.3
2.1	*Intake*	0.2
2.2	*Penstock*	10.7
2.3	*Powerhouse & Tailrace*	3.2
3	Turbine & Generator	3.9
4	Electrical & Mechanical Balance of Plant	4.0
	Sub-total (2)	**22.3**
LOWER POWER PLANT		
1.	Site Work	1.2
2.1	*Intake & Head Pond*	1.8
2.2	*Spruce Creek Diversion*	0.2
2.2	*Penstock (inc. surge facility)*	17.2
2.3	*Powerhouse & Tailrace*	3.0
3	Turbine & Generator	5.1
4	Electrical & Mechanical Balance of Plant	1.5
5	Transmission Line to Upper Powerhouse	0.9
6	Environmental & Mitigations	0.2
	Sub-total (3)	**31.0**
SUB-TOTAL DIRECT/INDIRECT COSTS (1-3)		**53.6**
	Engineering and Permitting (9.5 %)	5.3
	Construction supervision and owner's cost (9 %)	4.8
	Sub-total	**63.8**
	Contingency (25%)	15.9
HYDROELECTRIC PROJECT ONLY COSTS		**79.7**

Item	Cost (M 2016$)
TRANSMISSION LINE TO JAKES CORNER (4)	**24.1**
Planning, Engineering and Permitting (20%)	4.5
Project & Construction Management and owner's cost (18%)	4.1
Sub-total (4)	**32.7**
Contingency (25%)	8.2
TRANSMISSION LINE COSTS	**40.9**
TOTAL PROJECT COSTS W/ TRANSMISSION (1-4)	**120.7**

7.2 Schedule

Prior to the start of construction, all engineering and regulatory studies will have to be completed. A preliminary schedule is outlined based on the current state of the project and an optimistic development schedule (i.e. financial arrangements are in place). Additional details about engineering, environmental and regulatory studies are provided in section 7. It is assumed that funding will be made available to advance the required studies.

A preliminary construction sequence of the Atlin Hydro Expansion Project has been prepared. It is assumed that works are temporarily stopped during the middle of the winter period (mid-December to end of February). It is expected that construction would take 2 years to complete once all regulatory approvals are in place. It is assumed that work on the upper and lower power plants (and associated penstock) will be conducted simultaneously to achieve that schedule. If construction activities were to be conducted in sequence for each plant, it would likely require a third construction year to complete the project. The schedule that is currently proposed is the most optimal one to achieve the earliest in service date for the project.

Figure 7-1 provides an overview of the conceptual project schedule. A detailed construction schedule is provided in Appendix G.

Phase 1 – Surprise Lake Control Upgrade - Year 1 (March to May)

Work on upgrading the Surprise Lake Control structure should be done at a low-lake level period: March to May. The lake should be drawn down to the lowest level possible before commencing works. This phase could be conducted as early as the year before work on the power plants is initiated should regulatory approvals be in place. Commissioning the expanded operating range on Surprise Lake prior to downstream instream works is desirable because the lake's storage volume can be utilized to manage/minimize flows during downstream works. Work would include:

- Prepare shoreline access (snow / ice road) for excavation of upstream and downstream channel deepening;
- Raise overflow weir;
- Upgrade the fishway;
- Some reservoir clearing of low-area at west end of lake and other locations may be warranted.

Phase 2 –Upper & Lower Power Plants Year 1 (Feb to December)

Year 1 work consists primarily of site preparation and access, excavation and penstock construction. The construction is initiated during the winter with mobilization to site and preparation for the upcoming summer season. The following tasks will take place.

- Mobilization
- All falling and clearing work for intake pond, penstock and powerhouses should be conducted in late winter/spring so that it is completed prior to breading bird season;
- Develop access along the lower penstock and to lower powerhouse;
- Build lower penstock and lower powerhouse access roads;
- Excavation for penstocks and surge facility (overburden and rock);
- Install upper penstock and partially install lower penstock;
- Foundation preparation and excavation for both powerhouse;
- Construction of both powerhouses concrete substructure;
- Install superstructure for upper powerhouse (it should be possible to advance construction of the upper powerhouse faster because of its relatively lower complexity);

Phase 3 – Upper & Lower Power Plants - Year 2 (April to December)

Complete construction of all main works:

- Surprise Lake should be drawn down to lowest level possible prior to spring freshet to allow summer flows in Pine Creek to be attenuated by the lake;
- Construction of the second intake structure at the upper head pond – this should be done in spring when flows in Pine Creek are lowest;
- Excavation of the lower powerhouse tailrace should be done when Atlin Lake is at its lowest level: April and May.
- Excavation and construction of the lower head pond;
- Complete installation of penstock and surge pipe;
- Lower powerhouse superstructure construction;
- Turbines installation;
- Installation of mechanical and electrical balance of plant equipment;
- Construction of transmission line from lower powerhouse to switch yard at upper powerhouse;
- Filling of Surprise Lake up to the new full pond level;
- Commissioning of the upper power plant should be possible by the autumn of year 2 in time for winter generating period. Commissioning of the lower plant should be possible by the end of year two.

It is estimated that the construction of the transmission line to connect with the Yukon grid will take approximately 12 months to complete. It will take place at the same time as the construction of the project: over two summer/fall seasons approximately running from early May to end of October with any clearing done in the proceeding winter/early spring to avoid breeding bird conflicts. Completion of the transmission line should be scheduled to coincide with the commissioning of the upper power plant.

Figure 7-1. Overview Project Development Schedule

Atlin Hydro Expansion Prefeasibility Study

		2015				2016				2017				2018				2019				2020			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Engineering & Development																									
Pre-Feasibility	6 mo.	■																							
Feasibility*	1 yr		■	■	■	■																			
Detailed Design	1 yr						■	■	■	■															
Procurement	1.5 yr							←		■	■	■	■	■	■										
Construction	≤2 yr											←		■	■	■	■	■	■	■	■	→			
Commissioning - Reservoir Upgrade															*										
Commissioning - New Power plants																		←		*	*	→			
Regulatory																									
Regulatory Scoping		■																							
Environmental Baseline	6 mo. +/- 6 mo.	←	■	■	→																				
Regulatory Applications	6 mo.			■	■																				
YESAB	6 mo. +/- 6 mo.				←	■	■	→																	
Regulatory Approvals (BC & Yukon)	9 mo. +					■	■	■	→	- -	- -	- -	- -	→											

Notes: → *Arrows indicate range of schedule timing for item.*

** requires site investigation summer 2015.*

8 SUMMARY AND RECOMMENDATIONS

8.1 Summary

A simplified pre-feasibility study of the Atlin Hydroelectric Expansion Project has been completed. Pine Creek near Atlin, BC has been previously developed in 2009 as a 2.1 MW hydropower project to service the community's electrical needs. The objectives of this current study are:

1. Estimate the scale of the hydropower opportunity readily available for development on Pine Creek. How much power could be generated if the full potential of the site was developed? and
2. Is the expanded development of the site, for sale to the Yukon electrical grid, potentially economically viable?

The study is intended to determine the scale of the opportunity and determine if it is worthwhile to pursue. At this stage the development concepts have not taken into consideration environmental and social mitigations and only limited optimization of the project design has been completed. The design concepts presented in this study are preliminary in nature for the purpose of estimating project costs and are not necessarily representative of the ultimate design or layout of the project.

The study was supported by obtaining new 1-m topographic mapping of Pine Creek from the existing intake to Atlin Lake. A site visit was conducted in September 2014 that included a fly-over of the project site as well as a ground reconnaissance of the location of the proposed works, including a portion of the lower penstock alignment. The study did not include any geotechnical investigations on-site. Foundation condition assumptions for the proposed structures and penstock were determined based on site observations as well as past project experience at the site.

It is proposed to develop a total of 7.8 MW at Pine Creek, consisting of expanding the existing (upper) 2.1 MW powerhouse with an additional two turbines to bring the total installed capacity to 5 MW plus the addition of a second, or lower, powerhouse near Atlin Lake with an installed capacity of 2.8 MW. The upper power plant operates under a gross head of approximately 107 m and the lower plant has a gross head of approximately 56 m.

For the expansion of the upper power plant, a second 4 km long HDPE penstock will be required to convey a maximum flow of 3.55 m^3/s from the existing head pond to the powerhouse. The penstock will require the excavation of a trench, mainly through overburden materials except some limited bedrock excavations near the intake structure. The lower power plant requires 4 km of twin HDPE penstocks to convey a maximum flow of 7 m^3/s. A new excavated head pond just downstream of the existing (upper) powerhouse is required to supply the lower penstocks. Spruce Creek would be diverted into the lower head pond such that flows from Spruce Creek can be used to increase electrical generation at the lower power plant.

Increased storage in Surprise Lake to maximize winter electrical generation will be developed by modifying the existing control structure at the lake outlet. It is proposed to increase the storage range from 1.1 m to 2.5 m by increasing both top and bottom storage by approximately 0.7 m. This operating scheme would not require modification of the project's existing Permit Over Crown Land which allows storage of water up to elevation 913.85. The storage of water allows the project to

generate approximately 70% of its annual average energy production during winter months (November through April). Winter energy is of highest value to the Yukon's electrical grid.

In consideration of the existing hydropower infrastructure the Atlin Hydro Expansion Project has the potential to produce on average 44.6 GWh/yr of energy, of which at 36 to 38 GWh/yr is available for export to the Yukon after the community of Atlin's needs are met. Cost for the hydroelectric development only (without transmission) are estimated at **79.7M$** million. A total project cost of **120.7M$** estimated including a 69kV transmission line to connect with the Yukon's electrical grid at Jakes Corner.

8.2 Recommendations for Future Work

The financial analysis conducted as part of this study concludes that the Atlin Hydro Expansion Project appears to be potentially economically viable and therefore the project should be advanced to the feasibility stage. The feasibility study will need to confirm assumptions made in the current study and optimize technical and economic aspects of the project.

The following tasks should be conducted, in order, to confirm the project concept at the onset of the feasibility study:

1. Continue to operate year-round the flow and lake level monitoring program established in late 2014. The flow gauging program requires routine site visits to download the data and perform maintenance on the stations. Approximately 3 to 4 summer visits and at least 2 winter visits are warranted. Additional flow gauging should also be conducted at high water to refine the rating curves. In late 2015 update power estimates once the additional site-specific flow and water level data becomes available. The hydrology program should be continued until the project is completed.

2. Perform a preliminary geotechnical investigation program to determine foundation conditions at the location of the proposed lower powerhouse. This should initially consist of test pits and seismic surveys to determine soil conditions, groundwater levels and depth to bedrock. Follow-up geotechnical investigations (test pits) should look at foundation conditions at the upper powerhouse expansion, the lower head pond location and the lower penstock alignment. Additionally geotechnical drilling at the lower and upper powerhouse should be conducted to assess deep ground conditions.

3. Assess the economics of the alternative upper power plant arrangement that considers fully utilizing available head on upper Pine Creek. This alternate scheme may result in reduced utilization of the existing powerhouse, but could result in overall greater annual average power production.

4. With the additional data, complete a feasibility study based on the results of the geotechnical investigations, with further optimization of the proposed layouts. Additional attention should be given to the following elements:
    - Optimize operation of Surprise Lake with respect to environmental considerations and seasonal energy production. Optimize installed turbine capacity based on preferred operating schedule for Surprise Lake.

- Further assess the upgrade and outlet (hydraulic capacity) excavation needs for Surprise Lake control structure;
- Further assess the construction requirements for the lower head pond, specifically foundation conditions and impermeability of structures / foundation. Assess hydraulic performance of the lower head pond during winter conditions.
- Refine design of the lower penstock to address varied terrain conditions along the route.
- Optimization of design of the surge facility for the lower powerhouse.

5. Initiate supporting studies such as environmental baseline, land tenure assessment and regulatory matters.

6. Continue discussions regarding commercial arrangements for supply of energy to Yukon Territory's electrical grid.

Report Prepared and Reviewed by:

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JUNE 23, 2016

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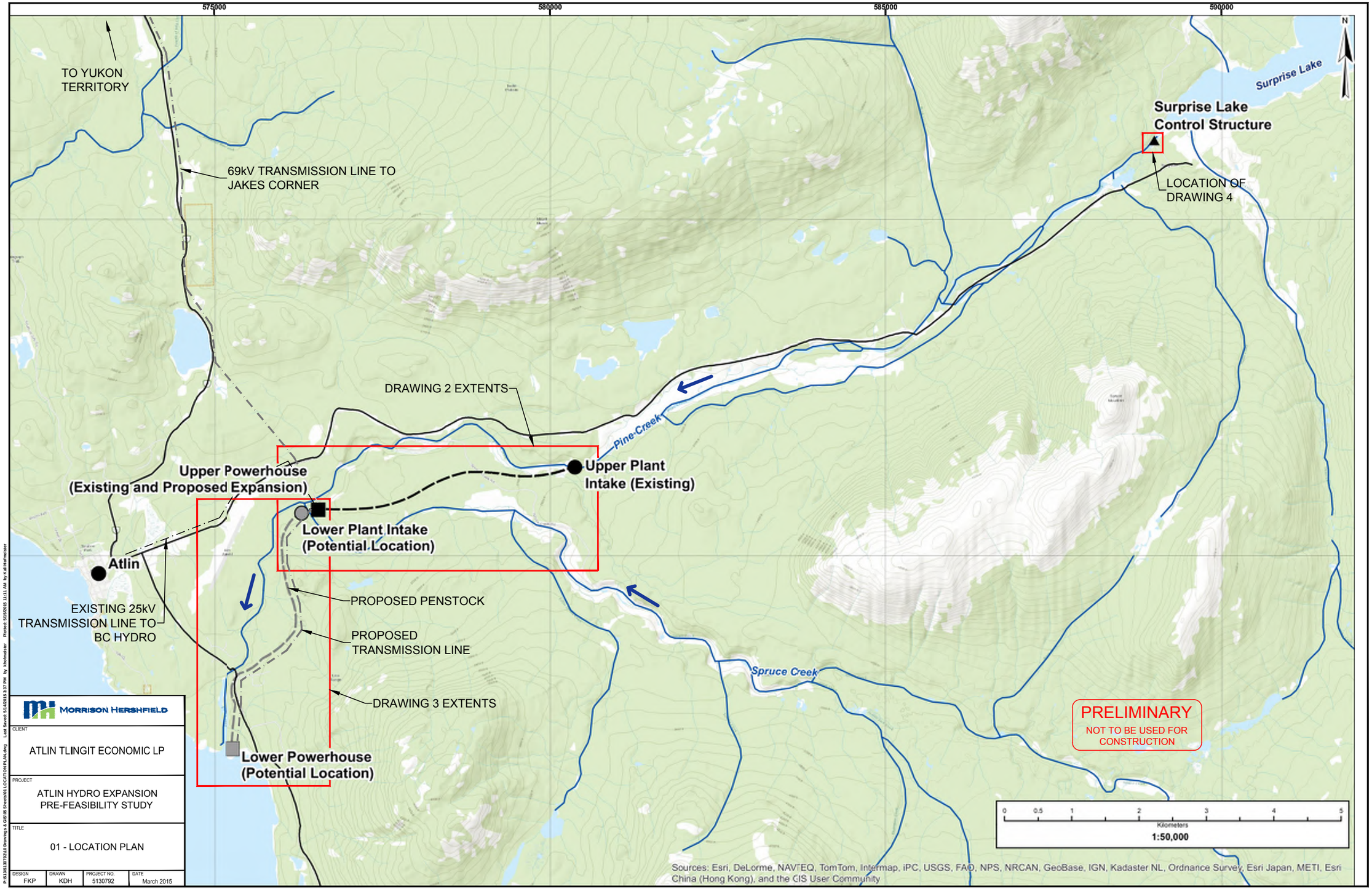
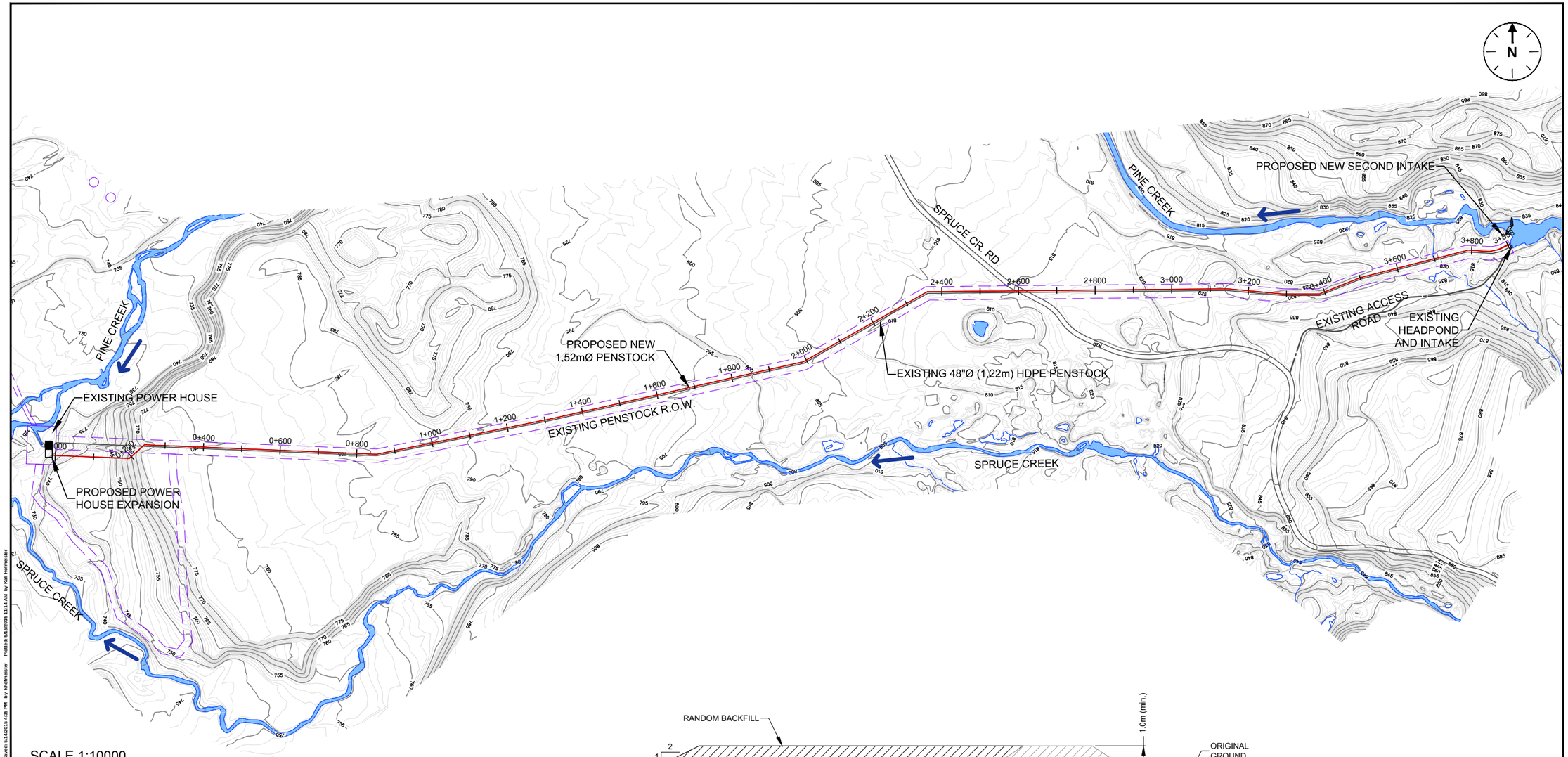
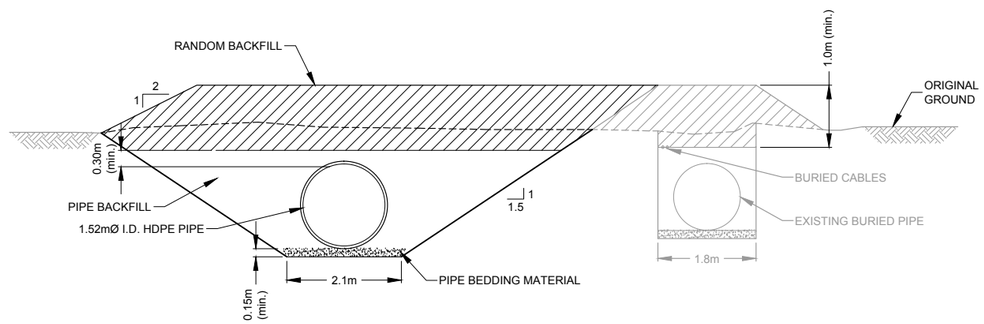
APPENDIX A:
Preliminary Design Drawings


575000
580000
585000
590000
N
TO YUKON TERRITORY
69kV TRANSMISSION LINE TO JAKES CORNER
Surprise Lake
Surprise Lake Control Structure
LOCATION OF DRAWING 4
DRAWING 2 EXTENTS
Pine Creek
Upper Plant Intake (Existing)
Upper Powerhouse (Existing and Proposed Expansion)
Lower Plant Intake (Potential Location)
Atlin
EXISTING 25kV TRANSMISSION LINE TO BC HYDRO
PROPOSED PENSTOCK
PROPOSED TRANSMISSION LINE
DRAWING 3 EXTENTS
Lower Powerhouse (Potential Location)
Spruce Creek
PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION
0 0.5 1 2 3 4 5
Kilometers
1:50,000
Sources: Esri, DeLorme, NAVTEQ, TomTom, Intermap, iPC, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), and the GIS User Community
MORRISON HERSHFIELD
CLIENT
ATLIN TLINGIT ECONOMIC LP
PROJECT
ATLIN HYDRO EXPANSION PRE-FEASIBILITY STUDY
TITLE
01 - LOCATION PLAN
DESIGN FKP
DRAWN KDH
PROJECT NO. 5130792
DATE March 2015





UPPER PENSTOCK TYPICAL SECTION

SCALE: 1:100

PROPERTY BOUNDARIES

LEASES & LICENSES

MORRISON HERSHFIELD

CLIENT	ATLIN TLINGIT ECONOMIC LP
PROJECT	ATLIN HYDRO EXPANSION PRE-FEASIBILITY STUDY
TITLE	02 - SITE PLAN - UPPER POWER PLANT EXPANSION

DESIGN	DRAWN	PROJECT NO.	DATE
FKP	KDH	5130792	March 2015

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

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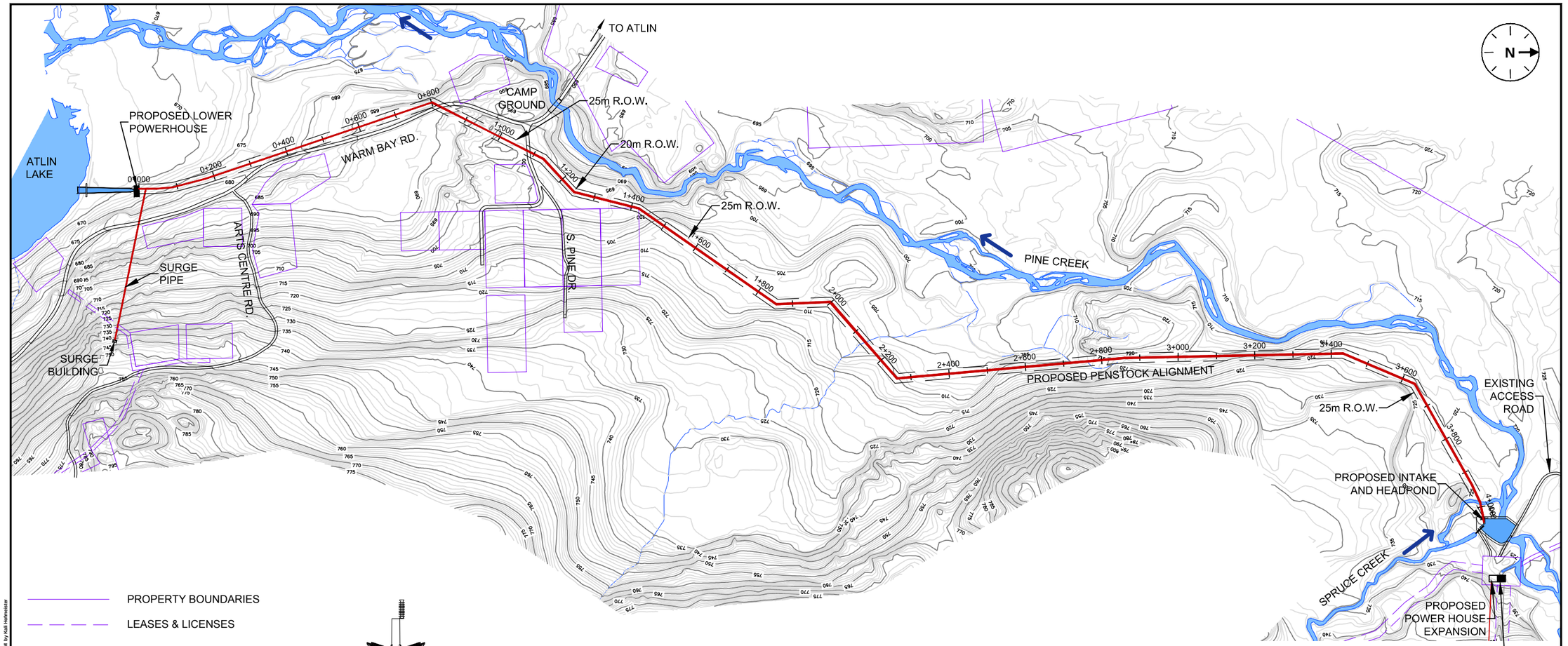

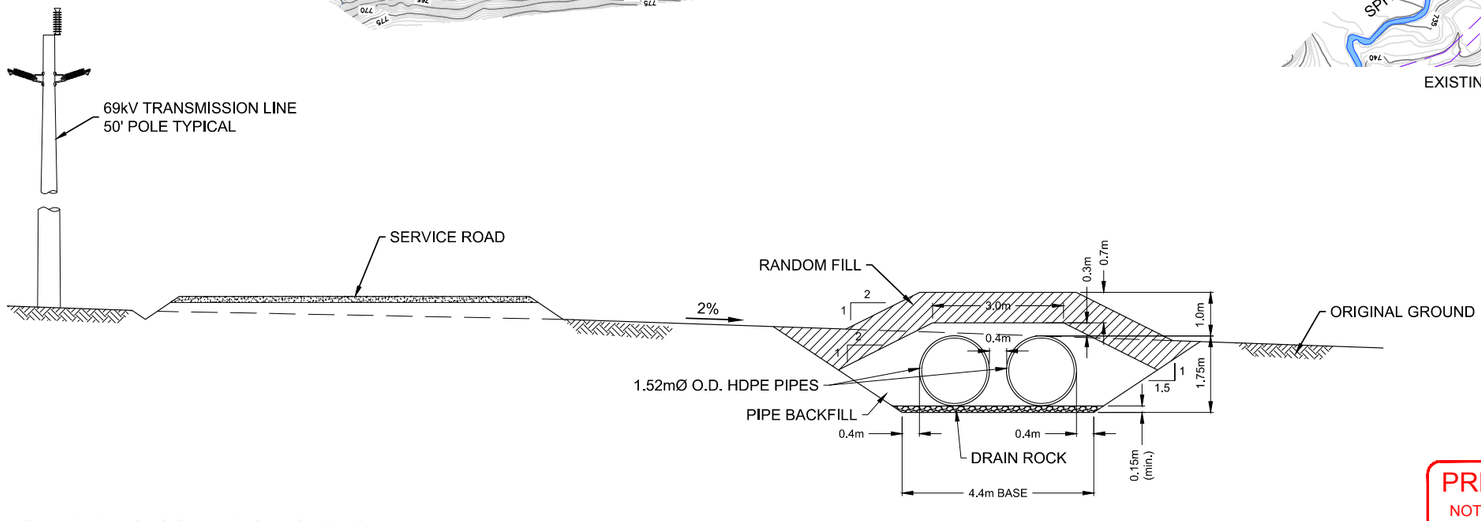

LOWER PENSTOCK TYPICAL SECTION

SCALE: 1:125

MORRISON HERSHFIELD

CLIENT	ATLIN TLINGIT ECONOMIC LP
PROJECT	ATLIN HYDRO EXPANSION PRE-FEASIBILITY STUDY
TITLE	03 - SITE PLAN - LOWER PLANT

DESIGN	DRAWN	PROJECT NO.	DATE
FKP	KDH	5130792	March 2015

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

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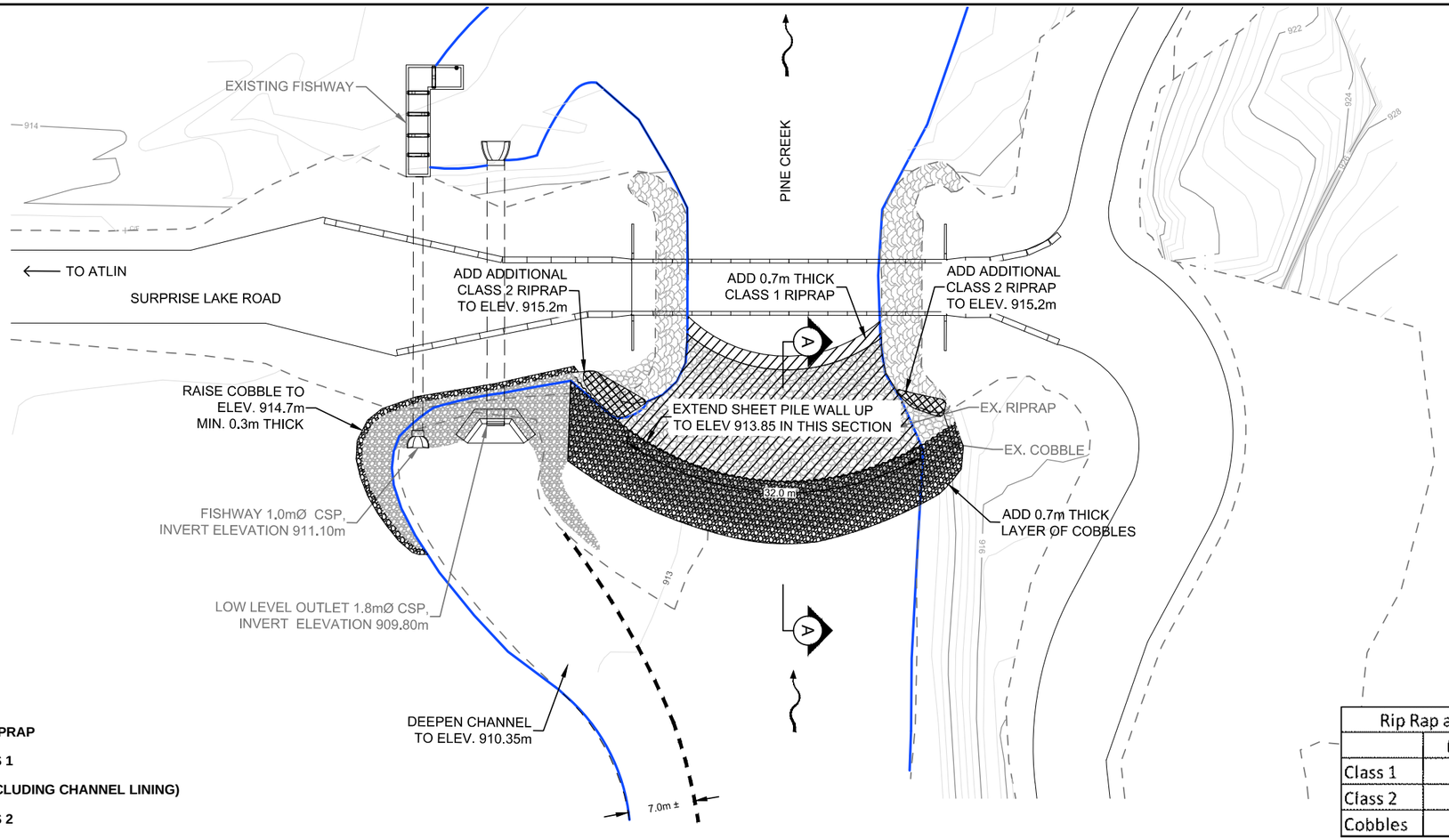
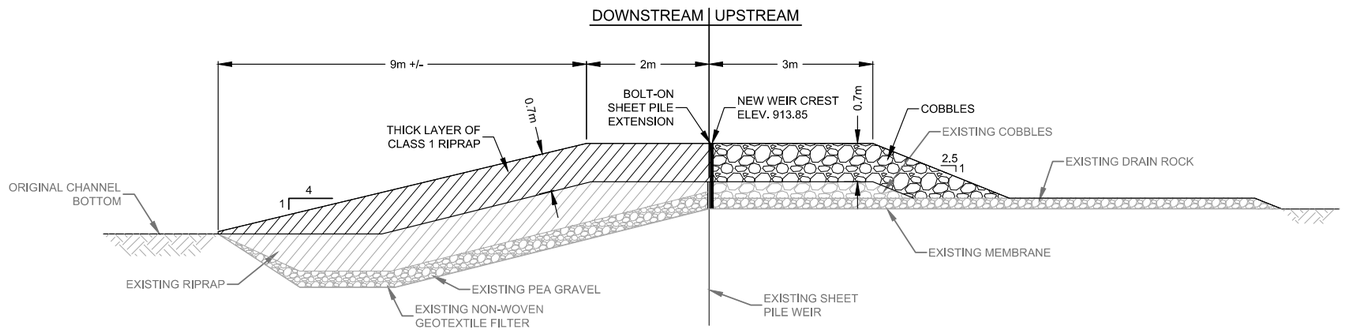


LEGEND

- AREA OF EXISTING LARGE RIPRAP
- AREA OF NEW RIPRAP CLASS 1
- AREA OF NEW COBBLES (EXCLUDING CHANNEL LINING)
- AREA OF NEW RIPRAP CLASS 2

Rip Rap and Cobble Dimensions			
	Dmin	D50	Dmax
Class 1	200	300	450
Class 2	300	500	800
Cobbles	50	200	350



SECTION A-A

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SCALE 1:500

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914.2	MAX FLOOD LEVEL
913.85	PROPOSED FULL POND LEVEL
913.15	CURRENT FULL POND LEVEL
912.10	CURRENT LOW POND LEVEL
911.35	PROPOSED LOW POND LEVEL

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

MORRISON HERSHFIELD

CLIENT: ATLIN TLINGIT ECONOMIC LP

PROJECT: ATLIN HYDRO EXPANSION PRE-FEASIBILITY STUDY

TITLE: 04 - SURPRISE LAKE CONTROL STRUCTURE

DESIGN	DRAWN	PROJECT NO.	DATE
FKP	KHD	5130792	March 2015

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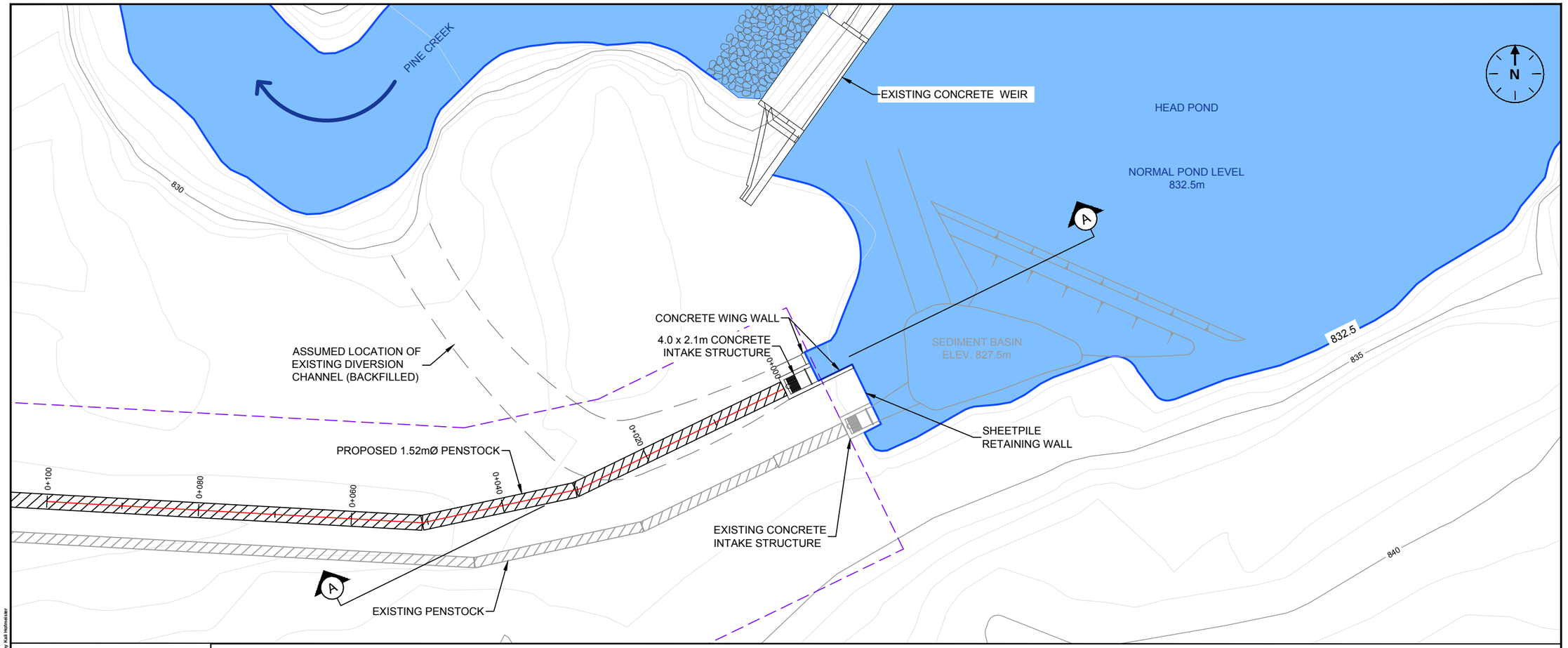

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

SCALE 1:500
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MORRISON HERSHFIELD

CLIENT
ATLIN TLINGIT ECONOMIC LP

PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
05 - UPPER PLANT INTAKE

DESIGN	DRAWN	PROJECT NO.	DATE
FKP	KDH	5130792	March 2015

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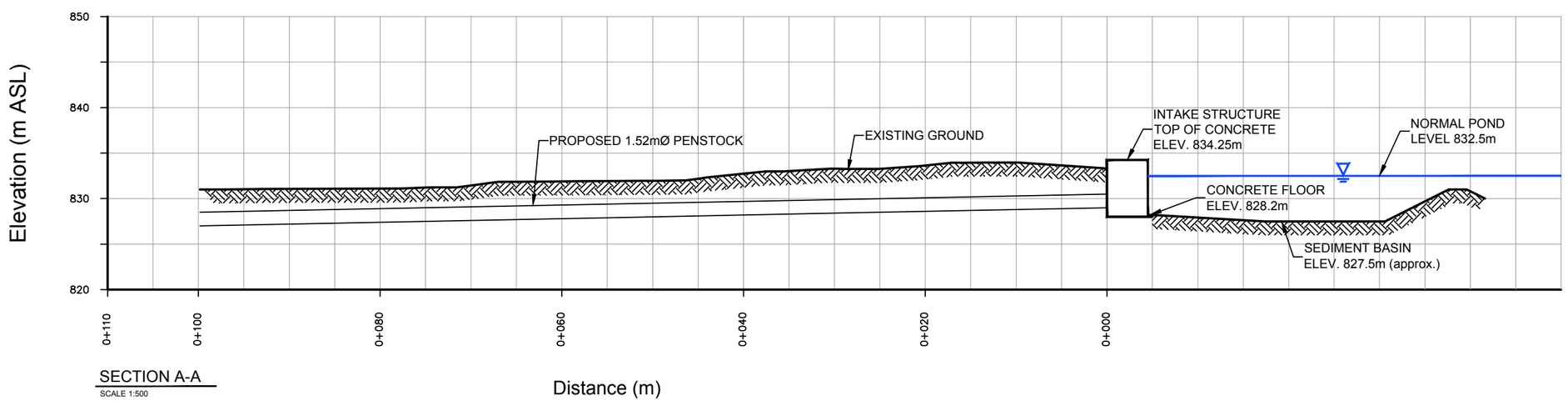

SECTION A-A
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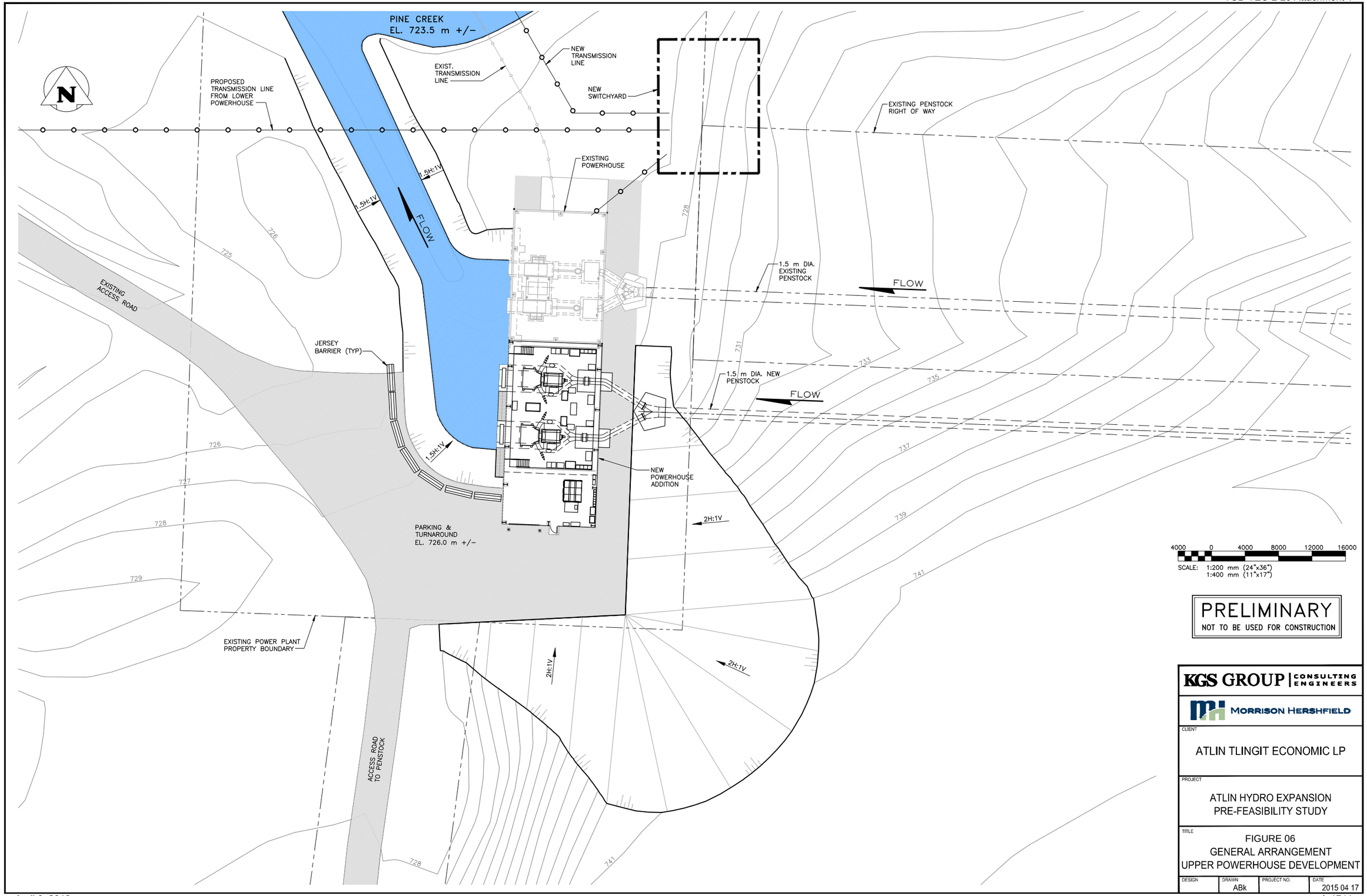

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1:400 mm (11"x17")

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

KGS GROUP | CONSULTING ENGINEERS

MORRISON HERSHFIELD

CLIENT
ATLIN TLINGIT ECONOMIC LP

PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
FIGURE 06
GENERAL ARRANGEMENT
UPPER POWERHOUSE DEVELOPMENT

DESIGN	DRAWN	PROJECT NO.	DATE
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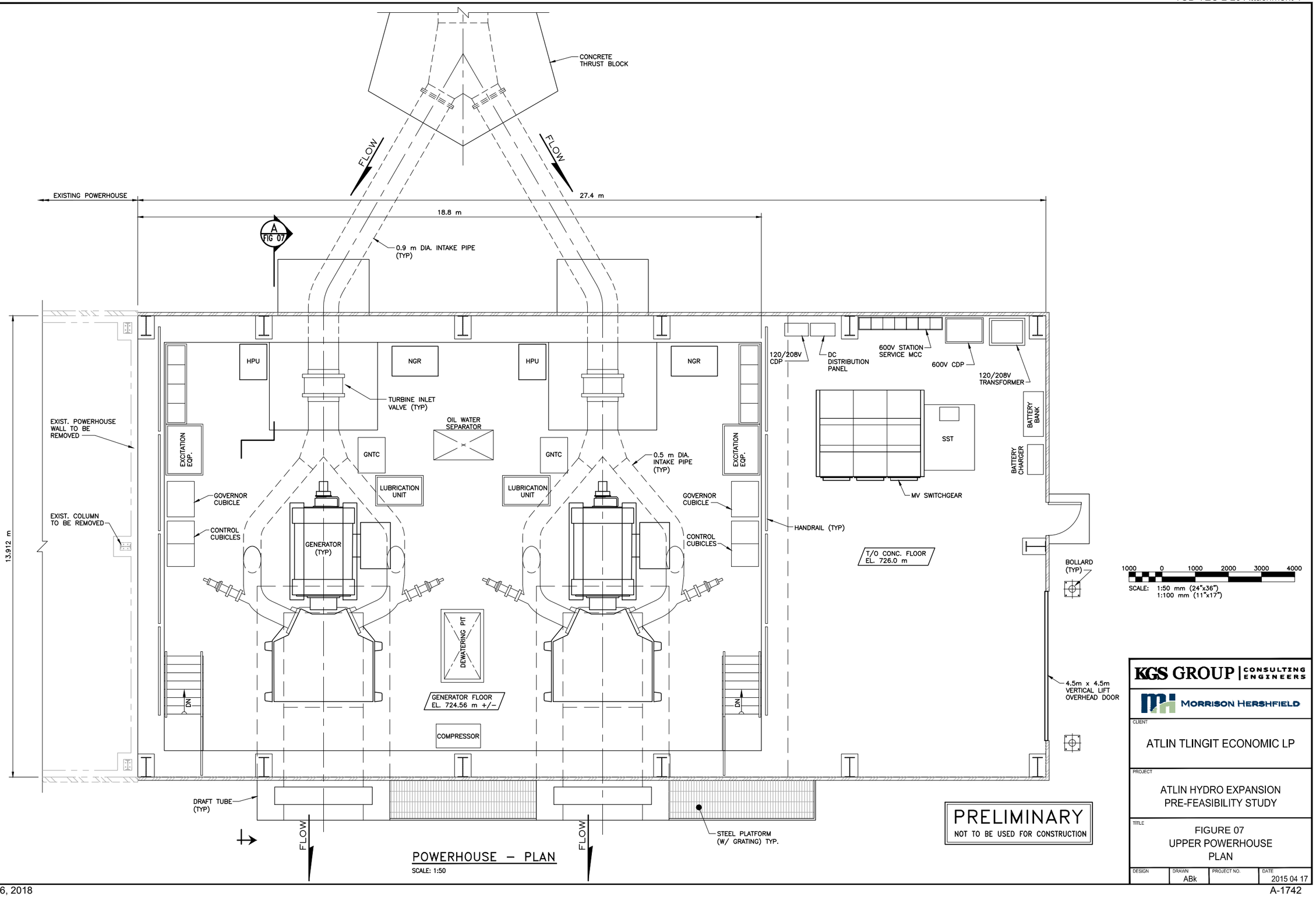

POWERHOUSE – PLAN
SCALE: 1:50

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

KGS GROUP | CONSULTING ENGINEERS
MORRISON HERSHFIELD

CLIENT
ATLIN TLINGIT ECONOMIC LP

PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
FIGURE 07
UPPER POWERHOUSE
PLAN

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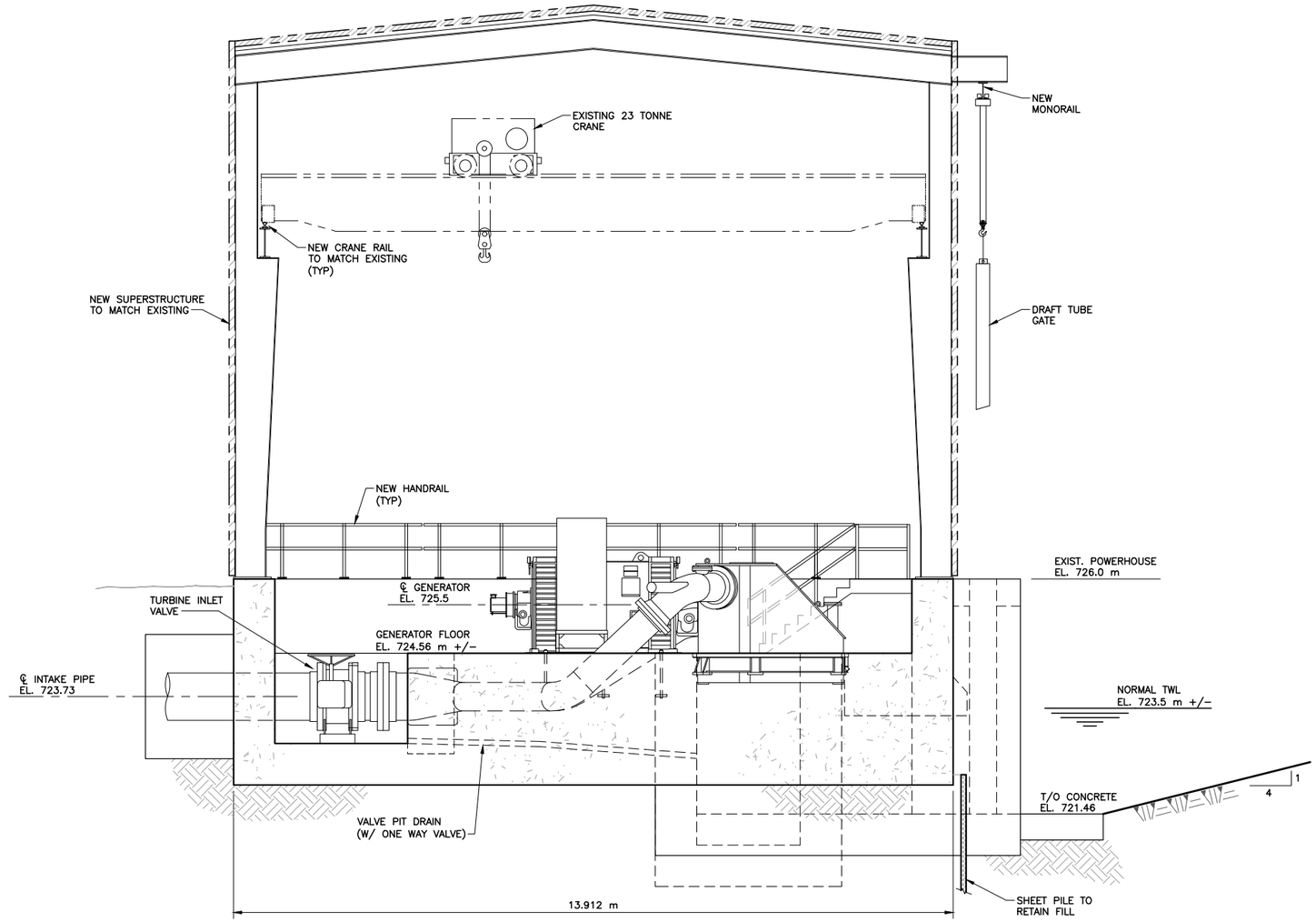

A FIG 06 POWERHOUSE – SECTION

SCALE: 1:50

NOTE: MISCELLANEOUS ELECTRICAL EQUIPMENT IS NOT SHOWN FOR CLARITY

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1:100 mm (11"x17")

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

KGS GROUP | CONSULTING ENGINEERS

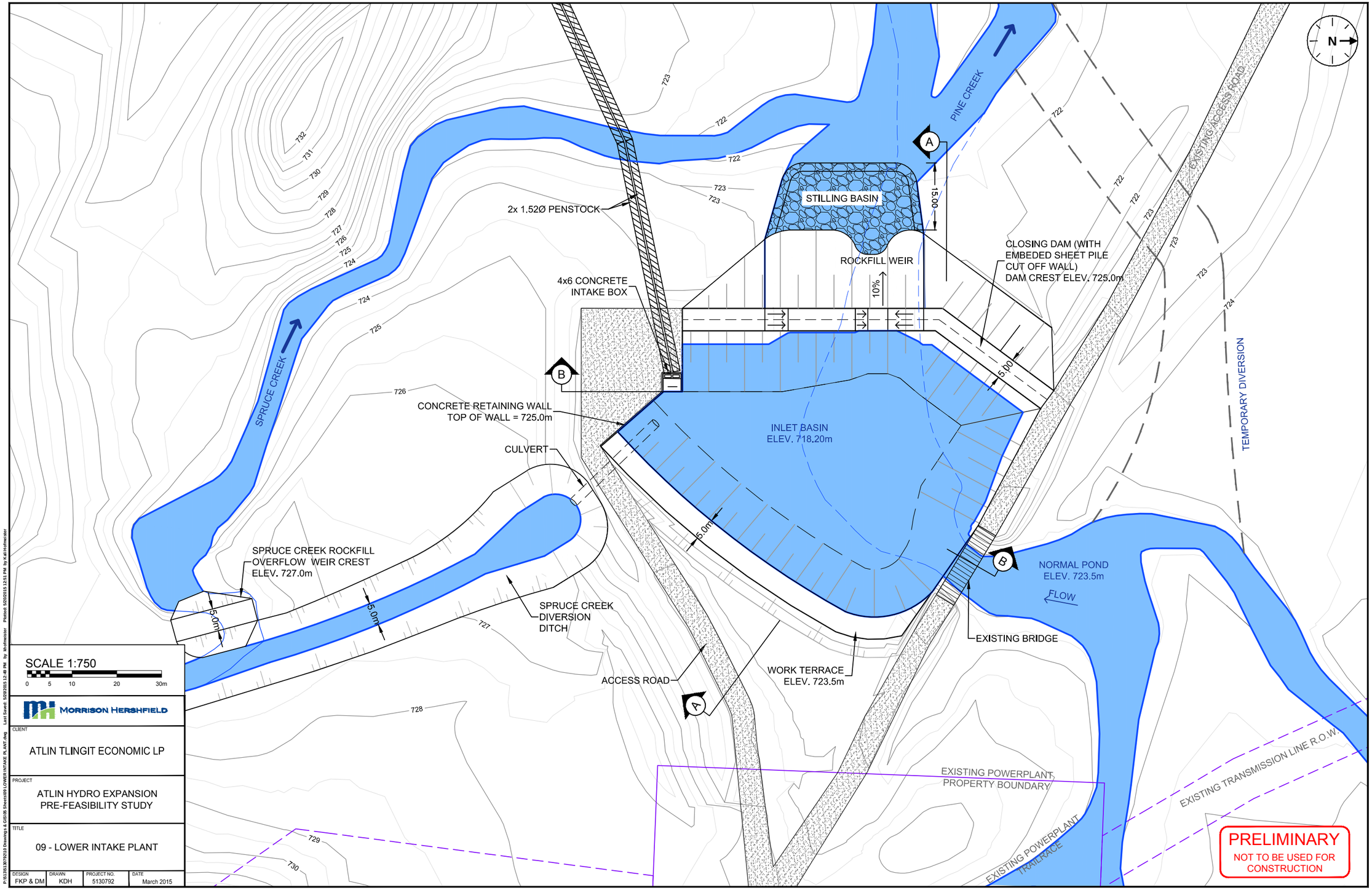
MORRISON HERSHFIELD

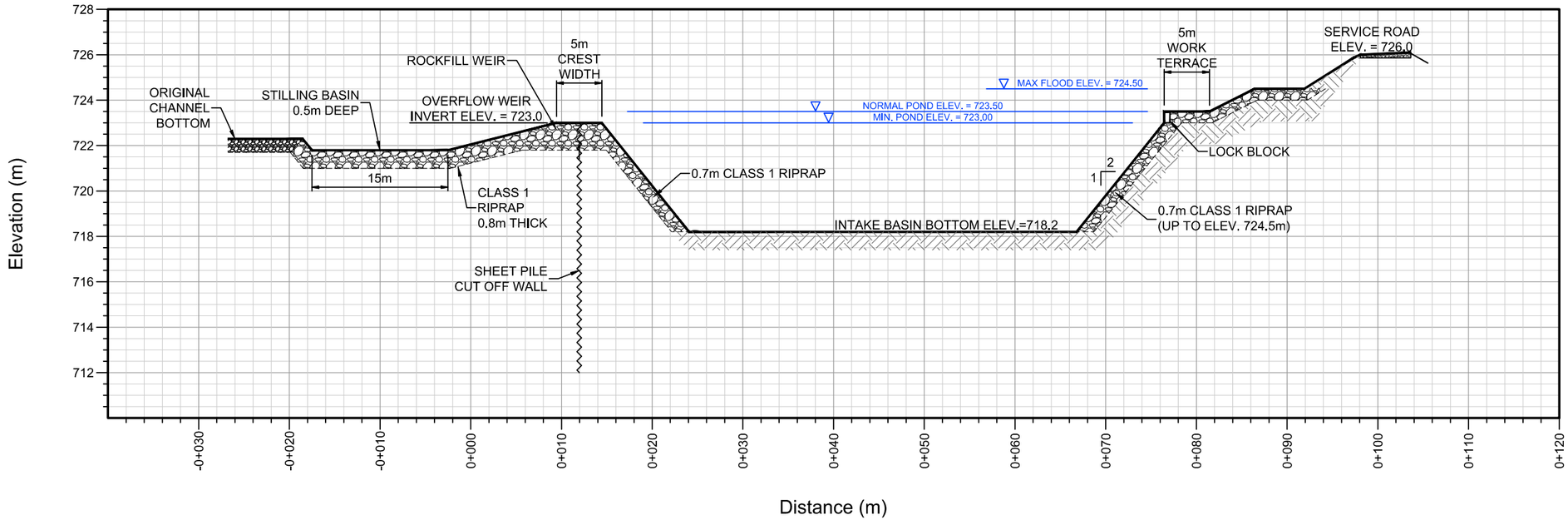
CLIENT
ATLIN TLINGIT ECONOMIC LP

PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
FIGURE 08
UPPER POWERHOUSE
SECTION

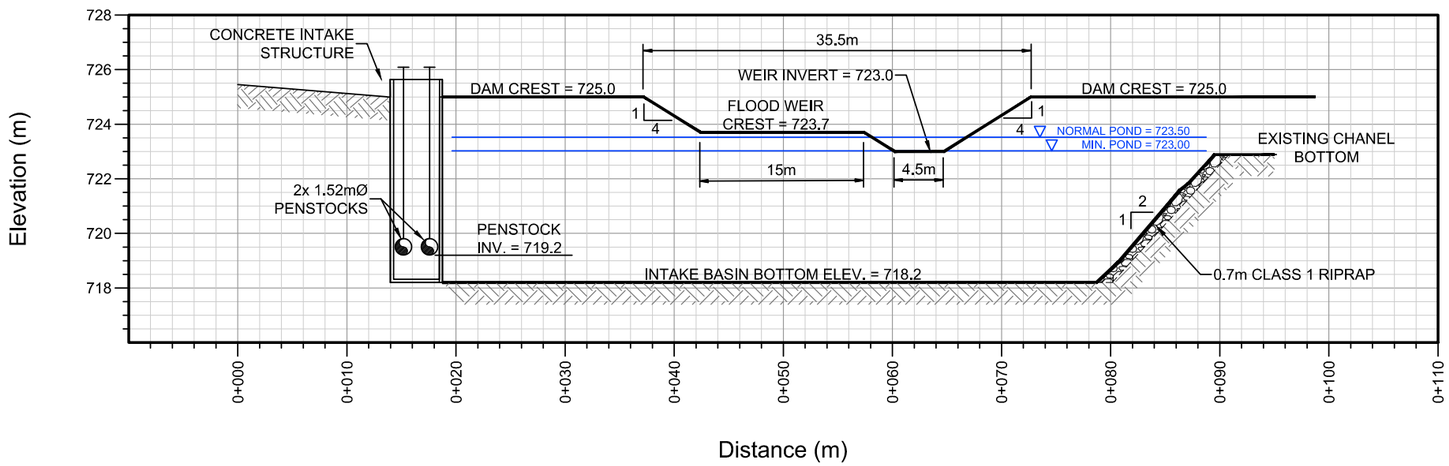
DESIGN	DRAWN	PROJECT NO.	DATE
	ABk		2015 04 17


N
PINE CREEK
SPRUCE CREEK
EXISTING ACCESS ROAD
TEMPORARY DIVERSION
2x 1.52Ø PENSTOCK
STILLING BASIN
15.00
ROCKFILL WEIR
10%
CLOSING DAM (WITH EMBEDED SHEET PILE CUT OFF WALL) DAM CREST ELEV. 725.0m
5.00
4x6 CONCRETE INTAKE BOX
CONCRETE RETAINING WALL TOP OF WALL = 725.0m
CULVERT
INLET BASIN ELEV. 718.20m
5.0m
SPRUCE CREEK ROCKFILL OVERFLOW WEIR CREST ELEV. 727.0m
SPRUCE CREEK DIVERSION DITCH
ACCESS ROAD
WORK TERRACE ELEV. 723.5m
EXISTING BRIDGE
NORMAL POND ELEV. 723.5m
FLOW
EXISTING POWERPLANT PROPERTY BOUNDARY
EXISTING POWERPLANT TAILRACE
EXISTING TRANSMISSION LINE R.O.W.
A
B
722
723
724
725
726
727
728
729
730
731
732
SCALE 1:750
0 5 10 20 30m
MORRISON HERSHFIELD
CLIENT
ATLIN TLINGIT ECONOMIC LP
PROJECT
ATLIN HYDRO EXPANSION PRE-FEASIBILITY STUDY
TITLE
09 - LOWER INTAKE PLANT
DESIGN FKP & DM
DRAWN KDH
PROJECT NO. 5130792
DATE March 2015
PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION



SECTION A-A LOWER INTAKE POND

SCALE: HORZ.=50 VERT.= 200



SECTION B-B LOWER INTAKE POND

SCALE: HORZ.=50 VERT.= 200

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

MORRISON HERSHFIELD

CLIENT	ATLIN TLINGIT ECONOMIC LP
PROJECT	ATLIN HYDRO EXPANSION PRE-FEASIBILITY STUDY
TITLE	10 - LOWER INTAKE SECTIONS

DESIGN	DRAWN	PROJECT NO.	DATE
FKP & DM	KDH	5130792	March 2015

P:\5130\43\WP\010 Drawings\4.4.5\5130_Sheets\010 LOWER INTAKE SECTIONS.dwg Last Saved: 05/5/2015 10:07 AM by Knothenbeir Plotted: 05/5/2015 11:23 AM by Kyle Hohmeier

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

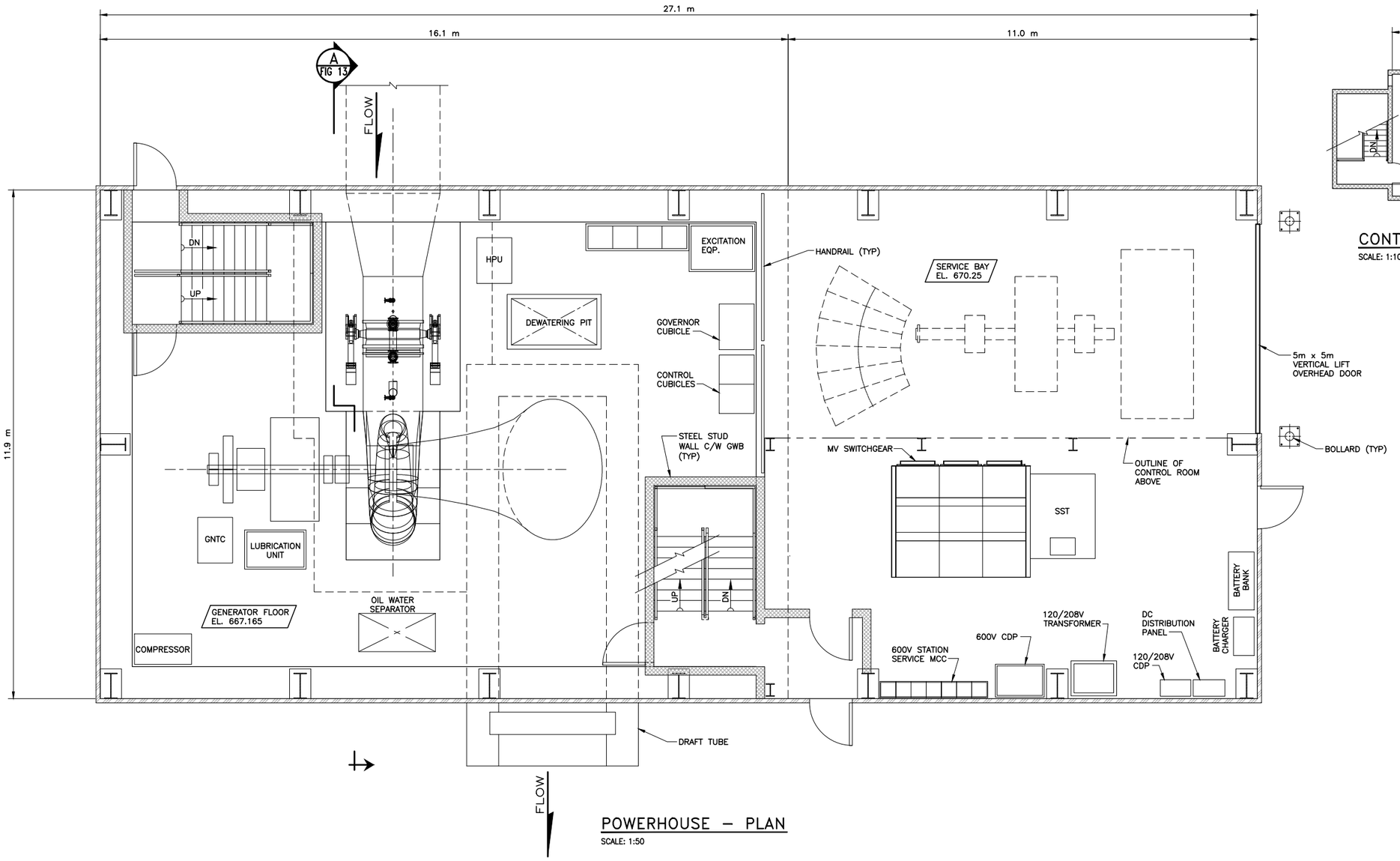
KGS GROUP | CONSULTING ENGINEERS
MORRISON HERSHFIELD

CLIENT
ATLIN TLINGIT ECONOMIC LP

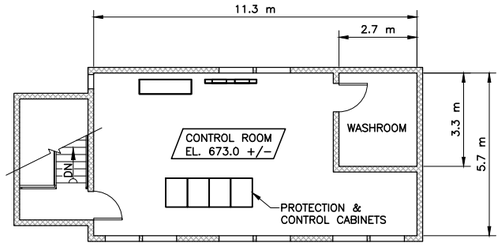
PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
FIGURE 11
GENERAL ARRANGEMENT
LOWER POWERHOUSE DEVELOPMENT

DESIGN	DRAWN	PROJECT NO.	DATE
	ABk		2015 05 20



POWERHOUSE – PLAN
SCALE: 1:50



CONTROL ROOM & OFFICE FLOOR PLAN
SCALE: 1:100

2000 0 2000 4000 6000 8000
SCALE: 1:100 mm (24"x36")
1:200 mm (11"x17")

1000 0 1000 2000 3000 4000
SCALE: 1:50 mm (24"x36")
1:100 mm (11"x17")

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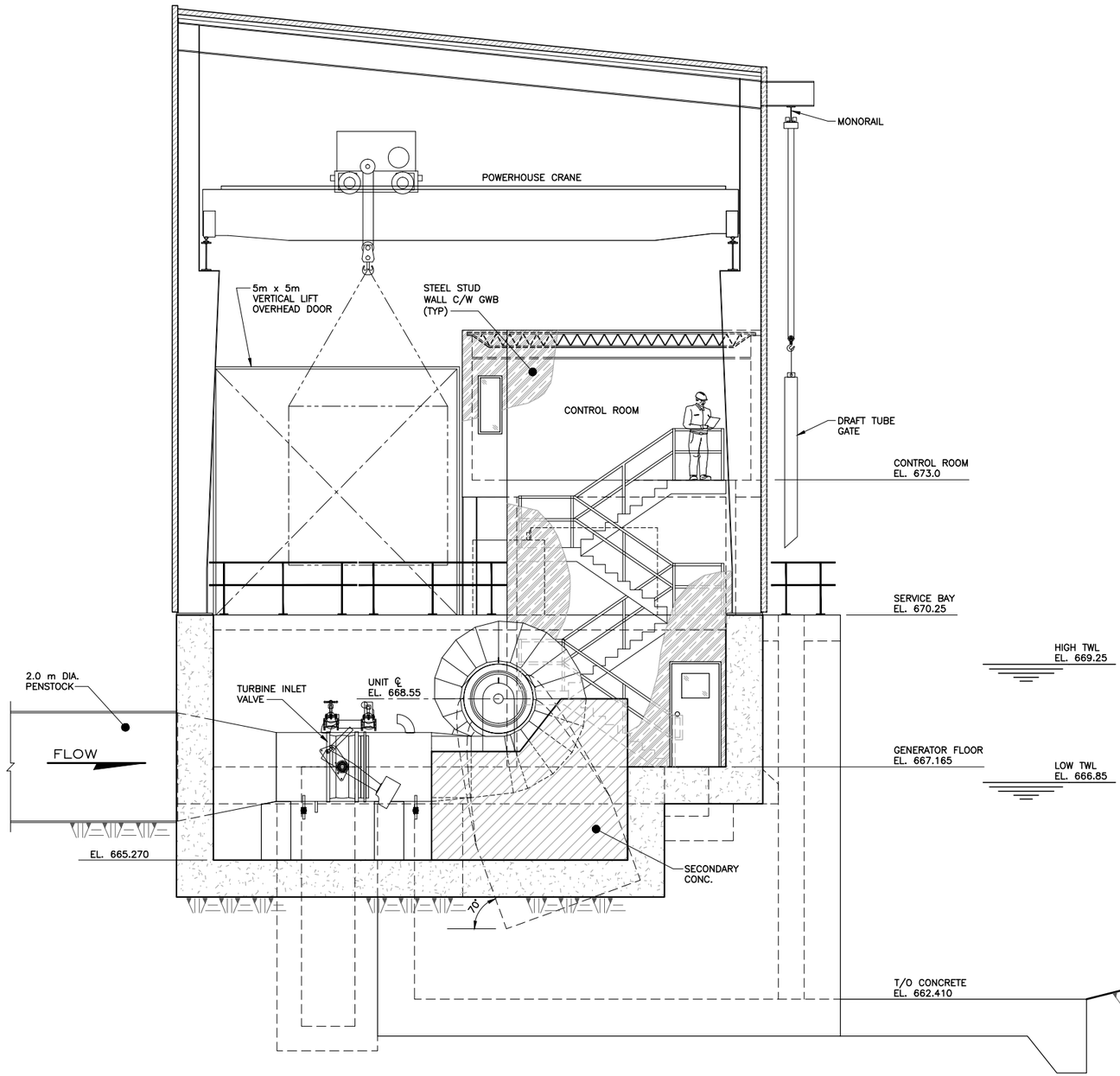
CLIENT
ATLIN TLINGIT ECONOMIC LP

PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
FIGURE 12
LOWER POWERHOUSE
PLAN

DESIGN	DRAWN	PROJECT NO.	DATE
	ABk		2015 05 20



A FIG 12 POWERHOUSE – SECTION
SCALE: 1:50

1000 0 1000 2000 3000 4000
SCALE: 1:50 mm (24"x36")
1:100 mm (11"x17")

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CLIENT
ATLIN TLINGIT ECONOMIC LP

PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
FIGURE 13
LOWER POWERHOUSE
SECTION

DESIGN	DRAWN	PROJECT NO.	DATE
	ABk		2015 05 20

APPENDIX B:
Topographic Mapping

N

EXISTING HEADPOND AND INTAKE

PINE CREEK

SPRUCE CK RD

EXISTING ACCESS ROAD

EXISTING 48"Ø HDPE PENSTOCK

EXISTING PENSTOCK R.O.W.

EXISTING POWER HOUSE

SPRUCE CREEK

SCALE 1:5000

0 50 75 100 125 150 175 200m

MORRISON HERSHFIELD

CLIENT

ATLIN TLINGIT ECONOMIC LP

PROJECT

ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE

02 - SITE PLAN - UPPER POWER PLANT EXPANSION

DESIGN	DRAWN	PROJECT NO.	DATE
_ _ _	KDH	5130792	Apr 16, 2015

\\mh.local\data\proj\513\51307921\0 Drawings & GIS\05 Sheets\02 SITE PLAN - UPPER POWER PLANT EXPANSION.dwg Last Saved: 4/16/2015 8:46 AM by srueda Plotted: 4/16/2015 12:35 PM by Sergio Rueda

N

SCALE 1:5000
0 50 75 100 125 150 175 200m

MORRISON HERSHFIELD

CLIENT
ATLIN TLINGIT ECONOMIC LP

PROJECT
ATLIN HYDRO EXPANSION
PRE-FEASIBILITY STUDY

TITLE
03 - SITE PLAN - LOWER PLANT

DESIGN	DRAWN	PROJECT NO.	DATE
_ _ _	KDH	5130792	Apr 16, 2015

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APPENDIX C:
Site Visit Memorandum

MEMORANDUM

MORRISON HERSHFIELD

TO:	File	ACTION BY:	-
FROM:	Forest Pearson, Project Manager	FOR INFO OF:	ATELP
PROJECT:	Atlin Hydro Expansion Pre	PROJECT No.:	5130792.02
RE:	Site Visit Memo	DATE:	September 26, 2014

M:\PROJ\5130792\09 DESIGN & DEVELOPMENT\SITE VISIT\MEMO-PREFEAS SITE VISIT_FKP-5130792-20140926.DOCX

Site visit to Atlin conducted by F. Pearson, Project Manager Morrison Hershfield, David Morissette, Water Resource Engineering Access Consulting Group; and Shaun Beatty, Structural Engineer KGS Group on September 24-25, 2014.

- Weather on both days clear, cool (0°C up to 10°C) fall weather. No precipitation, but heavy rain over the previous weekend.
- Site visit to visually observe Surprise Lake control structure 7-8pm September 24, 2014.
- Site visit to visually observe intake weir and potential Spruce Creek diversion location 9-10am Sept. 25, 2014.
- Kickoff meeting at ATELP office with Peter Kirby, TJ Esquiro & Stuart Simpson 10:15-12:15
- ½ hr overview flight with Discovery Helicopters (pilot Paula) with S. Simpson, D. Morissette, S. Beatty & F. Pearson. Observed lower power house location, Pine Creek, lower conveyance alignment, potential Spruce Creek diversion location and alternate upper conveyance alignment to lower powerhouse. 1:15-1:45pm.
- Site visit to potential lower power house location on Atlin Lake w/ S. Simpson. Looked at potential penstock drop down rock bluff near Monarch Mt. trail. Quickly observed alignment crossing over Art Centre road.
- Briefly looked at South Pine Drive and highest property (L1252) in this neighborhood. Encountered two local residents (names unknown). Stuart knew them and had discussion of land-owners in neighborhood.
- Visited existing powerhouse w/ S. Simpson
- Conducted 1.5km traverse (see Figure 1) downstream from existing powerhouse along upper portion of potential lower penstock to look at terrain & soil conditions and potential intake locations. Soils generally well drained, course gravel terraces. Large bedrock hill at south end of traverse with saddle on east side that maybe sufficiently low to accommodate penstock alignment. 4-5:30pm.

Staff Gauge Readings:

- Surprise Lake gauge: 0.35m @ 7pm Sept. 24, 2014
- Pine Creek intake weir gauge: 0.53m @ 9:30 am Sept. 15, 2014
- Spruce Creek gauge – not read.

MEMORANDUM

MORRISON HERSHFIELD

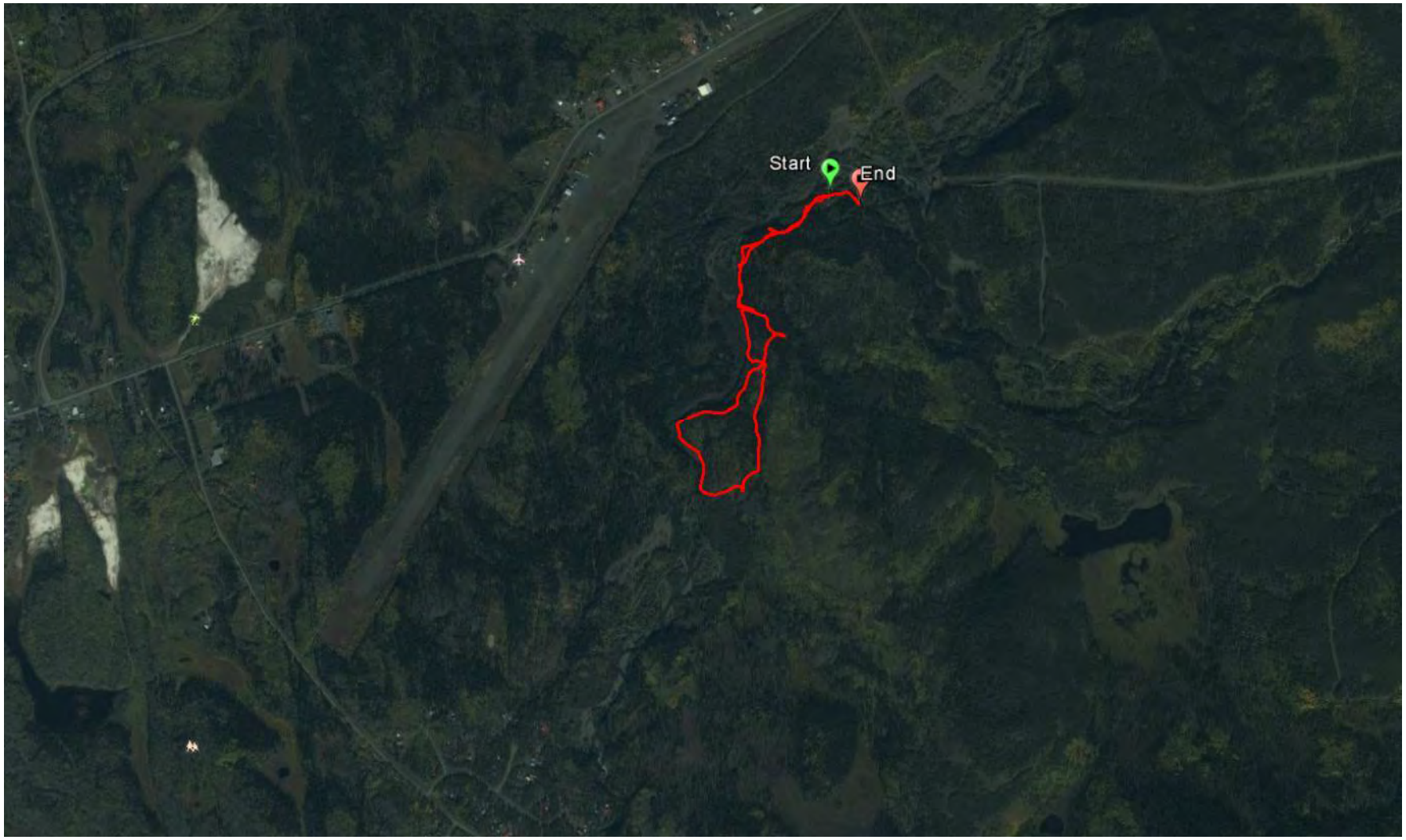

Figure 1. Lower penstock alignment traverse track - September 25, 2014

APPENDIX D:
Photo Log

SURPRISE LAKE CONTROL STRUCTURE

Photo 1: Existing rockfill weir looking downstream. Outlet structure on the left.

Photo 2: Surprise Lake rockfill weir, looking north.

Photo 3: Surprise Lake rockfill weir, looking south towards outlet structure

Photo 4: Existing outlet structure at Surprise Lake.

Photo 5: Existing fishway at Surprise Lake, looking downstream.

UPPER HEAD POND

Photo 1: Existing (upper) head pond, looking upstream. Note placer mine workings upstream.

Photo 2: Existing head pond, weir and existing intake structure, looking downstream.

Photo 3: Existing head pond, weir and existing intake structure, looking west.

Photo 4: Existing intake structure.

Photo 5: Existing intake structure.

Photo 6: Upstream side of weir.

Photo 7: Downstream side of weir.

Photo 8: North abutment of weir.

Photo 9: Overflow section of weir.

Photo 10: South side of weir. Note minor seepage and efflorescence.

EXISTING POWERHOUSE

Photo 1: Existing penstock right of way looking west towards powerhouse

Photo 2: Existing penstock right of way looking northwest

Photo 3: Existing powerhouse looking east towards penstock right of way

Photo 4: Existing powerhouse looking west from penstock right of way

Photo 5: Overview of existing powerhouse area and access road.

Photo 6: Tailrace exiting powerhouse towards Pine Creek

Photo 7: Tailrace confluence with Pine Creek, looking east. Existing powerhouse is to right of photo

Photo 8: Interior of existing powerhouse showing turbines and crane, looking north. Control room is to the right.

Photo 9: Interior view of south wall of powerhouse.

SPRUCE CREEK

Photo 1: Spruce Creek looking upstream towards possible upper diversion location

Photo 2: Possible upper diversion location on Spruce Creek

Photo 3: View of Spruce Creek looking upstream

Photo 1: Proposed lower head pond location downstream of existing access road bridge

Photo 2: Pine Creek looking upstream to proposed lower head pond location.

Photo 3: Proposed lower penstock alignment on south side of Pine Creek (left side), looking downstream. Note the low saddle between hill in mid-ground and mountain side on left side of photo.

Photo 4: Middle section of proposed lower penstock alignment on south side of Pine Creek (left side of photo), looking downstream

Photo 5: Middle section of proposed lower penstock alignment on south side of Pine Creek (right side of photo), looking upstream towards existing powerhouse. Note area of poorly drained soils in foreground.

Photo 6: Lower cascade on Pine Creek, looking upstream. Proposed lower penstock alignment would be on right side of photo.

Photo 7: Bottom portion of lower penstock alignment, looking east. Warm Bay Road in foreground with Arts Centre Road on the right.

LOWER POWERHOUSE

Photo 1: Mouth of Pine Creek

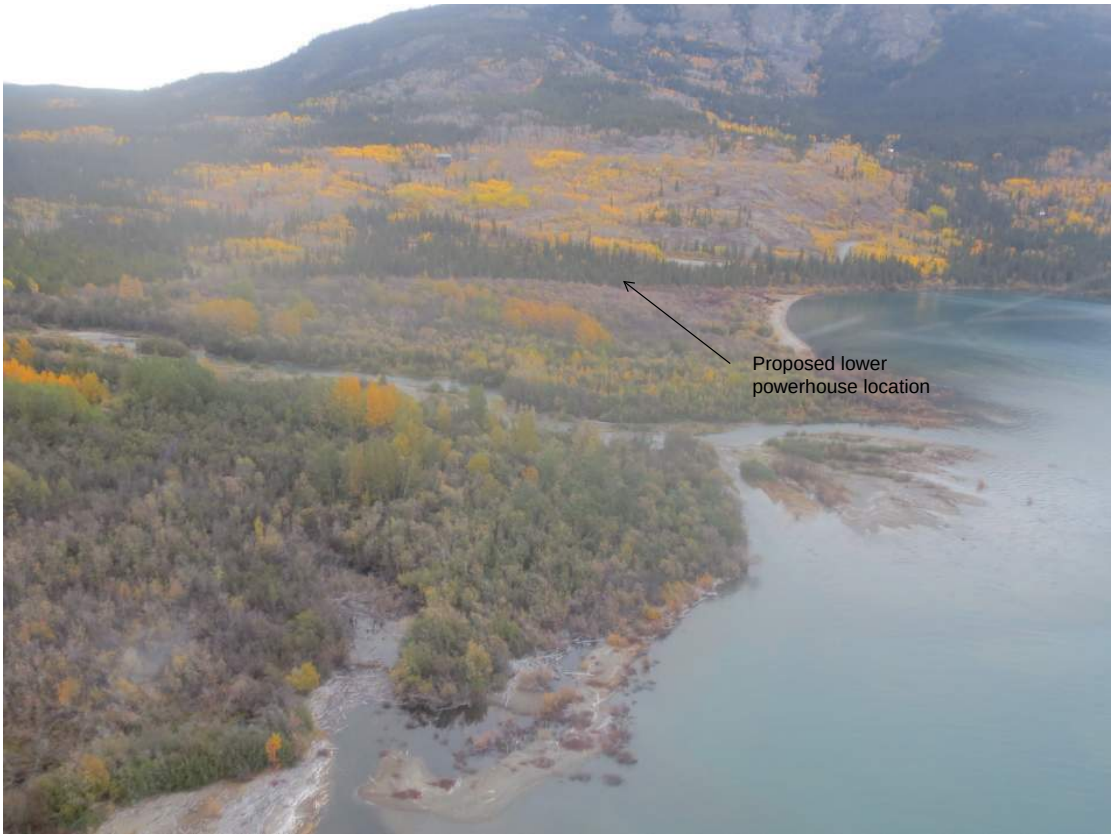

Photo 2: Mouth of Pine Creek looking south towards proposed lower powerhouse location.

Photo 3: Proposed lower powerhouse location, looking northeast. Alternate location considered is on the right hand side of photo.

Photo 4: Proposed lower powerhouse location, looking east Proposed penstock alignment in background.

Photo 5: Proposed lower powerhouse location, looking north.

Photo 6: Overview of proposed lower powerhouse location at base of hill below (north) of parking lot.

Photo 7: View of beach on Atlin Lake and location of proposed tailrace

Photo 8: Hillside above proposed lower powerhouse. Location of proposed surge facility.

Photo 9: Location of proposed surge facility, looking southeast. Note exposed bedrock

Photo 10: Looking down towards proposed lower powerhouse along surge pipe alignment.

Photo 11: View of alternate (southern most) powerhouse location considered.

Photo 12: Looking south along higher penstock alignment option. Note existing land uses.

Photo 13: Lower Pine Creek looking upstream from Warm Bay Road bridge.

APPENDIX E:
Transmission Options Assessment Study

b7kennedy & Associates Inc.

Transmission Options Assessment
Feasibility Study
Atlin to Jakes Corner 69 kV Transmission

Prepared for:

Morrison Herschfield
&
Magna IV

by

b7kennedy & Associates Inc.

W.O. (Bill) Kennedy, P.Eng., FEIC
Principal Engineer

December 21st, 2016

88 Midvalley Cres SE, Calgary, AB, T2X 1N3
Phone (403) 256-1863 (O) (403) 585-3037 (C) E-mail b7kennedy@shaw.ca

b7kennedy & Associates Inc.

Legal Notice

This feasibility study reports the results of examination of six possible transmission scenarios for the interconnection of new and existing generation at Atlin, BC to Jakes Corner, YK via a 69 kV transmission line between Atlin and Jakes Corner. The results are based on third party information which the author believes is credible and the author's experience in conducting feasibility studies.

Given the nature of the assumptions made for the study the results should not be relied on without further detailed study of the proposed interconnection.

Neither b7kennedy & Associates Inc. nor Morrison Herschfield nor Magna IV accepts any responsibility or liability for use of the information provided in this report outside of the report's stated purpose, that is, a feasibility study of transmission options to connect Atlin generation to the Southern Lakes load.

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b7kennedy & Associates Inc.

Executive Summary

Six transmission scenarios were examined for the Atlin interconnection with Yukon Electric. For all options the transmission line from Atlin to Jakes Corner was 69 kV using Ibis, 397 MCM conductor.

- Option 1a – the new interconnection serves the Southern Lakes load as isolated. That is, there is no interconnection to the existing Yukon electric system.
- Option 1b – the new interconnection serves the Southern Lakes load and is interconnected to the Yukon electric system via a 34.5 kV line to Whitehorse S150.
- Option 2a – Yukon develops 138 kV transmission south from Whitehorse existing station S171. The 69 kV interconnection to Jakes Corner is extended to Carcross and interconnected to the 138 kV system via a 138/69 kV transformer.
- Option 2b – the 69 kV transmission line between Jakes Corner and Carcross is replaced by a 138 kV interconnection between Jakes Corner and Carcross.
- Option 3a – a 138/69 kV transformer in installed at S171 and a 69 kV transmission line is constructed to Jakes Corner to interconnect with the new line from Atlin.
- Option 3b – a 138 kV line is constructed from S171 to Jakes Corner and a 138/69 kV transformer is installed at Jakes Corner to interconnect with the new line from Atlin.

With the exception of Option 1a, all other options are feasible and provide acceptable results from the point of view of voltage regulation and losses.

The preliminary conclusion is Option 1b provides the best interconnection for this project.

In addition, a number of issues have been identified for further study.

Additional work using more complete models of the two systems is required to firm up the preliminary conclusions and to develop equipment specifications.

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b7kennedy & Associates Inc.

Table of Contents

Legal Notice 2
Executive Summary 3
Introduction 5
Study Scenarios 5
Model Development 7
Study Parameters 8
Option 1a 9
Option 1b 10
Option 2a 11
Option 2b 13
Option 3a 14
Option 3b 16
Losses Atlin to Whitehorse 17
Other Issues 17
Conclusions 19

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b7kennedy & Associates Inc.

Introduction

Tlingit Homeland Energy Limited Partnership is proposing to develop additional run of the river hydro in the Atlin area of British Columbia. The expanded generation will consist of two 1.45 MW and one 2.8 MW generators. The generators are assumed to be rated at 0.85 pf. In addition, an existing 2.1 MW hydro set serves the community of Atlin.

This study examined the construction of 100 km of 69 kV transmission to interconnect Atlin with Jakes Corner, Yukon. The conductor of choice was Ibis, 397 MCM. Jakes Corner is in the southern part of Yukon. The area is known as the Southern Lakes and consists of four load centers Carcross, Tangish, Jakes Corner and Teslin with a peak load of 8 MW. For the purposes of this study, the load was lumped at Jakes Corner or divided between Jakes Corner and Carcross. The latter was used for Options 2a and 2b, load at Carcross and Jakes Corner. The load power is 0.95 pf. This is based on the winter heating load.

Study Scenarios

Six study scenarios were developed for this study.

- Option 1a – the new 69 kV interconnection serves the Southern Lakes load as isolated. That is, there is no interconnection to the existing Yukon electric system.
- Option 1b – the new 69 kV interconnection serves the Southern Lakes load and is interconnected to the Yukon electric system at the existing 34.5 kV bus in station S150.
- Option 2a – Yukon develops 138 kV transmission south from Whitehorse existing station S171 to Carcross. The 69 kV interconnection to Jakes Corner is extended to Carcross and interconnected to the 138 kV system via a 138/69 kV transformer.
- Option 2b – the 69 kV transmission line between Jakes Corner and Carcross is replaced by a 138 kV interconnection between Jakes Corner and Carcross. A 138/69 kV transformer is installed at Jakes Corner.
- Option 3a – Yukon develops 69 kV transmission south from Whitehorse existing station S171 to interconnect with the 69 kV transmission from Atlin. A 138/69 kV transformer is installed at S171.
- Option 3b – Yukon develops 138 kV transmission south from Whitehorse existing station S171 to interconnect with the 69 kV transmission line from Atlin. A 138/69 kV transformer is installed at Jakes Corner.

For all options studied, the 69 kV development and generation at Atlin, the 100 km 69 kV transmission line from Atlin to Carcross and the 69/34.5 kV transformer at Jakes Corner are common.

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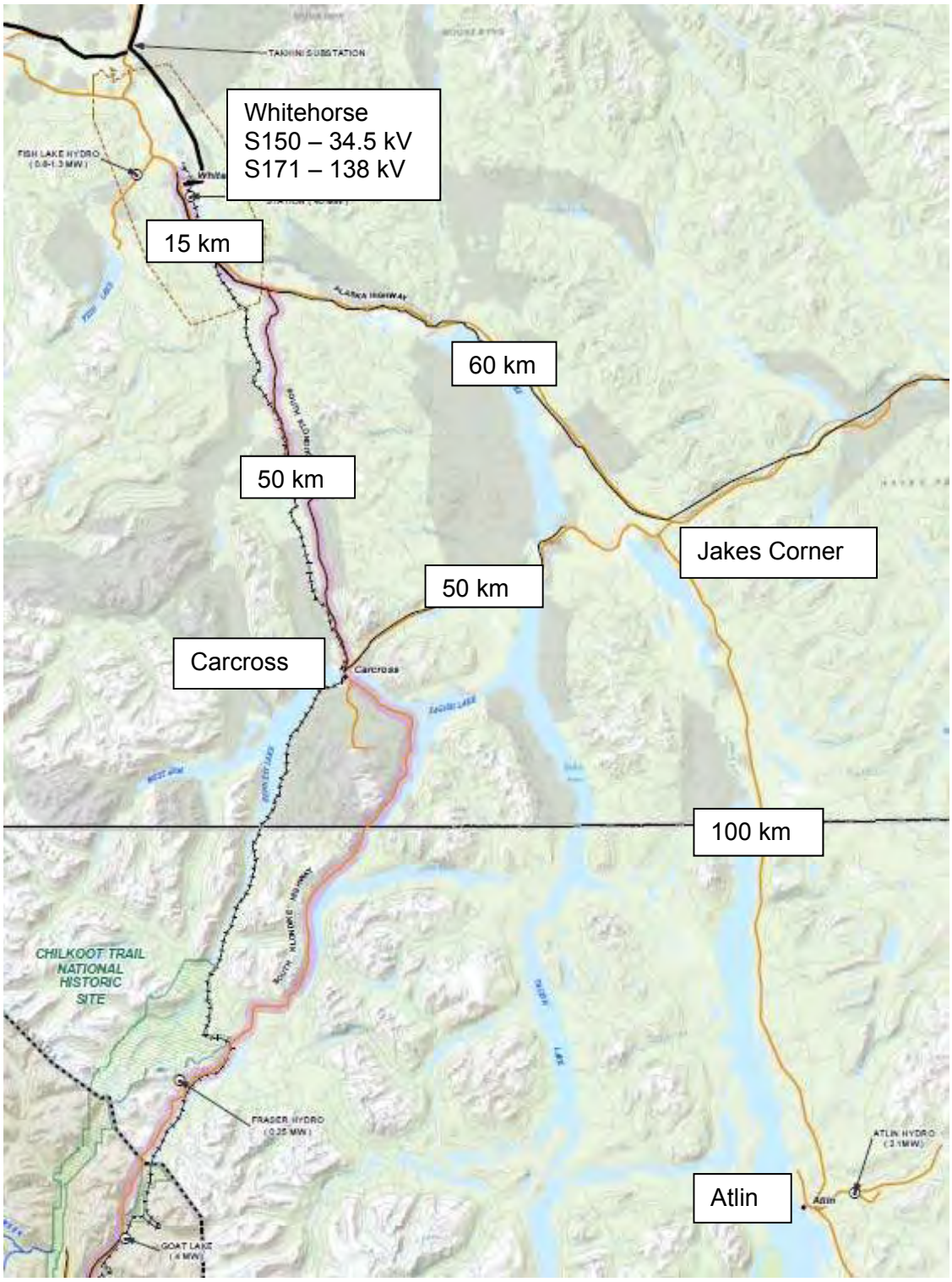
Figure 1 gives an overview of study area.

Figure 1: Map of the Study Area



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The existing system feeding the Southern Lakes consists of 34.5 kV transmission from S150 located in Whitehorse. A single circuit line extends south from S150 15 km where it bifurcates to supply Carcross and Jakes Corner. The Carcross section is 50 km and the Jakes Cromer section is 60 km. For this study the 34.5 kV to Jakes Corner from S150 was assumed to be single circuit 75 km in length. There is no interconnection between Carcross and Jakes Corner. The same distance was assumed for the 69 kV and 138 kV options from S171.

Model Development

Referring to Figure 2, a model was developed for Atlin Hydro expansion. The single line shown is Option 2b, the 69 kV interconnection of Jakes Corner to Carcross and the 138 kV interconnection to S171. The pie charts in the single line give an indication of the equipment loading based on line SIL or estimated maximum loading or typical transformer ratings. For example, 138 kV lines have a 50 MW SIL.

At Whitehorse there are two interconnection points; 34.5 kV at S150 and 138 kV at S171. With the exception of Option 1a, S150 or S171 was the swing bus for these studies. For Option 1a, one of the new generators at Atlin was made the swing bus.

Atlin Hydro Development. A new 69 kV bus and infrastructure was developed at Atlin, ATLIN TRM. The three new generators are connected in parallel to the new 69 kV station through their own transformers. Three new generators, two 1.45 MW and one 2.8 MW units are planned. An interconnection between ATLIN TRM and the existing ATLIN 25 kV was developed to allow the excess active power from the existing 2.1 MW hydro generation to the 69 kV bus. In addition, should the existing 2.1 MW be off line for any reason, the new generation can supply the 0.7 MW Atlin load. Finally, the single line shows existing BC Hydro diesel generation at Atlin. This generation was assumed off line for all of the studies.

69 kV Transmission Line. 100 km of transmission line with Ibis, 397 MCM, conductor connects ATLIN TRM to a new station called JAKES COR_69. To complete the interconnection, 69/34.5 kV 9 MVA transformer is installed to supply the Jakes Corner load.

Load Model. The Southern Lakes load is lumped as 8 MW with a power factor of 0.95 pf at Jakes Corner.

Interconnection to Yukon. Finally, the existing 34.5 kV transmission line up to S150 was modeled – see Figure 4. For this study, generation connected to either S150 or S171 was made the swing or slack bus. Figure 2 shows the development of 138 kV transmission from S171 to Carcross and the 69 kV transmission from Carcross to Jakes Corner..

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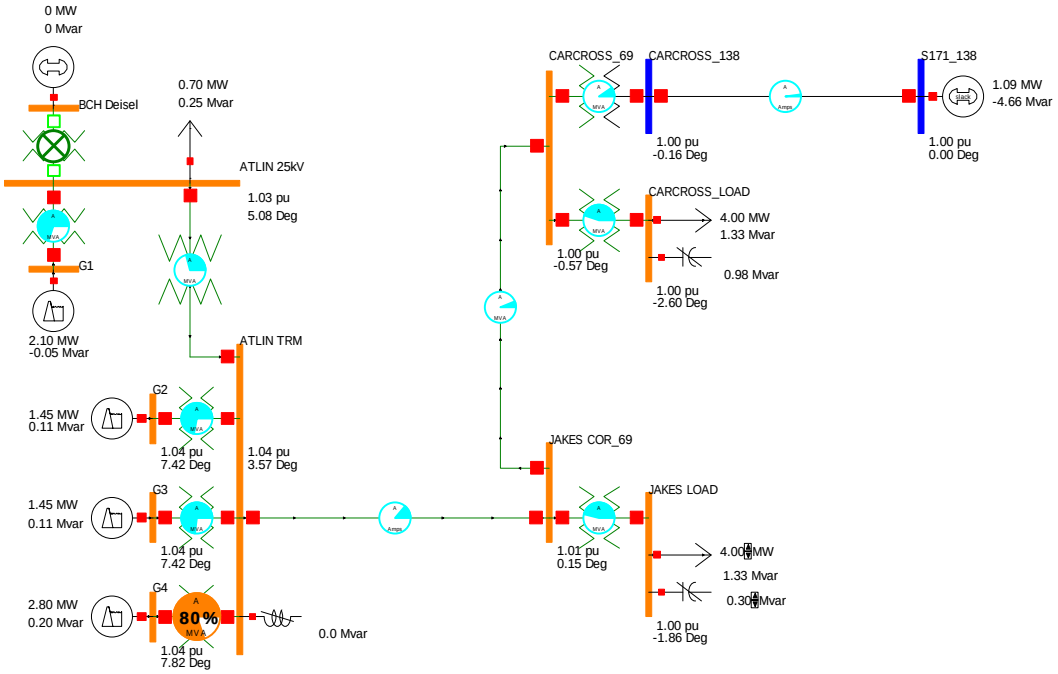
Figure 2: Basic System Studied – 138 kV Connection to S171



Study Parameters

Loading of transmission lines can be divided into three steps. For lines up 80 km in length, the thermal characteristics of the conductor predominate. Between 80 km and 230 km, NERC voltage drop criteria predominate. NERC commonly used criteria is to maintain an absolute voltage drop of no more than 5% between the sending and receiving end terminals during normal operating conditions, commonly called NERC A. Above 230 km, the steady state criterion predominates. These criteria state that the maximum angle across the transmission system between its equivalent Thevenin voltage sources is limited to 45^{o} electrical.

For this study, NERC voltage criteria were used along with keeping line losses to less than 5% of the active power transferred.

The results are presented in a series of tables. Generation at Atlin was increased in increments based on the generator size – 1.45 MW, 2.9 MW, 5 MW and 7.8 MW. The sending and receiving end voltages and active powers were measured along with the transmission line losses. Line losses are calculated as a percentage of sending end active power. In addition, if any shunt compensation was required, this is noted in the tables.

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Option 1a

Table 1, presents the results and the single line is shown in Figure 3. For this option, Jakes Corner load was treated as isolated. That is, there was no interconnection between the Southern Lakes Load and the existing Yukon system at either S150 or S171.

Figure 3: Atlin Transmission Supplying Isolated Southern Lakes Load

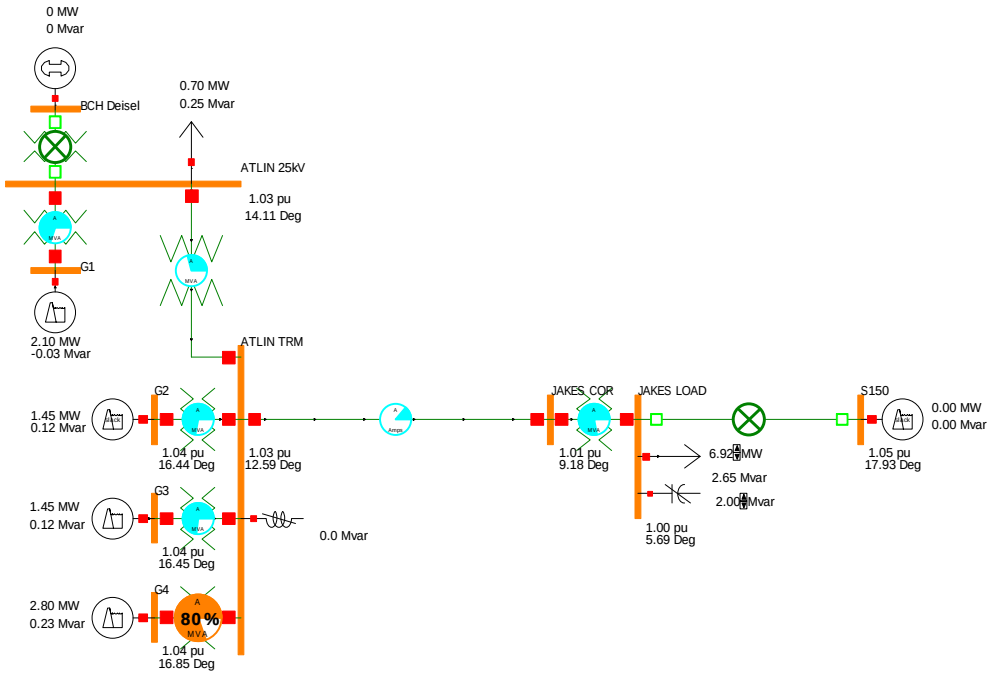

Table 1: Option 1a Results

Atlin Gen	Send Power (MW)	Rec Power (MW)	Vsend (pu)	Vrec (pu)	Vdrop (%)	Loss (MW)	Loss (%)	Comp Send (MVAr)	Comp Rec (MVAr)
1.45	0.74	0.74	1.03	1.02	1	0.004	0.54	0.00	0.86
2.9	2.20	2.18	1.03	1.02	1	0.018	0.82	0.00	0.91
5.0	4.29	4.23	1.03	1.01	2	0.059	1.38	0.00	1.35
7.8	7.09	6.93	1.03	1.01	2	0.157	2.21	0.00	2.00

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For this option, the load at Jakes Corner was adjusted to match the available generation at Atlin.

The results show that losses are less than 5% at full generation and voltage drop is limited to 2% at full generation. In addition, there is a requirement for shunt compensation at the load because there is no support from Yukon generation. However, Atlin generation is not able to supply the entire 8 MW Southern Lakes load under peak load conditions. This option is not recommended.

Option 1b

Table 2 gives the results and the single line is shown in Figure 4. For this case, Atlin is connected to Yukon at S150.

Figure 4: Atlin Transmission Supplying Integrated Southern Lakes Load

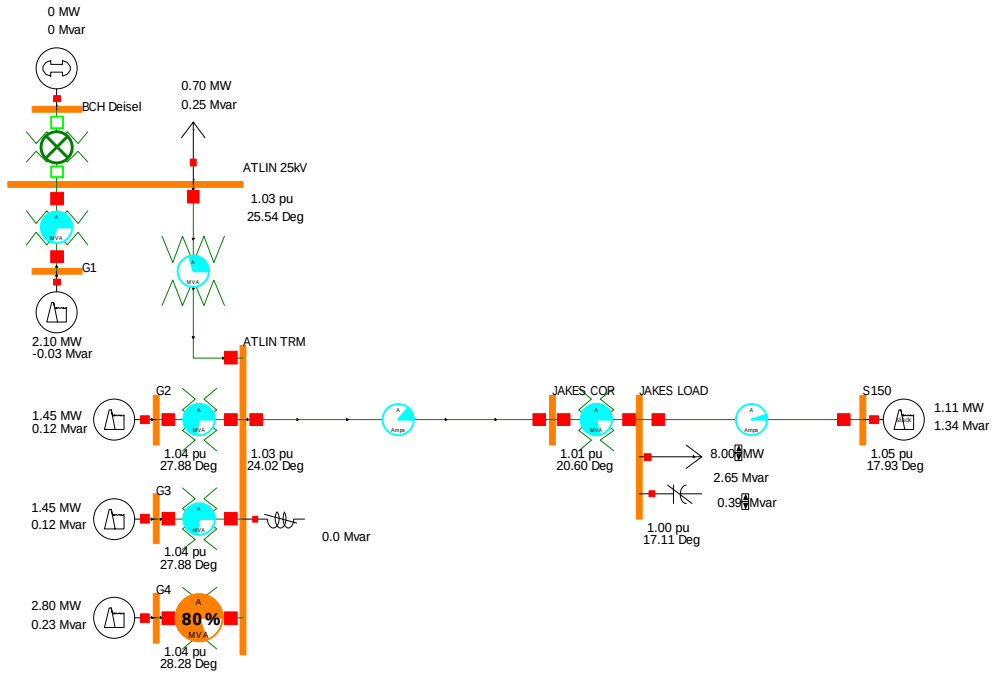

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Table 2: Option 1b Results

Atlin Gen	Send Power (MW)	Rec Power (MW)	Vsend (pu)	Vrec (pu)	Vdrop (%)	Loss (MW)	Loss (%)	Comp Send (MVAr)	Comp Rec (MVAr)
1.45	0.75	0.74	1.03	1.02	1	0.004	0.53	0.00	2.33
2.9	2.20	2.18	1.03	1.02	1	0.018	0.82	0.00	1.53
5.0	4.29	4.23	1.03	1.01	2	0.059	1.38	0.00	0.90
7.8	7.09	6.93	1.03	1.01	2	0.157	2.21	0.00	0.39

With the addition of source at Whitehorse, S150, losses are similar to the isolated case. That is losses are limited to 2.2% at full Atlin generation. Voltage regulation is the same is the same with the interconnection to Yukon. In addition, with a reactive source at S150, shunt compensation at the load reduces as the generation from Atlin increases.

The requirement for shunt compensation at the sending end is clarified in the section Other Issues of this report.

Option 2a

For this option, a 50 km 69 kV line is inserted between Jakes Corner and Carcross using Ibis, 397 MCM, conductor. It is expected that the section of line between Atlin and Jakes Corner will be constructed first making this option the most likely. In addition, there is no interconnection between Carcross and Jakes Corner. At Carcross, the 138 kV line from S171 is tapped and a 138/69 kV station is established. Hawk, 477 MCM, conductor has been assumed for 138 kV lines. In addition, the load was split between Jakes Corner and Carcross. The single line is shown in Figure 5 and the results in Table 3.

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Figure 5: Option 2a Single Line

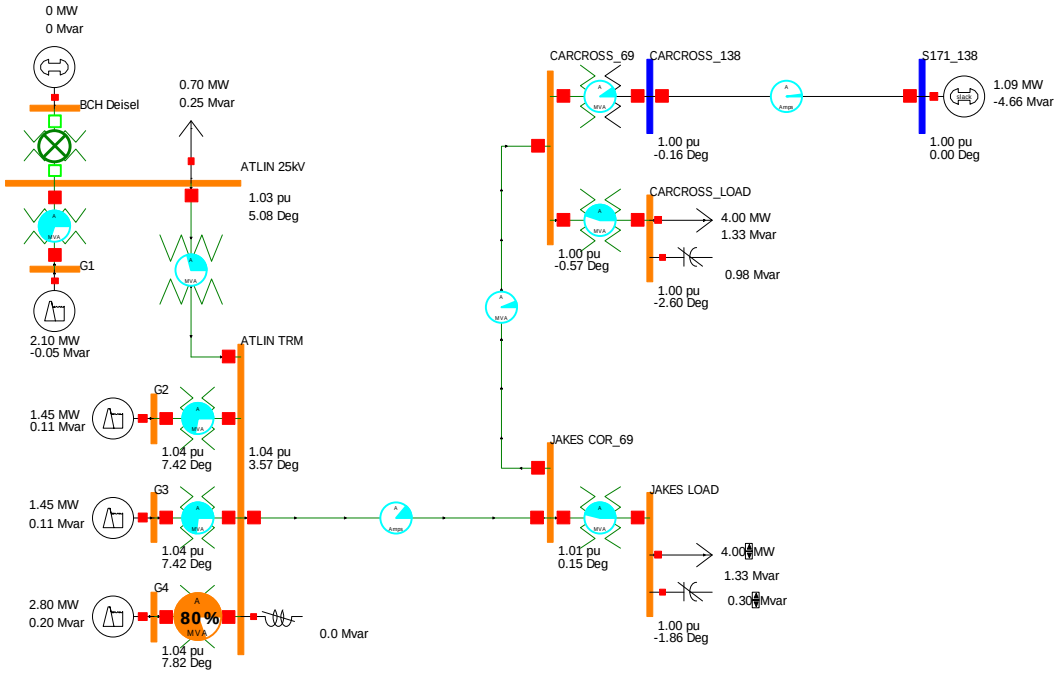

Table 3: Option 2a Results

Atlin Gen	Send Power (MW)	Rec Power (MW)	Vsend (pu)	Vrec (pu)	Vdrop (%)	Loss (MW)	Loss (%)	Comp Send (MVAr)	Comp Rec (MVAr)
1.45	0.75	0.74	1.02	1.01	1	0.005	0.67	0.00	1.30
2.9	2.20	2.18	1.03	1.01	2	0.019	0.86	0.00	1.08
5.0	4.29	4.23	1.03	1.01	2	0.060	1.40	0.00	1.11
7.8	7.09	6.93	1.04	1.01	3	0.157	2.21	0.00	1.28

The results are similar to Option 1b. Shunt compensation is required at the loads. Voltage regulation is within the 5% and losses maximize at full Atlin generation output of 2.2%.

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Option 2b

A second option had the 69 kV line between Carcross and Jakes Corner replaced by a 138 kV line. Load was modeled as for Option 2a. At Carcross a 138/34.5 kV transformer was added and at Jakes Corner a 138/69 kV transformer was added. A secondary option, not tested, was to build initially the Jakes Corner to Carcross line with 138 kV construction and energize the line at 69 kV. The single line for the 138 kV option between Carcross and Jakes Corner is shown in Figure 6 and the results in Table 4.

Figure 6: Option 2b Single Line

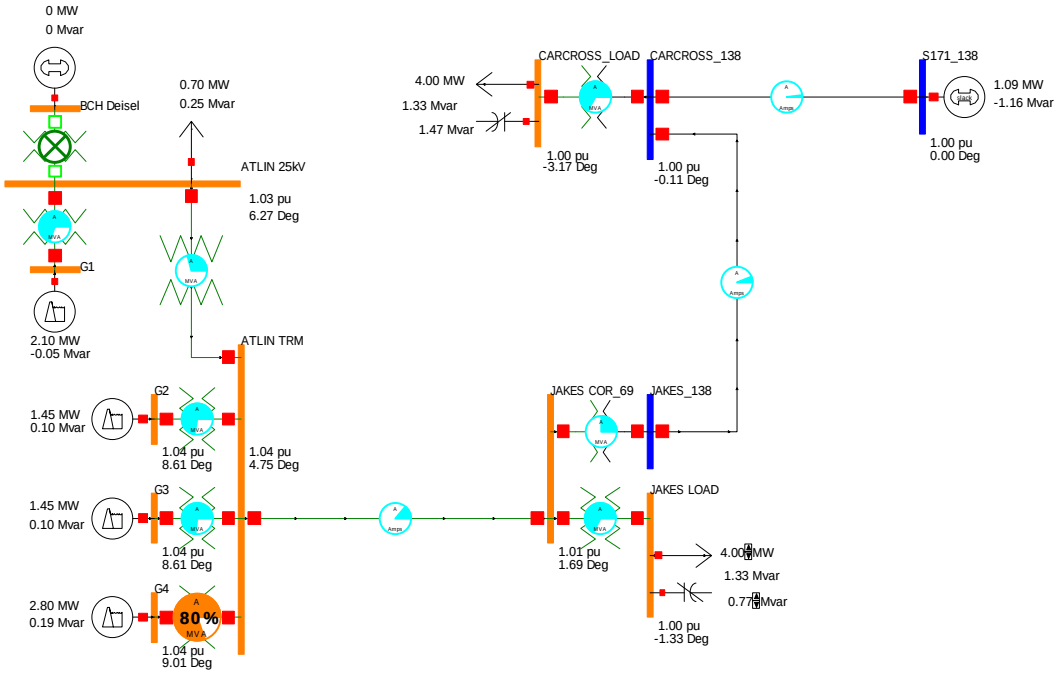

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Table 4: Option 2b Results

Atlin Gen	Send Power (MW)	Rec Power (MW)	Vsend (pu)	Vrec (pu)	Vdrop (%)	Loss (MW)	Loss (%)	Comp Send (MVAr)	Comp Rec (MVAr)
1.45	0.75	0.74	1.02	1.01	1	0.005	0.67	0.00	2.39
2.9	2.20	2.18	1.03	1.01	2	0.018	0.82	0.00	2.21
5.0	4.29	4.23	1.03	1.01	2	0.050	1.17	0.00	2.19
7.8	7.09	6.93	1.04	1.01	3	0.156	2.20	0.00	2.24

The results are similar to Option 2a. That is voltage regulation and losses are similar. However, with the split loads, additional shunt compensation is required for the laods.

Option 3a

Option 3a sees a 69 kV transmission line from S171 established. At S171, a 138/69 kV transformer is installed. Shunt compensation is installed at Jakes Corner for voltage support. The results are presented in Table 4 and the single line is shown in Figure 6.

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Figure 6 Option 3a Single Line

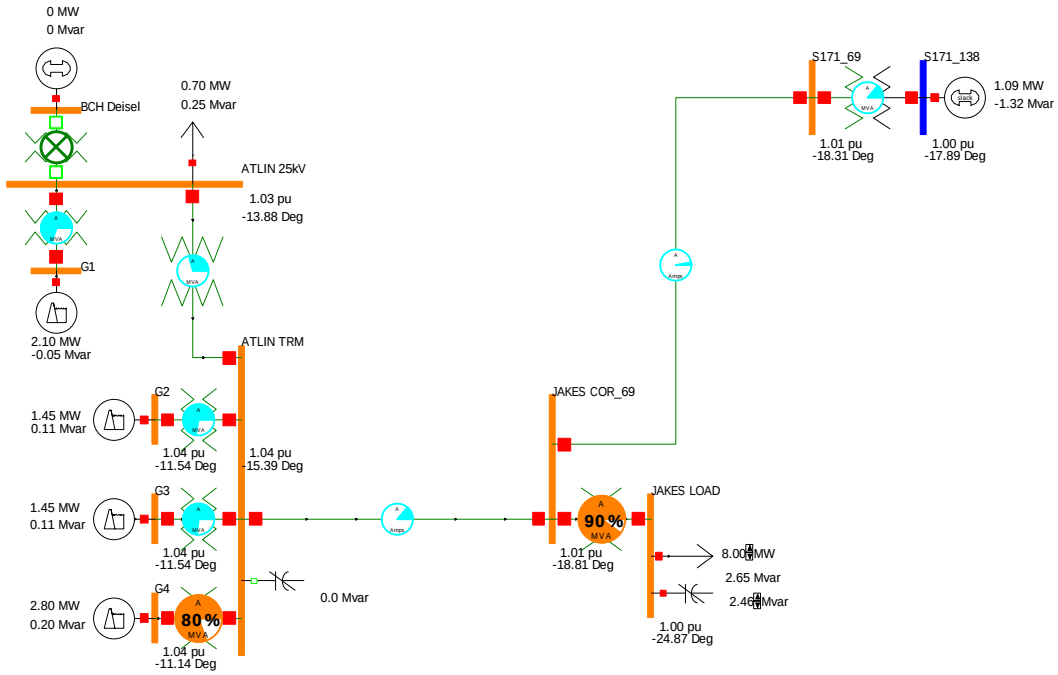

Table 4: Option 3a Results

Atlin Gen	Send Power (MW)	Rec Power (MW)	Vsend (pu)	Vrec (pu)	Vdrop (%)	Loss (MW)	Loss (%)	Comp Send (MVAr)	Comp Rec (MVAr)
1.45	0.75	0.74	1.02	1.01	1	0.005	0.67	0.00	2.78
2.9	2.20	2.18	1.03	1.01	2	0.019	0.86	0.00	2.55
5.0	4.29	4.23	1.03	1.01	2	0.060	1.40	0.00	2.48
7.8	7.09	6.93	1.04	1.01	3	0.157	2.21	0.00	2.46

For this option voltage drop at maximum transfer from Atlin is maximum at 3% and losses are slightly higher.

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Option 3b

Option 3b sees a 138 kV line from S171 to Jakes Corner. At Jakes Corner a 138/69 kV transformer is installed. Shunt compensation is installed for the load.

Figure 8: Option 3b Single Line

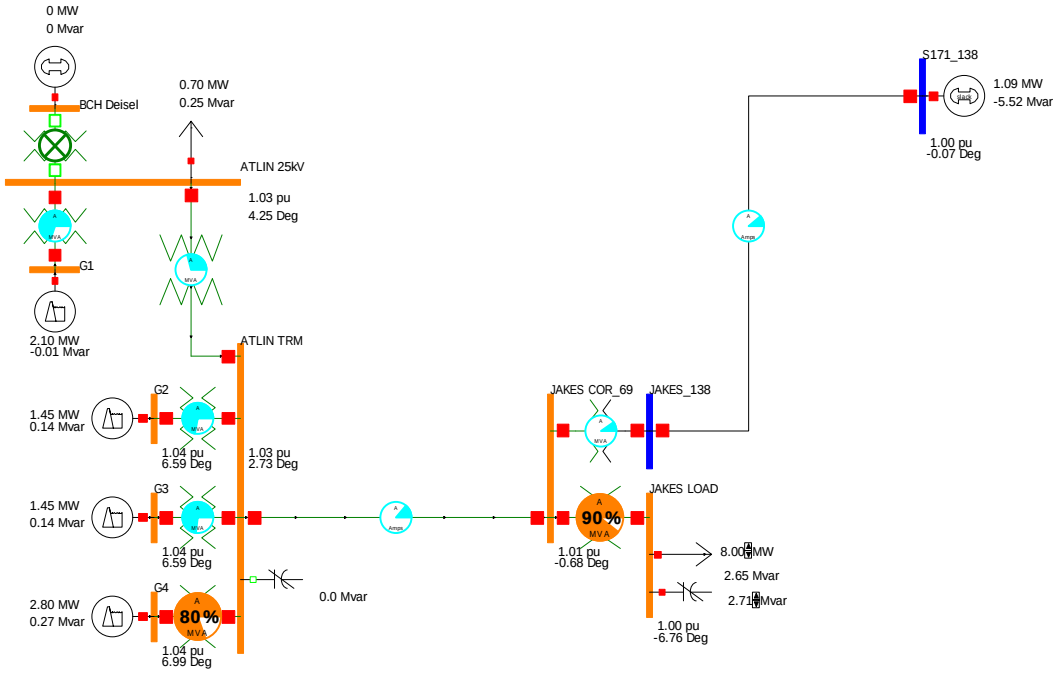

Table 6: Option 3b Results

Atlin Gen	Send Power (MW)	Rec Power (MW)	Vsend (pu)	Vrec (pu)	Vdrop (%)	Loss (MW)	Loss (%)	Comp Send (MVAr)	Comp Rec (MVAr)
1.45	0.75	0.74	1.02	1.01	1	0.005	0.67	0.00	2.68
2.9	2.20	2.18	1.03	1.01	2	0.019	0.86	0.00	2.59
5.0	4.29	4.23	1.03	1.01	2	0.060	1.40	0.00	2.62
7.8	7.09	6.93	1.03	1.01	3	0.158	2.22	0.00	2.71

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For this option voltage regulation and losses are similar to Option 3a.

Losses Atlin to Whitehorse

For all of the options studied except 1a, a calculation of the total losses was made for the case where all of Atlin output is absorbed at Whitehorse S150 or S171 as the case may be and the load at Jakes Corner and Carcross was switched off. For all options, Atlin was dispatched at maximum output of 7.8 MW. Table 7 presents the results

Table 7 Losses Atlin to Whitehorse

	Losses (MW)		
Case	Atlin to Jakes Corner	Jakes Corner to Whitehorse	Total
1b	0.108	0.295	0.403
2a	0.154	0.107	0.261
2b	0.154	0.092	0.246
3a	0.154	0.121	0.275
3b	0.157	0.030	0.187

Other Issues

This study used Ibis, 397 MCM, conductor for the 69 kV line. It's recommended that Partridge, 266 MCM, and Hawk, 477 MCM, be evaluated from a financial point of view. Conductor size influences lines costs between 30% to 50%.

Protection of the new 69 kV line can be accomplished using impedance protection. Use of high accuracy current and voltage transformers will allow the Zone 1 reach at each end to be set to 90% of line length. Effectively, this makes the line protection independent of telecommunications, although telecommunications, if available, should be used to enable the line differential protection function of the relay. High-speed autoreclose should be investigated, but may not be applicable to the interconnection.

With full development of Atlin generation, there will be an overfrequency condition when the line to Jakes Corner trip during a transient fault or other condition. The overfrequency or overspeed condition results when the generation exceeds the connected load. Anti-islanding protection will need to be applied for two cases.

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- Assume all generation is in service and the line trips. The 69/25 kV interconnecting transformer will need to be tripped and the 2.1 MW generator run back to 0.7 MW plus any losses. Hydro generators need to be tripped when their overspeed reaches 125% of rated speed. Assuming an inertia factor, H, of 2, this overspeed will be reached in approximately 0.750 seconds. Assuming a relay plus tripping time of 0.250 seconds, the overfrequency protection needs to initiate tripping within 0.500 seconds. It must be noted that these times are estimates and need further study.
- Assume the 2.1 MW generator is out of service and the remaining generation is in service. For this case to maintain load at Atlin a scheme needs to be devised to determine which generators are tripped and which generator has the runback scheme. A similar tripping scheme as noted above needs to be developed.

Operationally, with Yukon Energy being the larger generation source, the effect of normal load oscillations in Yukon and their effect on Atlin needs to be investigated. This may require additional controls on the Atlin generators, effectively Automatic Generation Control (AGC) to damp out the isolations between the two systems. Additionally, Yukon may need to adjust its AGC controls.

Transformer voltage control at the sending end can be accomplished by off-load transformer taps and the voltage adjusted automatically by the generators. Generators are typically run slightly overexcited. For this study, Atlin generation was operated at 104% voltage. Additional study of the preferred operating conditions is required.

At the receiving end an on-load tapchanger with a suitable range should be investigated.

System synchronization should take place at Atlin, however this needs to be discussed and agreed with Yukon Energy.

Running the Southern Lakes load isolated can be accomplished during times when the Southern Lakes load is below approximately 7 MW. Further study is required for this operating scenario.

Generators with automatic voltage regulation (AVR) have the ability to control their terminal voltage. This is accomplished by increasing or decreasing the rotor voltage. Typically, a generator has the capability to increase its reactive power, overexcited condition, output in the range of 50% of the generator's active power rating. For the underexcited condition, the range is 25%. Energizing the 69 kV transmission line from the Atlin end will require the Atlin generators to operate in their underexcited mode. For the 1.45 MW machines, this is approximately 0.35 MVAr. The charging reactive power of the 69 kV line is 2.0 MVAr. This requirement is greater than the estimated total reactive power capabilities of all four machines at Atlin. To compensate for this a 1.5 MVAr shunt reactor was connected to the 69 kV Atlin bus was added. Additional work needs to be done to determine the reactor size and its controls.

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Energizing the 69 kV line from the Yukon end and synchronizing at Atlin is the preferred method of connecting Atlin to Yukon. The capabilities of the Yukon generators need to be assessed.

The generation profile needs to be developed at Atlin to determine the energy profile.

The keraunic level for the area needs to be determined to determine the frequency and duration of transient line trips.

Conclusions

This feasibility study examined six scenarios for connecting Atlin generation to the Southern Lakes load in Yukon. All options gave acceptable voltage regulation and loss performance.

Option 1a is not recommended as Atlin generation cannot supply all of the Southern generation under maximum load conditions.

Regardless of the option chosen, the performance of the 69 kV interconnection was similar.

As noted above, Options 1b, 2a and 2b give acceptable performance. Option 1b is the recommended option since it will require the least construction to accomplish the interconnection. A 69/34.5 kV substation is required at Jakes Corner along with shunt reactor of 1.5 MVAr at Atlin.

Other issues identified include:

- Line protection
- Communication
- Anti-islanding and overfrequency protection
- Effect of Yukon load fluctuations on Atlin load.
- Sizing of transformers and the tapchanger requirements.
- Synchronization of the two systems.

Additional study using a full model of Yukon Electric system is required to confirm these results, optimize equipment, develop equipment specifications and identify other technical issues.

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APPENDIX F:
Atlin Substation Cost Estimate

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ATLIN

SUBSTATION COST ESTIMATE

ATLIN GENERATING STATIONS

January 28, 2016 File: M1457-16

1103 Parsons Road SW
Edmonton, Alberta, Canada
780 462 3111
Project Manager: Duane Grzyb, P. Eng.

TYPE OF REPORT FOR WHAT PROJECT

AMENDMENT RECORD			NAME	NAME	NAME
A	2016-01-29	Issue for Review	D Grzyb		
REV.	DATE	DESCRIPTION OF CHANGE(S)	PREPARED	REVIEWER	APPROVER

TABLE OF CONTENTS

1	EXECUTIVE SUMMARY	2
2	DATA SOURCES	2
3	WHAT'S INCLUDED (in the MAGNA ESTIMATES)	3
4	CONSTRUCTION METHODS	3
5	ASSUMPTIONS	4
6	SCOPE	5
7	SPECIAL CONSIDERATIONS	5
8	ALTERNATE CONSIDERED SOLUTIONS	5
9	CONCLUSIONS	5
10	REFERENCES	6
11	DRAWINGS AND TECHNICAL INFORMATION	6

1 EXECUTIVE SUMMARY

1.1 Magna has prepared the following Class 5 estimates (-30/+50%) for substations at Atlin Upper Generation Station, Atlin Lower Generating Station and Jake's Corner. Three options have been considered at Jakes Corner, which include an interconnect line to Carcross at 69 kV, a 138 kV interconnect line, and no interconnect to Carcross at all. Estimated installed costs are in Canadian dollars, including GST, PST, Engineering and contractor profits for the Substations are as follows:

Atlin Upper Substation	$ 4,240,000 CAD
Atlin Lower Substation	$ 1,118,000 CAD
Jakes Corner (Option 1b)	$ 1,620,000 CAD
Jakes Corner (Option 2a)	$ 2,800,000 CAD
Jakes Corner (Option 2b)	$ 3,013,000 CAD

1.2 As a comparison, a budget quotation was requested from a US vendor for prepackaged substations. The budget quote received included freight to site, but did not included GST and PST as do the figures above. Prices are in US dollars. Scope of work does not include fencing, site preparations, any required civil works, sub grade grounding etc. Although the initial pricing appears attractive, with currency exchange and the required site works that have not been included, it is inconclusive at this time if this is truly a less expensive option. What the pricing does effectively do, is corroborate the estimating performed in the previous paragraph, and we believe the pricing provided above, considering total installed price falls within the Class 5 estimate range specified.

Atlin Upper Substation	$ 1,919,000 USD
Atlin Lower Substation	$ 908,000 USD
Jakes Corner (Option 1b)	$ 1,987,000 USD
Jakes Corner (Option 2a)	$ 1,531,000 USD
Jakes Corner (Option 2b)	$ 1,545,000 USD

2 DATA SOURCES

2.1 Interconnection and sizing of equipment is based on the report prepared by b7kennedy & associates Inc.

2.2 The adjusted pricing included in the Magna estimate and the US prepackaged vendor quote date is Q1 2016.

2.3 Cost data in the Magna portion of the estimate has been drawn from several sources.

2.3.1 Sources prefixed with a 12 digit identification number have been taken from RSMeans Electrical Cost Data 2014 (January) edition. (Entries are highlighted green in the attached estimates) The "Anywhere USA" material, labour and equipment costs have been adjusted for Whitehorse construction location, using the "City" factors listed in the RSMeans book. This factor is 134.3 for materials and 69.8 for equipment and labour. Values highlighted in green located in columns "Extended Material, Estimated Labour and Equipment" are factored with these two values, as well as an inflation factor 1.25% per year for the year 2014 and 2015.

2.3.2 Data sources prefixed with "MIV" are deemed to be current Q1 2016 costs in Canadian dollars. These values are entered as estimated values using internal Magna information based on similar projects and vendor budget quotations.

2.3.3 Items prefixed with "MH" are unit rates that have been provided by Morrison Hershfield specific to this project as of January 2016.

2.4 Costs in the Dis-Tran provided quotation are provided by Dis-Tran and their origins are unknown, except that a number of sub-vendor names have been provided in the equipment lists, such as ABB, S&C, Tyco, Ohio Brass etc.

3 WHAT'S INCLUDED (IN THE MAGNA ESTIMATES)

3.1 Substations for Atlin Upper and Atlin lower are unaffected by various options considered at Jake's Corner.

3.2 Jake's Corner substation estimates are presented in three configurations, options 1b, 2a and 2b. These configurations are defined in the report provided by b7kennedy and associates.

3.3 Division 1 costs for the installation contractor, such as mobilize, demobilize, site costs, have been included at 7% of the itemized bare costs.

3.4 Installation contractor profit of 15% has been included.

3.5 Engineering has been included at 10% of the factored material, labour, equipment, contractor Division 1 costs and contractor profit.

3.6 PST at 7% has been included on installation cost and engineering.

3.7 GST at 5% has been included on installation cost and engineering.

4 CONSTRUCTION METHODS

4.1 The base estimates have been compiled based on stick built construction at the location, with the exception of:

4.1.1 Modularized substation building for Jakes corner, constructed in an Alberta or BC city.

4.1.2 Protection panels pre-constructed in a panel shop in Alberta or BC city.

4.2 Transformers 2 MVA or larger are to be placed on field constructed slab on grade concrete pads.

4.3 Substation equipment, transmission line dead ends, and other HV equipment is to be supported by fabricated steel structures, attached to screw in steel piles.

4.4 The following support structures are assumed:

4.4.1 34.5 kV disconnecting switches are assumed to be supported on single pole structures. These may be wood or steel.

4.4.2 69 and 138 kV disconnecting switches, circuit switchers, ct sets, etc. are assumed to be supported on two screw pilings with fabricated steel supports spanning the piles and supporting the equipment.

4.4.3 34.5 kV circuit switchers are supported on two screw piles with fabricated steel supports.

4.4.4 Dead end structures for 34.5, 69, and 138 kV are assumed to be supported on 4 screw piles. Dead end structures will also support integrated disconnecting switches where required.

4.4.5 Double dead end structure for 69 kV at Atlin Upper Substation is assumed to be supported by 4 screw piles, although they will likely need to be larger. Piling costs for varying pile sizes were not differentiated in the estimate.

4.5 Generator output cables will be underground, buried 1 meter, in DBII conduit.

4.6 Protection control panels will be located in a self-contained, prefabricated control building at the Jake's Corner substation. Costs for the building and placement have been included.

5 ASSUMPTIONS

5.1 Dual generator output transformers for generators G2 and G3 have been combined into a single generator transformer and 69 kV circuit switcher. Separate transformers and circuit switchers would add considerable cost to the substation and are not deemed necessary.

5.2 Atlin Upper and Atlin Lower substations are assumed to be located on disturbed (placier mining) earth, consisting of modest size rocky earth fill. As such ground wells have been allowed for, due to the likelihood of poor connection of typical 15 foot driven ground rods.

5.3 Jakes corner substation is assumed to be located on undisturbed land, consisting of earth and a lesser amount of rocks, thus negating the requirement of drilled ground wells. A traditional array of driven ground rods is assumed to provide adequate grounding.

5.4 Protection control panels will be located in owner provided space in Atlin Upper Generating Building and Atlin Lower Generating Building.

5.5 125 VDC supplied by station batteries and chargers is assumed to be supplied by the generating stations for the Upper and Lower substations.

5.6 125 VDC batteries and charging equipment shall be supplied by the scope of this estimate for Jake's Corner substation.

5.7 General earthworks will be provided by others. The assumed starting points for substation construction will be level, drained, compacted earth, with access roads provided. No pre-construction clearing or ground preparation costs are carried.

5.8 Costs for ground grid construction, fence construction, washed rock substation backfill, cable trenching and backfill have been included in the estimate.

5.9 Connection from the G1 generator output to the Upper Atlin Substation shall be underground, using insulated cables.

5.10 A lump sum of $85000, bare cost is carried for the connection of the G1 generator output to the Upper Atlin Substation tie transformer. $30,000 bare cost is carried for modifications to the existing G1 protective relay systems for the inclusion of the tie connections. This connection is not well defined at this time and may cost more or less.

6 SCOPE

6.1 Transmission line connection end of scope is the substation dead end. All line construction charges, right of ways, wires, hardware, poles etc are by others.

6.2 No equipment has been allowed for SCADA or other communications. Substations have no visibility to one another or any remote locations. Fibre optic equipment is not included.

6.3 Power metering for electricity sale has not be defined or included. Additional revenue class current transformers, potential transformers and metering equipment will be required at the locations determined by the sale contract.

7 SPECIAL CONSIDERATIONS

7.1 Carcross currently has no 138 kV systems in place.

7.2 Carcross currently has no 138 kV substation in place.

7.3 Equipment supplied for the "Carcross 138 kV substation" as part of estimates 2a and 2b (Jake's Crossing Substation options 2a and 2b) are "loose supplied" "free issue" equipment. The equipment supplied does in no way constitute a complete and working 138 kV substation. Specifically missing from the Carcross location are earthworks, fence, foundations, protection panels, protection equipment, wiring, 125 VDC batteries, 125 VDC chargers, station services, lighting, grounding, etc. The supplied equipment includes the power transformer, circuit switchers, support stands, dead end structures and disconnect switches. As the eventual scope at Carcross is undetermined at this time, attempting to provide necessary infrastructure for a small portion of an overall substation at Carcross would be misleading.

8 ALTERNATE CONSIDERED SOLUTIONS

8.1 The general remote location of the installation may benefit from pre-constructing skid units remotely and transferring them to site for interconnection. Pricing in US dollars, fob site is included in the appendix. Regrettably, the quotation provided did not include general arrangement details, size details, or much other information other than a BOM. As such, it is not possible to determine if this is a cost effective alternative to the stick built solution proposed by Magna. Specific items that are not included in the prepackaged alternative are site preparation, fencing, reactors grounding, connections to generators, connections to remote mounted protection panels, to name a few things. Further investigation will need to be done to determine the cost benefits / disadvantage of this route in upcoming phases of design and estimation.

9 CONCLUSIONS

9.1 The pricing shown in section 1.1 of this report, is believed to be accurate within the Class 5 estimate tolerances, subject to the conditions and assumptions listed.

10 REFERENCES

10.1 RSMeans Electrical Cost Data, 37th Annual Edition, 2014. ISBN 978-1-940238-04-3

11 DRAWINGS AND TECHNICAL INFORMATION

11.1 Single Line Diagram

11.2 Sketch of Atlin Upper Substation Layout

11.3 Sketch of Atlin Lower Substation Layout

11.4 Sketch of Jake's Corner Substation – Option 2b (only)

11.5 Estimate Worksheet - Atlin Upper Substation – Stick Built

11.6 Estimate Worksheet - Atlin Lower Substation - Stick Built

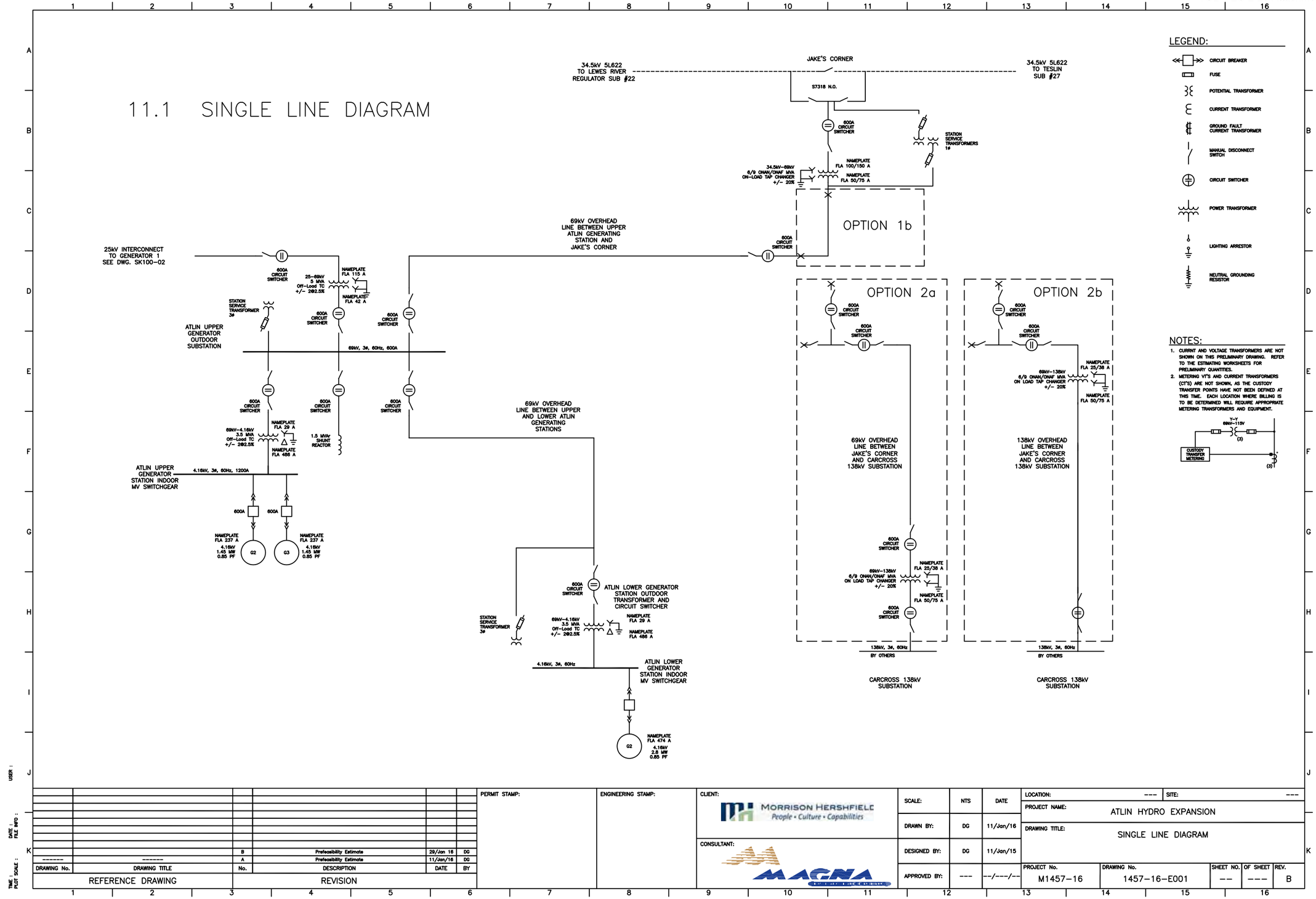
11.7 Estimate Worksheet - Jake's Corner – Option 1b

11.8 Estimate Worksheet - Jake's Corner – Option 2a

11.9 Estimate Worksheet - Jake's Corner – Option 2b

11.10 Quotation Documents from DISTRAN Packaged Substations

11.1 SINGLE LINE DIAGRAM



DRAWING No.	DRAWING TITLE	No.	DESCRIPTION	DATE	BY
------	------	B	Prefeasibility Estimate	29/Jan 16	DG
------	------	A	Prefeasibility Estimate	11/Jan/16	DG

REFERENCE DRAWING — REVISION

PERMIT STAMP:

ENGINEERING STAMP:

CLIENT: MORRISON HERSHFIELD — People • Culture • Capabilities

CONSULTANT: MAGNA

SCALE:	NTS	DATE
DRAWN BY:	DG	11/Jan/16
DESIGNED BY:	DG	11/Jan/15
APPROVED BY:	---	--/---/--

LOCATION: --- SITE: ---

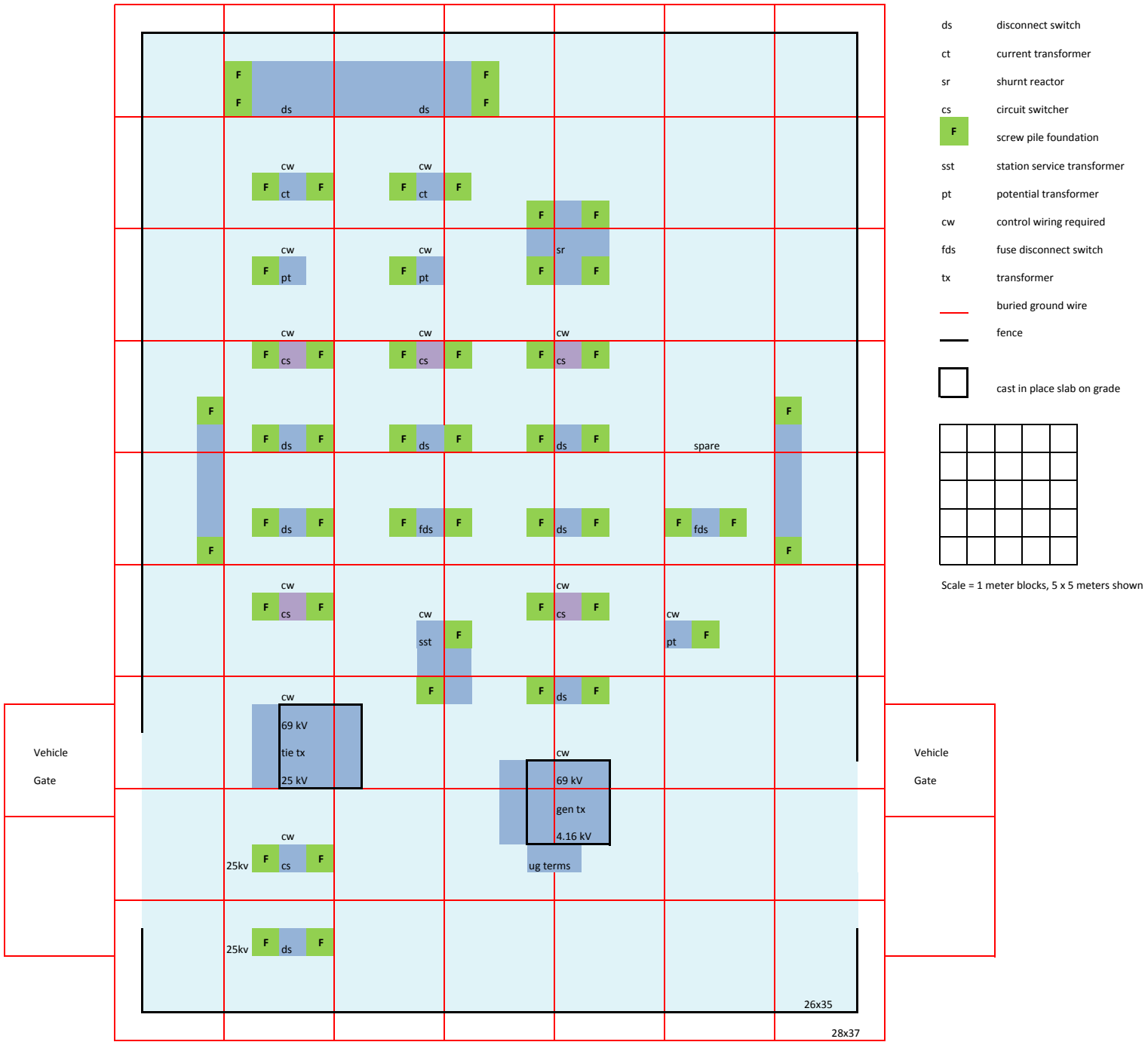
PROJECT NAME: ATLIN HYDRO EXPANSION

DRAWING TITLE: SINGLE LINE DIAGRAM

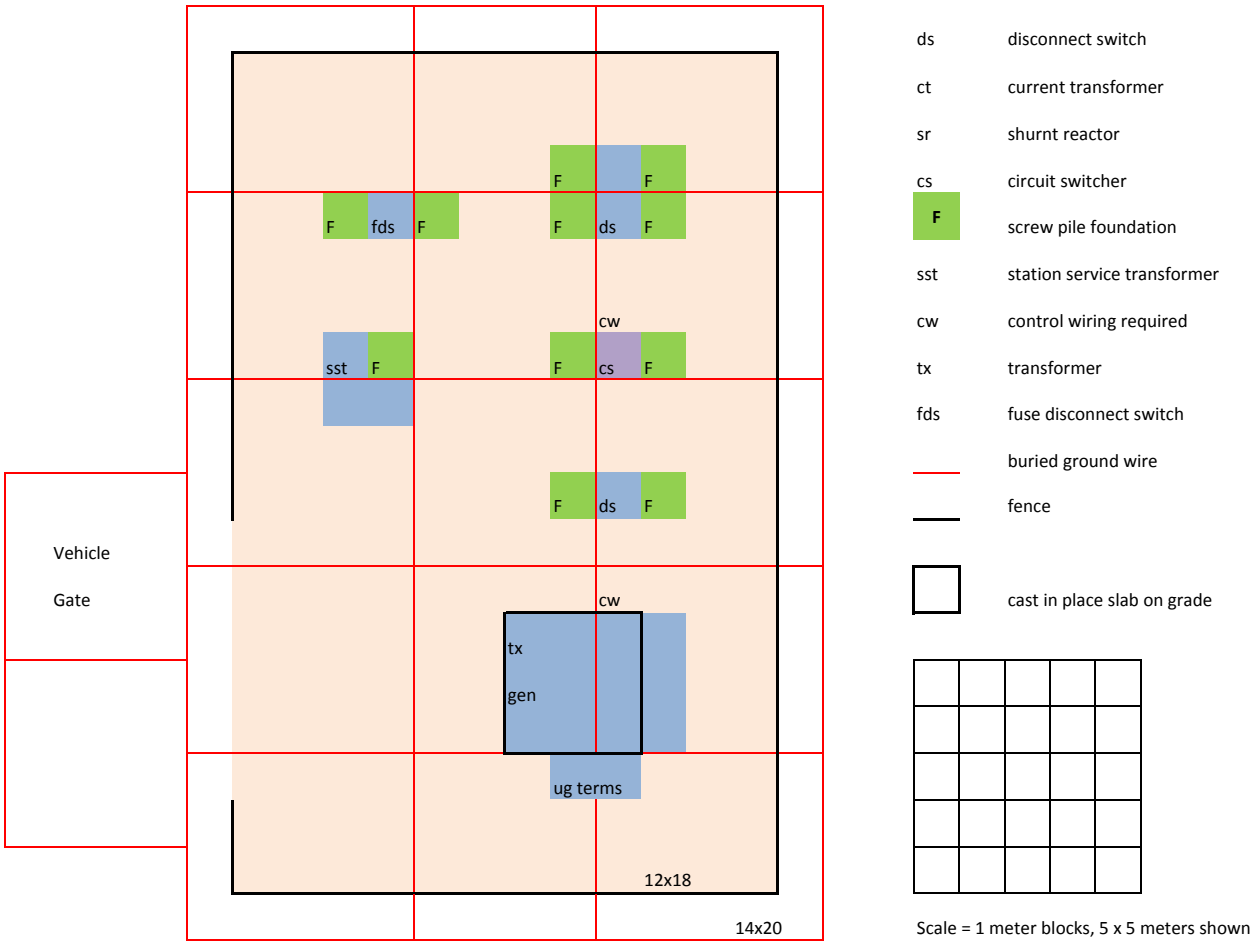
PROJECT No.	DRAWING No.	SHEET NO.	OF SHEET	REV.
M1457-16	1457-16-E001	--	---	B

USER :
DATE / FILE INFO :
TIME / PLOT SCALE :

11.2 UPPER ATLIN SUB, FENCED SIZE 26 X 35 METERS

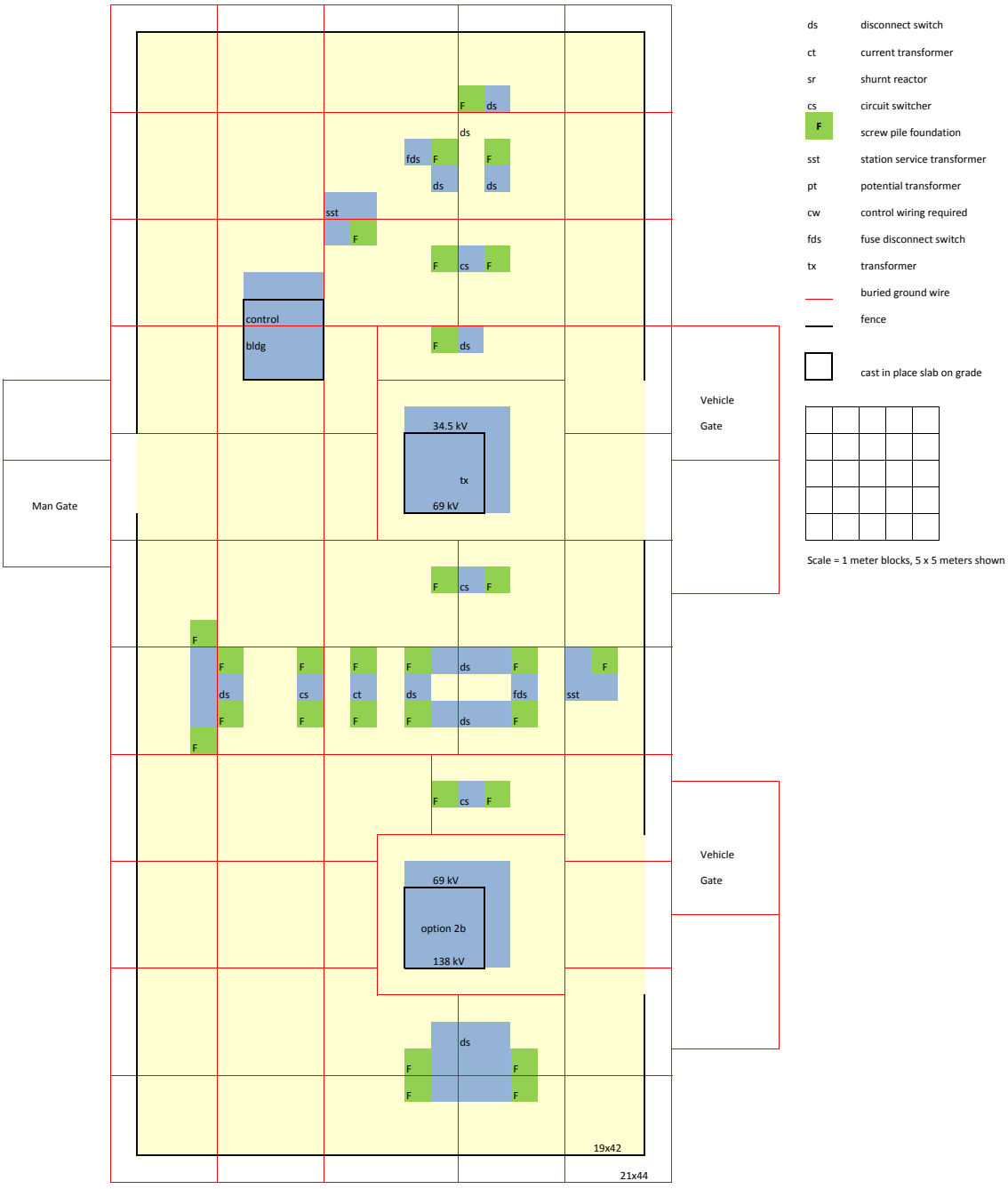


11.3 LOWER ATLIN SUB, FENCED SIZE 12 X 18 METERS



11.4 JAKE'S CORNER SUB, FENCED SIZE 19 X 42 METERS

Layout shows equipment for option 2b, which is the largest arrangement. Various equipment is deleted for other options.



11.5 ESTIMATE WORKSHEET - ATLIN UPPER SUBSTATION - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MH		Substation Fence 26 x 35 m	110	m	$4,950	$4,950	$1,100	100/m, 45, 45, 10/m M,L,E
MH		Substation Vehicle Gates 6m	12	m	$540	$540	$120	100/m, 45, 45, 10/m M,L,E
26 05 26 80 1000	4/0 wire and placement	Substation Grounding Grid 28 x 37 m x	630	m	$9,505	$3,100	$0	
26 05 26 80 2760	4/0 to 4/0 exothermic	Connectors	80	ea	$640	$4,880	$0	
26 05 26 80 5195	40' with hole clay rod clamp	Ground Wells	4	ea	$12,100	$1,700	$0	
26 05 26 80 0130	15' 3/4" cc steel	Ground Rods Driven	20	ea	$1,270	$2,140	$0	
33 75 53 13 3250	HV Switches Disconnecting Circuit Switcher <161kV	69 kV circuit switchers	5	ea	$457,500	$55,200	$10,875	
MIV		Circuit Switcher Stand	5	ea	$25,000	$5,000	$1,500	
33 75 53 13 3080	HV Switches Disconnecting Manual Operation 69kV	69 kv disconnect switches	8	ea	$202,400	$28,400	$8,880	
MIV		disconnect switch support / stand	8	ea	$16,000	$4,000	$800	
33 75 13 13 2100	HV Circuit Breaker Air CB 13-26kV	25 kv circuit switcher	1	ea	$59,000	$40,400	$1,575	
MIV		Circuit Switcher Stand 25 kv	1	ea	$4,000	$800	$250	
33 75 53 13 3060	HV Switches Disconnecting Manual Operation <26kV	25 disconnect switch	2	ea	$27,200	$13,800	$1,080	
MIV		mods to connect to G1 outputs with above	1	lot	$35,000	$35,000	$15,000	
		mods to protecton panels and settings for G1	1	lot	$5,000	$25,000		rev 2
MIV		69 kv current transformers set of 3	3	ea	$54,000	$10,500	$1,500	rev 2 - was qty 1
MIV		current transformer stand	3	ea	$6,000	$1,500	$300	rev 2 - was qty 1
MIV		69 kv current transformers set of 3 (high accurac	1	ea	$22,000	$3,500	$500	
MIV		current transformer stand	1	ea	$2,000	$500	$100	
MIV		69 kv pt's set of 3	3	sets	$99,000	$10,500	$1,500	
MIV		pt transformer stand	3	ea	$6,000	$1,500	$300	rev 2 - was qty 1
MIV		69 kv fuse disconnect outdoor	2	ea	$30,000	$3,000	$500	
MIV		69 kv fuse disconnect support structure	2	ea	$4,000	$1,000	$200	
33 75 39 13 8050	<26 kV Surge Arrestor	25 kv Surge Arrestor	3	ea	$4,575	$456	$143	
MIV		25 kv Surge Arrestor Support	3	ea	$2,250	$900	$600	
33 75 39 13 8070	69 kv Surge Arrestor	69 kv Surge Arrestors	12	ea	$63,600	$3,036	$954	
MIV		69 kv Surge Arrestor Support	12	ea	$9,000	$3,600	$2,400	
33 73 23 20 1070		T2 25 - 69 kV Tie Transformer 5MVA	5	MVA	$95,500	$4,550	$1,425	
33 73 23 20 1070		T3 Generator Output Transformer	3	MVA	$57,300	$2,730	$855	
26 12 19 10 0300	500 kva 15 kV pad mount	SST2 - Station Services Transformer	1	ea	$18,000	$2,650	$350	
MIV - Trench Quote		SR1 - Shunt Reactor 69 kV, .6 MVA	3	ea	$117,450	$5,000	$3,000	
MIV		Support Shunt Reactor Steel & Insulators	3	ea	$9,000	$2,250	$600	
MIV		69 kV Dead Ends	4	ea	$100,000	$30,000	$4,000	
MIV		ACSR	500	m	$4,000	$2,000	$2,000	
MIV		ACSR Connectors	150	ea	$9,000	$6,000	$1,500	
26 56 36 55 0120	Led Flood 90 watt	Outdoor Lighting	6	ea	$9,000	$642	$180	
MIV	Lighting Wiring	2c12 teck, in concrete wireway & up poles	150	m	$600	$300	$0	
MIV		Lightning crosswires	400	m	$800	$600	$800	
MIV		Lightning corner poles	4	ea	$3,000	$1,200	$800	
26 05 19 20 0400	Means price 3c#6 average cable cost	Field Control Wiring	8450	m	$126,108	$38,248	$0	
MIV		Generator Output Wiring	300	m	$34,500	$6,000	$1,500	
MIV		Terminations Small	800	ea	$0	$2,400	$0	
MIV		Terminations Generator	6	ea	$510	$510	$240	
MIV		Teck Connectors Small Average	160	ea	$1,600	$4,240	$0	
MIV		Teck Connectors Generator	6	ea	$510	$510	$0	
MIV		Protection Panel 1, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		B1 - Bus Differential Relay	1	ea	$7,500			SEL-487B
MIV		T2 - Atlin Tie TX Protection Relay	1	ea	$3,500			SEL-787

11.5 ESTIMATE WORKSHEET - ATLIN UPPER SUBSTATION - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MIV		T3 - GSU Protection Relay	1	ea	$3,500			SEL-787
MIV		Protection Panel 2, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		L1 - Jake's Corner Line Prot. Relay	1	ea	$5,500			SEL-311L
MIV		L2 - Atlin Lower Line Prot. Relay	1	ea	$5,500			SEL-311L
MIV		Sat. Clock, anttenna	1	ea	$2,000			SEL-2407
MIV		Commissioning	1	lot		$40,000	$10,000	
MH		Washed Rock	150	m^3	$9,000	$1,500	$1,500	
MIV		Foundations Small Screw Pile	51	ea	$31,875	$18,360	$12,240	
MIV		Survey	1	lot		$35,000		
MH	4m x 4m x .33m	Gen Tx Foundation	5.3	m^3	$13,332	$5,333	$2,666	
MH	4m x 4m x .33m	Tie Tx Foundation	5.3	m^3	$13,332	$5,333	$2,666	
MH	4m x 12m x .2m	Shunt Reactor Foundation	9.6	m^3	$24,000	$9,600	$4,800	
MIV	1m x 1m	Trench and backfill for gen cables	75	m		$1,875	$1,875	
MIV		Generator Output Conduits	300	m	$1,200	$600	$300	
MIV	.6m x .2m	Trench and backfill for sub grounding	630	m		$1,890	$1,890	
MIV	600 x 300 x 1000	Precast Concrete Trenchway with Lid (in sub)	160	m	$32,000	$16,000	$16,000	
MIV	600 x 300 x 1000	Precast Concrete Trenchway with Lid (sub to gs	70	m	$14,000	$7,000	$7,000	
MIV	24" Aluminum Ladder	Cable Tray in Building for Control Cables	25	m	$2,500	$1,250	$500	
MIV	.6m x .4m	Excavation for Trenchway	230	m		$1,380	$1,380	**TOTALS**
				SUBTOTAL	**$1,841,115**	**$504,924**	**$93,833**	**$2,439,873**
RSMeans Adjustment Factors for Inflation and Location on all RS Means Indexed Items								
2014 Escalation compounded / yr on RS Means amounts			1.25%		**$29,651.63**	**$5,960.31**	**$1,039.37**	**$36,651**
RSMeans Adjustment Factors for Whitehorse and CDN conversion		**Electrical 134.3 M / 69.8 L**			**$404,293.50**	**-$71,553.37**	**-$12,477.58**	**$320,263**
				SUBTOTAL	**$2,275,060**	**$439,331**	**$82,395**	**$2,796,786**
Division 01	**General Requirements @ 7%**				**$159,254**	**$30,753**	**$5,768**	**$195,775**
	General Contractor Overhead and Profit	**GC O & P 15%**			**$365,147**	**$70,513**	**$13,224**	**$448,884**
	Engineering	**Engineering @ 10%**			**$279,946**	**$54,060**	**$10,139**	**$344,145**
				SUBTOTAL	**$3,079,408**	**$594,657**	**$111,525**	**$3,785,590**
	GST	**GST @ 5%**			**$153,970**	**$29,733**	**$5,576**	**$189,280**
	PST	**PST @ 7%**			**$215,559**	**$41,626**	**$7,807**	**$264,991**

Data Sources:

Where prefixed with a line number, data for material cost, labour cost and equipment cost is taken from 2014 RSMeans data

Where prefixed with MIV the data is estimated value from Magna IV Engineering internal sources and best practices

Where prefixed with MH the values are estimated values provided from Morrison Hershfiield

*Unadjusted anywhere usa" Rsmeans estimating values shown in green highlight cells only

GRAND TOTAL	**CDN$**	**$4,239,861**

11.6 ESTIMATE WORKSHEET - ATLIN LOWER SUBSTATION - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MH		Substation Fence 26 x 35 m	42	m	$1,890	$1,890	$420	100/m, 45, 45, 10/m M,L,E
MH		Substation Vehicle Gates 6m	6	m	$270	$270	$60	100/m, 45, 45, 10/m M,L,E
26 05 26 80 1000	4/0 wire and placement	Substation Grounding Grid 28 x 37 m x	170	m	$2,565	$836	$0	
26 05 26 80 2760	4/0 to 4/0 exothermic	Connectors	25	ea	$200	$1,525	$0	
26 05 26 80 5195	40' with hole clay rod clamp	Ground Wells	4	ea	$12,100	$1,700	$0	
26 05 26 80 0130	15' 3/4" cc steel	Ground Rods Driven	12	ea	$762	$1,284	$0	
33 75 53 13 3250	HV Switches Disconnecting Circuit Switcher <161kV	69 kV circuit switchers	1	ea	$91,500	$55,200	$2,175	
MIV		Circuit Switcher Stand	1	ea	$5,000	$1,000	$300	
33 75 53 13 3080	HV Switches Disconnecting Manual Operation 69kV	69 kv disconnect switches	2	ea	$50,600	$28,400	$2,220	
MIV		disconnect switch support / stand	2	ea	$4,000	$1,000	$200	
MIV		69 kv pt's set of 3	1	sets	$33,000	$3,500	$500	
MIV		pt transformer stand	1	ea	$2,000	$500	$100	
MIV		69 kv fuse disconnect outdoor	1	ea	$15,000	$1,500	$250	
MIV		69 kv fuse disconnect support structure	1	ea	$2,000	$500	$100	
33 75 39 13 8070	69 kv Surge Arrestor	69 kv Surge Arrestors	3	ea	$15,900	$759	$239	
MIV		69 kv Surge Arrestor Support	3	ea	$2,250	$900	$600	
33 73 23 20 1070		T3 Generator Output Transformer	3.5	MVA	$66,850	$3,185	$998	
26 12 19 10 0300	500 kva 15 kV pad mount	SST2 - Station Services Transformer	1	ea	$18,000	$2,650	$350	
MIV		69 kV Dead Ends	1	ea	$25,000	$7,500	$1,000	
MIV		ACSR	80	m	$640	$320	$320	
MIV		ACSR Connectors	30	ea	$1,800	$1,200	$300	
26 56 36 55 0120	Led Flood 90 watt	Outdoor Lighting	2	ea	$3,000	$214	$60	
MIV	Lighting Wiring	2c12 teck, in concrete wireway & up poles	80	m	$320	$160	$0	
MIV		Lightning crosswires	100	m	$200	$150	$200	
MIV		Lightning corner poles	2	ea	$1,500	$600	$400	
26 05 19 20 0400	Means price 3c#6 average cable cost	Field Control Wiring	1000	m	$14,924	$4,526	$0	
MIV		Generator Output Wiring	300	m	$34,500	$6,000	$1,500	
MIV		Terminations Small	100	ea	$0	$300	$0	
MIV		Terminations Generator	6	ea	$510	$510	$240	
MIV		Teck Connectors Small Average	20	ea	$200	$530	$0	
MIV		Teck Connectors Generator	6	ea	$510	$510	$0	
MIV		Protection Panel 1, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		TX1 - Atlin Lower TX Protection Relay	1	ea	$3,500			SEL-787
MIV		L1 - Atlin Upper Line Protection Relay	1	ea	$5,500			SEL-311L
		Sat. Clock	1	ea	$2,000			SEL-2407
MIV		125 VDP Battery, Charger, PDP	1	ea	$5,000	$1,500	$100	
MIV		Commissioning	1	lot		$25,000	$5,000	
MH		Washed Rock	50	m^3	$3,000	$500	$500	
MIV		Foundations Small Screw Pile	11	ea	$6,875	$3,960	$2,640	
MIV		Survey	1	lot		$10,000		
MH	4m x 4m x .33m	Gen Tx Foundation	5.3	m^3	$13,332	$5,333	$2,666	
MIV	1m x 1m	Trench and backfill for gen cables	75	m		$1,875	$1,875	
MIV		Generator Output Conduits	300	m	$1,200	$600	$300	
MIV	.6m x .2m	Trench and backfill for sub grounding	170	m		$510	$510	
MIV	4 parallel runs	Multiconduits Sub to GS	100	m	$2,000	$2,000	$400	
MIV	.6m x 1m	Conduit Excavation and Backfill	100	m		$1,500	$1,500	
MIV	individual runs 4	Conduits to each equipment in sub	80	m	$480	$480	$160	
MIV	.2m x 1m	Conduit Excavation and Backfill	100	m		$1,500	$1,500	**TOTALS**

11.6 ESTIMATE WORKSHEET - ATLIN LOWER SUBSTATION - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MIV	24" Aluminum Ladder	Cable Tray in Building for Control Cables	25	m	$2,500	$1,250	$500	
				SUBTOTAL	**$451,198**	**$190,413**	**$23,437**	**$665,048**
RSMeans Adjustment Factors for Inflation and Location on all RS Means Indexed Items								
2014 Escalation compounded / yr on RS Means amounts			1.25%		**$6,953.21**	**$2,522.66**	**$151.97**	**$9,628**
RSMeans Adjustment Factors for Whitehorse and CDN conversion		**Electrical 134.3 M / 69.8 L**			**$94,805.53**	**-$30,284.50**	**-$1,824.38**	**$62,697**
				SUBTOTAL	**$552,957**	**$162,651**	**$21,765**	**$737,372**
Division 01	**General Requirements @ 7%**				**$38,707**	**$11,386**	**$1,524**	**$51,616**
	General Contractor Overhead and Profit	**GC O & P 15%**			**$88,750**	**$26,105**	**$3,493**	**$118,348**
	Engineering	**Engineering @ 10%**			**$68,041**	**$20,014**	**$2,678**	**$90,734**
				SUBTOTAL	**$748,455**	**$220,156**	**$29,460**	**$998,070**
	GST	**GST @ 5%**			**$37,423**	**$11,008**	**$1,473**	**$49,904**
	PST	**PST @ 7%**			**$52,392**	**$15,411**	**$2,062**	**$69,865**
							GRAND TOTAL	**CDN$** **$1,117,839**

Data Sources:
Where prefixed with a line number, data for material cost, labour cost and equipment cost is taken from 2014 RSMeans data
Where prefixed with MIV the data is estimated value from Magna IV Engineering internal sources and best practices
Where prefixed with MH the values are estimated values provided from Morrison Hershfiield
*Unadjusted anywhere usa" Rsmeans estimating values shown in green highlight cells only

11.7 ESTIMATE WORKSHEET - JAKE'S CORNER SUB OPTION 1b - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MH		Substation Fence 19 x 25 m	82	m	$3,690	$3,690	$820	100/m, 45, 45, 10/m M,L,E
MH		Substation Vehicle Gates 6m	6	m	$270	$270	$60	100/m, 45, 45, 10/m M,L,E
26 05 26 80 1000	4/0 wire and placement	Substation Grounding Grid 21 x 27 x	450	m	$6,790	$2,214	$0	
26 05 26 80 2760	4/0 to 4/0 exothermic	Connectors	46	ea	$368	$2,806	$0	
26 05 26 80 5195	40' with hole clay rod clamp	Ground Wells	0	ea	$0	$0	$0	
26 05 26 80 0130	15' 3/4" cc steel	Ground Rods Driven	14	ea	$889	$1,498	$0	
33 75 53 13 3250	HV Switches Disconnecting Circuit Switcher <161kV	69 kV circuit switchers	1	ea	$91,500	$55,200	$2,175	
MIV		Circuit Switcher Stand	1	ea	$5,000	$1,000	$300	
33 75 53 13 3080	HV Switches Disconnecting Manual Operation 69kV	69 kv disconnect switches	1	ea	$25,300	$28,400	$1,110	
MIV		disconnect switch support / stand	1	ea	$2,000	$500	$100	
33 75 13 13 2100	HV Circuit Breaker Air CB 13-26kV	34.5 kv circuit switcher	1	ea	$59,000	$40,400	$1,575	
MIV		Circuit Switcher Stand 34.5 kv	1	ea	$4,000	$800	$250	
33 75 53 13 3060	HV Switches Disconnecting Manual Operation <26kV	34.5 disconnect switch	3	ea	$40,800	$13,800	$1,620	
MIV		69 kv current transformers set of 3 (high accura	1	ea	$22,000	$3,500	$500	
MIV		current transformer stand	1	ea	$2,000	$500	$100	
MIV		69 kv pt's set of 3	2	sets	$66,000	$7,000	$1,000	rev 2 - was 1
MIV		pt transformer stand	2	ea	$4,000	$1,000	$200	rev 2 - was 1
MIV		69 kv fuse disconnect outdoor	1	ea	$15,000	$1,500	$250	
MIV		69 kv fuse disconnect support structure	1	ea	$2,000	$500	$100	
33 75 39 13 8050	<26 kV Surge Arrestor	34.5 kv Surge Arrestor	3	ea	$4,575	$456	$143	
MIV		34.5 kv Surge Arrestor Support	3	ea	$2,250	$900	$600	
33 75 39 13 8070	69 kv Surge Arrestor	69 kv Surge Arrestors	3	ea	$15,900	$759	$239	
MIV		69 kv Surge Arrestor Support	3	ea	$2,250	$900	$600	
33 73 23 20 1070		6/9 MVA 69 - 34.5 kV Transformer	6	MVA	$114,600	$5,460	$1,710	
33 73 23 20 1070	add 10% for 138 kV	6/9 MVA 69 - 138 kV Transformer	0	MVA	$0	$0	$0	
26 12 19 10 0300	500 kva 15 kV pad mount	SST2 - Station Services Transformer	1	ea	$18,000	$2,650	$350	
MIV		69 kV Dead Ends	1	ea	$25,000	$7,500	$1,000	
MIV		138 kV Dead Ends	0	ea	$0	$0	$0	
MIV		ACSR	100	m	$800	$400	$400	
MIV		ACSR Connectors	50	ea	$3,000	$2,000	$500	
26 56 36 55 0120	Led Flood 90 watt	Outdoor Lighting	3	ea	$4,500	$321	$90	
MIV	Lighting Wiring	2c12 teck, in concrete wireway & up poles	80	m	$320	$160	$0	
MIV		Lightning crosswires	120	m	$240	$180	$240	
MIV		Lightning corner poles	4	ea	$3,000	$1,200	$800	
26 05 19 20 0400	Means price 3c#6 average cable cost	Field Control Wiring	900	m	$13,432	$4,074	$0	
MIV		Terminations Small	200	ea	$0	$600	$0	
MIV		Teck Connectors Small Average	100	ea	$1,000	$2,650	$0	
MIV		Protection Panel 1, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		TX1 - Jake's Corner TX Protection Relay	1	ea	$3,500			SEL-787
MIV		L1 - Atlin Upper Line Protection Relay	1	ea	$5,500			SEL-311L
MIV		Protection Panel 2, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		L2 - Utility Line Protection Relay	1	ea	$5,500			SEL-311L
MIV		SCADA, Teleprotection	1	lot	$7,000			SEL-3530, 2730M
MIV		Sat. Clock	1	ea	$2,000			SEL-2407
MIV		125 VDP Battery, Charger, PDP	1	ea	$8,000	$2,000	$80	
MIV		Commissioning	1	lot		$25,000	$7,000	
MH		Washed Rock	70	m^3	$4,200	$700	$700	
MIV		Survey	1	lot		$25,000		

11.7 ESTIMATE WORKSHEET - JAKE'S CORNER SUB OPTION 1b - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MIV		Foundations Small Screw Pile	18	ea	$11,250	$6,480	$4,320	
MH	5m x 5m x .4m	6/9 tx Foundation 34.5 kV	10.0	m^3	$25,000	$10,000	$5,000	
MH	5m x 5m x .4m	6/9 tx Foundation 138 kV	0.0	m^3	$0	$0	$0	
MH	4m x 8m x .333m	Building Foundation	8.0	m^3	$20,000	$8,000	$4,000	
MIV		3 x 5 building, heat,			$175,000	$30,000	$40,000	
MIV	.6m x .2m	Trench and backfill for sub grounding	450	m		$1,350	$1,350	
MIV	600 x 300 x 1000	Precast Concrete Trenchway with Lid (in sub)	75	m	$15,000	$7,500	$7,500	
MIV	.6m x .4m	Excavation for Trenchway	75	m		$450	$450	**TOTALS**
				SUBTOTAL	**$641,423**	**$293,968**	**$33,931**	**$969,322**
RSMeans Adjustment Factors for Inflation and Location on all RS Means Indexed Items								
2014 Escalation compounded / yr on RS Means amounts			1.25%		**$9,953.15**	**$3,975.64**	**$226.68**	**$14,155**
RSMeans Adjustment Factors for Whitehorse and CDN conversion		**Electrical 134.3 M / 69.8 L**			**$135,709.05**	**-$47,727.40**	**-$2,721.32**	**$85,260**
				SUBTOTAL	**$787,085**	**$250,216**	**$31,436**	**$1,068,738**
Division 01	**General Requirements @ 7%**				**$55,096**	**$17,515**	**$2,201**	**$74,812**
	General Contractor Overhead and Profit	**GC O & P 15%**			**$126,327**	**$40,160**	**$5,046**	**$171,532**
	Engineering	**Engineering @ 10%**			**$96,851**	**$30,789**	**$3,868**	**$131,508**
				SUBTOTAL	**$1,065,359**	**$338,680**	**$42,551**	**$1,446,590**
	GST	**GST @ 5%**			**$53,268**	**$16,934**	**$2,128**	**$72,329**
	PST	**PST @ 7%**			**$74,575**	**$23,708**	**$2,979**	**$101,261**
						GRAND TOTAL	**CDN$**	**$1,620,181**

Data Sources:
Where prefixed with a line number, data for material cost, labour cost and equipment cost is taken from 2014 RSMeans data
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Where prefixed with MH the values are estimated values provided from Morrison Hershfiield
*Unadjusted anywhere usa" Rsmeans estimating values shown in green highlight cells only

11.8 ESTIMATE WORKSHEET - JAKE'S CORNER SUB OPTION 2a - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MH		Substation Fence 19 x 42 m	110	m	$4,950	$4,950	$1,100	100/m, 45, 45, 10/m M,L,E
MH		Substation Vehicle Gates 6m	12	m	$540	$540	$120	100/m, 45, 45, 10/m M,L,E
26 05 26 80 1000	4/0 wire and placement	Substation Grounding Grid 21 x 44 x	600	m	$9,053	$2,952	$0	
26 05 26 80 2760	4/0 to 4/0 exothermic	Connectors	72	ea	$576	$4,392	$0	
26 05 26 80 5195	40' with hole clay rod clamp	Ground Wells	0	ea	$0	$0	$0	
26 05 26 80 0130	15' 3/4" cc steel	Ground Rods Driven	20	ea	$1,270	$2,140	$0	
33 75 53 13 3250	HV Switches Disconnecting Circuit Switcher <161kV	69 kV circuit switchers	4	ea	$366,000	$55,200	$8,700	1 free issue at carcross*
MIV		Circuit Switcher Stand	4	ea	$20,000	$4,000	$1,200	1 free issue at carcross
33 75 53 13 3080	HV Switches Disconnecting Manual Operation 69kV	69 kv disconnect switches	5	ea	$126,500	$28,400	$5,550	2 free issue at carcross*
MIV		disconnect switch support / stand	5	ea	$10,000	$2,500	$500	2 free issue at carcross
33 75 13 13 2100	HV Circuit Breaker Air CB 13-26kV	34.5 kv circuit switcher	1	ea	$59,000	$40,400	$1,575	
MIV		Circuit Switcher Stand 34.5 kv	1	ea	$4,000	$800	$250	
33 75 53 13 3060	HV Switches Disconnecting Manual Operation <26kV	34.5 disconnect switch	3	ea	$40,800	$13,800	$1,620	* free issue materials at carcross
MIV		69 kv current transformers set of 3 (high accura	2	ea	$44,000	$7,000	$1,000	do not include protection devices,
MIV		current transformer stand	2	ea	$4,000	$1,000	$200	station services, earthwork,
MIV		69 kv pt's set of 3	2	sets	$66,000	$7,000	$1,000	grounding, fence, control building
MIV		pt transformer stand	2	ea	$4,000	$1,000	$200	etc. All supplied as part of greater
MIV		69 kv fuse disconnect outdoor	1	ea	$15,000	$1,500	$250	substation by others
MIV		69 kv fuse disconnect support structure	1	ea	$2,000	$500	$100	
33 75 39 13 8050	<26 kV Surge Arrestor	34.5 kv Surge Arrestor	3	ea	$4,575	$456	$143	
MIV		34.5 kv Surge Arrestor Support	3	ea	$2,250	$900	$600	
33 75 39 13 8070	69 kv Surge Arrestor	69 kv Surge Arrestors	3	ea	$15,900	$759	$239	
MIV		69 kv Surge Arrestor Support	3	ea	$2,250	$900	$600	
33 73 23 20 1070		6/9 MVA 69 - 34.5 kV Transformer	6	MVA	$114,600	$5,460	$1,710	
33 73 23 20 1070	add 10% for 138 kV	6/9 MVA 69 - 138 kV Transformer	6	MVA	$126,060	$6,006	$1,881	
26 12 19 10 0300	500 kva 15 kV pad mount	SST2 - Station Services Transformer	1	ea	$18,000	$2,650	$350	
MIV		69 kV Dead Ends	1	ea	$25,000	$7,500	$1,000	
MIV		138 kV Dead Ends	1	ea	$30,000	$8,500	$1,200	
MIV		ACSR	200	m	$1,600	$800	$800	
MIV		ACSR Connectors	100	ea	$6,000	$4,000	$1,000	
26 56 36 55 0120	Led Flood 90 watt	Outdoor Lighting	6	ea	$9,000	$642	$180	
MIV	Lighting Wiring	2c12 teck, in concrete wireway & up poles	150	m	$600	$300	$0	
MIV		Lightning crosswires	200	m	$400	$300	$400	
MIV		Lightning corner poles	4	ea	$3,000	$1,200	$800	
26 05 19 20 0400	Means price 3c#6 average cable cost	Field Control Wiring	1800	m	$26,863	$8,148	$0	
MIV		Terminations Small	360	ea	$0	$1,080	$0	
MIV		Teck Connectors Small Average	180	ea	$1,800	$4,770	$0	
MIV		Protection Panel 1, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		TX1 - Jake's Corner TX Protection Relay	1	ea	$5,500			SEL-387
MIV		L1 - Atlin Upper Line Protection Relay	1	ea	$5,500			SEL-311L
MIV		Protection Panel 2, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		TX2 - Carcross TX Protection Relay	1	ea	$5,500			SEL-387
MIV		L3 - Carcross Line Protection Relay	1	ea	$5,500			SEL-311L
MIV		Protection Panel 3, misc. devices	1	lot	$5,000	$15,000		panel, fab., wiring
MIV		L2 - Utility Line Protection Relay	1	ea	$5,500			SEL-311L
MIV		SCADA, Teleprotection	1	lot	$7,000			SEL-3530, 2730M
		Sat. Clock	1	ea	$2,000			SEL-2407
MIV		125 VDP Battery, Charger, PDP	1	ea	$10,000	$3,000	$100	

11.8 ESTIMATE WORKSHEET - JAKE'S CORNER SUB OPTION 2a - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MIV		Commissioning	1	lot		$40,000	$10,000	
MH		Washed Rock	120	m^3	$7,200	$1,200	$1,200	
MIV		Survey	1	lot		$30,000		
MIV		Foundations Small Screw Pile	26	ea	$16,250	$9,360	$6,240	
MH	5m x 5m x .4m	6/9 tx Foundation 34.5 kV	10.0	m^3	$25,000	$10,000	$5,000	
MH	5m x 5m x .4m	6/9 tx Foundation 138 kV	10.0	m^3	$25,000	$10,000	$5,000	
MH	4m x 8m x .333m	Building Foundation	10.7	m^3	$26,640	$10,656	$5,328	
MIV		3 x 6 building, heat,			$200,000	$40,000	$50,000	
MIV	.6m x .2m	Trench and backfill for sub grounding	630	m		$1,890	$1,890	
MIV	600 x 300 x 1000	Precast Concrete Trenchway with Lid (in sub)	100	m	$20,000	$10,000	$10,000	
MIV	.6m x .4m	Excavation for Trenchway	100	m		$600	$600	**TOTALS**
				SUBTOTAL	**$1,275,537**	**$371,005**	**$56,807**	**$1,703,349**
RSMeans Adjustment Factors for Inflation and Location on all RS Means Indexed Items								
2014 Escalation compounded / yr on RS Means amounts			1.25%		**$23,098.39**	**$4,311.89**	**$552.10**	**$27,962**
RSMeans Adjustment Factors for Whitehorse and CDN conversion		**Electrical 134.3 M / 69.8 L**			**$314,941.57**	**-$51,764.17**	**-$6,627.99**	**$256,549**
				SUBTOTAL	**$1,613,577**	**$323,552**	**$50,731**	**$1,987,860**
Division 01	**General Requirements @ 7%**				**$112,950**	**$22,649**	**$3,551**	**$139,150**
	General Contractor Overhead and Profit	**GC O & P 15%**			**$258,979**	**$51,930**	**$8,142**	**$319,052**
	Engineering	**Engineering @ 10%**			**$198,551**	**$39,813**	**$6,242**	**$244,606**
				SUBTOTAL	**$2,184,057**	**$437,944**	**$68,667**	**$2,690,668**
	GST	**GST @ 5%**			**$109,203**	**$21,897**	**$3,433**	**$134,533**
	PST	**PST @ 7%**			**$152,884**	**$30,656**	**$4,807**	**$188,347**
						GRAND TOTAL	**CDN$**	**$3,013,549**

Data Sources:
Where prefixed with a line number, data for material cost, labour cost and equipment cost is taken from 2014 RSMeans data
Where prefixed with MIV the data is estimated value from Magna IV Engineering internal sources and best practices
Where prefixed with MH the values are estimated values provided from Morrison Hershfiield
*Unadjusted anywhere usa" Rsmeans estimating values shown in green highlight cells only

11.9 ESTIMATE WORKSHEET - JAKE'S CORNER SUB OPTION 2b - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MH		Substation Fence 19 x 42 m	95	m	$4,275	$4,275	$950	100/m, 45, 45, 10/m M,L,E
MH		Substation Vehicle Gates 6m	6	m	$270	$270	$60	100/m, 45, 45, 10/m M,L,E
26 05 26 80 1000	4/0 wire and placement	Substation Grounding Grid 21 x 44 x	525	m	$7,921	$2,583	$0	
26 05 26 80 2760	4/0 to 4/0 exothermic	Connectors	65	ea	$520	$3,965	$0	
26 05 26 80 5195	40' with hole clay rod clamp	Ground Wells	0	ea	$0	$0	$0	
26 05 26 80 0130	15' 3/4" cc steel	Ground Rods Driven	18	ea	$1,143	$1,926	$0	
33 75 53 13 3250	HV Switches Disconnecting Circuit Switcher <161kV	69 kV circuit switchers	3	ea	$274,500	$55,200	$6,525	
MIV		Circuit Switcher Stand	3	ea	$15,000	$3,000	$900	
33 75 53 13 3080	HV Switches Disconnecting Manual Operation 69kV	69 kv disconnect switches	3	ea	$75,900	$28,400	$3,330	
MIV		disconnect switch support / stand	3	ea	$6,000	$1,500	$300	
33 75 13 13 2100	HV Circuit Breaker Air CB 13-26kV	34.5 kv circuit switcher	1	ea	$59,000	$40,400	$1,575	
MIV		Circuit Switcher Stand 34.5 kv	1	ea	$4,000	$800	$250	
33 75 53 13 3060	HV Switches Disconnecting Manual Operation <26kV	34.5 disconnect switch	3	ea	$40,800	$13,800	$1,620	
MIV		69 kv current transformers set of 3 (high accura	2	ea	$44,000	$7,000	$1,000	rev 2 - was 1
MIV		current transformer stand	2	ea	$4,000	$1,000	$200	rev 2 - was 1
MIV		69 kv pt's set of 3	1	sets	$33,000	$3,500	$500	
MIV		pt transformer stand	1	ea	$2,000	$500	$100	
MIV		69 kv fuse disconnect outdoor	1	ea	$15,000	$1,500	$250	
MIV		69 kv fuse disconnect support structure	1	ea	$2,000	$500	$100	
33 75 39 13 8050	<26 kV Surge Arrestor	34.5 kv Surge Arrestor	3	ea	$4,575	$456	$143	
MIV		34.5 kv Surge Arrestor Support	3	ea	$2,250	$900	$600	
33 75 39 13 8070	69 kv Surge Arrestor	69 kv Surge Arrestors	4	ea	$21,200	$1,012	$318	1 set free issue carcross
MIV		69 kv Surge Arrestor Support	4	ea	$3,000	$1,200	$800	
33 73 23 20 1070		6/9 MVA 69 - 34.5 kV Transformer	6	MVA	$114,600	$5,460	$1,710	
33 73 23 20 1070	add 10% for 138 kV	6/9 MVA 69 - 138 kV Transformer	6	MVA	$126,060	$660	$1,320	free issue to carcross sub
26 12 19 10 0300	500 kva 15 kV pad mount	SST2 - Station Services Transformer	1	ea	$18,000	$2,650	$350	
MIV		69 kV Dead Ends	3	ea	$75,000	$22,500	$3,000	1 free issue at carcross
MIV		138 kV Dead Ends	0	ea	$0	$0	$0	
MIV		ACSR	180	m	$1,440	$720	$720	
MIV		ACSR Connectors	90	ea	$5,400	$3,600	$900	
26 56 36 55 0120	Led Flood 90 watt	Outdoor Lighting	6	ea	$9,000	$642	$180	
MIV	Lighting Wiring	2c12 teck, in concrete wireway & up poles	150	m	$600	$300	$0	
MIV		Lightning crosswires	160	m	$320	$240	$320	
MIV		Lightning corner poles	4	ea	$3,000	$1,200	$800	
26 05 19 20 0400	Means price 3c#6 average cable cost	Field Control Wiring	1400	m	$20,894	$6,337	$0	
MIV		Terminations Small	300	ea	$0	$900	$0	
MIV		Teck Connectors Small Average	150	ea	$1,500	$3,975	$0	
MIV		Protection Panel 1, misc. devices	1	ea	$5,000	$15,000		panel, fab., wiring
MIV		TX1 - Jake's Corner TX Protection Relay	1	ea	$5,500	$5,500		SEL-387
MIV		L1 - Atlin Upper Line Protection Relay	1	ea	$5,500	$5,500		SEL-311L
MIV		L3 - Carcross Line Protection Relay	1	ea	$5,500	$5,500		SEL-311L
MIV		Protection Panel 2, misc. devices	1	ea	$5,000	$15,000		panel, fab., wiring
MIV		L2 - Utility Line Protection Relay	1	ea	$5,500	$5,500		SEL-311L
MIV		SCADA, Teleprotection	1	lot	$7,000	$7,000		SEL-3530, 2730M
		Sat. Clock	1	ea	$2,000	$2,000		SEL-2407
MIV		125 VDP Battery, Charger, PDP	1	ea	$10,000	$3,000	$100	
MIV		Commissioning	1	lot		$35,000	$8,000	
MH		Washed Rock	100	m^3	$6,000	$1,000	$1,000	

11.9 ESTIMATE WORKSHEET - JAKE'S CORNER SUB OPTION 2b - Stick Built

Data Source	RSMeans Description Jan 2014	MIV Description	Qty	Unit	Extended Material	Extended Labour	Equipment	Comments
MIV		Survey	1	lot		$35,000		
MIV		Foundations Small Screw Pile	26	ea	$16,250	$9,360	$6,240	
MH	5m x 5m x .4m	6/9 tx Foundation 34.5 kV	10.0	m^3	$25,000	$10,000	$5,000	
MH	5m x 5m x .4m	6/9 tx Foundation 138 kV	0.0	m^3	$0	$0	$0	none - carcross scope
MH	4m x 8m x .333m	Building Foundation	10.7	m^3	$26,640	$10,656	$5,328	
MIV		3 x 6 building, heat,			$200,000	$40,000	$50,000	
MIV	.6m x .2m	Trench and backfill for sub grounding	525	m		$1,575	$1,575	
MIV	600 x 300 x 1000	Precast Concrete Trenchway with Lid (in sub)	90	m	$18,000	$9,000	$9,000	
MIV	.6m x .4m	Excavation for Trenchway	90	m		$540	$540	**TOTALS**
	No protection devices, station services provided at carcross, must be supplied by larger substation installation. Same goes for fence, grounding, earthworks etc.	138 kV circuit switchers	2	ea	$219,600	$400	$1,000	free issue at carcross end
		Circuit Switcher Stand	2	ea	$12,000	$200	$100	unload equipment only
		138 kV disconnect switches	2		$55,660	$31,240	$2,442	free issue at carcross end
		138 kV disconnect stands	2		$4,400	$1,100	$220	unload equipment only
				SUBTOTAL	**$1,094,418**	**$377,231**	**$49,161**	**$1,520,809**
RSMeans Adjustment Factors for Inflation and Location on all RS Means Indexed Items								
2014 Escalation compounded / yr on RS Means amounts			1.25%		**$26,398.28**	**$4,908.76**	**$516.02**	**$31,823**
RSMeans Adjustment Factors for Whitehorse and CDN conversion		**Electrical 134.3 M / 69.8 L**			**$359,934.87**	**-$58,929.55**	**-$6,194.78**	**$294,811**
				SUBTOTAL	**$1,480,751**	**$323,210**	**$43,482**	**$1,847,443**
Division 01	**General Requirements @ 7%**				**$103,653**	**$22,625**	**$3,044**	**$129,321**
	General Contractor Overhead and Profit	**GC O & P 15%**			**$237,661**	**$51,875**	**$6,979**	**$296,515**
	Engineering	**Engineering @ 10%**			**$182,206**	**$39,771**	**$5,350**	**$227,328**
				SUBTOTAL	**$2,004,270**	**$437,481**	**$58,855**	**$2,500,606**
	GST	**GST @ 5%**			**$100,214**	**$21,874**	**$2,943**	**$125,030**
	PST	**PST @ 7%**			**$140,299**	**$30,624**	**$4,120**	**$175,042**
						GRAND TOTAL	**CDN$**	**$2,800,679**

Data Sources:
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*Unadjusted anywhere usa" Rsmeans estimating values shown in green highlight cells only

APPENDIX G:
Cost Estimate

Table G.1 Atlin Hydro Expansion Cost Summary

Atlin Hydro Expansion Prefeasibility Study

Hydroelectric Generation Project Only

Item #	Items	Cost (2016$)	Notes
DIRECT COSTS			
1	Surprise Lake Control Structure Upgrade	$ 291,357	
2	Upper Powerplant Expansion	$ 22,328,547	
3	Lower Powerplant	$ 30,981,824	
	SUB-TOTAL DIRECT COSTS	$ 53,601,728	
ADDITIONAL OWNER COSTS			
	Prefeasibility Study	$ 226,700	Current study actual cost plus hydrology & regulatory scan.
	Feasibility Study	$ 825,725	Assume 1.5% of Direct Costs
	Final Design	$ 2,680,086	Assume 5% of Direct Costs
	Assessment & Licensing	$ 1,608,052	Assume 3% of Direct Costs
	Site Assistance & Quality Assurance	$ 2,680,086	
	Other Owner Costs	$ 2,144,069	Assume 4% of Direct Costs
	SUB-TOTAL COSTS	$ 63,766,447	
	Contingency (25%)	$ 15,941,612	
TOTAL HYDRO GENERATION PROJECT COSTS		**$ 79,708,059**	

Transmission Line

4	Transmission Line to Jakes Corner (inc. substations)	$ 22,699,000	69 kV from MH 2016
5	Jakes Corner Substation	$ 1,446,590	From MagnaIV 2016, including engineering
ADDITIONAL OWNER COSTS (Tranmssion line only)			
	Planning	$ 680,970	3%
	Property Aquisiton & Permitting	$ 1,588,930	7%
	Survey & Structure Staking	$ 453,980	2%
	Engineering	$ 1,815,920	8%
	Project Management	$ 1,588,930	7%
	Construction Management	$ 1,134,950	5%
	Other Owner Costs	$ 1,350,591	5.95%
	SUB-TOTAL COSTS	$ 32,759,861	
	Contingency (25%)	$ 8,189,965	
TOTAL TRANSMISSION LINE COSTS		**$ 40,949,826**	

TOTAL PROJECT COSTS (GENERATION + TRANSMISSION) $ 120,700,000

Table G.2 Surprise Lake Control Structure Upgrade Cost Details

Atlin Hydro Expansion Pre-feasibility Study

Item #	Items	Unit	Quantity	Unit Cost	Cost (2014$)	Notes
1. SITEWORK						
1.1	**Mobilization**	LS	1	$ 50,000	$ 50,000	
1.2	**Clearing**					
	Inlet channel	ha	0.2	$ 20,000	$ 3,800	
	Re-vegetation	LS	1	$ 2,000	$ 2,000	Assuming re-seeding only.
1.3	**Diversion & dewatering**	LS	0	$ 65,000	$ -	Dewatering intake for replacement of gates.
1.4	**Remove & replace fencing, log boo**	LS	1	$ 8,000	$ 8,000	
1.5	**Misc. traffic control, etc.**	LS	1	$ 15,000	$ 15,000	
2. STRUCTURES & EXCAVATION						
2.1	**Inlet channel excavation**					
	Excavation	m^3	2600	$ 18	$ 47,320	Assume ~7m wide x 190m long x aver 2m depth excavation
	Supply & place cobble/riprap	m^3	270	$ 113	$ 30,375	Assume 0.2m thick layer
2.2	**Intake upgrade**				$ -	
	Raise intake platform	LS	1	$ 10,000	$ 10,000	Allowance raising walkway, fencing, etc.
2.3	**Weir upgrade**				$ -	
	Extend sheet pile weir	m^2	45	$ 295	$ 13,220	Assume 1.4m extension by 32m long
	Supply & place rip rap	m^3	364	$ 113	$ 40,929	0.7 m thick Class 1 over 500m2 plus 16m2 Class 2 at bridge abutments
6. ENVIRONMENTAL & MITIGATION ITEMS						
6.1	**Other**	LS	1	$ 15,000	$ 15,000	Environmental measures, during works
6.2	**Upgrade of Fishway**	LS	1	$ 50,000	$ 50,000	Add additional basins & modifications to openings

TOTAL COSTS **$ 285,644.22**

Note all rates are blended with idirects and OH& Profit

Table G.3 Upper Power Plant Expansion Cost Details
Atlin Hydro Expansion Pre-feasibility Study

Item #	Items	Unit	Quantity	Unit Cost	Cost (2015$)	Notes
1. SITEWORK						
1.1	**Mobilization**	LS	0.5	$ 400,000	$ 200,000	Mob for lower power plant project - cost split with upper plant
1.2	**Clearing**					
	Penstock	ha	0.45	$ 18,000.00	$ 8,100	Assumed expanded clearing down the hill to powerhouse expansion - 300m x 15m
	Powerhouse & tailrace	ha	0.375	$ 18,000.00	$ 6,750	Assumed hillside clearing 50m x 75m
	Contractor laydown area	ha	0	$ 18,000.00	$ -	Assumed existing areas will be used and no new laydowns required
1.3	**Access Road**					
	Powerhouse	m	100	$ 50.00	$ 5,000	Additional road around powerhouse
1.4	**Dewatering**					
	Head pond	months	2	$ 20,000.00	$ 40,000	
	Powerhouse	months	0	$ 20,000.00	$ -	Assume no dewatering needed for powerhouse
1.5	**Foundation Preparation**					
	Intake	sq metre	22	$ 32.00	$ 704	2.1x5m for intake box + 6m of wing-walls
	Powerhouse	sq metre	364	$ 32.00	$ 11,648	footprint of 26m x 14m powerhouse
2. STRUCTURES & EXCAVATION						
2.1	**Intake**					
	General excavation	cubic metre	450	$ 11.25	$ 5,063	re-excavation of diversion channel (6m wide, 15m long, 5 m deep)
	Rock excavation	cubic metre	0	$ 100.00	$ -	assume no rock excavation due to previous diversion ex.
	Retaining wall - sheet pile	m2	30	$ 295.10	$ 8,853	sheet pile between intake boxes
	Retaining wall - concrete	cubic metre	25	$ 2,500.00	$ 62,500	Assume 10m of wing wall
	General backfill	cubic metre	450	$ 37.50	$ 16,875	
	Intake structure & trash racks	LS	1	$ 113,750.00	$ 113,750	
	Gates	ea	1	$ 36,250.00	$ 36,250	
2.2	**Penstock**					
	General excavation	cubic metre	37821	$ 11.25	$ 425,484	Assume general excavation from 0+00 to 3+698
	Rock excavation	cubic metre	6600	$ 100.00	$ 660,000	Assume 330 m requires rock excavation - 4x5m
	Supply & Install 1.5 m Φ DR41 HDPE penstock	m	1828	$ 1,239.00	$ 2,264,892	
	Supply & Install 1.5 m Φ DR32.5 HDPE penstock	m	256	$ 1,414.00	$ 361,984	
	Supply & Install 1.5 m Φ DR26 HDPE penstock	m	713	$ 1,619.80	$ 1,154,917	
	Supply & Install 1.5 m Φ DR21 HDPE penstock	m	768	$ 1,863.40	$ 1,431,091	
	Supply & Install 1.5 m Φ steel penstock	m	438	$ 2,300.00	$ 1,007,400	based on current all in pricing from New Post Creek minimum handling thickness
	Granular fill	cubic metre	33523	$ 81.25	$ 2,723,728	
	Random backfill	cubic metre	11109	$ 37.50	$ 416,599	Based on typical cross section providing 0.7m of cover over granular fill.
	Bifurcation	LS	1	$ 40,000.00	$ 40,000	
2.3	**Powerhouse**					
	General excavation	cubic metre	11600	$ 11.25	$ 130,500	clearing for PH and new parking and lay down area to 726 with 2:1 slopes up hill. Neat line for depth of powerhouse
	Reinforced concrete	cubic metre	800	$ 2,500.00	$ 2,000,000	
	Superstructure and architectural finishes	LS	1	$ 410,000.00	$ 410,000	
	Draft tube gates/mechanical	LS	1	$ 100,000.00	$ 100,000	
	Crane supply & install	LS	1	$ 50,000.00	$ 50,000	extension of crane rails from existing building into new
	Miscellaneous embedded and non-embedded items	LS	1	$ 400,000.00	$ 400,000	Assumes existing crane and control room will be used
2.4	**Tailrace**					
	General excavation	cubic metre	1300	$ 11.25	$ 14,625	expand tailrace to 6 m base width, at Elv 723 (1 to 1.5 m depth of flow), expand over plan area shown on drawing to encompass both PH tailraces, less existing 3m wide 1.5:1 tailrace.
	Riprap - supply & place	cubic metre	440	$ 112.50	$ 49,500	assumed new riprap over extents of area 0.4m deep
3. TURBINE - GENERATOR UNIT						
3.1	**Turbine**	ea	2	$ 357,000.00	$ 714,000	
3.2	**Generator**	ea	2	$ 273,000.00	$ 546,000	
3.3	**Turbine Inlet Valve (TIV)**	ea	2	$ 105,000.00	$ 210,000	
3.4	**Auxiliary Systems**	LS	1	$ 210,000.00	$ 210,000	
3.5	**Project Service & Install**	LS	1	$ 2,145,000.00	$ 2,145,000	includes all installation, i.e. electrical, controls, mechanical, hydraulic, and commissioning costs
4. ELECTRICAL & MECHANICAL BALANCE OF PLANT						
4.1	**Mechanical Balance of Plant**	LS	1	$ 130,000.00	$ 130,000	
4.2	**Electrical Balance of Plant**	LS	1	$ 250,000.00	$ 250,000	
4.3	**Switchyard (Supply)**	LS	1	$ 3,529,520.10	$ 3,529,520	From MagnaIV 2016 (not including engineering), inflation adjusted to 2015.
6. ENVIRONMENTAL & MITIGATION ITEMS						
6.1	**Other**	LS	0		$ -	

TOTAL DIRECT COSTS **$ 21,890,732**

Note all rates are blended with idirects and OH& Profit

Table E.4 Lower Power Plant Cost Details

Atlin Hydro Expansion Pre-feasibility Study

Item #	Items	Unit	Quantity	Unit Cost	Cost (2015$)	Notes
1. SITEWORK						
1.1	**Mobilization**	LS	0.5	$ 400,000	$ 200,000	Mob for lower power plant project - cost split with upper plant
1.2	**Clearing**				$ -	
	Head pond	ha	0.5	$ 20,000	$ 10,800	Triangular area 105m x 90m + 30x45m triangle on N side of creek - scaled off drawing 9
	Spruce Creek Diversion	ha	0.3	$ 20,000	$ 6,000	Assumed 100m long x 30m wide
	Penstock & surge pipe	ha	10.8	$ 20,000	$ 216,650	4.0km x 25m wide + 340m x 25m for surge pipe
	Powerhouse & tailrace	ha	1.1	$ 20,000	$ 21,100	4700 m2 for powerhouse plus 130m long tailrace @ 45m wide clearing
	Contractor laydown area	ha	0	$ 20,000	$ -	Assumed existing areas will be used and no new laydowns required
	Stumpage Fee	LS	1	$ 8,100	$ 8,100	Assumed to be the same as 2009 project
1.3	**Access Road**					
	Penstock	m	4000	$ 100.00	$ 400,000	access/service road paralleling penstock
	Powerhouse	m	175	$ 100.00	$ 17,500	75m to powerhouse + 100m to surge bldg.
1.4	**Dewatering**					
	Head pond	months	3	$ 15,000.00	$ 45,000	
	Powerhouse	months	17	$ 15,000.00	$ 255,000	Dewatering will be required over the length of construction
1.5	**Foundation Preparation**					
	Intake	sq metre	58	$ 32.00	$ 1,856	KGS to provide - assume 5x5m for intake box + 33m of wing-walls
	Powerhouse	sq metre	336	$ 32.00	$ 10,752	KGS to provide - assumed footprint of 28m x 12m powerhouse
2. STRUCTURES & EXCAVATION						
2.1	**Head pond**					
	Pine Creek temporary diversion	cubic metre	2160	$ 11.25	$ 24,300	Assumes 120 m long x 2m deep by 5m base width
	Cobbles for temporary diversion	cubic metre	324	$ 112.50	$ 36,450	Assume 0.3m thick cobbles
	Access over temporary diversion	LS	1	$ 50,000.00	$ 50,000	Assumes culverts/temporary bridge or temporary relocation of existing bridge
	Head pond Excavation	cubic metre	14859	$ 11.25	$ 167,158	pond volume from Civil3D + 2600m3 subcut for 0.7m thick riprap
	Stilling basin	cubic metre	683	$ 11.25	$ 7,678	inc. subcut for riprap - 15m x 35m x 1.3m deep
	Embankment sub-cut	cubic metre	2700	$ 11.25	$ 30,375	Assume 90m long x 30m wide by 1 m subcut.
	Rock fill embankment	cubic metre	4600	$ 112.50	$ 517,500	1900 m3 from Civil 3D plus 1 m subcut volume of 2700
	Sheet pile cutoff wall	sq metre	1288	$ 295.10	$ 380,089	92m long x 14m deep
	Riprap - supply & place	cubic metre	1859	$ 112.50	$ 209,081	0.7m thick on back slope of pond. Dam/weir riprap included in above
	Intake structure	LS	1	$ 113,636.36	$ 113,636	Includes concrete
	Trash racks	LS	1	$ 70,000.00	$ 70,000	Supply & install, double wide
	Gates	ea	2	$ 42,000.00	$ 84,000	for 2 gates
	Fishway	LS	1	$ 95,450.00	$ 95,450	Escalated cost from Surprise Lake fishway
2.2	**Spruce Creek Diversion**				$ -	
	Diversion ditch excavation	cubic metre	2400	$ 11.25	$ 27,000	Assume 4m wide, ave. depth 3m @80 long
	Diversion rock fill weir	cubic metre	190	$ 112.50	$ 21,375	Assume 20m long x 5m wide crest c/w 0.5 m subcut.
	Culvert - supply & install	LS	1	$ 80,500.00	$ 80,500	Assuming 1.5m CSP c/w 2 sets of headwalls.
	Riprap - supply & place	cubic metre	307.2	$ 112.50	$ 34,560	1000m2 x 0.3m thick class 1 riprap
2.3	**Penstock (inc. surge pipe)**					Penstock typ. section should be optimized to reduce volumes.
	General excavation	cubic metre	45679	$ 11.25	$ 513,883	4.4km minus rock segments below
	Rock excavation	cubic metre	3947	$ 100.00	$ 394,740	Assumed rock ex. from 0+800 to 1+075, 2+500 to 2+725 & 310 for surge pipe: total 810m
	Supply & Install 2 m Φ penstock steel	m	1000	$ 3,040.00	$ 3,040,000	
	Supply & Install 2x 1.6m Φ penstock DR41 HDPE	m	3025	$ 2,478.00	$ 7,495,950	
	Supply & Install 2x 1.6m Φ penstock DR26 HDPE	m	375	$ 3,240.00	$ 1,215,000	
	Granular fill	cubic metre	30674	$ 81.25	$ 2,492,279	
	Random backfill	cubic metre	35158	$ 37.50	$ 1,318,440	Based on typical cross section providing 0.7m of cover over granular fill.
	Bifurcation	LS	1	$ 50,000.00	$ 50,000	
	Surge facility (vents and instrumentation)	LS	1	$ 300,000.00	$ 300,000	surge section only, vent structure and instrumentation building
2.4	**Powerhouse**					
	General excavation	cubic metre	19700	$ 11.25	$ 221,600	includes tailrace and road excavation out along penstock route, 3:1 slopes
	Rock excavation	cubic metre	1000	$ 100.00	$ 100,000	assumes rock below 270.25 in PH footprint only
	Reinforced concrete	cubic metre	450	$ 2,500.00	$ 1,125,000	
	Superstructure and architectural finishes	LS	1	$ 465,000.00	$ 465,000	
	Draft tube gates/mechanical	LS	1	$ 100,000.00	$ 100,000	set of stop logs, guides, small hoist
	Crane supply & install	LS	1	$ 350,000.00	$ 350,000	
	Miscellaneous embedded and non-embedded items	LS	1	$ 400,000.00	$ 400,000	
2.5	**Tailrace**					
	General excavation	cubic metre	6000	$ 11.25	$ 67,500	Based on 140 m long tailrace, 5.4 m deep, 8 m wide at base w/ 2.5H:1V slopes
	Riprap - supply & place	cubic metre	1264	$ 112.50	$ 142,200	Class 1 riprap 0.4m thick
3. TURBINE - GENERATOR UNIT						
3.1	**Turbine**	ea	1	$ 1,143,528.10	$ 1,143,528	
3.2	**Generator**	ea	1	$ 1,567,600.00	$ 1,567,600	
3.3	**Turbine Inlet Valve (TIV)**	ea	1	$ 361,753.92	$ 361,754	
3.4	**Auxiliary Systems**	LS	1	$ 482,338.60	$ 482,339	
3.5	**Project Service & Install**	LS	1	$ 1,430,000.00	$ 1,430,000	
4. ELECTRICAL & MECHANICAL BALANCE OF PLANT						
4.1	**Mechanical Balance of Plant**	LS	1	$ 260,000.00	$ 260,000	
4.2	**Electrical Balance of Plant**	LS	1	$ 250,000.00	$ 250,000	
4.3	**Switchyard and Interconnection**	LS	1	$ 929,575.00	$ 929,575	From MagnaIV 2016 (not including engineering) , inflation adjusted to 2015.
5. TRANSMISSION LINE						
5.1	**Clearing**	ha	0	$ 20,000.00	$ -	Clearing assumed to be included in lower penstock ROW
5.2	**Transmission Line**	km	4	$ 209,009.80	$ 836,039	69 kV from MH 2016 estimate, inflation adjusted to 2015.
6. ENVIRONMENTAL & MITIGATION ITEMS						
6.1	**Footbridge over tailrace**	LS	1	$ 30,000.00	$ 30,000	Assumed wooden, locally built by ATELP
6.2	**Other**	LS	1	$ 100,000.00	$ 100,000	Environmental monitoring
6.3	**Tree Planting and Landscaping**	LS	1	$ 50,000.00	$ 50,000	Cosmetic fixes near residential areas and campground to accelerate reclaimation of cleared areas

TOTAL DIRECT COSTS **$ 30,374,337**

Note all rates are blended with idirects and OH& Profit

Appendix 5.9
Wind Site Inventory (CBER, Envint and V3 Energy 2016)

YUKON Wind Site Inventory

Final Report

RFP 2015-060

Prepared for:

YUKON ENERGY

Prepared by:

CBER

with

envint Consulting *and* V3 Energy, LLC

August 9, 2016

EXECUTIVE SUMMARY

For its new planning cycle, the Yukon Energy Corporation (YEC) is investigating renewable energy sources and several parallel assessments have been commissioned. These assessments are to inform YEC of the potential viability of each power generation resource in Yukon, identify suitable sites, estimate capital and operating costs, and determine the resulting per-kWh power generation cost. These results then feed into a resource option plan that evaluates power generation options according to the financial, technical, socio-economic and environmental attributes of each technology.

This report addresses utility-scale wind power, one of the technologies YEC identified as a potential source of electricity generation for the territory. The study has four major objectives:

- **Wind site inventory** to identify potential wind project sites near existing or planned power infrastructure. This task included reviewing existing wind mapping and selecting preferred sites for detailed analysis;
- **Develop potential wind projects at a conceptual level** to include wind resource assessment, site turbine layout, infrastructure footprints, and modelled gross and net power output;
- **Economic modelling** to create site-specific cost estimates for development, construction, power production, and determining the cost of power and energy;
- **Additional information pertaining to wind farm development** that might affect its viability.

The Yukon has significant wind resources although development of those resources is challenging due to the territory's mountainous nature. Most suitable wind farm sites are located on mountaintops, peaks, ridges or crests while YEC's transmission lines naturally route through valleys. The result is a challenging exercise of identifying sites that are not only windy but also able to be *developed*.

A number of criteria influenced the wind site prospecting task. These include:

- **Wind and atmospheric considerations**, such as high mean wind speed and wind power density;
- **Site development considerations**, such as a reasonable distance to a community or YEC office for maintenance purposes or proximity to existing roads.
- **Environmental and human factor considerations**, including potential harmful effects on wildlife and birds, vicinity to parks, use for recreational purposes and other environmental restrictions.

Another criterion was a desire to represent northern, central and southern Yukon. Part of the intent was to screen as wide an area as possible and represent sites of varying characteristics. Because the

Yukon is a high-latitude region with a mostly sub-arctic-to arctic, often maritime-influenced climate, winter-time icing at higher elevations is operationally challenging. For this reason, the most desirable wind-power sites are at lower elevations where icing conditions do not occur. There are, however, few sites in the territory that are both windy and low elevation. Kluane Lake is an exception.

Out of a longlist of 26 sites we selected five locations for an in-depth review and conceptual design. The selections were based on wind speed, distance to transmission lines, road access, and land ownership. Other factors such as potential conflicts with other land uses or anticipated public opposition were also evaluated to determine a shortlist of seven sites. Of the seven, only Kluane Lake is a low-elevation site.

We developed representative wind turbine arrays of 20, 10 and 6 MW capacity for each of the seven selected sites. The site layout and location are on a conceptual level only but sufficient for estimating the power output and the cost of installing wind farms. The layout of each wind farm accounts for the prevailing wind direction(s) and topographic optimization. To locate an access road to each site, we retained an average gradient and turning radius within the limits of requirements to transport a 45 meter blade and a 70 tonne nacelle to the sites.

In the absence of measured wind data, this report relies on computer models that predict wind direction, wind speed, turbulence and power production from wind turbines at a given site. We chose a 2 MW, 80 meter hub height Vestas V90 model as the generic turbine for modeling purposes.

Apart from the generic turbine used for financial modeling, we also separately compared three alternate turbines for each site based on the AWS Truepower Advanced Reports. The resulting monthly data shows that for most sites a turbine designed for higher wind speeds produced less energy per year, but more during the period from October to April when electricity is most need in the Yukon.

At the site with the highest output, Miller's Ridge near Carmacks, a 20 MW farm would produce 57 GWh of energy a year, equivalent to the annual consumption of 5,800 households in the Yukon. For YEC, the annual net energy production may be less important than generation during the colder period of the year. From May to September there is generally a power surplus from existing hydropower generation facilities. Fortunately, all seven sites show a clear pattern of lower monthly mean power production during the summer months compared to winter, despite the higher percentage of energy loss due to icing during winter. On average, three-fourths of wind energy generated would be during the seven months from October to April.

The mean annual power output is 26% to 28% of the nominal wind farm capacity, i.e. a 10 MW wind farm, for example, would generate on average 2.6 to 2.8 MW over the course of the year, more during the winter, less in summer. Wind power is a variable resource and technically cannot guarantee any minimum output at any time of the year. There may be days when wind speeds are below the start-up wind speed; output will drop to zero during these hours.

Capital costs, including hard and soft costs, such as financing and project development costs, range

from $31 million for a 6 MW wind farm to $66 million for a 20 MW project for the average of all seven sites. This equates to mean specific costs of $5.2 million per MW to $3.3 million per MW, respectively. The overall accuracy of these cost estimates is ±30%, commensurate with the project definition of a pre-feasibility or screening level study. Operational costs are approximately $300,000 of fixed cost, and variable cost of around $25 per MWh of net energy produced. These costs are similar for all sites.

The levelized cost of energy at almost all sites and all sizes remains under the current Yukon standard offer price of 21 ¢/kWh but often above the average residential retail price of 12 ¢/kWh, see the table below. Of the seven sites selected, five show above-average performance in terms of the cost of energy produced. These sites are, in the order of performance, Miller's Ridge near Carmacks, Thulsoo Mountain near the Aishihik hydroelectric facility, Kluane Lake, a mountain ridge near Cyprus Mine, close to Faro, and Mt. Sumanik near Whitehorse. The table below provides key economic parameters. There is little difference in energy production cost between these five sites; non-monetary factors may play an important role in selecting the preferred location.

Miller's Ridge near Carmacks and Thulsoo Mountain near the Aishihik hydroelectric facility are the sites with the highest wind resource and a low cost of energy (LCOE). Thulsoo Mountain is near an existing facility, but Miller's Ridge has more expansion potential. Sumanik Mountain is attractive due to its location near Whitehorse. Cyprus Mountain is the furthest from Whitehorse, but appealing due to its brownfield nature next to an abandoned mine. Kluane Lake gets a qualified recommendation because of its low elevation and low energy costs (LCOE), but requires a transmission line to be built first. Tehcho and Sugarloaf are not recommended because the other site options clearly are superior, both in terms of annual energy production and energy cost.

Key Financial Parameter of the Three Wind Farm Sizes at the Seven Sites Evaluated

Site	6 MW		10 MW		20 MW	
	Capital Cost (million $)	Levelized Cost of Energy *	Capital Cost (million $)	Levelized Cost of Energy *	Capital Cost (million $)	Levelized Cost of Energy *
Cyprus Mine	34	17.3¢/kWh	44	13.8¢/kWh	69	11.7¢/kWh
Kluane Lake	26	15.1¢/kWh	36	12.6¢/kWh	62	11.0¢/kWh
Miller's Ridge	39	17.1¢/kWh	49	13.1¢/kWh	73	10.7¢/kWh
Sugarloaf Mountain	28	22.6¢/kWh	38	18.7¢/kWh	62	15.3¢/kWh
Mt. Sumanik	30	17.2¢/kWh	39	14.6¢/kWh	64	12.4¢/kWh
Tehcho (Ferry Hill)	28	21.4¢/kWh	39	16.4¢/kWh	64	15.1¢/kWh
Thulsoo Mountain	36	16.8¢/kWh	46	13.2¢/kWh	72	10.9¢/kWh
Average	**32**	**18.2¢/kWh**	**42**	**14.6¢/kWh**	**67**	**12.5¢/kWh**

** at 3.38% real weighted average cost of capital (WACC)*

Due to fixed costs and economies of scale, larger wind farms have lower energy production costs than smaller ones. The cost of energy at the seven sites averages 13 ¢/kWh for a 20-MW wind farm but increases to 18 ¢/kWh for a 6-MW capacity. Our modelling assumes that all energy produced will be used. Curtailment of the operation during the summer when YEC has a surplus of power

would increase the cost of energy produced during the rest of the year by more than a quarter.

A sensitivity analysis of a 10-MW wind farm at Kluane Lake showed that the cost of energy is most sensitive to forecasted energy production. This underlines the importance of monitoring wind speed, rime icing, and temperature at selected sites. These are key parameters that will determine the output of a generator and thereby the financial performance of the wind farm.

Developing a wind farm in the Yukon will likely require four years, including a wind monitoring campaign during the first year. The schedule may be more relaxed or could be condensed to three years for sites with existing and suitable road access.

If the update to YEC's 20-year plan yields that wind power is a viable source of electricity, then further research should be done on the five sites mentioned above. We recommend a full-scale feasibility study for some or all of those sites, and wind and icing monitoring at several sites in parallel to then select the most suitable one for development.

Table of Contents

1 Introduction 8

1.1 Background 8

1.2 Scope and Objective 8

1.3 Previous Work 9

2 Wind power site identification 10

2.1 Site Identification Criteria 10

2.2 Initial Site Inventory 12

2.2.1 Northern Yukon Sites of Interest 13

2.2.2 Central Yukon Sites of Interest 15

2.2.3 Southern Yukon Sites of Interest 17

2.3 Yukon Site Visit 21

2.4 Site Selection 22

3 Conceptual Wind Farm Development 25

3.1 Cyprus Mine Hill 26

3.1.1 Site Description 26

3.1.2 Site Layout 27

3.2 Kluane Lake (West Shore) 28

3.2.1 Site Description 29

3.2.2 Site Layout 30

3.3 Miller's Ridge 31

3.3.1 Site Description 31

3.3.2 Site Layout 32

3.4 Sugarloaf Mountain 33

3.4.1 Site Description 33

3.4.2 Site Layout 34

3.5 Mount Sumanik 35

3.5.1 Site Description 35

3.5.2 Site Layout 36

3.6 Tehcho (Ferry Hill) 38

3.6.1 Site Description 38

3.6.2 Site Layout 39

3.7 Thulsoo Mountain 39
3.7.1 Site Description 40
3.7.2 Site Layout 41
3.8 Land Use 41
4 Wind Farm Energy Production 43
4.1 Annual Gross Energy Production 43
4.2 Energy Losses 44
4.2.1 Wake Losses 44
4.2.2 Extreme Temperature Curtailment 45
4.2.3 De-icing Energy and De-icing Downtime 46
4.2.4 Transformer Losses 46
4.2.5 Sub-optimal Performance 47
4.2.6 Maintenance Downtime 47
4.2.7 Total Losses and Net Output 47
4.3 Annual Net Energy Production 48
4.4 Monthly Generation Profile 49
4.5 Reliable Winter Capacity 52
4.6 Turbine Choice 54
5 Financial Analysis 58
5.1 Capital and Development Cost Estimates 58
5.1.1 Logistics 59
5.1.2 Civil Works 59
5.1.3 Electrical Infrastructure 60
5.1.4 Labour Costs 61
5.1.5 Financing Costs 62
5.1.6 Land Costs 62
5.1.7 Development Costs 63
5.1.8 Equipment Costs 63
5.1.9 Contingencies 63
5.1.10 Total Capital and Development Costs 64
5.2 Operational Costs Estimate 66
5.2.1 Fixed Operational Costs 66

5.2.2 Variable Operational Costs 66
5.3 Financial Modelling 68
5.4 Sensitivity Analyses 70
6 Additional Information 73
6.1 Ice Mitigation Review 73
6.2 Birds and Parks 76
6.3 Comparison to Recent Site-Specific Consultant Reports 78
7 Preliminary Project Schedule 80
8 RIsk assessment 82
8.1 Introduction 82
8.2 Key Risks 82
8.3 Lesser Risks 83
9 Conclusions and Recommendations 86

APPENDIX A: Map of Yukon Electric Grid
APPENDIX B: AWS Truepower Maps of Seven Selected Sites
APPENDIX C: Capital and Operational Cost Sheets (Excel)
APPENDIX D: Financial Analysis (Excel)
APPENDIX E: AWS Truepower Compass Report (all 26 Sites)
APPENDIX F: Additional Site Visit Photos
APPENDIX G: WAsP Wind Farm Reports for Seven Selected Sites
APPENDIX H: Energy Performance of the Selected Sites
APPENDIX I: AWS Truepower Advanced Reports (7 sites)

Notice to Reader

This report was prepared by Cornelius Suchy of Canadian Biomass Energy Research (CBER) Ltd, Martin Tampier of ENVINT Consulting and Douglas Vaught, P.E. of V3 Energy, LLC. The material in it reflects the authors' best judgement in light of the information available to them at the time of preparation.

The sole purpose of this report is to assist Yukon Energy Corporation in its decision of whether to pursue the initiatives discussed herein. The authors and CBER, as the main contractor, accept no responsibility if any party relies on this report for any purpose that Suchy, Tampier and Vaught have not expressly agreed to. Any reliance placed on this report by another party will be at that party's risk and without recourse to Cornelius Suchy or CBER Ltd.

This report involves matters that cannot be precisely determined. Our calculations generally depend on subjective judgements and uncertainties that increase as we forecast further into the future. Much of the information available to us is based on estimates and assumptions provided by third parties. Accordingly, this report does not guarantee a specific result; instead, it is a means of assessing the relative desirability of alternative courses of action, a range of investment requirements, and anticipated income or cash flow, as the case may be.

Cornelius Suchy, Martin Tampier and Douglas Vaught reserve the right (but will be under no obligation) to review all calculations referred to in this report and, if we consider it necessary, to revise them in light of new facts, trends, or changing conditions that become apparent to us after the report is published.

Interested parties are cautioned that decisions of whether to rely on the accuracy and completeness of the information in this report, and whether to invest or provide financing, are theirs alone and neither Cornelius Suchy nor CBER will assume any responsibility for losses resulting from such decisions. Decisions to invest or provide financing will likely require additional information beyond the information in this report.

Opinions expressed in this report are those of the authors and do not necessarily reflect the opinion of the Yukon Energy Corporation.

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Conversion of units used in this report

1 kilometer (km)	=	0.62	miles (mi)
1 meter (m)	=	3.28	feet (ft)
1 meter per second (m/s)	=	3.6	kilometre per hour (km/h)
1 kilogram (kg)	=	2.2	pounds (lb)
1 metric tonne (t)	=	2,205	pounds (lb)
1 pound (lb)	=	0.45	kilograms (kg)
1 metric tonne (t)	=	1,000	kilograms (kg)
1 square metre (m^2)	=	10.8	square foot (sft)
1 square foot (sft)	=	0.09	square meter (m^2)
1 cubic metre (m^3)	=	1,000	litres (L)
1 cubic metre (m^3)	=	1.3	cubic yard (cyd)
1 hectare (ha)	=	2.5	acres (ar)
1 hectare (ha)	=	0.01	square kilometers (km^2)
1 acre (ar)	=	0.4	hectare (ha)
1 gigawatt hour (GWh)	=	1,000	megawatt hour (MWh)
1 megawatt hour (MWh)	=	0.001	gigawatt hour (MWh)
1 megawatt hour (MWh)	=	1,000	kilowatt hour (kWh)
1 kilowatt hour (kWh)	=	0.001	megawatt hour (MWh)

Glossary and Acronyms

$	Canadian dollar; all costs in this report are given in CAD
¢	Cent
AACE	Association for the Advancement of Cost Engineering
AB	Alberta
AOI	Area of Interest
AEP	Annual Energy Production
AWS	Company providing wind energy modelling
BC	British Columbia
Capacity factor	Mean annual power output divided by rated power or the total annual power output divided by the capacity and by 8760, the number of hours in a year
CAPEX	Capital cost
DDP	Delivered Duty Paid, an Incoterm for point of delivery
DEM	Digital Elevation Map
ELCC	Effective Load Carrying Capability
ENE	East-Northeast
Enercon	A German wind turbine manufacturer
EPC	Engineer-Procure-Construct, a contract form where the EPC Contractor is responsible for all activities from design, procurement, construction, to commissioning and handover of the project to YEC
FN	First Nation
GE	General Electric, an American wind turbine manufacturer
GeoYukon	Yukon's online geographic information system (GIS)
GIS	Geographic Information System
Hwy	Highway
IEC wind class	A wind speed and turbulence classification of the International Electrotechnical Commission.
IRENA	International Renewable Energy Association
km	Kilometer
kV	Kilovolt
LCOE	Levelized Cost of Energy
LIDAR	Light Detection and Ranging is a method of measuring distance or wind speeds by projecting a laser into the air and detecting the backscatter from random particles in the atmosphere.

Meso-scale	Model with a raster size of 1 x 1 km
MW	Megawatt
N	North
NE	Northeast
NNE	North-Northeast
NNW	North-Northwest
NW	Northwest
O & M	Operation and maintenance
OPEX	Operational cost
PPA	Power Purchase Agreement
RFP	Request for Proposals
SE	Southeast
SW	Southwest
SSW	South-Southwest
TIF	Tagged Image File (Format)
Tx	transmission
U.S.	United States
UTM	Universal Transverse Mercator
Vestas	A Danish wind turbine manufacturer
WACC	Weighted Average Cost of Capital
Wake loss	The loss a wind turbine may experience due to turbulences from the ground or nearby wind turbines.
WAsP	Wind Atlas Analysis and Application Program
WTG	Wind turbine generator
YEC	Yukon Energy Corporation

1 INTRODUCTION

1.1 Background

The Yukon Energy Corporation (YEC) has a winter peak demand of 82 MW[1] and dependable renewable capacity of 72 MW. Thermal generation is used to provide peak power. If consumer loads continue to grow or if a large industrial customer is added then additional sources of energy may be required.

This report is the result of a two-month study of the wind energy potential in the Yukon Territory. This work will support the planning process that aims at identifying potential resource options to meet the long-term load forecast (2016-2035) of the area served by Yukon Energy Corporation (YEC).

YEC has entered a new planning cycle. A five-year update of YEC's Integrated Resource Plan is scheduled for completion at the end of 2016. To this end, YEC has commissioned a series of assessments on several energy technologies. These assessments are to inform YEC about the potential viability of each power generation resource in the Yukon, identify suitable sites, estimate capital and operating costs, and determine the resulting per-kWh power generation cost.

The assessments then feed into a Resource Option Report that evaluates the various options for power generation according to financial, technical, socio-economic an environmental attributes of the individual technology options.

1.2 Scope and Objective

This report is about power generation from wind turbines. The report is of a technical nature and mainly aimed at YEC staff, but also provides information for other parties interested in wind power with a general understanding of the technology.

This study has four major objectives:

1. **Wind site inventory**: Mesoscale wind mapping (1 x 1 km resolution) to identify potential wind project sites near existing and planned power infrastructure. Select sites for detailed analysis of wind farm capacity (Chapter 2);
2. **Develop potential wind projects at a conceptual level**: Detailed analysis of wind farm capacity, including wind resource assessment (200 x 200 m resolution), site turbine layout, infrastructure footprints (Chapter 3), and gross and modelled net power output (Chapter 4);
3. **Economic modelling**: Create site-specific cost estimates for development, construction, power production, and power costs (Chapter 5);
4. **Additional information pertaining to wind farm development**: Technical and other considerations affecting the viability of wind power development, including potential for rime icing and possible mitigation measures, development risks, and typical development schedules (Chapter 6 to 8).

[1] YEC's generation profile for 2015, Excel spreadsheet provided by Yukon Energy Croporation on March 15th, 2016

1.3 Previous Work

The Yukon has numerous potential sites with excellent wind power potential in addition to the operational Haeckel Hill wind turbine project near Whitehorse. YEC recognizes this and commissioned previous wind resource studies to explore YEC's wind power development options. They are:

- Yukon Energy Corporation, Regional Mesoscale Modelling, Natural Power, February, 2011
- Yukon Energy Corporation, Aishihik Area Mesoscale Modelling, MG Renewables Consulting, July 2012

Other reports and papers reviewed include the Ferry Hill (referred to as Tehcho below) wind feasibility study (two parts) by Natural Power, 2010, *Wind Climate of the Whitehorse Area in Arctic*, by JP Pinard, Sept. 2007, *Wind Power Development in Sub-Arctic Conditions with Severe Rime Icing*, by John Maissan, Mar. 2001, and the *Mt Sumanik Wind Feasibility and Icing Study*, by Natural Power Consultants, Sept. 2010.

These reports were very useful for this project analysis and in several cases our site recommendations overlap. The primary difference is that the present study has a stronger bias toward site access and constructability and less toward optimum wind resource as the primary salient criteria. A strong wind resource is highly desirable, of course, but only if it can be developed at reasonable cost and effort.

2 WIND POWER SITE IDENTIFICATION

2.1 Site Identification Criteria

Due to the Yukon's mountainous topography, most suitable wind farm sites are located on mountaintops, peaks, ridges or crests. YEC's transmission lines naturally route through valleys, typically following highway corridors. The result is a challenging exercise of identifying sites that are not only windy, but can also be *developed*. During the initial screening process, potentially suitable wind power sites were identified within 25 km of existing and planned or proposed Yukon power infrastructure (see Appendix A for a map). YEC determined, and the project team concurs, that potential wind sites located beyond 25 km from existing power infrastructure are too costly to develop and operate, regardless of their wind resource merits.

As can be seen in Figure 1, the Yukon has somewhat less wind potential than the NWT and the eastern part of Alaska. There is more wind power potential (green-yellow areas on the map) in the higher elevation western part of the Yukon than in the lower elevation east. All sites identified are therefore situated in the western half of the Territory. This also reflects the concentration of population and infrastructure in the western and especially southwestern Yukon.

A number of criteria were considered for the wind site prospecting task, including:

Wind and atmospheric considerations

- Desirable wind resource, defined as relatively high mean annual wind speed and wind power density, normal or near normal Weibull distribution, low turbulence and acceptable extreme wind behavior
- Atmospheric rime icing environment (high/low probability)
- Ice throw distance to roads/other public use facilities

Site development considerations

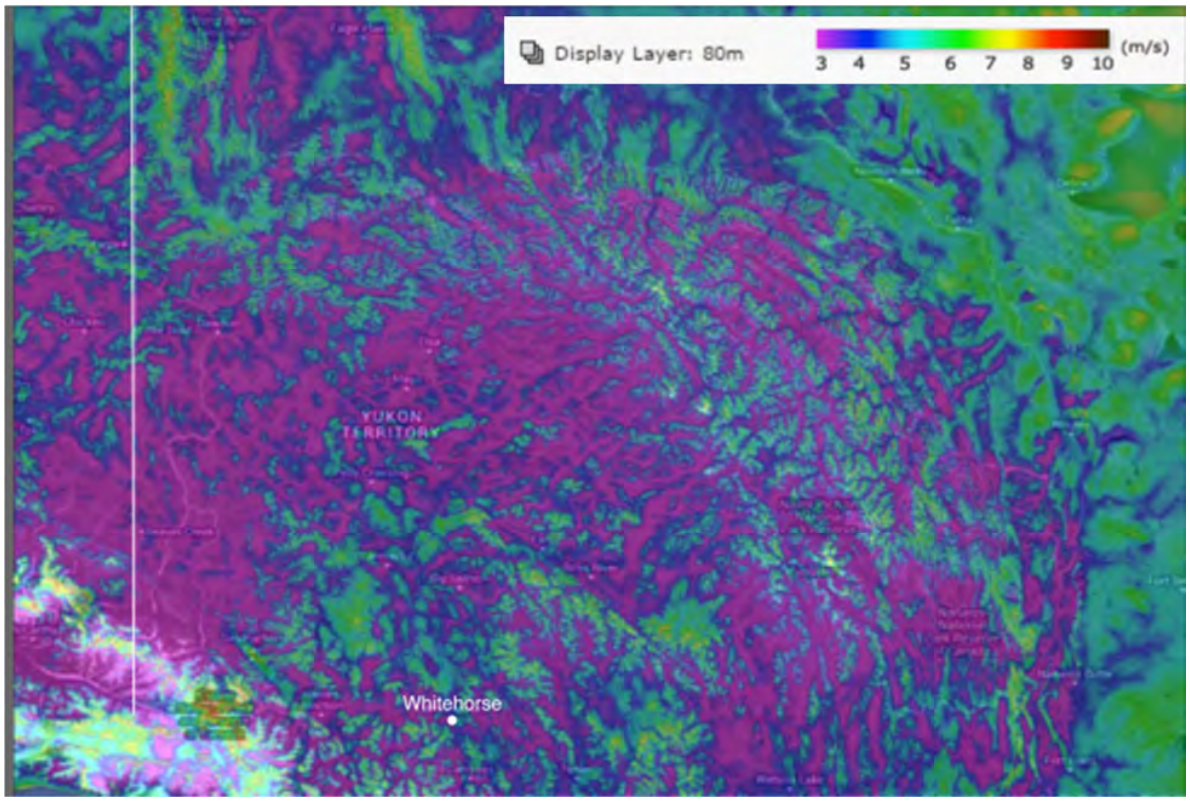
- Reasonable distance to a community, industry, or other electric loads
- Near existing or proposed power transmission infrastructure (<25 km for this project)
- Capacity of existing transmission to accept maximum power output of wind farm
- Suitable geotechnical conditions for foundations and access roads
- Proximity to existing roads; prospective cost to develop access (steepness, river crossings etc.); serviceability
- Airspace restrictions; proximity to airports and/or military airspace use areas
- Land use availability (land ownership, parks, easement restrictions, likely lease rates, nearby cultural sites or natural parks)
- Local geology (based on GeoYukon website)

Environmental and human factor considerations

- Deleterious effect on terrestrial wildlife and avian species (high-level)
- Wetlands, parks and other high-level environmental restrictions
- Noise, and aesthetic considerations; closeness to recreational activities

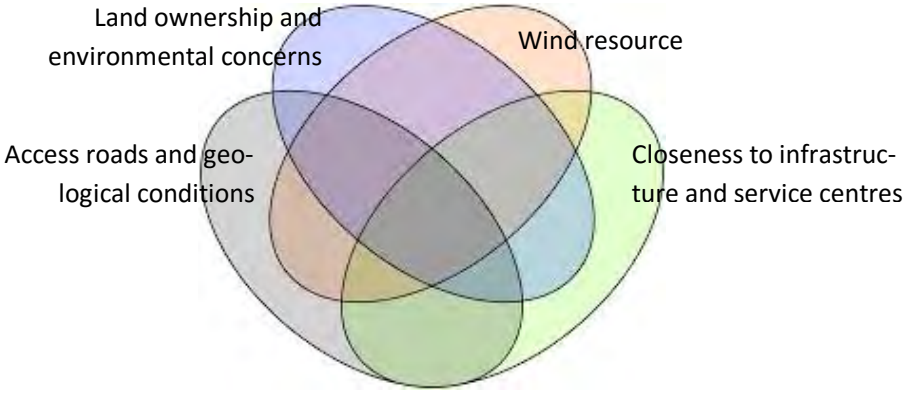
Other criteria were a desire to represent northern, central and southern Yukon and a preference for locations close to cities, larger towns, or existing hydroelectric infrastructure to facilitate wind turbine operations and servicing. Part of the intent was to screen as wide an area as possible and represent sites of varying characteristics.

Figure 1 Yukon Territory AWS Truepower Meso-Scale Wind Resource Map



The authors developed an initial long-list of potential sites that meet all or most of the criteria listed above. The conceptual image of a Venn diagram in Figure 2 below illustrates the process. Each ellipse represents a criterion listed above; the best or most promising solutions lie at the intersection of all criteria.

Figure 2 Conceptual Venn Diagram of Wind Site Criteria and Site Selection



Beginning the site search by reference to the wind resource we selected preliminary options by referencing two data sources, in addition to previously published wind studies noted above:

1. International Renewable Energy Agency (IRENA) 1,000 x 1,000-meter resolution,[2] 100-meter level (representing a typical utility-scale wind turbine hub height), mesoscale wind resource data. Note that IRENA employs Technical University of Denmark (DTU) wind data using their methodology.
2. AWS Truepower Windnavigator 200 x 200-meter resolution, 100-meter and 80-meter level (80 meters also represents a typical utility-scale turbine hub height), microscale wind resource data. AWS data has 25 times higher resolution than IRENA .

Large area AWS Truepower 200 x 200-meter resolution maps of three regional subsets of the territory – northern, central and southern – are presented below. From a broad territory-wide perspective, one can see that high winds are found at higher elevations – mountains, hills, high elevation plateaus – and low winds are found in lower elevation areas, such as valleys.

The Yukon is a high latitude region with a mostly sub-arctic-to arctic, often maritime-influenced climate. The consequence is atmospheric icing at higher elevations that creates wintertime rime ice conditions which are operationally challenging. For this reason, the theoretically most desirable high latitude wind power sites are at lower elevations where rime icing conditions don't occur. But, as one can see in the AWS Truepower Windnavigator wind maps of the Yukon, there are no sites in the territory that are both windy and (relatively) low elevation, with the exception of Kluane Lake, which is a site of interest for this study.

2.2 Initial Site Inventory

Using the Venn diagram model as a conceptual guide, 26 potentially promising sites for wind power development were initially identified and considered before narrowing the list to five sites (later expanded to seven sites with the inclusion of Tehcho and Mt. Sumanik). The 26 sites were evaluated

[2] The resolution refers to the spatial grid resolution of the computational fluid dynamics model. Both IRENA's and AWS's data are based on numerical analysis conducted for a specific land area. The finer the grid the lower the modelling error.

using the criteria mentioned above in a desktop analysis to screen all sites. The results of this exercise are presented in Table 5.

2.2.1 Northern Yukon Sites of Interest

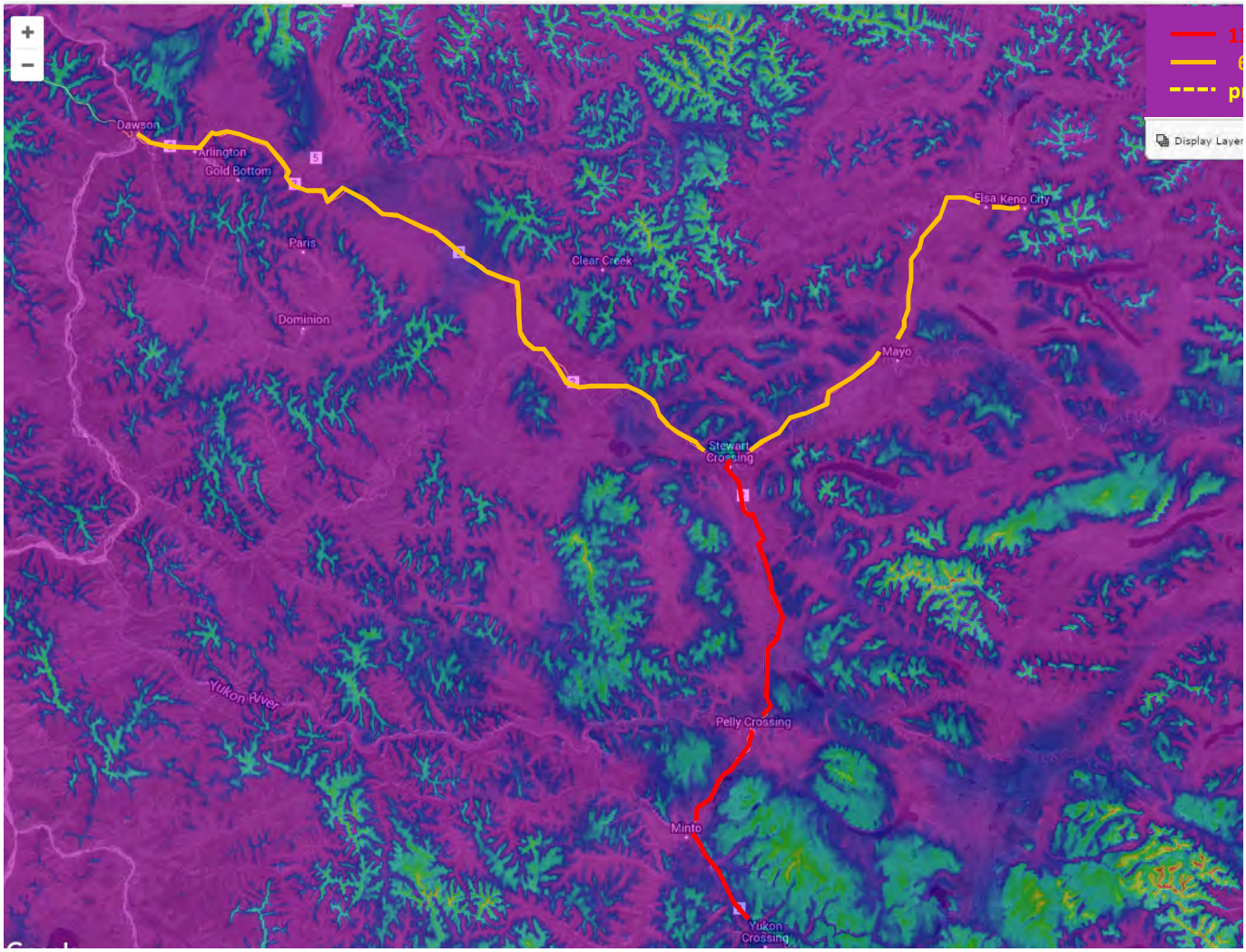
The wind resources in the northern Yukon are fairly sparse compared to the Yukon's central and southern regions. Our analysis did not extend north beyond the developed Dawson-to-Mayo parallel at approximately 64° N latitude. Options are generally limited to particularly high and mostly isolated mountaintops and ridges. The sites listed in Table 1 represent a range of possible wind power development options for this region. Site identification numbers are the same as those used throughout this report on maps and in tables.

The wind resources of the central Yukon that can potentially be developed represent, for the most part, the Carmacks-to-Faro meridian at about 62° N latitude. They are generally quite good but, as noted earlier and true of most of the Yukon, are limited to higher mountain ridges or plateau-like areas.

Table 1 Northern Yukon Wind Sites Considered

#	Site Name	Location	Brief Description
16	Keno City hill	7 km east of Keno City	Hills complex just east of Keno City; access from Keno City
10	Unnamed hill between Wareham and Janet Lakes	11 km northeast of Mayo	Large, plateau-like hill; plenty of space for turbines; near AOI's 9 and 10 identified by Natural Power (2011 report) but easier access
6	Tehcho (Ferry Hill)	Near Stewart Crossing	Hill immediately north of Stewart Crossing; Natural Power study addressed wind power options and icing potential
19	Willow Hills	16 km SSW of Stewart Crossing; 12 km west of Hwy 2	Broad area of hills increasing elevation from east to west; plenty of space for turbines; possible site access from utility easement or due west from Hwy 2

Figure 3 Northern Yukon AWS Truepower Meso-Scale Wind Map



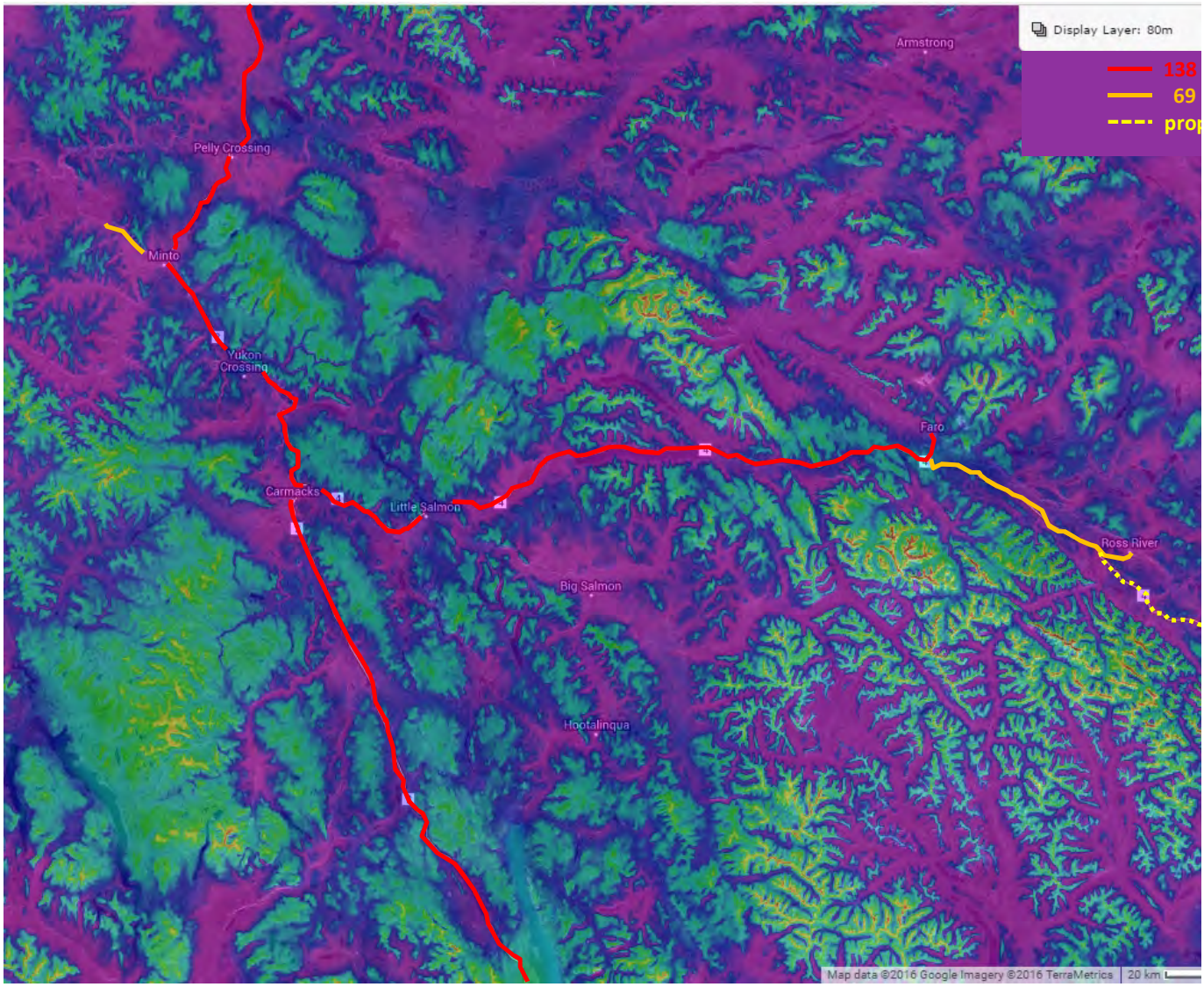
2.2.2 Central Yukon Sites of Interest

The wind resources of the central Yukon, representing for the most part the Carmacks-to-Faro parallel at about 62° N latitude, are generally quite good: They are, however, as noted earlier and true of most of the Yukon, are limited to higher mountain ridges or plateau-like areas. The sites listed in Table 2 represent a range of possible wind power development options for this region.

Table 2 Central Yukon Wind Sites Considered

#	Site Name	Location	Brief Description
3	Miller's Peak/Ridge	15 km west of Carmacks	Large, broad ridge; plenty of space for turbines; identified as AOI 4 by Natural Power (2011 report); near area access via gravel road W of Carmacks; site access from the gravel road
21	Mt. Berdoe	8 km SSE of Carmacks	Large hill near Carmacks with existing road access for a communications tower; site access exists
17	Unnamed hill east of Minto (between Pelly Crossing and Carmacks)	27 km SE of Minto; 18 km from highway	Large hill complex east side of highway near Minto, north of Carmacks
18	Little Salmon hill	39 km east of Carmacks	Very large and broad hill complex north of highway
22	Unnamed hills between Little Salmon and Drury Lakes	85 km E of Carmacks	Two parallel sloping ridges ascending from Little Salmon Lake to NW; plateau-like on top; possible site access from Hwy 4 east side of lake
11	Hill west of Faro, north of highway	27 km west of Faro	North-south trending low ridge just north of highway; access from hwy
12	Hill west of Faro, south of highway	27 km west of Faro	Hill complex south of highway and river access would require river crossing
1	Cyprus Mine hill	20 km N of Faro and 7 km north of the mine	Compact ridgeline immediately north of the mine pit and also a similar hill immediately SE of the mine; possible site access from the mine itself or from mine access roads
26	Hill SE of Ross River	75 km SE of Ross River	Hill group 16 km south of highway; access from the highway

Figure 4 Central Yukon AWS Truepower Meso-Scale Wind Map



2.2.3 Southern Yukon Sites of Interest

The wind power site options identified in the southern Yukon are generally quite good and include the relatively low elevation Kluane Lake. Low elevation has the advantage of low rime icing risk and avoids the considerable operational challenges that icing entails. The southern Yukon includes Whitehorse and hence is the population center of the Territory. That is advantageous from a wind farm operations perspective due to ready proximity to Whitehorse-based utility staff and contractors. The sites listed in Table 3 represent a range of possible wind-power development options for this region.

Table 3 Southern Yukon Wind Sites Considered

#	Site Name	Location	Brief Description
2	Kluane Lake, west shore	8 km SE of Destruction Bay	Midpoint of west shore of Kluane Lake; between Alaska Hwy and the lake
14	East shore of Kluane Lake	12 to 15 km N of Silver City	Two adjacent options: slopes above Grayling Lake, and NE-SW trending ridge just north of Rat Lake. Identified as AOI 4 by MB Renewables (2012 report) and NP (2011 report); gravel road access from Silver City
23	Anticline Mountain and adjacent ridges	75 km NNW of Whitehorse	Two SE-NW trending ridges just east of Little Fox Lakes and Hwy 2; jeep road access on southern ridge from Hwy 2
20	Hard Time Mountain	15 km ENE of Paint Mtn. and 11 km NW of Canyon	Southern end of mountain complex trending N from Hwy 1; site access possible from Hwy 1 west of Canyon
7	Thulsoo Mountain	21 km NNE of Canyon near Aishihik Hydro facility	High, rounded mountain immediately east of Aishihik hydro facility; identified as AOI 1 by MG Renewables (2012 report); site access from Canyon Lake road
15	Flat Mountain ridge	35 km NW of Whitehorse; west of south side of Lake Laberge	Rounded ridge immediately SW of Flat Mountain itself; site access possible from Hwy
4	Mount Sumanik	Immediately west of Whitehorse and existing Haeckel Hill wind turbines	Large, broad hill complex; equipped with Lidar for ongoing wind resource assessment study
9	Grey Mountain	9 km SE of Whitehorse	North-south trending ridgeline; access road to comm. tower on southern end; Whitehorse city recreational parkland
8	Mount Lorne subpeak (Minto Hill)	East of Hwy 2 between Mount Lorne and Carcross, 8 km SE of Mount Lorne	Gentle-top grouping of connected hills just S of more rugged Mount Lorne; no existing access; possible site access from Hwy 2
5	Northeast	7 km SSE of Carcross	Very broad, flat, wide, exposed, above treeline fea-

#	Site Name	Location	Brief Description
	slope of Sugarloaf Mtn.		ture comprising the north slope of Sugarloaf Mtn; plenty of room for turbines; site access via existing gravel road/jeep trail to Montana Mountain from Carcross
25	White Pass	On Canada/ U.S. Border, in B.C.	Open areas of the pass immediately east or west of Hwy 2 on Canada side and AK Hwy 98 on U.S. side; near Klondike Nat'l Historic Park; access from the highway
13	Hayes Peak	10 km S of Johnsons Crossing	Broad shouldered hill just west of northern shore of Teslin Lake

Figure 6 is a map of the 26 sites identified as possibly suitable for wind power production. Sites are colour-coded as red (the preferred seven sites), orange (potential alternate sites) and grey (unlikely to be developed).

Figure 5 Southern Yukon AWS Truepower Meso-Scale Wind Map

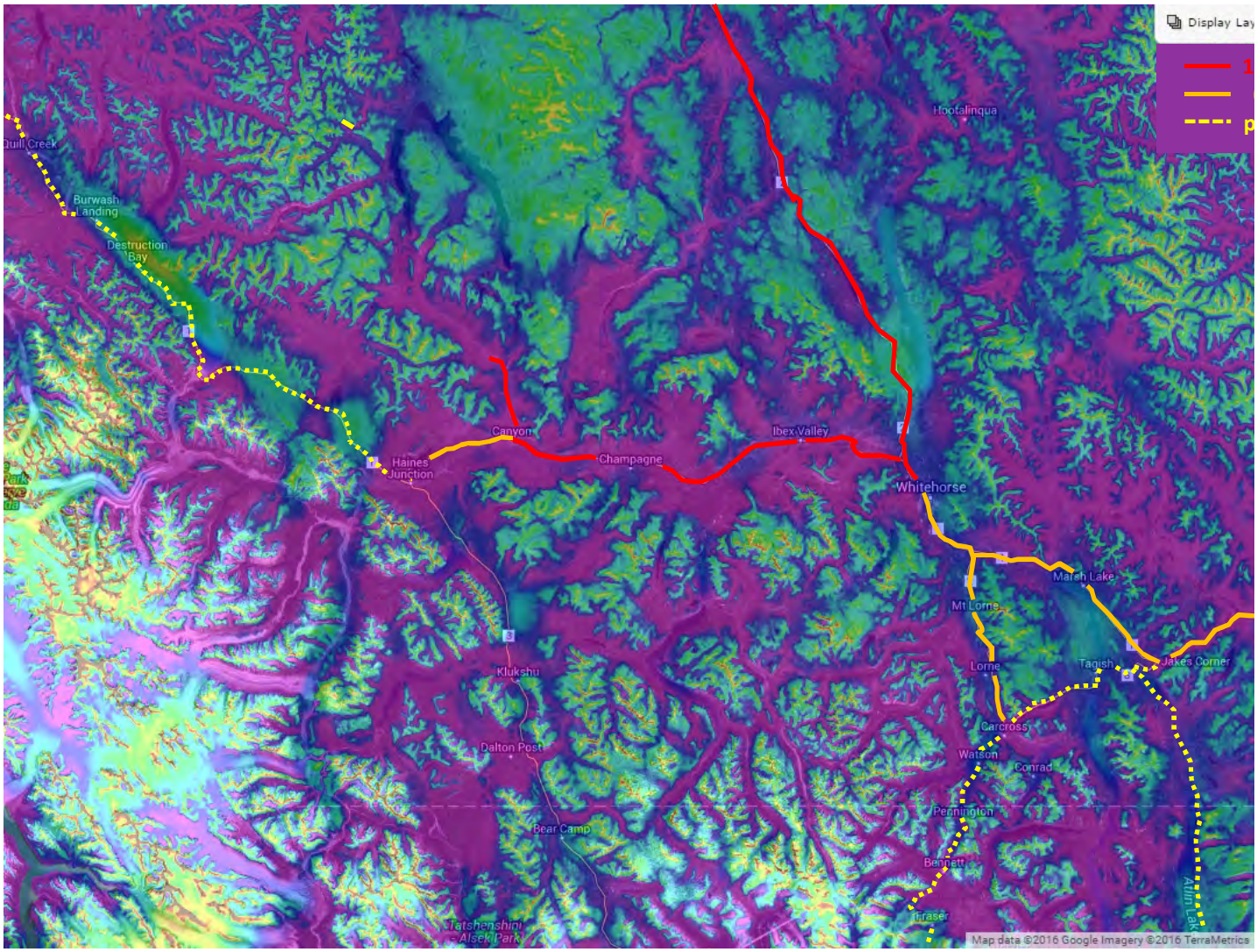
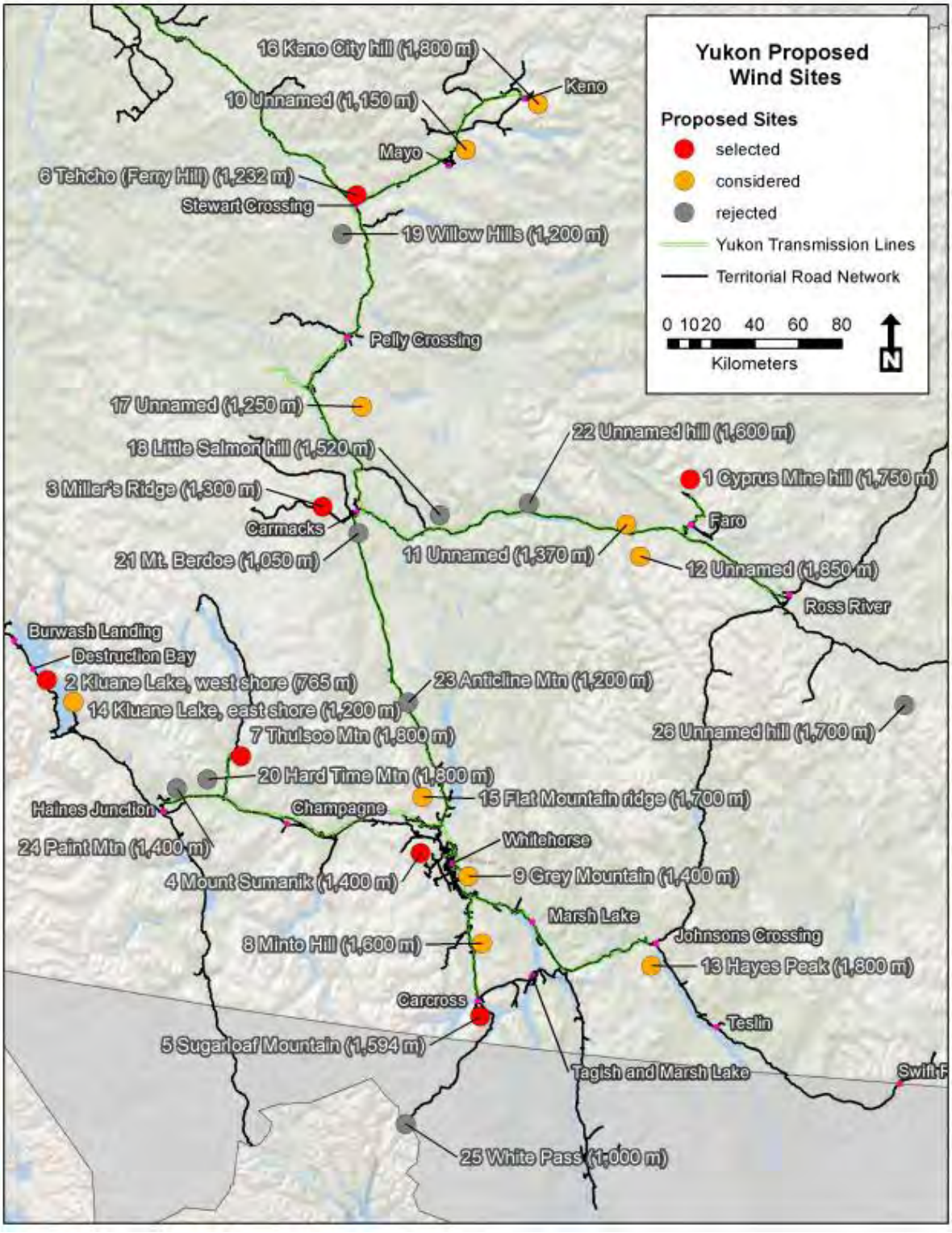


Figure 6 Map of Potential Wind Farm Sites



2.3 Yukon Site Visit

Douglas Vaught, P.E. (Ak) of V3 Energy LLC visited the proposed central and southern Yukon sites by helicopter and/or from roads during a site visit in late April 2016 to confirm the selection of the seven preferred sites, obtain photographs of the sites themselves and possible access routes, and garner a general qualitative assessment of site development potential. A number of photos were taken for documentation and to provide additional information. One photo per site was included in Chapter 3; additional photos can be found in Appendix F.

With reference to Figure 6, sites visited from the air in a broad flight loop from Whitehorse to Carmacks, to Faro, to Johnsons Crossing, to Carcross and then back to Whitehorse. Also visited and/or observed by ground travel were the potential sites in the vicinity of and west of Whitehorse.

Table 4 Observations of Yukon Site Visit

#	Site	Observation
4	Mt. Sumanik	Reasonably good access options, somewhat narrow ridge, near Whitehorse, high potential
15	Flat Mountain	Complex ridgeline, hard to access, low potential
23	Anticline Mountain	Complex ridgelines, access appears difficult, low potential
21	Mt. Berdoe	Heavily forested, small site area, very low potential
3	Miller's Ridge	Reasonably good access option with use of Nansen Mine road, huge site area, great exposure, very high potential
17	Unnamed Minto hill	Too far away from the highway, remote site, low potential
22	Unnamed hills between Little Salmon and Drury Lakes	Complex ridgelines, difficult access, remote site, low potential
1	Cyprus Mine hill plus alternate nearby	Easy access, turbine site options limited to ridge edge, alternate site has good site options, confirmed brownfield nature of site, high potential
11, 12	Unnamed hills west of Faro	Access to hill south of highway difficult, not as promising as Cyprus, low potential
13	Hayes Peak	Difficult access, peak too steep to develop, low potential
5	Sugarloaf Mountain	Good access, large, open site, moderate potential
8	Mt. Lorne subpeak/Minto Hill	Difficult access options, remote, low potential
2	Kluane Lake, west shore	Very easy access, new transmission land route would be difficult, very windy day of visit, moderate potential
14	Kluane Lake, east shore	Observed from across lake, transmission connection easier than west shore, moderate potential
24	Paint Mountain	Difficult access, small area, low potential
20	Hard Time Mountain	Difficult and expensive access, too remote, low potential
7	Thulsoo Mountain	Observed from a distance, site ridge appears promising
9	Grey Mountain	Very windy day of visit, complex ridgeline, high value recreational use, low potential

Information gathered from the site visits primarily reinforced the team's thoughts regarding site suitability developed through reference to mapping, Google Earth, photographs available on-line, previous reports, and other sources. Impressions of the site visit are documented in Table 4 above.

2.4 Site Selection

The 26 sites were assessed according to the following criteria:

1. Mean wind velocity (IRENA and AWS data at 80 and 100-meter hub heights)
2. Distance to transmission line (straight line distance)
3. Road access (straight line distance)
4. Land ownership and usage

Other non-quantifiable factors such as potential conflict with other land uses or public opposition expected for certain sites were then evaluated to determine a shortlist of seven sites. This shortlist includes two sites that had previously been examined, Mt. Sumanik and Tehcho (Ferry Hill), that YEC had requested to be included so they could be compared to the sites identified through the comprehensive territorial wind site assessment conducted for this study.

The result of the selection process can be seen in the Table 5 below. Red shaded rows are sites we shortlisted. Second-tier candidates are marked in yellow, while less desirable sites are shaded grey. The emphasis was to give preference to "low-hanging fruit" sites that seemed easiest to develop. Second tier sites are usually also good candidates and could be considered for replacing shortlisted sites that prove too difficult to develop, e.g. after monitoring revealed excessive periods of rime icing.

The location of these sites is illustrated in Figure 6 above. AWS Truepower wind resource maps for the seven selected sites can be found in Appendix B and AWS Truepower Compass-level site reports of all 26 sites can be found in Appendix E.

Table 5 Assessment of Potential Wind Farm Sites

ID	Name	Elevation above sea level	Mean wind velocity AWS data At 80 m hub	Distance to transmission line	Type	Road access River Crossing Required?	Straight line distance to hwy	Hw pav
1	Cyprus Mine Hill	1,750 m	7.0 m/s	7.2 km	138kV Tx Line	Yes	6.9 km	Ur
2	Kluane Lake, west shore	765 m	6.5 m/s	77.9 km	69kV Tx Line	No	1.7 km	P
3	Miller's Peak/Ridge	1,300 m	7.3 m/s	15.5 km	138kV Tx Line	No	2.6 km	Ur
4	Mount Sumanik	1,594 m	6.2 m/s	10.2 km	138kV Tx Line	No	5.2 km	Ur
5	Northeast slope of Sugarloaf Mtn.	1,400 m	5.7 m/s[3]	9.1 km	69kV Tx Line	No	1.7 km	Ur
6	Tehcho (Ferry Hill)	1,232 m	5.8 m/s	3.0 km	69kV Tx Line	No	0.3 km	Ur
7	Thulsoo Mtn	1,800 m	7.8 m/s	5.5 km	138kV Tx Line	No	3.8 km	Ur
8	Mount Lorne subpeak (Minto Hill)	1,600 m	7.7 m/s	4.6 km	69kV Tx Line	Yes	5.1 km	P
9	Canyon Mountain / Grey Mountain	1,400 m	7.1 m/s	3.6 km	69kV Tx Line	No	1.3 km	Ur
10	Mayo, unnamed hill between Wareham and Janet Lakes	1,150 m	4.9 m/s	3.9 km	69kV Tx Line	No	4.0 km	Ur
11	Hill west of Faro, north of highway	1,370 m	7.1 m/s	3.6 km	138kV Tx Line	No	3.6 km	P
12	Hill west of Faro, south of highway	1,850 m	8.5 m/s	10.9 km	138kV Tx Line	Yes	10.8 km	P
13	Hayes Peak	1,800 m	7.4 m/s	10.6 km	69kV Tx Line	No	6.2 km	Ur
14	East shore of Kluane Lake	1,200 m	6.7 m/s	7.5 km	Proposed	No	0.9 km	Ur
15	Flat Mountain Ridge	1,700 m	7.6 m/s	9.4 km	138kV Tx Line	Yes	8.6 km	Ur
16	Keno City Hill	1,800 m	6.8 m/s	7.2 km	69kV Tx Line	Yes	4.9 km	Ur
17	Hill east of Minto (south of Pelly Crossing)	1,250 m	6.9 m/s	18.0 km	138kV Tx Line	No	18.1 km	Ur
18	Little Salmon Hill	1,520 m	7.3 m/s	6.4 km	138kV Tx Line	No	6.5 km	P
19	Willow Hills	1,200 m	6.4 m/s	9.1 km	138kV Tx Line	Yes	9.2 km	P
20	Hard Time Mtn	1,800 m	6.7 m/s	7.7 km	69kV Tx Line	Possibly	7.9 km	P

[3] Reflects average wind speed at proposed turbine sites; AWS Truepower reference wind speed higher on Sugar-loaf knob (compass report) and lower at AWS Truepower data reference point between knob and turbine sites.

ID	Name	Elevation above sea level	Mean wind velocity AWS data At 80 m hub	Distance to transmission line		Road access		
					Type	River Crossing Required?	Straight line distance to hwy	Hw pav
21	Mt. Berdoe	1,050 m	5.4 m/s	1.4 km	138kV Tx Line	No	0.1 km	
22	Unnamed hills between Little Salmon and Drury Lakes	1,600 m	6.6 m/s	3.7 km	138kV Tx Line	No	3.7 km	Ur
23	Anticline Mtn and adjacent ridges	1,200 m	6.2 m/s	2.7 km	138kV Tx Line	Yes	2.1 km	C
24	Paint Mtn	1,400 m	4.3 m/s	5.2 km	69kV Tx Line	No	5.1 km	F
25	White Pass	1,000 m	5.3 m/s	0.5 km	Proposed	No	0.4 km	F
26	Hill SE of Ross River	1,700 m	9.0 m/s	75.1 km	Proposed	Yes	15.8 km	Ur

3 CONCEPTUAL WIND FARM DEVELOPMENT

We developed representative wind turbine arrays of 20, 10 and 6 MW capacity for each of the seven selected sites. The site layout and location is on a conceptual level only. The level of detail is sufficient for estimating the power output and the cost of installing wind farms of the respective size at these sites. Further and more detailed engineering will be required, though, should YEC decide to move forward any of these proposed installations.

For modelling of the wind farm we employed a wind modelling software called WAsP (Wind Atlas Analysis and Application Program). The WAsP software is a Danish PC-based software for predicting wind climates, wind resources and power production from wind turbines and wind farms and was used to model wind turbine performance. WAsP is the most widely used wind power analysis software in the world. WAsP modelling begins with a digital elevation map (DEM) of the wind farm site and surrounding area and conversion of coordinates to Universal Transverse Mercator (UTM).[4] WAsP modeling results for the seven selected sites can be found in Appendix G.

A wind data reference point (for this project, a purchased AWS Truepower annual data series file for a representative location at the site of interest) is added to the digital elevation map, wind turbine locations identified, and a particular wind turbine (for this project, as noted, a generic 2.0 MW model) selected to perform the calculations. WAsP considers the orographic (terrain) effects on the wind, plus surface roughness and obstacles, and calculates wind velocity increase or decrease at all nodes of the map. The mathematical model has a number of limitations, including the assumption that the overall wind regime of the turbine site is same as the met tower reference site, prevailing weather conditions are stable over time, and surrounding terrain at the wind data reference point and turbine sites is sufficiently gentle and smooth to ensure laminar, attached wind flow. The version of WAsP software used for this study is not capable of modelling turbulent wind flow resulting from sharp terrain features such as mountain ridges, canyons and shear bluffs.

To compare sites, we modelled each site using a generic 90-meter rotor diameter, 2.0 MW capacity, 80-meter hub height wind turbine. Although the modelled turbine is a Vestas V90, it is considered generic for the purpose of this exercise and can be considered representative of other turbines of the same power output class. Note, however, that the generic turbine in this exercise may not be the best choice at every site.

Specific turbine selection is a detailed and significant process of customer and manufacturer consideration and hence appropriate to the detailed design phase of a project. With that in mind, the generic 2.0 MW turbine modelled is a compromise choice. Although it would be suitable for most of the sites, or most turbine locations within a site, for other sites or locations other wind turbine models or manufacturers may be preferable.

[4] UTM is a geographic coordinate system that uses a two-dimensional Cartesian coordinate system to identify locations on the surface of Earth. UTM coordinates reference the meridian of its particular zone (60 longitudinal zones are further subdivided by 20 latitude bands) for the easting coordinate, and distance from the equator for the northing coordinate. Units are meters. Elevations of the DEMs are converted to meters if necessary for import into WAsP software. Digital elevation data was obtained from Natural Resources Canada (http://geogratis.gc.ca/site/eng/extraction) as TIFF format files.

For the representative wind turbine layouts presented in this section, an approximate turbine separation of five rotor diameters, or 450 meters, was consistently used. This is the conservative end of the three-to-five rotor diameter separation range generally recommended in the wind power industry for turbines oriented perpendicular to the prevailing wind. For turbine placement parallel to the prevailing wind, which only applies to the Kluane Lake site, a separation distance of approximately 1,000 meters, or 11 rotor diameters was chosen. This separation distance is also consistent with industry practice.

For actual design of a wind farm, an optimization analysis of turbine separation distance would be accomplished. The optimization of turbine separation and placement recognizes the non-coincident relationship between turbine distance and wake loss. Increased inter-turbine distance decreases wake loss but increases project development costs. This is because of the need for longer access roads, larger land area purchases or lease, longer electrical transmission lines, etc. The opposite, naturally, is also true. There is no one correct answer, other than to reference industry practice and guidelines of approximately five percent aggregate wind farm wake loss as a suitable compromise with respect to site development costs.

The following sections summarize the results of the WAsP model and observations from Google Earth and site visits. Details on annual gross energy production, wake losses and monthly generation profiles for each site can be found in Appendix H.

3.1 Cyprus Mine Hill

The hill complex immediately north of Cyprus Mine near Faro is an excellent wind farm site option due to the 'brownfield'[5] nature of the mine. Additional industrial-type development at a brownfield site, such as a wind farm, generally elicits less public opposition than greenfield development.

3.1.1 Site Description

Being close to a former large mine, significant advantages of Cyprus Mine Hill are the vicinity of a 138 kV transmission and partially developed high quality road access to the site. The ridge has a desirable orientation perpendicular to prevailing wind directions. Figure 7 shows a Google Earth image of the site area, and Figure 8 is a photo taken during the site visit, with the site area shown in the foreground (orange line).

A possible alternative or adjunct to Cyprus Mine Hill as a wind power site are hills of similar elevation immediately east of the connecting road between the northern and southern mine pits. AWS Truepower and WAsP modelling both predict a strong wind resource on the more accessible western slopes and ridges of these hills. Should a wind power project be contemplated for Cyprus Mine area, we recommend that data collection with met towers or LIDARs [6] of both hill groups: the proposed and the alternate.

[5] Term to describe land previously used for industrial purposes and potentially contaminated with hazardous waste or pollution.

[6] LIDAR: Light Detection And Ranging is a method of measuring wind speeds by projecting a laser into the air and detecting the backscatter from random particles in the atmosphere.

Figure 7 Cyprus Mine Prospective Wind Power Site, Google Earth Image

Figure 8 Cyprus Mine Prospective Wind Power Site, Photo (East view)

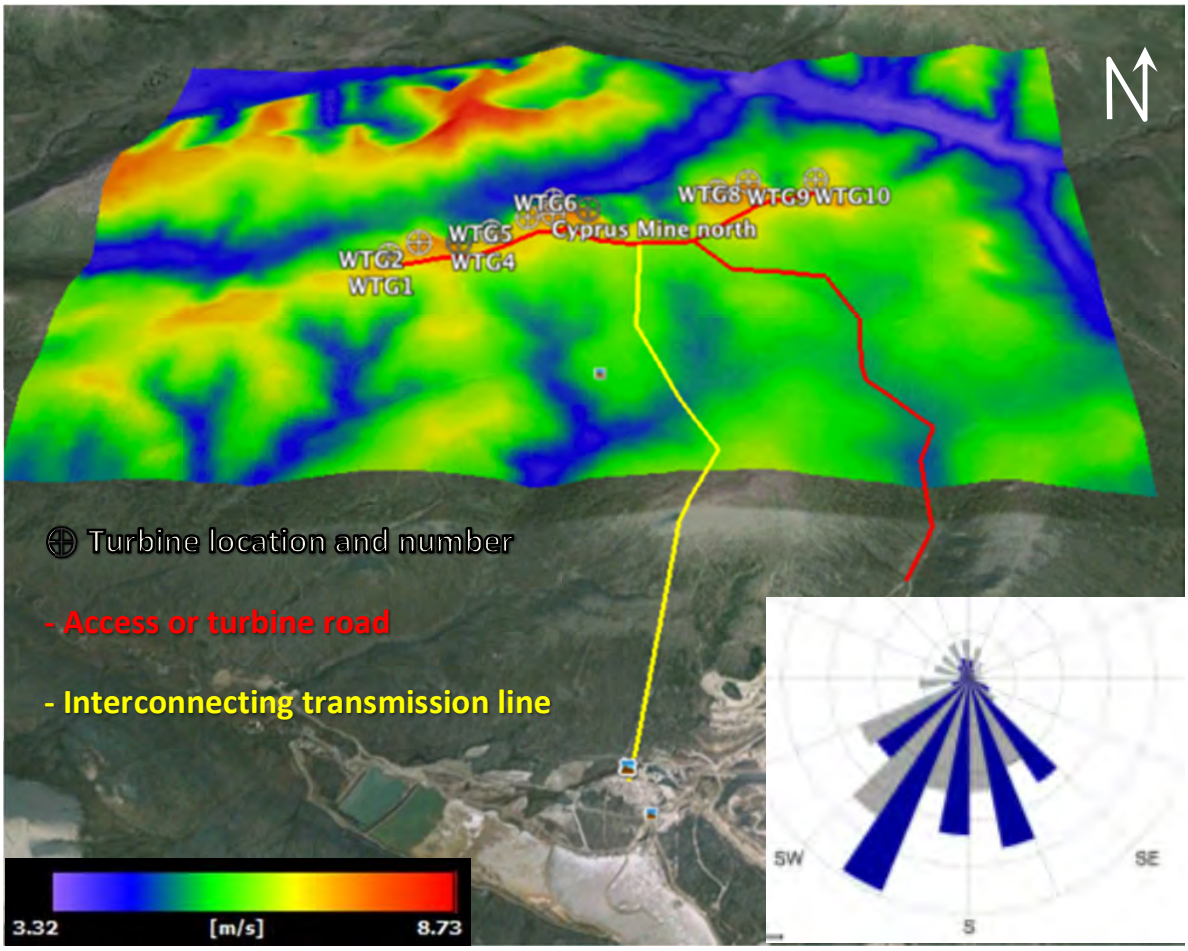
3.1.2 Site Layout

The ridgeline where turbines would be located is quite long and perpendicular to the prevailing wind direction as noted in Figure 9. This is advantageous in that the ridge can support installation of many wind turbine and wake loss would be minimal.

A 20 MW wind farm (ten two-MW wind turbines) would be arrayed at higher elevation points along the ridge as shown in Figure 10 below. Turbines in this figure are identified as "WTG", the AWS Truepower data reference point for the WAsP model is noted by "Cyprus Mine north", recommended turbine access roads are indicated by red lines, and the existing communication tower electrical connection that would be upgraded to support wind turbines is indicated by the yellow line.

Additional turbines to the west of Turbine 1 (WTG1) are possible as are installing turbines on an adjoining parallel ridge to the north. Access to that ridge would be possible via a broad "pass" between the two (visible left center of Figure 8). Beyond this site area, the alternate site option east of the two mine pits could support at least another 20 MW of wind power capacity, if not more.

Figure 10: 20 MW Wind Farm Layout for Cyprus Mine Hill Site, WAsP Wind Speed Overlay



3.2 Kluane Lake (West Shore)

As a prospective wind power site, the west shore of Kluane Lake presents intriguing possibilities. It is the only relatively-low-elevation location in the Yukon with projected high wind speeds. The mountains west and east of the lake concentrate and funnel wind along the long axis of the lake.

Although the highest wind speeds at Kluane are straight down the middle of the lake, as one would expect, the west shore has only a minimally lower wind resource.

3.2.1 Site Description

At 720 meters above sea level, Kluane Lake is much lower elevation than the six other sites profiled in this report. As such, the problematic winter rime icing environments that would be an operational challenge at the higher elevation sites would not exist at Kluane Lake, or at least would be significantly reduced in frequency and severity.

A disadvantage of Kluane Lake is that currently there is no electrical transmission line nearby, although a planned new line would run very closely to the site. Today, YEC's transmission terminates at the Aishihik Generating Station and all communities and load centers to the west operate as isolated grids. The map in Appendix A shows the proposed transmission to possibly as far west as Destruction Bay. If constructed, a Kluane Lake project would be quite viable. The west shore of Kluane Lake as a site recommendation is presented in this report based on a presumption that the proposed transmission is constructed independently of a wind project; in other words, a Kluane Lake wind project would not absorb the cost of transmission to Haines Junction.

A possible site alternative to the west shore of Kluane Lake are sloping hills near Grayling and Rat Lakes, nearly directly across the lake from the west shore site and about 12 to 15 km from Silver City. An advantage of the east shore is a shorter transmission connection to Haines Junction, should an extension of the transmission line to the west shore Kluane Lake communities of Destruction Bay and Burwash Landing not be possible. Disadvantages are higher elevation sites and more complex access and construction requirements.

Figure 11 indicates the proposed Kluane Lake west shore site on a Google Earth image, and Figure 13 shows a photo of the lake shore near the site, which was taken during a site visit in late April 2016.

Figure 11 Kluane Lake Prospective Wind Power Site, Google Earth Image

3.2.2 Site Layout

A ten-turbine, 20 MW wind farm (assuming 2 MW wind turbines) could be arrayed in two rows of five turbines between the Alaska Highway and the Kluane Lake shoreline as shown in Figure 14. The site area is entirely forested and pad areas and access roads would require clearing. The AWS Truepower data reference point for the WAsP model is adjacent to WTG6, recommended access roads (one road for two turbines) are indicated by red lines, the recommended new wind farm electrical sub-transmission connection to existing transmission is indicated by the yellow line (under "WTG3"), and the planned transmission line is indicated as a light blue line.

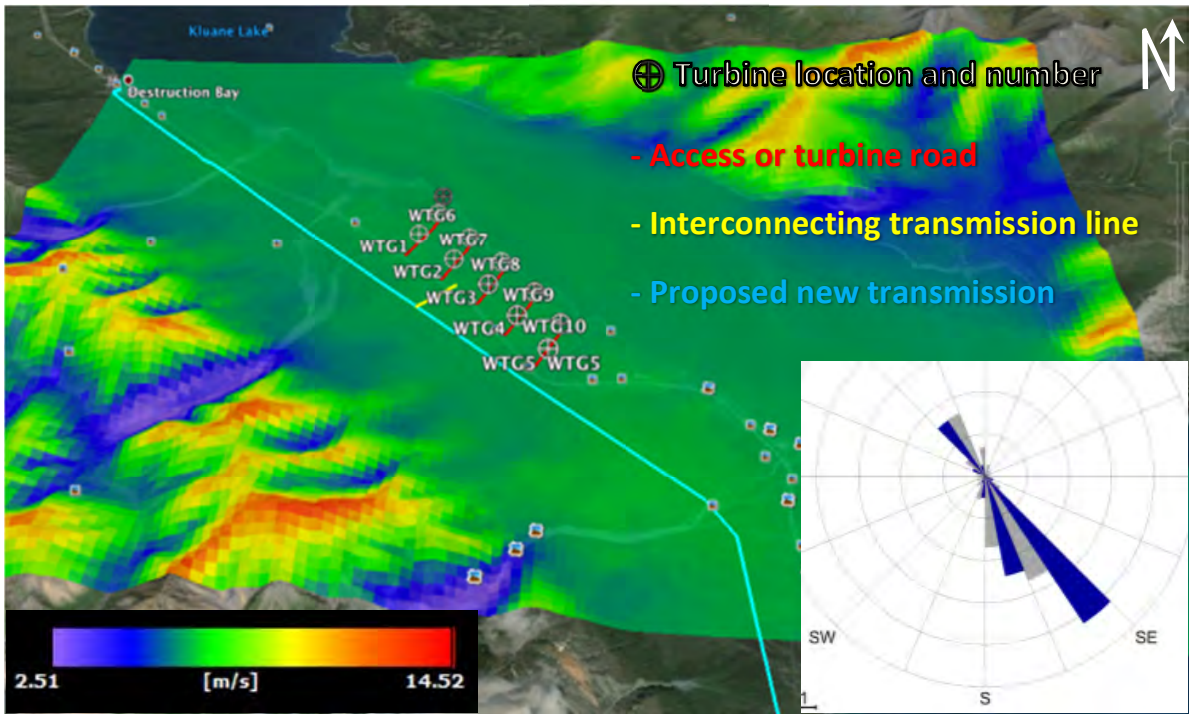
To account for the highly directional nature of the Kluane Lake wind resource (refer to Figure 12) along the axis of the lake and the site constraint that requires turbine alignment along the same axis, inter-turbine distances are higher for the parallel-to-wind turbines than the perpendicular-to-wind turbines, requiring a larger overall site footprint than one might expect for a ten turbine array.

The west shore of Kluane Lake has room for at least twice, if not three times, the number of turbines shown in Figure 14. The proposed access arrangement of one road to serve two turbines could be repeated northwest all the way to Destruction Bay and southeast along the shoreline. The maximum site capacity is estimated to be in the range of 40 to 60 MW rated output.

Figure 13 Kluane Lake Site, Photo of West Shore Site

Note: turbine sites would be in the forested area to the left

Figure 14: 20 MW Wind Farm Layout for Kluane Lake (West Side), WAsP Wind Speed Overlay



3.3 Miller's Ridge

Miller's Ridge near Carmacks has superb potential for wind power production and perhaps is the most preferred site for a large wind farm of 20 MW or more capacity. The ridge is expansive, very wide, fairly flat, well exposed in all directions, and suitably oriented to the prevailing winds.

3.3.1 Site Description

A significant advantage of Miller's Ridge as a wind power site is the existing Nansen Mine Road, which runs immediately under the south side of the ridge. Although further road access to the ridge itself would be required, Nansen Mine Road transforms what otherwise would have been a suitable but rather isolated site into one with considerable development potential.

An electrical transmission connection to Carmacks would be expensive, though, as would an access road to the ridge, so a larger capacity wind farm on Miller's Ridge would be preferable to a smaller one. Figure 15 shows a Google Earth image indicating the site area, and Figure 16 shows a photo taken during site visits, illustrating the openness and flatness of this location.

Figure 15 Miller's Ridge Prospective Wind Power Site, Google Earth Image

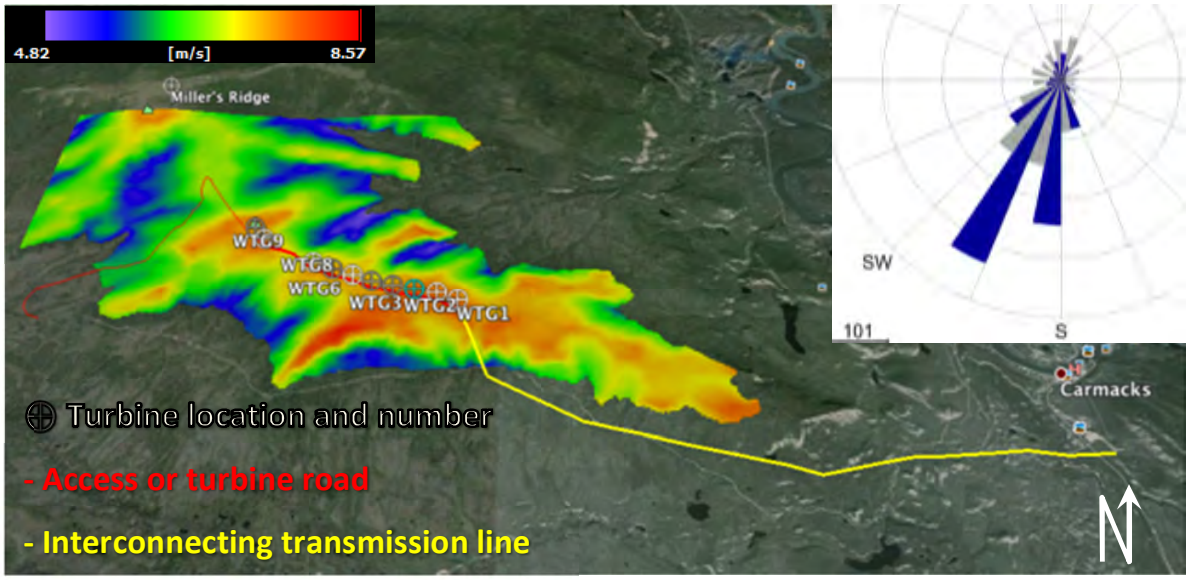
Figure 16 Miller's Ridge Site, Photo of NW View

3.3.2 Site Layout

The mostly east-west orientation of Miller's Ridge is perpendicular to the strongly south-southwest prevailing wind (see Figure 17), which is ideal for a wind farm layout and results in low wake loss.

A 20 MW wind farm (10 turbines each 2 MW) would be arrayed at higher elevation points along the ridge as shown in Figure 18 below. Turbines in this figure are identified as "WTG", the AWS Truepower data reference point for the WAsP model is noted by "Miller's Ridge", recommended access roads (to Nansen Mine Road) are indicated by red lines, and the recommended new wind farm electrical sub-transmission connection to existing transmission is indicated by the yellow line.

Figure 18: 20 MW Wind Farm Layout for Miller's Ridge Site, WAsP Wind Speed Overlay



3.4 Sugarloaf Mountain

Sugarloaf Mountain near Carcross, due to its lower wind resource, was perhaps the most difficult prospective wind turbine site recommendation in this report, but site access is very good and it would be easiest site in the southern Yukon to develop for wind power.

3.4.1 Site Description

Site access to Sugarloaf – not the high knob itself but the lower portion of the alpine slope below it to the northeast – is already possible via the Montana Mountain jeep road, and a transmission extension from Carcross to reach the site would be relatively short. But wind speeds at the site appear to be fairly low in comparison to the other profiled sites. Modelled data is not perfect, however, and may underestimate the actual wind resource. With that in mind, obtaining site data from a met tower or Lidar is recommended.

Note that a possible alternative to Sugarloaf Mountain is Mt. Lorne Subpeak just northeast of Carcross. Although higher and windier, the site is more remote than Sugarloaf with no improved road, or even trail, access. Further, due to topography and terrain features, road access options would be somewhat circuitous. The trade-off of development costs versus higher energy production potential for Sugarloaf and Mt. Lorne Subpeak is beyond the scope of this project. Figure 19 shows a Google Earth image identifying the site area, and Figure 20 is a photo taken during the site visits, also showing the existing access road.

Figure 19 Sugarloaf Mtn. Prospective Wind Power Site, Google Earth Image

Figure 20 Sugarloaf Mountain Site, Photo of NW View Showing Access Road

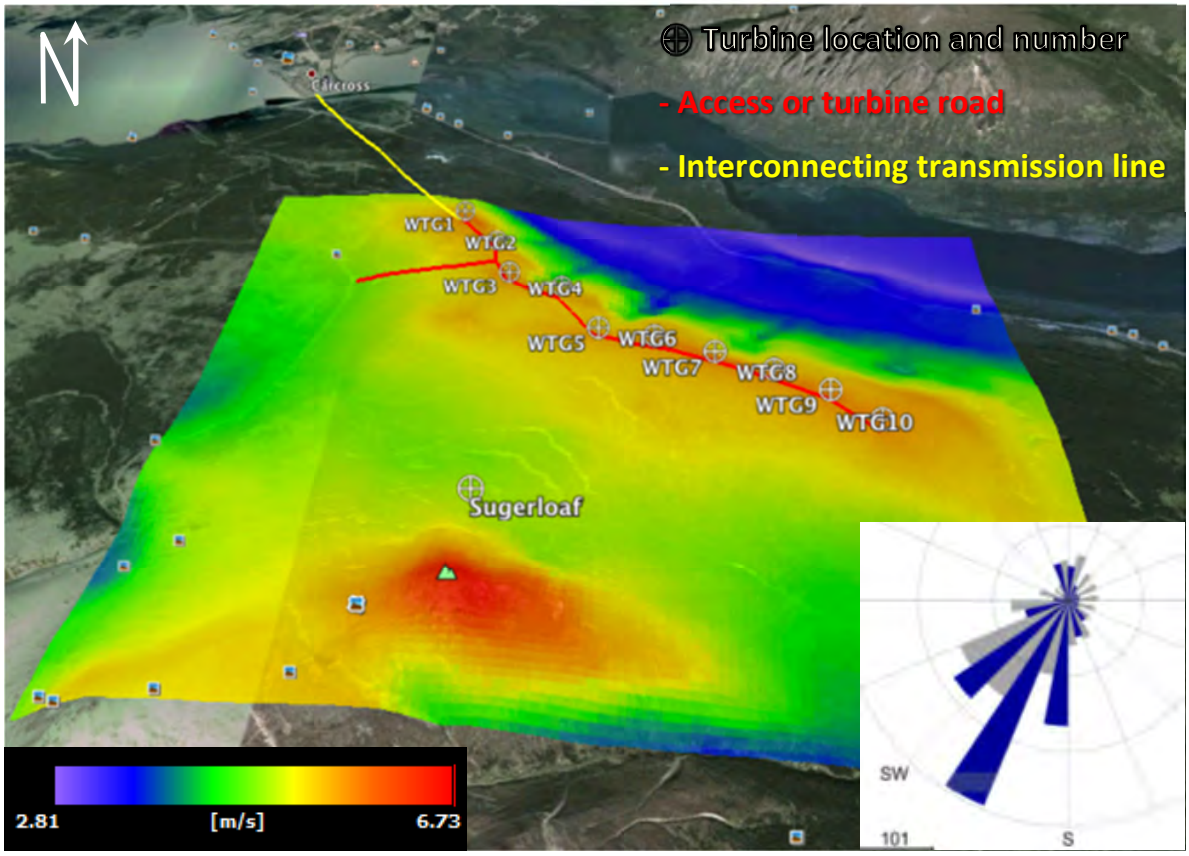
3.4.2 Site Layout

A 20-MW wind farm (ten turbines each 2 MW) would be arrayed at higher elevation points along the ridge as shown in Figure 23. The AWS Truepower data reference point for the WAsP model is noted by "Sugarloaf." The orientation of the prospective wind turbine site area is perpendicular to the southwest prevailing wind (see Figure 21) and hence would result in minimal wake loss.

Also note in Figure 23 below that the wind resource of Sugarloaf suitable for wind power development is limited to the low bench that marks the transition between lower elevation forest and higher elevation tundra. The summit of Sugarloaf itself indicates a very good wind resource but this knob is too small and steep for installation of wind turbines. WAsP modelling indicates that winds between the knob and the bench are low, although interestingly, very well defined wind-blown snow sastrugi was observed during the late April site visit overflight.

Additional wind turbines at Sugarloaf beyond the ten turbine layout of Figure 22 would be possible by closer inter-turbine spacing or use of larger turbines. The modelled array wake loss was very low and a tighter turbine spacing would be acceptable.

Figure 23: 20 MW Wind Farm Layout for Sugarloaf Mountain, WAsP Wind Speed Overlay



3.5 Mount Sumanik

Mount Sumanik was originally excluded from the project analysis by YEC and then added later for comparison to the five sites identified during the site assessment.

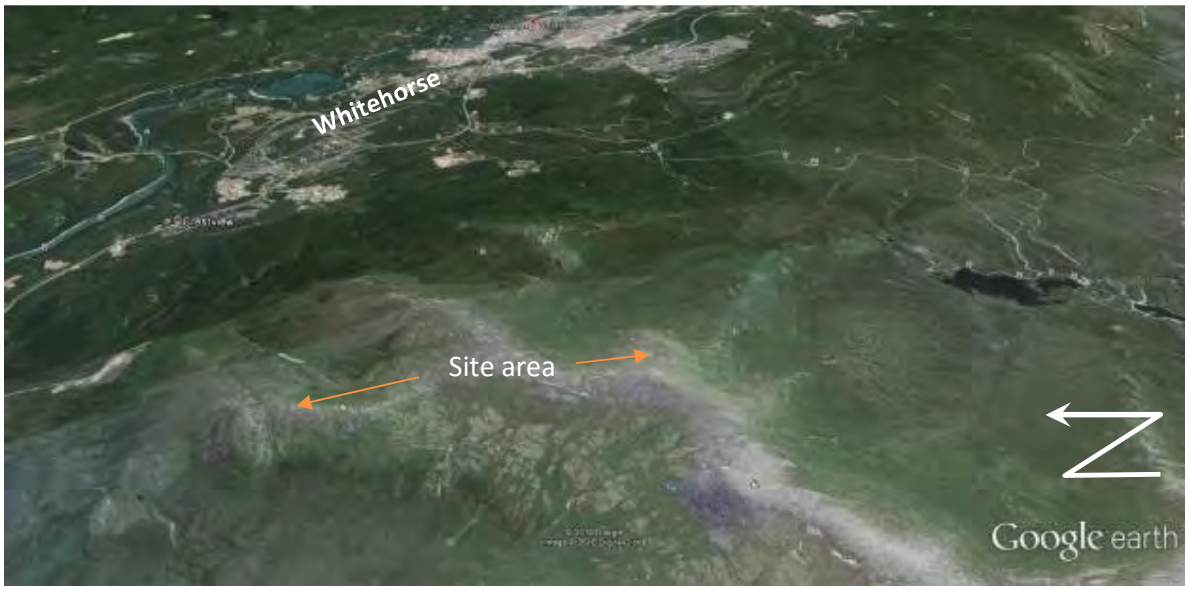
3.5.1 Site Description

Mount Sumanik is a natural wind turbine site option due to its immediate proximity to Whitehorse, the presence of two older wind turbines (reportedly, only one is presently operational) on nearby Haeckel Hill, and exhibits a very good wind resource. YEC's interest in Mount Sumanik as a wind

turbine project site is extensive and long-standing. At present, the site wind resource is being measured with a Lidar unit located on the summit of the mountain (more accurately described as the high point of a long ridgeline).

Development access to Mount Sumanik might be somewhat challenging though as an extension of the Haeckel Hill access road may not be the ideal access route to the Sumanik ridge itself. It appears that better access may be via a quarry/borrow pit northeast of the mountain. **Error! Reference source not found.** shows a Google Earth image indicating the site location, and Figure 25 is a photo taken during the site visits, also showing the Lidar monitoring device (middle of photo).

Figure 24 Mount Sumanik Prospective Wind Power Site, Google Earth Image

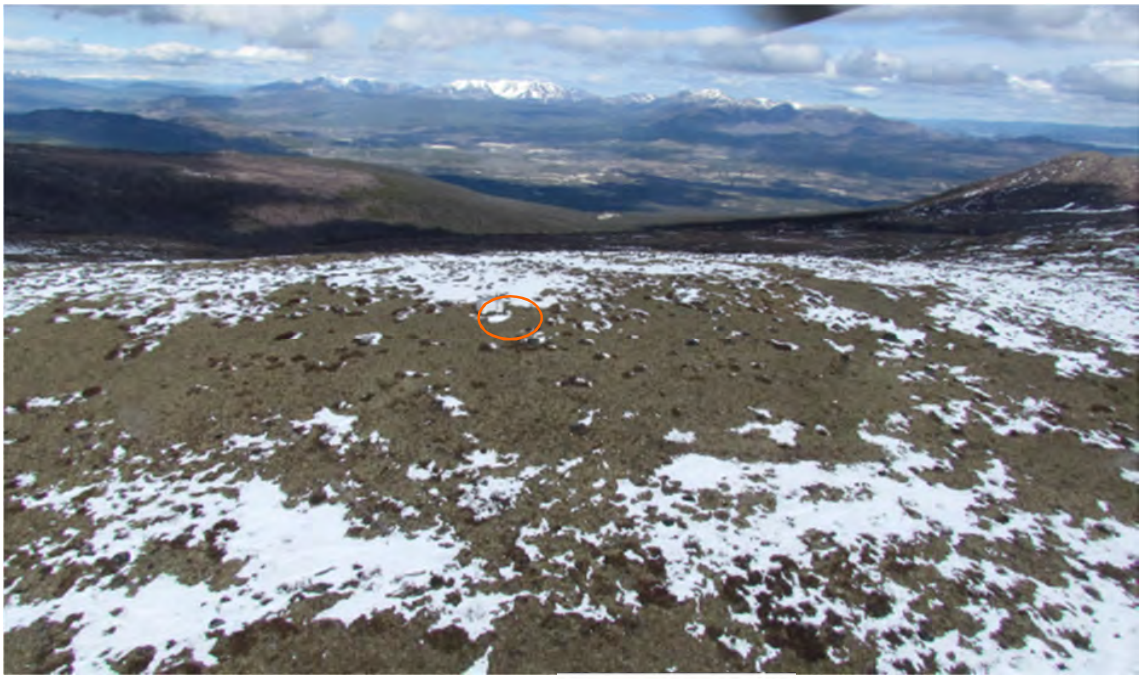


3.5.2 Site Layout

The Mount Sumanik wind resource predicted by AWS Truepower predicts mostly southerly winds with some variability from east-to-west, as seen below in Figure 26. Power production winds, however, appear to be strongly south-southeasterly, which complicates wind turbine layout at the site as the ridge orientation is north-south.

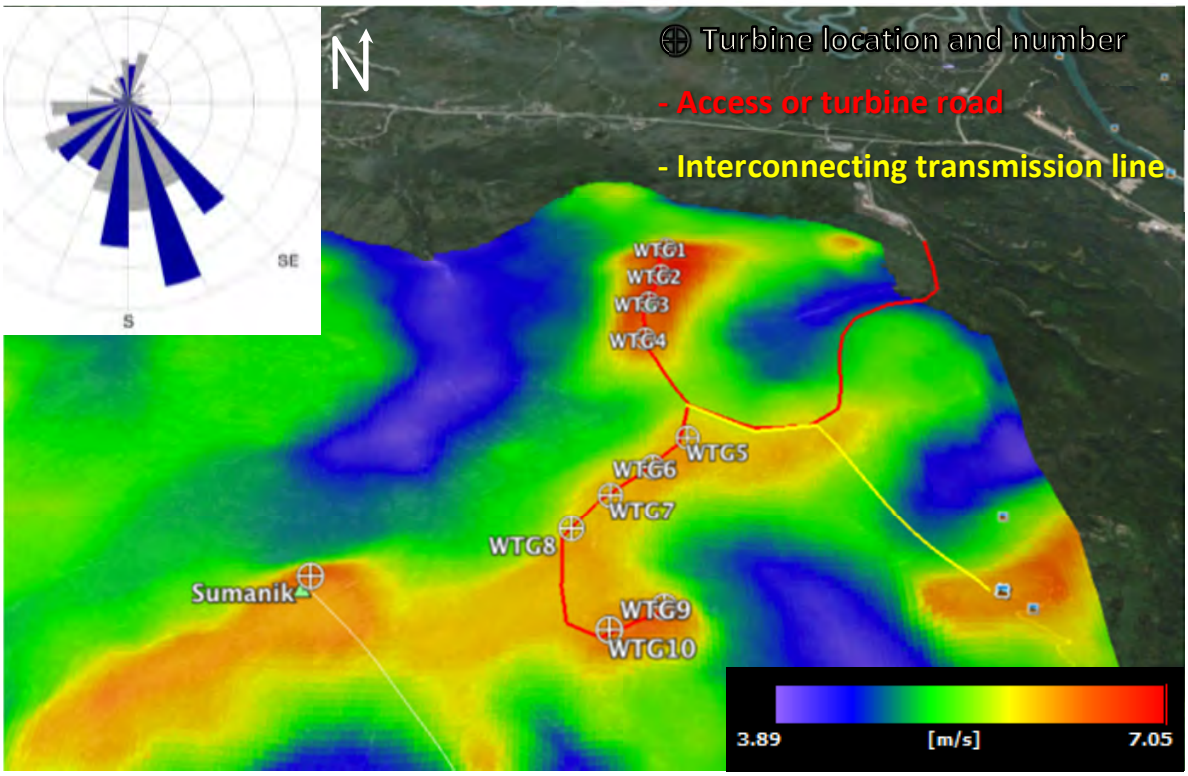
Interestingly, it appears from modelling that a 10 x 2-MW wind farm would be best arrayed along the ridgelines north of the actual summit area as shown in Figure 25, not along the higher elevations of the summit itself. Turbines in this figure are identified as "WTG", the AWS Truepower data reference point for the WAsP model is noted by "Sumanik." Although road access via the north-side borrow pit is recommended, electrical sub-transmission connection to existing transmission at the Haeckel Hill wind turbine site would likely be most efficient and is indicated by the yellow line in Figure 25.

Figure 25 Mount Sumanik Site, Photo Looking East



Note: LIDAR wind monitoring equipment can be seen in the middle of the photo

Figure 26 20 MW Wind Farm Layout for Mount Sumanik, WAsP Wind Speed Overlay



As demonstrated in Figure 27, the proposed turbine site area consists of two separate ridges north of the summit itself. Additional turbines could be installed along the ridge line extending towards the peak, although wind speeds are somewhat lower from south of WTG8 to near the Mt. Sumanik summit where WAsP modelling indicates they would be higher. Sumanik could accommodate a larger wind farm with use of additional or larger capacity wind turbines.

3.6 Tehcho (Ferry Hill)

Tehcho, previously referred to as Ferry Hill, was originally excluded by YEC from the project analysis and then later added for comparison to the 5 originally recommended sites.

3.6.1 Site Description

Tehcho would be relatively straightforward to develop due to an existing road to the summit of the hill and an existing transmission line from Stewart Crossing to the summit to power a communications tower. Although the transmission line would require an upgrade, the existing easement is a significant development advantage. Figure 27 shows the site area on a Google Earth image.

Tehcho has received considerable attention as a possible wind turbine site with installation of two met towers and a 2011 two-part study by Natural Power that assessed the met tower data, icing potential and prospective wind turbine layout. Project history of the met tower study is not entirely clear, but the Natural Power report indicates that data was collected from October 2001 until June 2005. In their study, Natural Power did not analyze the overall measured wind resource *per se*; rather, they concentrated on data loss due to icing, assessment of effects of rime icing on energy production at the site, and a financial analysis of a prospective wind project.

Figure 27 Tehcho Prospective Wind Power Site, Google Earth Image

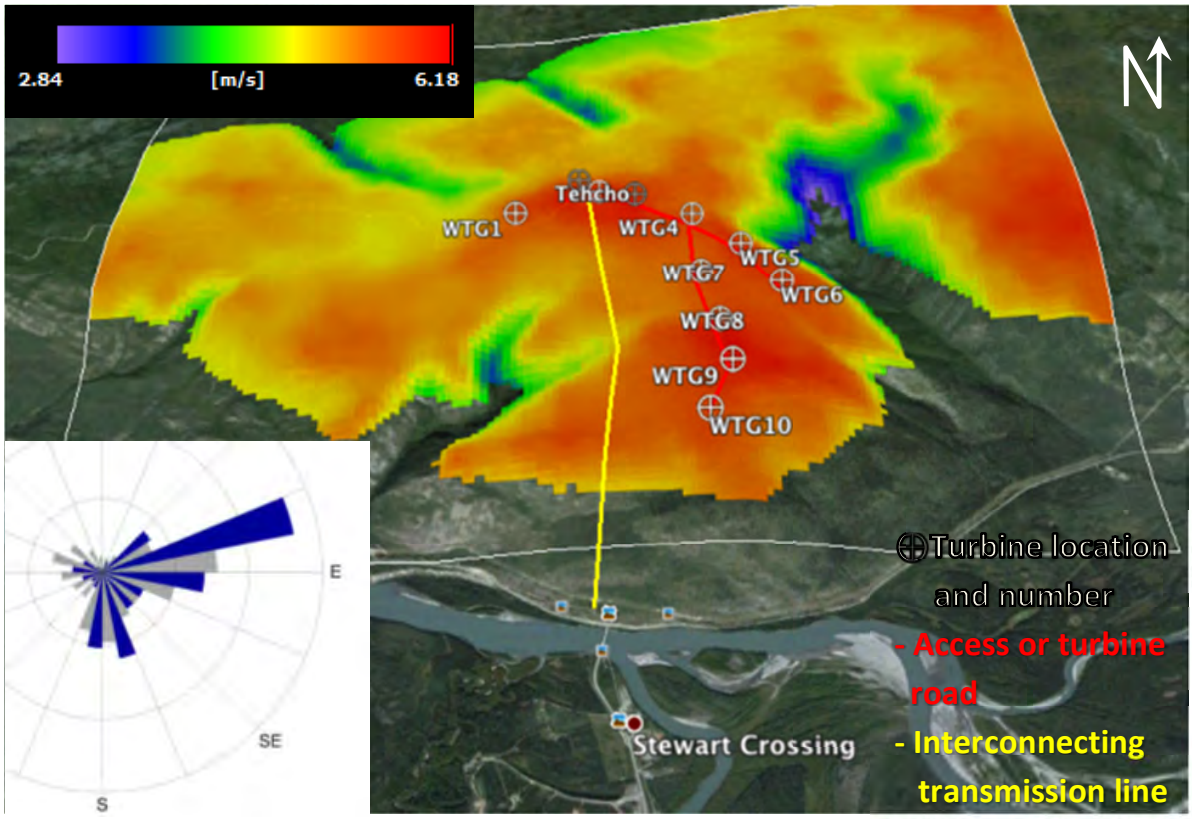
3.6.2 Site Layout

The Tehcho wind rose, as predicted by AWS Truepower, indicates mostly easterly, with some southerly, winds (see Figure 28). For the more frequent easterly winds, this is advantageous as the ridgeline orientation is generally north-south.

A ten-turbine, 20-MW wind farm would be arrayed along the southern shoulder of Tehcho as shown in Figure 28 below. This is slightly different than Natural Power's 2011 site layout, which concentrated wind turbines along the southwest shoulder of the hill. Note that the AWS Truepower data reference point for the WAsP model is indicated by "Tehcho". This is the same site as the larger met tower in the 2001 to 2005 wind study.

Additional wind turbine capacity at Tehcho could be installed on the southwest shoulder of the hill as laid out by Natural Power in 2011.

Figure 28: 20 MW Wind Farm Layout for Tehcho, WAsP Wind Speed Overlay



Note: the connection may have to go to Stewart Crossing south substation, on the south side of the Stewart River (not the north side as shown) as there is probably enough space at the existing substation. This would slightly increase the capital costs for his project.

3.7 Thulsoo Mountain

Thulsoo Mountain near the Aishihik hydroelectric facility (north of Canyon, between Haines Junction and Whitehorse) has superb potential for wind power production and, along with Miller's

Ridge, can be considered the preferred sites for wind power in the Yukon, although Thulsoo has less absolute wind power capacity potential than Miller's Ridge.

3.7.1 Site Description

Although there is no existing access road to the summit of Thulsoo, a new access road would be relatively short. Similarly, transmission to tie to the Aishihik substation would be short distance as well. Figure 29 is a Google Earth image identifying the site, and Figure 30 is a photo taken during the site visit trip in April 2016. Unfortunately, flight scheduling did not enable us to have an over-flight during the site visit and poor weather prevented a close visual examination of the mountain from the Aishihik canyon access road.

Figure 29 Thulsoo Mtn. Prospective Wind Power Site, Google Earth Image

Figure 30 Thulsoo Mtn. Site, Photo taken from Alaska Hwy (view north)

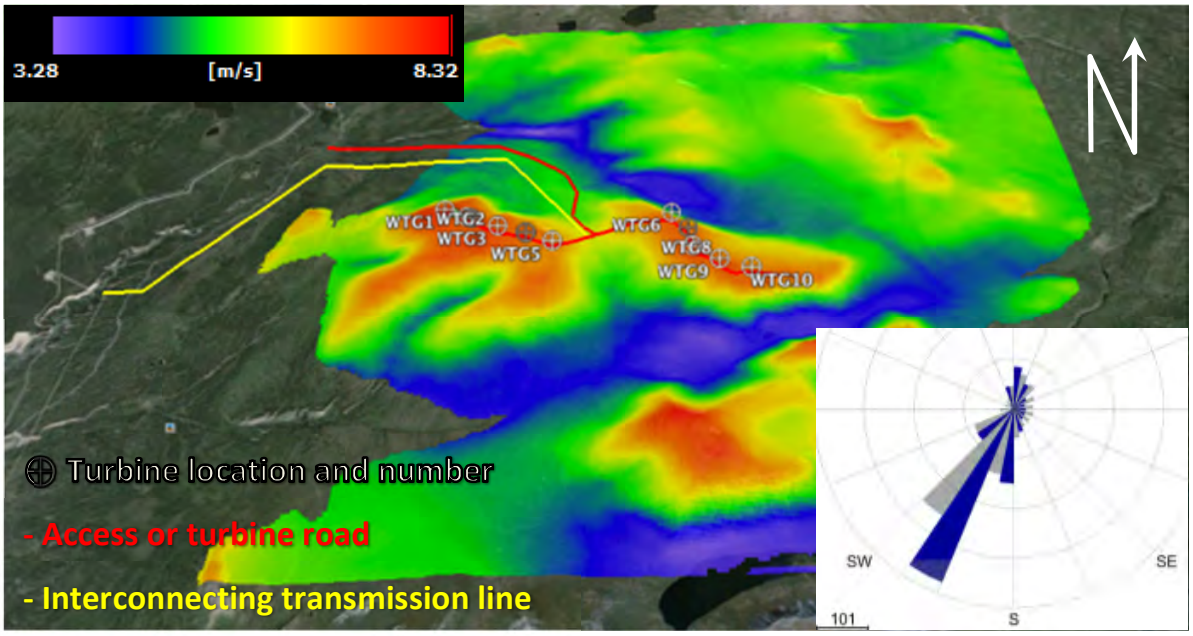
3.7.2 Site Layout

Thulsoo Mountain has an excellent wind resource with strongly prevailing south-southwesterly winds that complement the generally east-west orientation of the mountain (see Figure 31), but the site area that can be developed is somewhat constrained.

For a 10 x 2.0-MW wind farm, half the turbines would be located at an adjacent ridge of Thulsoo Mountain as shown in Figure 31. Turbines in this figure are identified as "WTG", the AWS Truepower data reference point for the WAsP model is adjacent to WTG5.

The site might allow one additional 2.0 MW turbine to the northeast of turbine WTG10 to be installed at the end of the turbine road. The maximum capacity of the site would then be 22 MW (11 x 2 MW). No other additional turbines could be deployed without negatively affecting the performance of the 20-MW array.

Figure 31: 20 MW Wind Farm Layout for Thulsoo Mountain, WAsP Wind Speed Overlay



3.8 Land Use

Wind farms require significant amount of land. For a 20 MW wind farm at each of these seven sites between 70 and 190 hectare of land are required, three to nine hectare per MW of installed capacity. Only about one third of the land is used by the turbines themselves, the rest is for the access road and a connection to YEC's transmission line, including the required easement offset. On average, both, the access road to the site and the interconnecting transmission line are six to seven kilometer long.

Land will be used for the turbines itself, a road connecting the turbine, an access road, unless existing and a power line connecting the turbines to YEC's grid. Along power lines and access roads we

assumed an easement of 60 meters. The latter includes the width of the road, typically around seven meters.

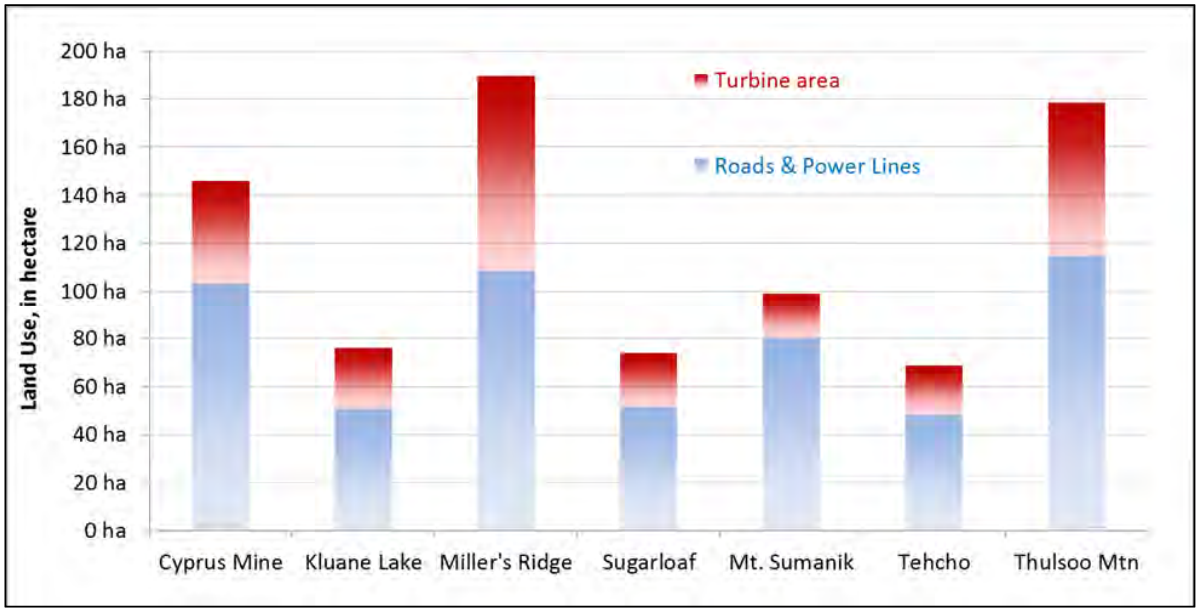
We used a buffer of 45 meters around the turbine. This is the rotor radius for a 2.0-MW turbine. From a bird's eye view the tower can swivel 360°. The downward projection of this area, a circle 90 m in diameter, needs to be purchased from a legal point of view.

The 45-meter buffer would go along the entire array of turbines. The total land to be purchased would be the length of the road connecting the array of turbines (the 'turbine road') plus 45 m x 45 m on either end of the road. An underground collector line between the turbines will run along the turbine road. The 90-meter easement will also be used by turbine transformer and the area for the switch yard. Finally, this easement allows the rotors and turbine to be laid down during construction. Usually the three blades are assembled on the ground and then lifted up onto the erected tower.

As an example: An array of 10 turbines, each placed five rotor diameters apart, are arranged in a line, e.g. along the ridge of a mountain. This array may be 5 km long. There has to be a 45 m buffer on either side of this array. The total width of the buffer is 90 meters. If the array is 5 km long the total area would be 5 km x 90 m = 45 ha.

Trees can create turbulence. Most of the wind-farm sites are on ridgelines above the tree line, though. No cost for land clearing has been assumed for the turbines or the turbine road. Kluane Lake is an exception to this.

Figure 32: Land Use of a 20 MW Wind Farm at the Seven Selected Sites



4 WIND FARM ENERGY PRODUCTION

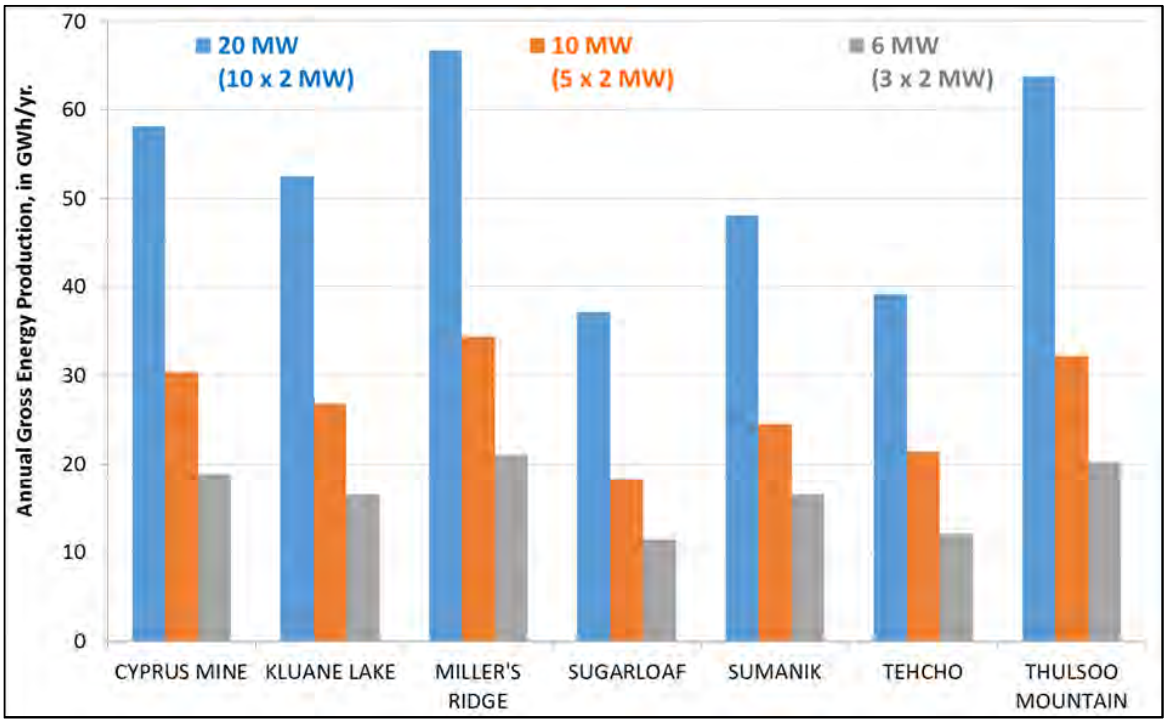
This chapter presents projected energy output of wind farms at the seven selected sites. Modelled energy production is a key input to the financial model in Chapter 5. Details on energy production , losses, and monthly generation profiles for each of the seven sites are given in Appendix H.

4.1 Annual Gross Energy Production

For modelling the energy production of the various sizes of wind farms at the seven sites we employed the wind modelling software called WAsP mentioned in the previous chapter. Based on topography, wind resource and site layout WAsP determines the Annual Energy Production (AEP).

A 20 MW wind farm produces 52 GWh per year on average at the seven sites, equivalent to the annual consumption of 5,300 households in the Yukon.[7] A 6 MW farm will only generate 17 GWh annually. Comparing the three sizes of wind farms, a clear pattern can be recognized: the fewer wind turbines there are on site, the lower the wake losses and the higher the capacity factor. While the annual energy production is obviously higher for larger wind farms, the average capacity factor is lower (generally about 2-4% lower for 10 MW and about 4-7% lower for a 20 MW farm, compared to 6 MW). A wind farm with five turbines produces slightly more than half the energy that the wind farm with ten turbines – see Figure 33 below.

Figure 33 **Summary Results of WAsP Wind Farm Modelling:** Annual gross energy generation of various wind farm sizes, 2 MW generic turbine



[7] Over the past years, Yukon residential customers consumed an average of 9,801 KWh per year. Source: Yukon Bureau of Statistics, "Yukon Energy Facts 2013", see www.eco.gov.yk.ca/pdf/energy_2013.pdf, accessed on June 7th, 2016

4.2 Energy Losses

The actual energy fed into the grid is lower than the numbers stated above. A wind farm will face the following losses:

- Wake loss due to turbulences and the shadowing effect turbines have on each other;
- Curtailment during extreme temperatures and icing to protect the blades
- Parasitic energy, such as electricity for melting ice on the blades,
- Conversion losses when transforming turbine voltage to grid transmission voltage
- Sub-optimal performance, e.g. due to soiled blades
- Downtime necessary for maintenance;

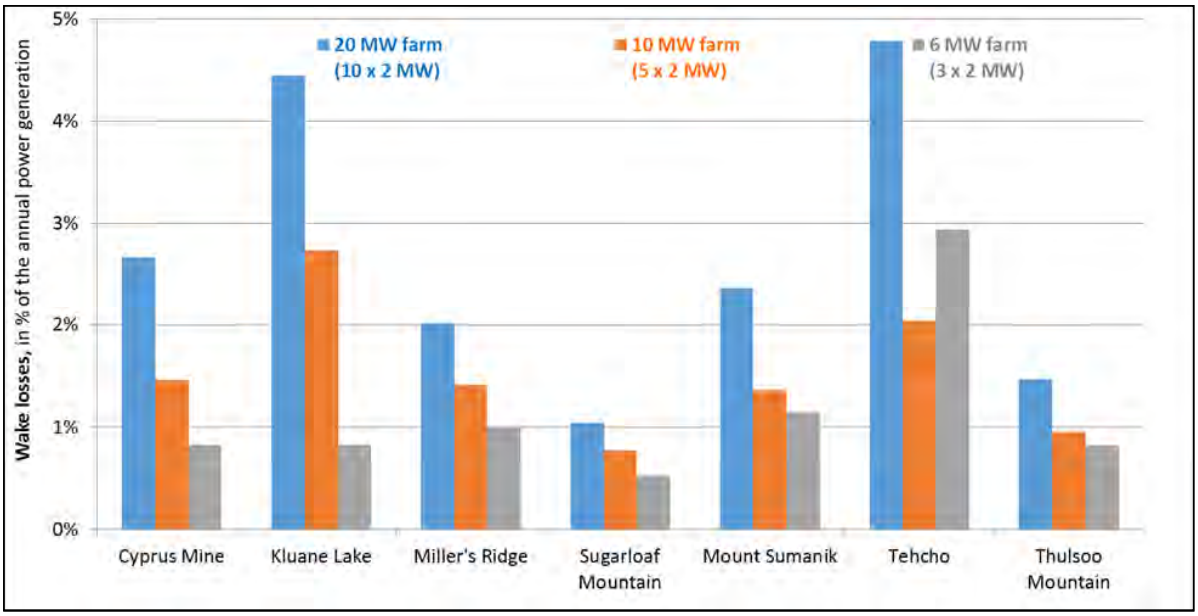
The following chapters quantify these losses.

4.2.1 Wake Losses

Turbine array wake loss is due to the shadowing effect that upwind turbines have on those down-wind. This effect is highest very near a turbine and dissipates with distance until the wind-free stream velocity resumes. As one might expect, wake loss is relatively high in large arrays, especially those with multiple rows of wind turbines, and high at sites with complicated or highly variable prevailing winds.

Wake losses for the seven selected site range from 0.5% to close to 5%, depending on the site and the size of the wind farm. This is well within an industry standard range of three to five percent. Of the seven sites studied in this report, wake losses are predicted as highest at Kluane Lake and Tehcho and lower at the other sites. As discussed in Section 3, this is due to the unavoidable parallel-to-the-prevailing wind orientation of turbines at Kluane Lake and the constrained site size at Tehcho.

Figure 34 Wake Losses of the Three Wind Farm Sizes at each of the Seven Sites



Wake loss can be reduced by moving turbines further apart, both parallel and perpendicular to prevailing winds, but there is a cost tradeoff. A larger site footprint is more expensive to develop, hence the industry rule of thumb of three to five percent wake loss as economically optimal.

4.2.2 Extreme Temperature Curtailment

For many wind turbine models, power output automatically curtails (by sensor input, via the turbine control system) at temperatures below -30°C and the turbine shuts down at -40°C. This protective feature reflects metal fatigue and lubricant limitations in severe cold. Whereas temperatures below -40°C are rare, even in the Yukon, the AWS hourly time series data for each site suggests a number of hours below -30°C each year. For Tehcho, near Stewart Crossing, and the coldest site, AWS hourly time series data predicts 241 hours a year with air temperatures below -30°C. At Kluane Lake by comparison -30°C are predicted for only five hours per year. Using these numbers of hours, we determined the curtailment losses due to extreme temperatures, see Table 6 below.

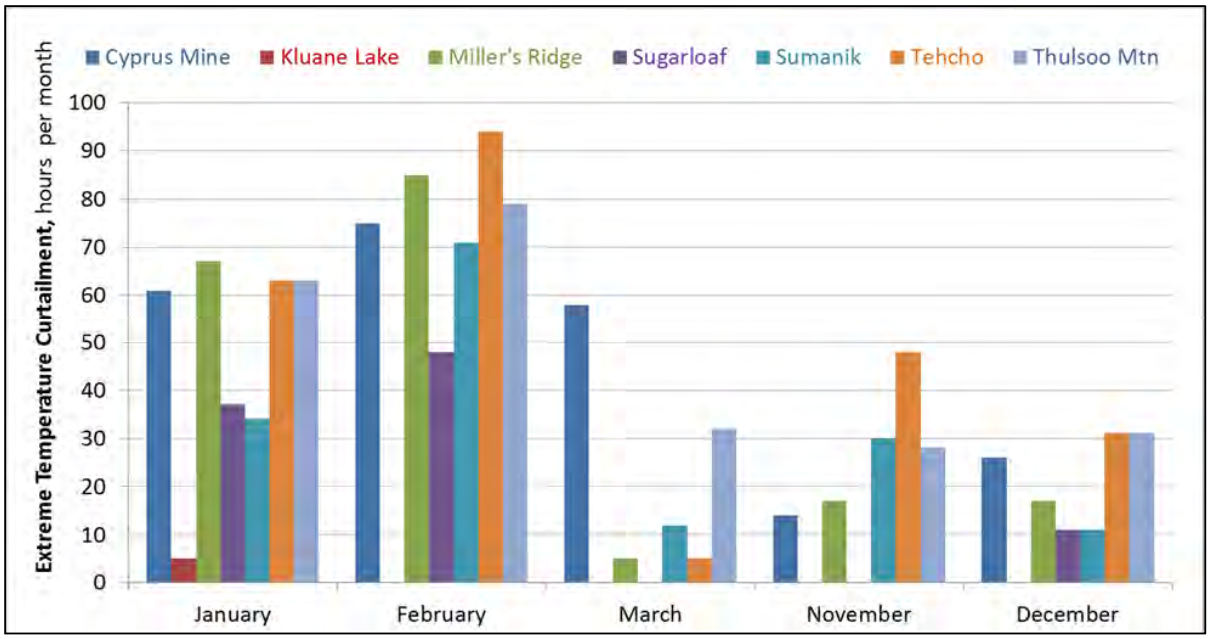
Table 6 Losses Due to Low Temperature Turbine Curtailment

Site	Hours below -30°C	Curtailment losses of a 20 MW wind farm	
Cyprus Mine	234 hours / year	2.7%	-1,552 MWh/yr.
Kluane Lake	5 hours / year	0.1%	-30 MWh/yr.
Miller's Ridge	191 hours / year	2.2%	-1,455 MWh/yr.
Sugarloaf Mountain	96 hours / year	1.1%	-407 MWh/yr.
Sumanik	158 hours / year	1.8%	-868 MWh/yr.
Tehcho	241 hours / year	2.8%	-1,077 MWh/yr.
Thulsoo Mountain	233 hours / year	2.7%	-1,695 MWh/yr.
Average	**165 hours / year**	**1.9%**	**-1,012 MWh/yr.**

Although some manufacturers allow their turbines to operate below -30°C, especially direct drive turbines, we have conservatively assumed that the turbine will stop operating to protect the turbines against extreme cold-weather risk. It is likely that the entire wind farm will stop operating during these hours.

Because these losses occur during winter, they can reduce output during the coldest months by up to 14% in an extreme case (Tehcho in February), although typical cold-temperature curtailment would be much lower. Curtailment due to extremely cold temperatures is presented in Figure 35.

Figure 35 Hours of Curtailment due to Temperatures below -30°C



4.2.3 De-icing Energy and De-icing Downtime

Another factor reducing turbine output is icing. Contrary to cold temperatures, icing may only affect one or some of the turbines at a given time so that the plant can maintain a portion of its power-generation ability. Icing losses have been estimated as 7.8% of total production in the Natural Power's 2010 Tehcho study,[8] and above 25% of production in the study on Mt Sumanik (also referenced in Section 2.1).

For all sites except Kluane Lake, which is not expected to display icing, we assume that 20% icing loss could occur without mitigation. De-icing equipment is expected to largely reduce the downtime from icing but will consume energy. In total, we estimate that the annual loss can be reduced to 5% of annual gross output with de-icing equipment. Half of this – 2.5% – will be downtime due to rime icing, the other half will be energy required for de-icing. Again, this energy loss will be mainly during the winter and could account for ten or more percent of a winter month's energy production.

4.2.4 Transformer Losses

There will be two types of step-up transformers at each wind farm: one from the turbine voltage, around 1,000 V, depending on the model, to 12.47 kV. Each turbine will be equipped with a transformer to achieve the turbine connection bus voltage. A final transformer will be at the end of the collector lines in the switch yard. This transformer will step-up the voltage from 12.47 kV to either 69 kV or 138 kV, depending on the voltage of the transmission line it will connect to.

Both transformers are estimated as 98% efficient. Combined losses are therefore approximately 4% of turbine power output. Line losses are included in this estimate.

[8] Natural Power, *Ferry Hill Wind Feasibility Study, Stages 1 and 2*, 2010

4.2.5 Sub-optimal Performance

A number of factors, such as soiled rotor blades, can lead to sub-optimal performance of a turbine. We have assumed 1% losses due to sub-optimal functioning.

4.2.6 Maintenance Downtime

Each turbine will require preventive maintenance and will also experience some unscheduled downtime. The former may be accomplished in the summer when YEC has a surplus of hydropower and wind turbines can be taken off line with little consequence. We estimate that 2% of the potential annual energy output will be lost due to maintenance; half of this will be unscheduled over the course of the year, the other half during the summer as a regular revision.

4.2.7 Total Losses and Net Output

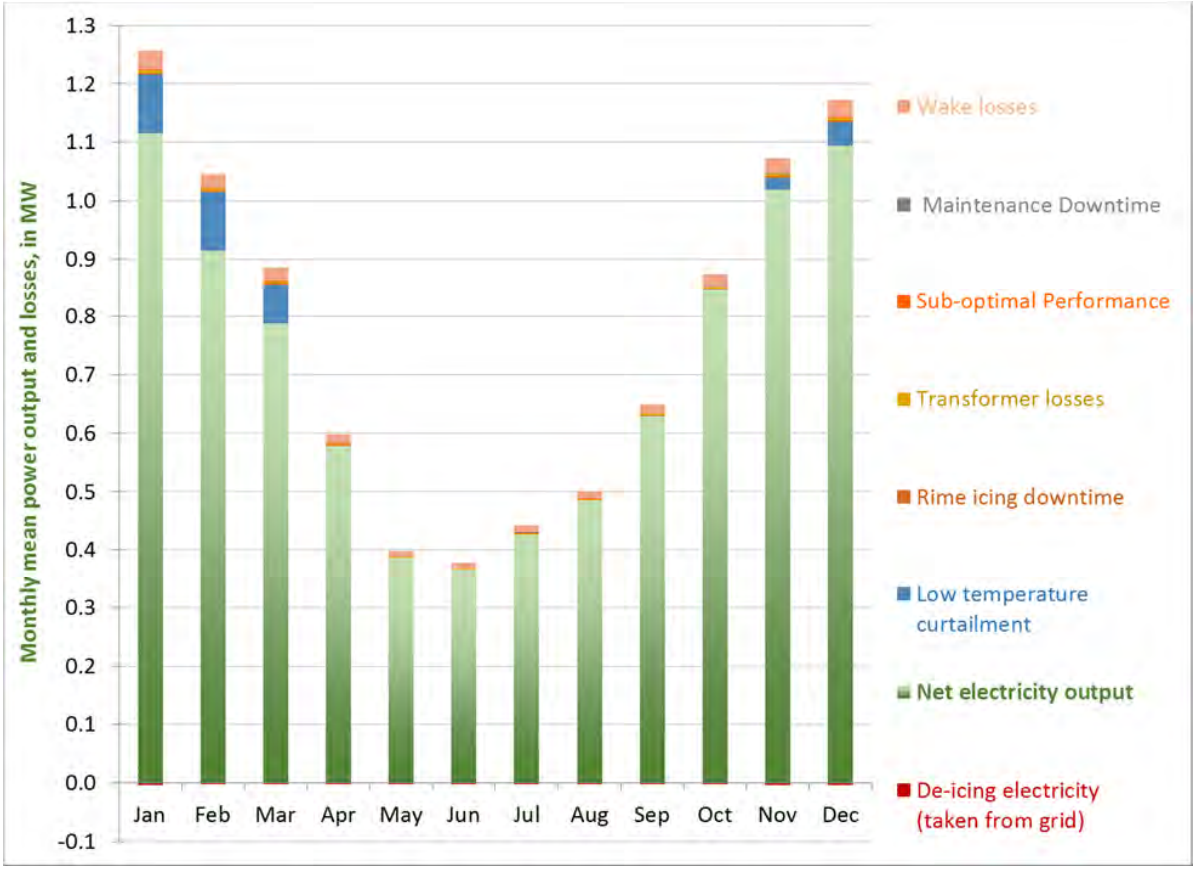
WAsP wind farm analysis software, which was used to create turbine layouts presented in Section 3, calculates wake losses due to shadowing between turbines, are specific to each capacity option per site, and are summarized in the following subsections. All other losses, however, are summarized in Table 7. Wake losses aside, we estimate approximately 9% annual energy loss for Kluane Lake and 14% for the other sites.

Table 7 Wind Farm Energy Production Loss Summary

		Kluane Lake	All other sites
1	Wake losses	0.83% - 4.45%	0.5% - 4.8%
2	Rime-icing downtime	1.0%	2.5%
3	De-icing energy (taken from the grid)	1.0%	2.5%
4	Low-temperature curtailment	0.7%	1.1% - 2.7%
5	Transformer losses	4.0%	4.0%
6	Sub-optimal performance	1.0%	1.0%
7	Maintenance	2.0%	2.0%
	Annual net production	**86% - 89%**	**81% - 86%**
	(% of gross output)		

Other restrictions may apply, such as curtailment of the wind turbines due to overcapacity of energy production during the summer. These limitations are outside the scope of this study and are not considered in Table 7 and other analyses of this report.

Figure 36: Monthly Mean Net Power Output for a GE-100-1.7 MW Turbine at Cyprus Mine

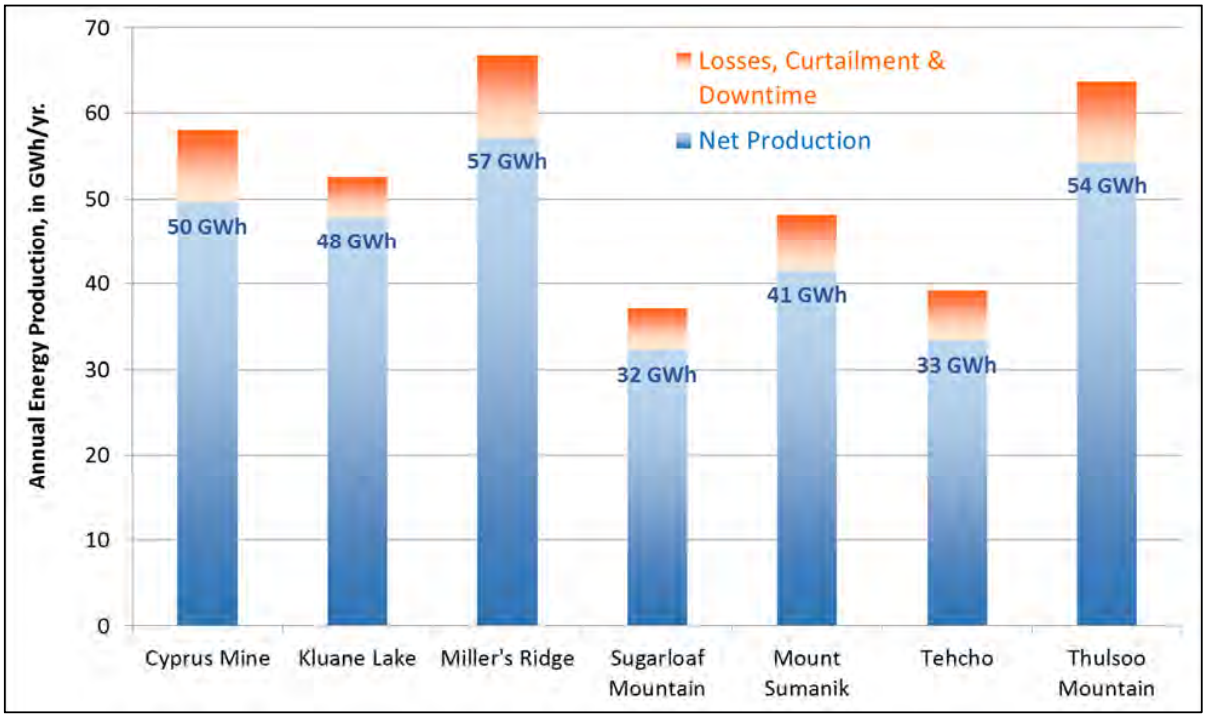


4.3 Annual Net Energy Production

The following graph compares the seven sites in terms of their annual net energy production (Figure 37) by site. Thulsoo and Miller's Ridge appear to be the highest yield sites, followed by Cyprus Mine. Sugarloaf Mountain, Sumanik Mountain and Tehcho are expected to produce significantly less energy. Kluane Lake, the only low elevation site, shows a sligthly lower annual gross output than the top performing sites. This comparison is based on a generic 2.0 MW turbine and does not take into account that different turbine choices might result in an improved performance. The overall ranking of the seven sites is unlikely to change.

A wind farm at Kluane Lake will still perform well due to lower de-icing losses and less curtailment due to extreme weather, such as temperatures below -30°C when most turbines are stalled to avoid failures. The financial analysis in the next chapter also takes lower site development costs for this site into account.

Figure 37 Summary Results of 20 MW Wind Farm Modelling: Annual net energy generation and losses;

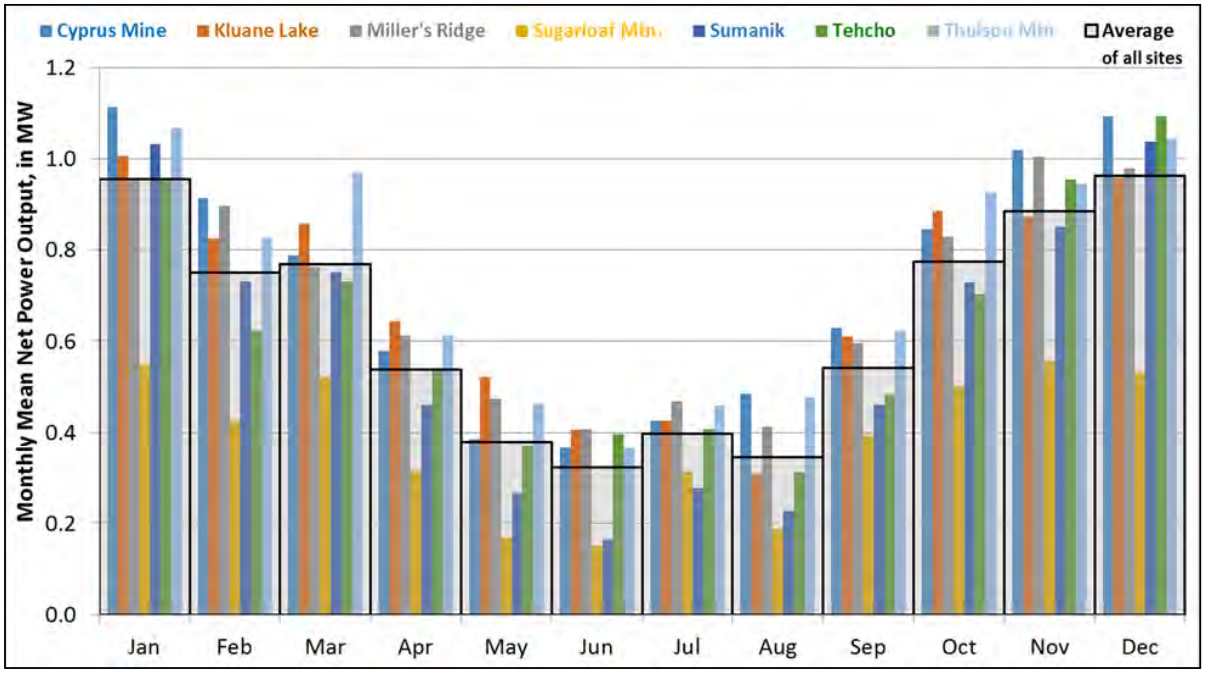


4.4 Monthly Generation Profile

All sites show a clear pattern of lower monthly mean power production in summer than in winter. This is despite the higher percentage of curtailment and parasitic electricity in winter. On average, two-thirds of the energy that the turbines feed into the grid are generated during the seven months from October to April. Mean power output in June and August is one third of the output in January. Wind power therefore fits well into YEC's demand profile.

There is no wind farm site that clearly outperforms all other sites for every month of the year – see Figure 38 below. The numbers below are based on the turbine model with the highest winter output. Wake losses are not included.

Figure 38 Monthly Power Output Profile of a Single 1.7 MW to 2.35 MW Turbine at the Seven Sites (excluding wake losses)



The mean annual power output is 26% to 28% of the nominal wind farm capacity, i.e. a 10 MW wind farm, for example, would generate on average 2.6 to 2.8 MW over the course of the year, more during the winter, less in summer.

For the purpose of creating data of monthly net electricity output of the three sizes of wind farms combined the annual gross energy production forecasted by the WAsP model with the monthly distribution of energy production of the AWS report. We then subtracted all other losses described in the main report to obtain monthly net electricity production data. The results given below are for a generic turbine (Vestas V-90) only. While the sum of the monthly electricity generation is accurate, the monthly data is an approximation only.

Table 8 Losses and Net Annual Energy Production of the Three Wind Farm Sizes
(after wake losses, after all other losses)

20 MW WINDFARM

Month	Cyprus	Kluane	Millers Ridge	Sugarloaf	Sumanik	Techho	Thulsoo
Jan	7.0 GWh	6.1 GWh	6.5 GWh	4.1 GWh	6.8 GWh	4.5 GWh	7.2 GWh
Feb	5.0 GWh	4.4 GWh	5.2 GWh	2.7 GWh	4.0 GWh	2.4 GWh	4.8 GWh
Mar	4.6 GWh	5.1 GWh	5.3 GWh	3.8 GWh	4.6 GWh	3.2 GWh	6.3 GWh
Apr	3.1 GWh	3.6 GWh	4.1 GWh	2.0 GWh	2.6 GWh	2.2 GWh	3.5 GWh
May	2.1 GWh	3.1 GWh	3.4 GWh	1.0 GWh	1.4 GWh	1.6 GWh	2.7 GWh
Jun	2.0 GWh	2.3 GWh	2.8 GWh	1.0 GWh	0.8 GWh	1.7 GWh	2.1 GWh
Jul	1.9 GWh	2.0 GWh	2.8 GWh	2.0 GWh	1.2 GWh	1.5 GWh	2.3 GWh
Aug	2.9 GWh	1.7 GWh	3.0 GWh	1.3 GWh	1.3 GWh	1.4 GWh	3.0 GWh
Sep	3.5 GWh	3.5 GWh	4.2 GWh	2.8 GWh	2.7 GWh	2.1 GWh	3.7 GWh
Oct	4.9 GWh	5.4 GWh	6.0 GWh	3.6 GWh	4.5 GWh	3.1 GWh	5.9 GWh
Nov	5.9 GWh	5.0 GWh	7.0 GWh	3.9 GWh	5.0 GWh	4.3 GWh	5.9 GWh
Dec	6.7 GWh	5.7 GWh	7.0 GWh	3.9 GWh	6.7 GWh	5.2 GWh	6.8 GWh
Year	**49.6 GWh**	**47.8 GWh**	**57.3 GWh**	**32.3 GWh**	**41.5 GWh**	**33.4 GWh**	**54.4 GWh**

10 MW WINDFARM

Month	Cyprus	Kluane	Millers Ridge	Sugarloaf	Sumanik	Techho	Thulsoo
Jan	3.7 GWh	3.1 GWh	3.4 GWh	2.0 GWh	3.4 GWh	2.5 GWh	3.6 GWh
Feb	2.6 GWh	2.2 GWh	2.7 GWh	1.3 GWh	2.0 GWh	1.3 GWh	2.4 GWh
Mar	2.4 GWh	2.6 GWh	2.7 GWh	1.9 GWh	2.3 GWh	1.8 GWh	3.2 GWh
Apr	1.6 GWh	1.9 GWh	2.1 GWh	1.0 GWh	1.3 GWh	1.2 GWh	1.8 GWh
May	1.1 GWh	1.6 GWh	1.7 GWh	0.5 GWh	0.7 GWh	0.9 GWh	1.4 GWh
Jun	1.1 GWh	1.2 GWh	1.5 GWh	0.5 GWh	0.4 GWh	1.0 GWh	1.1 GWh
Jul	1.0 GWh	1.0 GWh	1.4 GWh	1.0 GWh	0.6 GWh	0.8 GWh	1.2 GWh
Aug	1.5 GWh	0.9 GWh	1.5 GWh	0.7 GWh	0.7 GWh	0.7 GWh	1.5 GWh
Sep	1.8 GWh	1.8 GWh	2.2 GWh	1.4 GWh	1.4 GWh	1.2 GWh	1.9 GWh
Oct	2.6 GWh	2.7 GWh	3.1 GWh	1.8 GWh	2.3 GWh	1.7 GWh	3.0 GWh
Nov	3.1 GWh	2.6 GWh	3.6 GWh	1.9 GWh	2.5 GWh	2.4 GWh	3.0 GWh
Dec	3.5 GWh	2.9 GWh	3.6 GWh	1.9 GWh	3.4 GWh	2.8 GWh	3.5 GWh
Year	**26.0 GWh**	**24.4 GWh**	**29.5 GWh**	**15.9 GWh**	**21.1 GWh**	**18.3 GWh**	**27.5 GWh**

6 MW WINDFARM

Month	Cyprus	Kluane	Millers Ridge	Sugarloaf	Sumanik	Techho	Thulsoo
Jan	2.3 GWh	1.9 GWh	2.1 GWh	1.3 GWh	2.3 GWh	1.4 GWh	2.3 GWh
Feb	1.6 GWh	1.4 GWh	1.6 GWh	0.8 GWh	1.4 GWh	0.7 GWh	1.5 GWh
Mar	1.5 GWh	1.6 GWh	1.7 GWh	1.2 GWh	1.6 GWh	1.0 GWh	2.0 GWh
Apr	1.0 GWh	1.1 GWh	1.3 GWh	0.6 GWh	0.9 GWh	0.7 GWh	1.1 GWh
May	0.7 GWh	1.0 GWh	1.1 GWh	0.3 GWh	0.5 GWh	0.5 GWh	0.9 GWh
Jun	0.7 GWh	0.7 GWh	0.9 GWh	0.3 GWh	0.3 GWh	0.5 GWh	0.7 GWh
Jul	0.6 GWh	0.6 GWh	0.9 GWh	0.6 GWh	0.4 GWh	0.5 GWh	0.7 GWh
Aug	0.9 GWh	0.5 GWh	0.9 GWh	0.4 GWh	0.5 GWh	0.4 GWh	1.0 GWh
Sep	1.1 GWh	1.1 GWh	1.3 GWh	0.9 GWh	0.9 GWh	0.7 GWh	1.2 GWh
Oct	1.6 GWh	1.7 GWh	1.9 GWh	1.1 GWh	1.5 GWh	1.0 GWh	1.9 GWh
Nov	1.9 GWh	1.6 GWh	2.2 GWh	1.2 GWh	1.7 GWh	1.3 GWh	1.9 GWh
Dec	2.2 GWh	1.8 GWh	2.2 GWh	1.2 GWh	2.3 GWh	1.6 GWh	2.2 GWh
Year	**16.1 GWh**	**15.0 GWh**	**18.1 GWh**	**9.9 GWh**	**14.2 GWh**	**10.3 GWh**	**17.3 GWh**

4.5 Reliable Winter Capacity

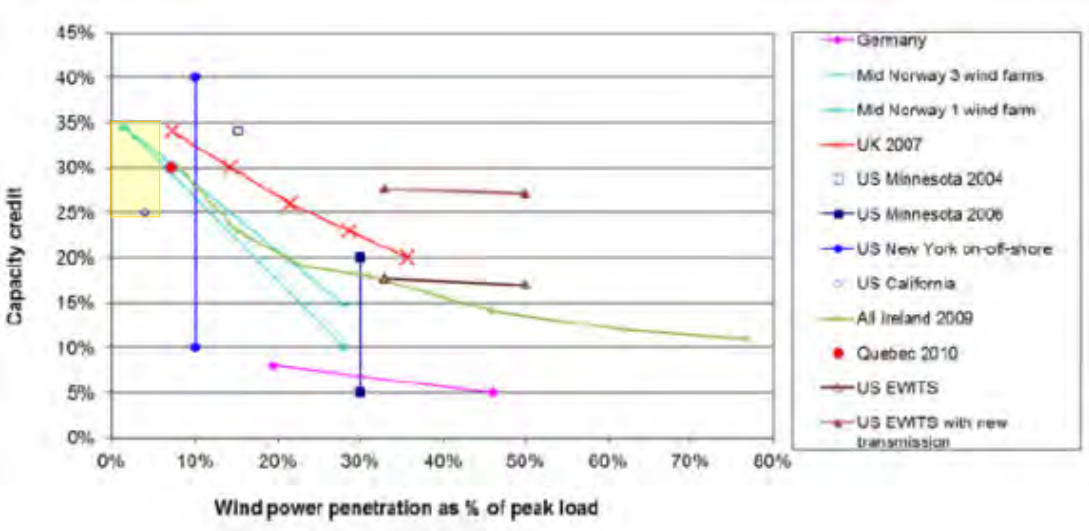
The Excel sheet for the financial analysis provided by YEC asks us to estimate "reliable winter capacity." We understand this to mean firm capacity for power generation, i.e. a minimum guaranteed output. Wind power is a variable resource and technically cannot guarantee any minimum output at any time of the year. There may be days when wind speeds are below the start-up wind speed, so output will drop to zero during these hours.

On the other hand, for planning purposes, wind power is recognized as having an ability to displace other power generation sources. For example, in Germany, the Effective Load Carrying Capability (ELCC) of wind power is valued at about 10% of its rated capacity for planning purposes.[9]

The capacity credit depends on various factors including grid penetration levels. The capacity credit decreases as the share of wind power on the grid grows. A 6-MW wind farm in the Yukon would have a 3% penetration of YEC's generation in 2015. For a 20-MW wind farm, the penetration level would increase to approximately 11% of the total generation in 2015 (416 GWh). A single wind farm in the Yukon can be considered low-penetration and would be located in the far left side of the graph below. [10] Worldwide, the ELCC for low penetration wind energy has been determined to be between 25% and 35% of total rated wind power capacity on the grid, see the yellow highlighted area in Figure 39 below.

At maximum output a 20-MW wind farm would deliver about one-quarter of the peak winter capacity demand and one-half of summer demand. There is a high correlation with the seasonally-changing load of YEC's grid: A wind farm will supply more energy in winter when more energy is needed.

Figure 39 Capacity Credit of Wind Power in Various Parts of the World[11]

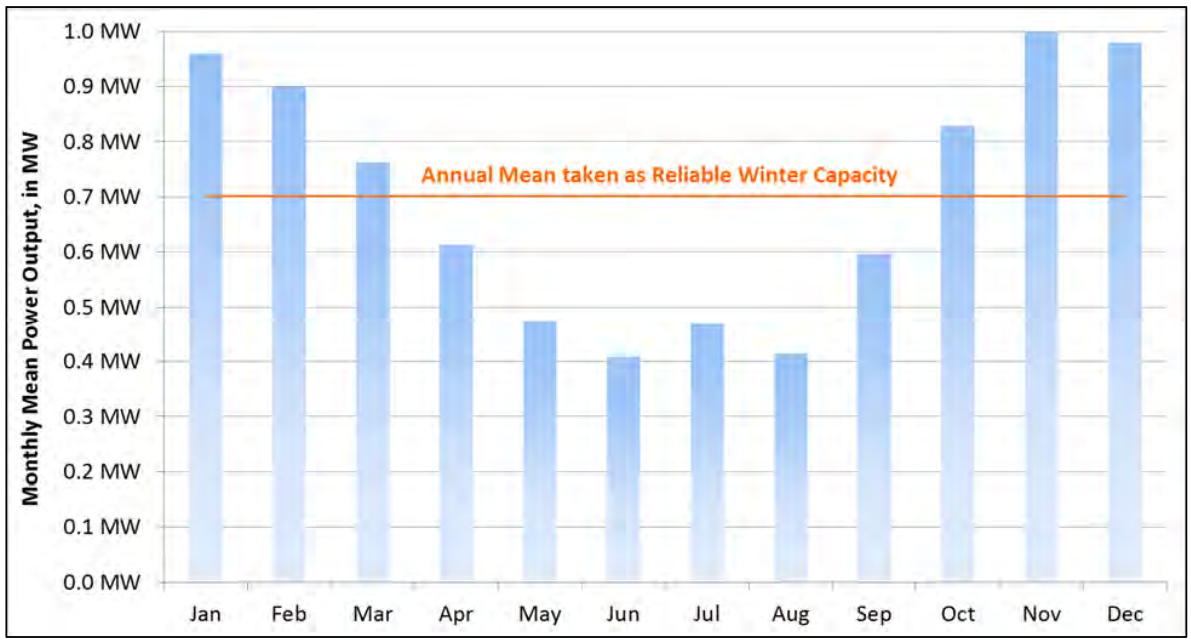


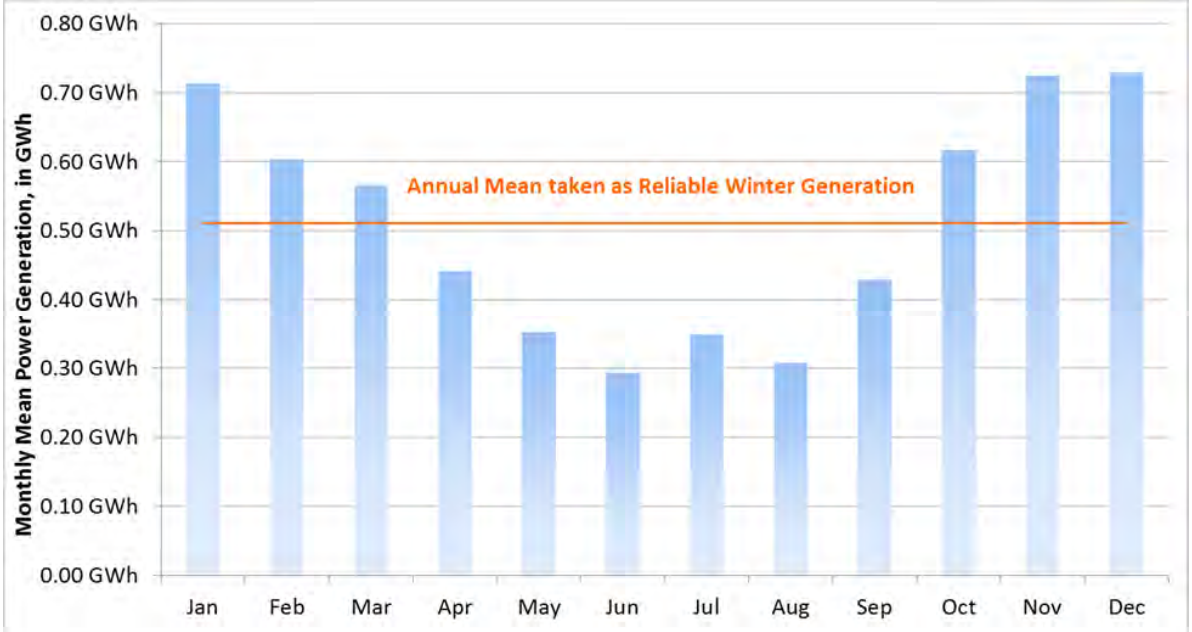
[9] See http://www.wind-energy-the-facts.org/capacity-credit-values-of-wind-power.html
[10] Penetration is defined as the fraction of energy produced by wind compared with the total generation
[11] Source: http://energyskeptic.com/2015/wind-capacity-value-elcc/

To account for varying capacity factors at the different sites examined, we estimate the reliable winter capacity is equal to the mean annual power output. This estimate is conservative, because the winter output from a wind farm in the Yukon is higher than the mean output see Figure 40 below.

This approach is an estimate and should be confirmed based on the Yukon energy mix, taking into account system flexibility, load profiles, and specific wind farm parameters. Additional wind farms would lower the capacity credit per farm; they could also increase the ability of wind to provide base load power (firm capacity) when they are geographically distant. This separation of sites increases the probability that wind will still blow at one site when it does not at the other. The combined wind farms will provide a minimum output because the start-up wind speed is virtually always reached at one of the wind farms.

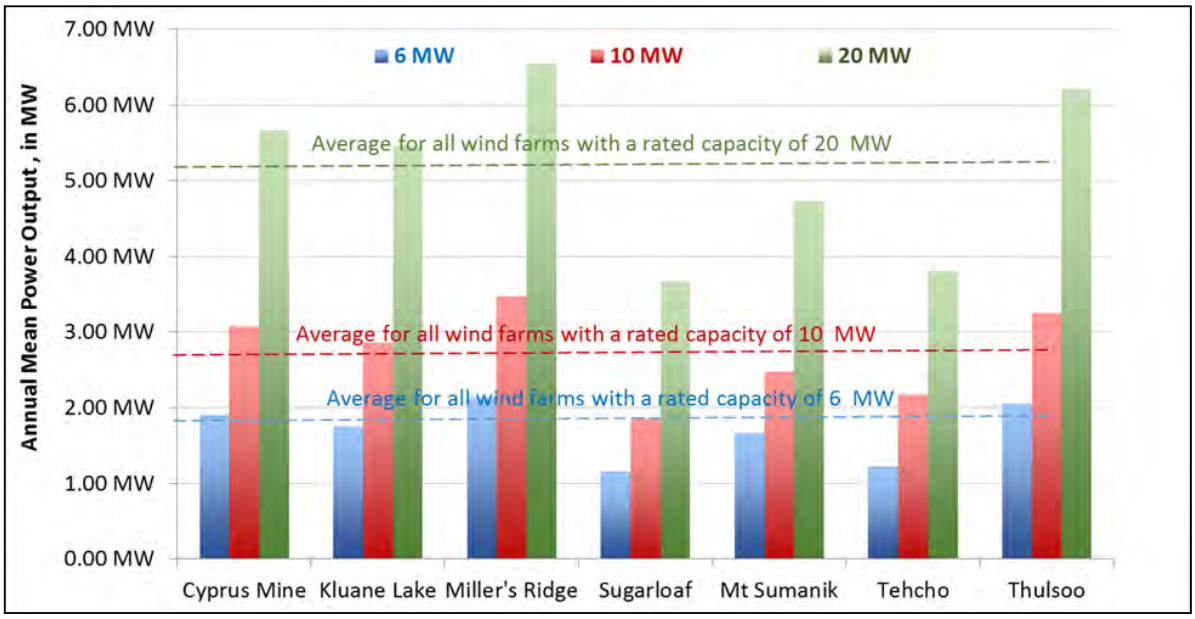
Figure 40 Seasonal Power Output and Reliable Winter Capacity of a 2.35 MW Enercon Turbine at Miller's Ridge





Applying this approach to all wind farm sizes and sites, the firm winter capacity ranges from 1.7 MW for a wind farm rated 6 MW (28% capacity factor) to 5.2 MW for a 20-MW wind farm (26% capacity factor) – see below.

Figure 41 Annual Mean Power Output taken as Reliable Winter Capacity



4.6 Turbine Choice

AWS Truepower Advanced Wind Site Assessment Reports were obtained for each of the seven selected sites. The advanced reports are designed to present an in-depth prediction of the wind resource of a site to include annual and month-specific mean wind speed, power density, Weibull dis-

tribution of wind speed, 50-year maximum gust, diurnal variation of speed and power density, and frequency and energy wind roses. The wind data in the AWS advanced reports is modelled at 80 meters above ground level, which is the hub height of the generic 2.0 MW wind turbine discussed in above and is a typical hub height of wind turbines in the approximately 2 MW class range. AWS Truepower Advanced Reports for each site can be found in Appendix I.

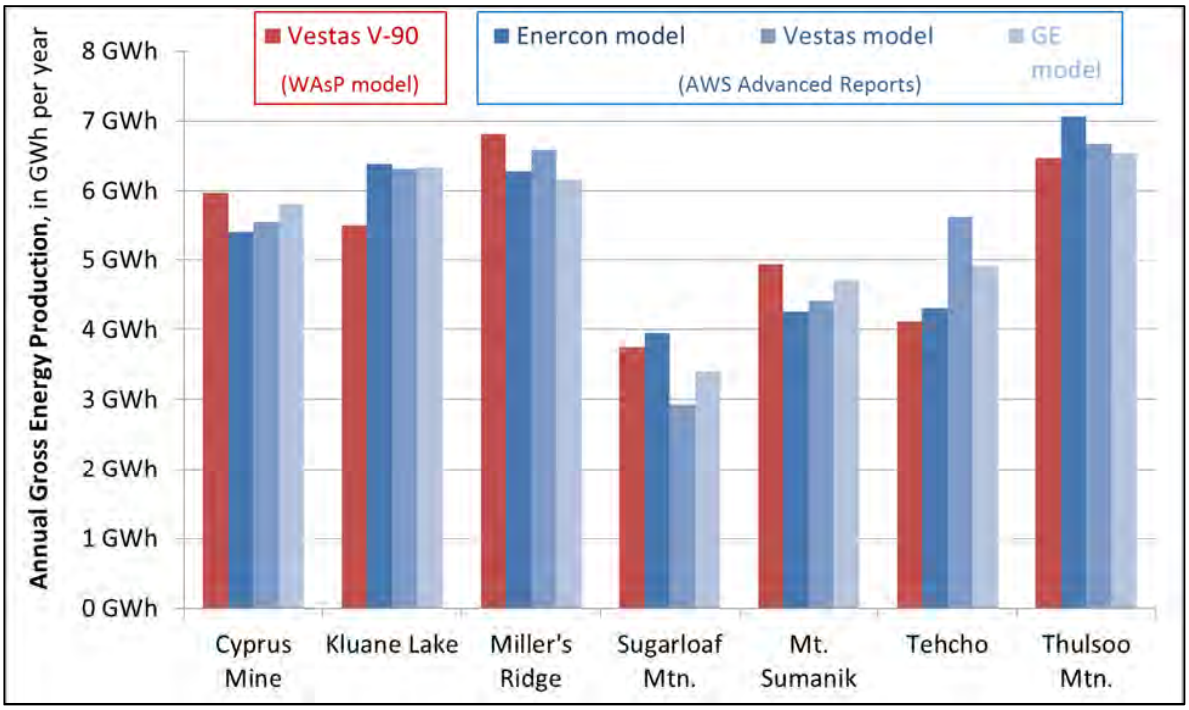
Besides a highly detailed description of the wind resource, AWS Truepower advanced reports contain annual energy production estimates for three different wind turbines selected by the user, at user-specified hub height. The project team focused on three wind turbine manufacturers: Enercon of Germany, Vestas of Denmark, and General Electric (GE) of the United States. All three are large, well-established companies with long track records of highly successful projects. For each of the seven profiled sites, an IEC wind classification was presumed based on the mean annual 80-meter height wind speed. With that, and by reference to the Enercon, Vestas, and GE websites, suitable 2 MW class wind turbine models were chosen and are listed in Table 9.

Table 9 Wind Turbines Profiled in AWS Truepower Advanced Reports

Site	Latitude	Longitude	Assumed IEC class	Enercon model	Vestas model	GE model
Cyprus Mine	62.422	-133.417	II-B	E92	V100-2.0	GE 1.7-100
Kluane Lake	61.214	-138.665	III-B	E92	V100-2.0	GE 1.7-100
Miller's Ridge	62.109	-136.568	II-B	E82 E2/2.3	V90-1.8	GE 1.85-87
Sugarloaf Mtn.	60.118	-134.642	III-B	E92	V110-2.0	GE 1.7-103
Mt. Sumanik	60.744	-135.284	III-B	E92	V100-2.0	GE 1.7-100
Tehcho	63.413	-136.677	III-B	E92	V110-2.0	GE 1.7-103
Thulsoo Mtn.	61.034	-136.932	II-B	E82 E2/2.3	V90-1.8	GE 1.85-87

With this selection AWS Truepower prepared Advanced Wind Site Assessment Reports for each of the seven sites (Appendix I). We then compared the annual gross energy output of each turbine provided in the Advanced Reports with the results of the WAsP model (Appendix G), see Figure 42 below.

Figure 42 Annual gross energy generation of various turbines using two models



For all sites, except Kluane Lake and Tehcho, the annual energy production predicted by AWS is in close agreement with the results of the WAsP model. In three out of the seven sites the Vestas V-90 turbine outperforms the best turbine of the Advanced Reports.

Table 10 Best Performing Turbine Models for each of the Seven Sites

Site	Best Turbine Model	Rated Capacity
Cyprus Mine	Vestas V-90	2.0 MW
Kluane Lake	Enercon E92	2.35 MW
Miller's Ridge	Vestas V-90	2.0 MW
Sugarloaf Mtn.	Enercon E92	2.35 MW
Mt. Sumanik	Vestas V-90	2.0 MW
Tehcho	Vestas V110-2.0	2.0 MW
Thulsoo Mtn.	Enercon E82 E2/2.3	2.35 MW

These results have to be taken with a grain of salt: A main difference in the two models is that the Advanced Reports determine the annual energy production of a turbine at only one particular location within the site. This site may not be the optimal location. WAsP, on the other hand, calculates wind speed and subsequently annual energy production at every location with the site. This allows placing turbines at the best spots. As a consequence WAsP tends to yield higher annual energy production than AWS. WAsP, on the other hand, takes the effect of the terrain's topography and turbu-

lences created by neighbouring turbines into account. In general the agreement between the two models is within 10% of each other providing sufficient confidence in the outcome.

The comparison also does not take into account the difference in low-temperature curtailment. Gearless turbines, like all Enercon models, can be operated below -30°C. For some sites, such as Tehcho this might increase output by up to 3.7% and outweigh the advantage of an optimized foil design.

Finally, the data above are annual energy productions. Seasonal energy production, e.g. from October to mid-May when electricity is most needed and when wind speeds tend to be higher favours turbines optimized for high wind speeds. Appendix H provides further detail.

In detail the following can be said about the turbine choice at each site:

- **Cyprus Mine**: The advanced report turbines and the WAsP V90 (20 MW average) are in close agreement, there is little difference between the four turbine types.
- **Kluane Lake**: Clearly, the turbines profiled in the advanced reports are more suitable for the Kluane wind regime than the Vestas V90.
- **Miller's Ridge**: Like Cyprus, the advanced report turbines and the generic turbine used for WAsP are in close agreement. The models worked well together.
- **Sugarloaf**: This site was complicated to analyze, with significant differences between the WAsP and AWS models. The close agreement of the results between the two is coincidental and masks these differences. Results for this site should therefore be regarded preliminary and would require on-site monitoring to confirm the resource.
- **Mount Sumanik**: The advanced report turbines and the WAsP V90 (20 MW average) are in close agreement. The models worked well together. That said, there are significant differences between the WAsP and AWS models.
- **Tehcho**: The turbines profiled in the advanced reports are more suitable for the Tehcho wind regime than the Vestas V90. Note though that the annual energy production of the Vestas V110 is quite a bit higher than the other two. Consultation with Vestas would be required to ensure that it is indeed a suitable choice for the site.
- **Thulsoo Mountain**: The advanced report and the WAsP V90 are in close agreement except with the Enercon E82. The other two choices are very similar. Consultation with Enercon would be required to ensure that it is indeed a suitable choice for the site.

Note that wind turbine manufacturer and model choice is a complex task and should a large wind project be developed in the Yukon, YEC is encouraged to consider not only other manufacturers besides Enercon, Vestas, and GE, but also the full suite of available models from each. It is possible, of course, that more optimal turbine choices are possible than those profiled in the AWS Truepower advanced reports.

5 FINANCIAL ANALYSIS

We conducted financial analyses for the seven sites described in the previous two chapters. The analyses are based on three main inputs:

1. Gross and net energy production of the wind farms
2. Capital cost estimates
3. Operational cost estimates

A predetermined Excel file supplied by YEC was used to determine various financial parameters. The file calculates these parameters in the same way for all energy technologies, allowing cross comparisons. The cost data feeding into the financial model were determined based on a variety of sources as outlined below, including direct quotes, expert estimates, previous studies, and experience with similar projects in remote areas.

For the financial analysis, we used the same turbines for all sites to allow for better comparability. In reality, turbine choices (brands and capacities) may vary between sites and should only be selected once one year of wind monitoring results are available.

5.1 Capital and Development Cost Estimates

We estimated capital costs for each of the seven sites and each of the three capacity sizes, 6 MW, 10 MW and 20 MW. The cost presented includes hard and soft costs, such as financing and project development costs. All costs are calculated at the point of interconnection to YEC's transmission line and in constant 2015 dollars.

Where applicable, we factored costs according to parameters determined during the layout of the wind farm as described in Chapter 3 above. Details are provided as Appendix C in the form of three Excel-files, one for each wind farm size.

The overall accuracy of these cost estimates is ± 30%, commensurate with the project definition of a pre-feasibility or screening level study (AACE Class 4). This accuracy can only be applied to the total capital cost, not individual line items.

For each site, we grouped capital costs into nine categories:

1. Logistics
2. Civil Works
3. Electrical Works
4. Labour Costs not already included in other cost items
5. Financing Costs
6. Land Costs
7. Project Development Costs
8. Equipment Costs
9. Contingencies

5.1.1 Logistics

This item summarizes all costs related to transporting the equipment to the site, including the following:

Transportation cost: $500,000 for transporting one complete turbine from the manufacturer by sea to either the Port of Skagway, Alaska,[12] or from the port of Vancouver, Oregon by train through Nelson, BC and on by truck. From the port it will take three trips per turbine by truck to transport mast, nacelle, tower, and other wind-farm-related parts, such as transformers. A 20-MW wind farm would require three trips to the site. Each trip is assumed to cost $100 per km, including empty returns. Transportation costs for a 20-MW wind farm range from $5.3 million for Kluane Lake to $6.5 million for Cyprus Mine, the farthest site from the port.

90-tonne crane for lay down etc.: A crane for taking equipment off the trucks and laying it down will be needed. A hydraulic crane of this capacity is available in Whitehorse. A lump sum of $30,000 is assumed for mobilization and de-mobilization plus $2,500 per day in the field. On average, four days are required to erect a turbine. High wind conditions may require an additional two days per turbine, for a total of six days. The total cost of the 90-tonne crane is $180,000 for a 20-MW wind farm.

550-tonne crane: A larger 550-tonne crane is required to erect the mast and lift the assembled rotors and nacelle in its location. Again, six days are assumed to erect a turbine, including idling time due to high or gusting wind conditions. This crane will have to be brought in from Edmonton at a cost of $200,000. Daily rental costs are assumed to be $15,000, whether in operation or idle. The total cost of the 550-tonne crane is $1,100,000 for a 20-MW wind farm.

Erection cost: Operating the crane and all other labour involved in the erection and installation of the complete wind turbine is budgeted at $450,000 per turbine. This is based on previous experience in remote BC and AB locations.

5.1.2 Civil Works

Construction costs include several items relating to access, site preparation, foundations, and transport of construction material such as gravel. These costs also vary based on site location, the length of the access road, and distance to Whitehorse. Additional factors can be the type of prevalent rock and the gradient to reach the site.

In general, gradients should not exceed 10% with a maximum of 14% to transport turbines by truck. Road width is five meters, the maximum road loading 70 tonnes. The minimum turning radius is 25 meters. This may require adjusting the access roads sketched out for this assessment, which may then become longer than anticipated at the prefeasibility level. It may also be necessary to use blasting to create access.

Road ways and road sides can be accurately planned using high-resolution LIDAR-derived digital elevation maps.

[12] Transport via White Pass and Highway #2 is unrestricted up to 77 tonnes (Dan Nickason, Highways & Public Works, April 2016)

Table 11 Costs of Civil Works

#	Item	Specific Cost	Comments
1.	Geo-technical report, Digital terrain model, Road way design	$75,000 total	Assume an engineer from AB or BC, some of the cost is mobilization; LIDAR map taken from flight over site
2.	Access road	250,000 $/km	From existing road to turbine road; may vary significantly according to geotechnical conditions
3.	Turbine road	250,000 $/km	Assuming gravel pit within 20 km distance
4.	Cement supply for foundation	300 m^3 per base, $575 per m^3	Mobile concrete plant
5.	Cost of rebar including delivery	35,000 kg per base, $1.5 per lb	Delivered to site
6.	Foundation installation cost	$60,000 per base, including labour	Depends on type of foundation (geo-tech conditions)

The construction of a wind farm is expected to take at least three years in the Yukon, due to the short construction season of only five months. We assume that the road would be built in one year and then the turbines would be purchased and set up in the following year. Turbine parts would be transported by truck, with two blades and two nacelles per truck.

Note that a special permit is necessary for transporting loads heavier than 77 tonnes.[13] The construction crane may weigh considerably more than this, but components such as the boom or counter weights are usually transported separately. Without these the transport weight of the crane would be 54 tonnes.

We anticipate about 90 days of construction activity to pour ten foundations for wind turbines. This concrete needs to cure for about 30 days, which means that turbine erection can start halfway into the concrete-pouring task while the last foundations are still being completed. Turbine foundations may be either anchors or concrete foundations (assumed here, and conservatively costlier than anchors). We have based our estimate on a quote for labour and material from a local construction company, resulting in costs between $475,000 to $1,029,000 per turbine, depending on the size of the wind farm.

For the access and turbine-connecting roads, we assume a cost of $250,000 per km. A local service provider quoted a budget price above $1 million per km though. This quote is, however, not in line with previous Yukon experience and is based on trucking gravel from Whitehorse. On the other hand, the need for blasting or adjusting gradients and poor geotechnical conditions may increase road construction costs at specific sites.

5.1.3 Electrical Infrastructure

The following items were considered for the cost of the electrical infrastructure:

[13] The stator/rotor of an Enercon turbine may weigh more than 80 tonnes.

Table 12 Electrical Infrastructure Costs

#	Item	Specific Costs	Comment
1.	Low voltage step-up transformers	$60,000 per piece	Per turbine 1 kV/12.47 kV step-up transformer
2.	Collection system	$200,000 per km	Underground cable
3.	Substation	$2,500,000 total	12.47 kV/138 kV step up transformer & switching yard
4.	Interconnection to existing transmission line	$500,000 per km + 17% engineering and interest	Including labour; see Table 13 for details
5.	Line-tap & protection system	$1,500,000 total	From high voltage transmission to utility tx (gang switch with fused cut-outs)

To interconnect the turbines before they are connected to the transmission line transformer (collection lines), we assumed costs of $200,000 per km, including the cost of burying cables and/or a concrete channel.

The estimate for transmission line construction (about $500,000 per km plus 17% owner's cost) is informed by the Stewart Keno project cost estimate, see Table 13 below.

Table 13 Per-Kilometre Line Construction Costs

Cost Item	Yukon, Stewart Keno Project Estimate
Material, labour & line	$366,882
Contingency & Escalation	$67,632
Project management	$51,312
Other	$12,684
Sub-total	**$498,510**
Owner's cost (17%)	$84,747
TOTAL	**$583,257**

In addition to transmission line construction, a protective switch (line-tap & protection system from high voltage to utility transmission) needs to be installed at the interconnection with existing long-distance transmission. We ascribed this cost to transmission cost and budgeted $1.5 million. Transformers ($600,000 per wind farm) were considered part of the wind farm capital cost and are thus are not included in the transmission costs.

Total interconnection cost range from $3.5 million for Tehcho to $9.4 million for Miller's Ridge. Land costs are not included and are given in Table 14 below.

5.1.4 Labour Costs

Much of the labour cost has been included in the estimated above, e.g. for road and transmission construction. Additional labour costs for personnel involved in turbine erection and other tasks above and beyond what is already accounted for are estimated at 10-person-years per site and 1 person-year per turbine. We assumed labour costs of $200,000 per person-year including over-

head, but excluding per diem. The latter adds $150 per day per person for 250 days of construction over a two-year period. Again it is assumed that most of these personnel will come from outside the Territory or will be too far from their homes and therefore require accommodation.

5.1.5 Financing Costs

Legal costs to arrange financing are estimated at $800,000, independent of the size of the project. Additionally, we budgeted bank financing costs or lender charges at 1.5% of capital cost, i.e. around $1 million for a 20 MW farm. These are charges leveraged by credit institutions to cover for the administrative costs of arranging for a loan.

5.1.6 Land Costs

We have estimated land costs based on the surface area required for both the wind farm and road and transmission access, for each of the seven sites as laid down in Chapter 3.8 above. For land without existing ownership as per the GeoYukon site, we assume the land will be purchased at a rate of $500 per acre.[14] At this rate, costs range between $60,000 and $230,000, less than 1% of the total cost.

For turbines, roads and/or transmission lines on First Nation land we assume land will be leased. Annual leasing rates for First Nation land are assumed as 10% of purchasing costs, and are not included here but under operational costs in Chapter 5.2.

Total land area to be acquired, including access roads and easement for power lines, range between 76 ha (Kluane Lake) and 189 ha (Miller's Ridge) for a 20 MW farm, see Table 14 below. Land for Kluane Lake and Sugarloaf Mountain will have to be leased. A developer may want to rent enough land to set up the turbines for the initial three years of the project and then purchase only the land required by the turbines.

Table 14 Land Costs for a 20 MW wind farm

Site	Total road length	Total power line length	Land area	Land price	Land Cost
Cyprus Mine	13.4 km	16.2 km	146 ha	$2,000 /acre	$703,956
Kluane Lake	2.0 km	6.2 km	76 ha	$2,500 /acre	Lease only
Miller's Ridge	8.3 km	21.8 km	189 ha	$2,000 /acre	$913,294
Sugarloaf Mountain	6.8 km	10.6 km	74 ha	$2,500 /acre	Lease only
Sumanik	7.5 km	10.7 km	99 ha	$2,500 /acre	$596,511
Tehcho	7.4 km	10.8 km	69 ha	$2,000 /acre	$332,088
Thulsoo Mountain	8.5 km	19.2 km	178 ha	$2,000 /acre	$860,283

[14] YEC paid up to $2,000 per acre for the development of the Mayo B plant area in 2010. According to the YUKON AGRICULTURE STATE OF THE INDUSTRY REPORT 2010–2011–2012, titled agricultural lands within 30 minutes from Whitehorse have been valued at over $3,000 per acre while land located 30 to 60 minutes from Whitehorse has been valued at around $2,500 per acre.

5.1.7 Development Costs

We budgeted eight items for the development of a wind energy project. Development costs presented include all aspect of project development. Table 15 itemizes individual items.

Development costs are estimated at $1.9 million. This also includes wind monitoring,[15] bird/bat studies, stakeholder relations and internal personnel costs.

Development costs are a fixed cost and are the same for a 6 MW wind farm as for a 20 MW wind farm.

Table 15 Development Costs (2015 $)

#	Item	Cost	Comments
1.	Wind measurement campaign	$200,000	LIDAR equipment lease or Met-tower purchase, installation & operation
2.	Environmental assessment (incl. FN consultation)	$300,000	Bird/bat studies
3.	Stakeholder relations	$100,000	Open houses, etc.
4.	Engineering	$300,000	For logistics, construction layout, interconnection studies, turbine supply
5.	Legal fees (various)	$500,000	Leases/land agreements, FN joint agreement, construction contracts, project equity
6.	Legal fees for turbine supply agreement	$250,000	Sales contract
7.	Legal fees for stakeholder relations	$50,000	Appeals, tribunals
8.	Development personnel and travel	$200,000	Owner's cost / YEC staff
	TOTAL	**$1,900,000**	

5.1.8 Equipment Costs

Wind turbine costs for the Vestas V-90 2.0 MW turbine, including de-icing kits, are estimated as $1.2 million per MW, delivered-duty-paid (DDP). A comparable Enercon turbine would be $1.3 million per MW but would likely have less curtailment and lower maintenance costs. Higher up-front capital costs would be traded for lower operational costs. This option, however, has not been modelled but should be researched during the next phase of the project.

5.1.9 Contingencies

10% contingency is included in the capital cost estimate. This includes the risk of currency fluctuations.

[15] To develop a wind site in the Yukon, both wind monitoring and icing monitoring are necessary. The report on Ferry Hill (Tehcho) estimates costs of about $200,000 for the wind monitoring mast with icing detector, as well as annual costs of about $25,000 for a generator and cell phone connection.

5.1.10 Total Capital and Development Costs

Figure 43 compares the capital costs of each of the seven wind farm sites selected for this assessment. Land and development costs are small items compared to equipment costs, transmission (electrical), and labour required for wind farm construction. Road costs are included in civil works, together with the turbine foundations, but are not among the most significant cost items.

Most of the larger cost items are fairly well established based on past experience with wind farms. As such, it appears that currency exchange risk is the most important factor that could affect wind farm construction costs, since it may affect equipment costs and also much of the labour cost anticipated. Site-specific differences, such as more expensive road construction, would not by themselves have a major impact on overall capital costs. Capital costs for the seven sites range from $3.0 million to $3.6 million per MW of rated capacity and are within a 20% margin of each other.

As Figure 44 shows, less than one-third of the total capital expense is for the turbine equipment itself. Most of the money will be spent in the Yukon. Kluane Lake would be the cheapest to develop as it would be right next to a planned transmission line.

Figure 43 Capital and Development Costs of the Seven 20 MW Wind Farm Sites

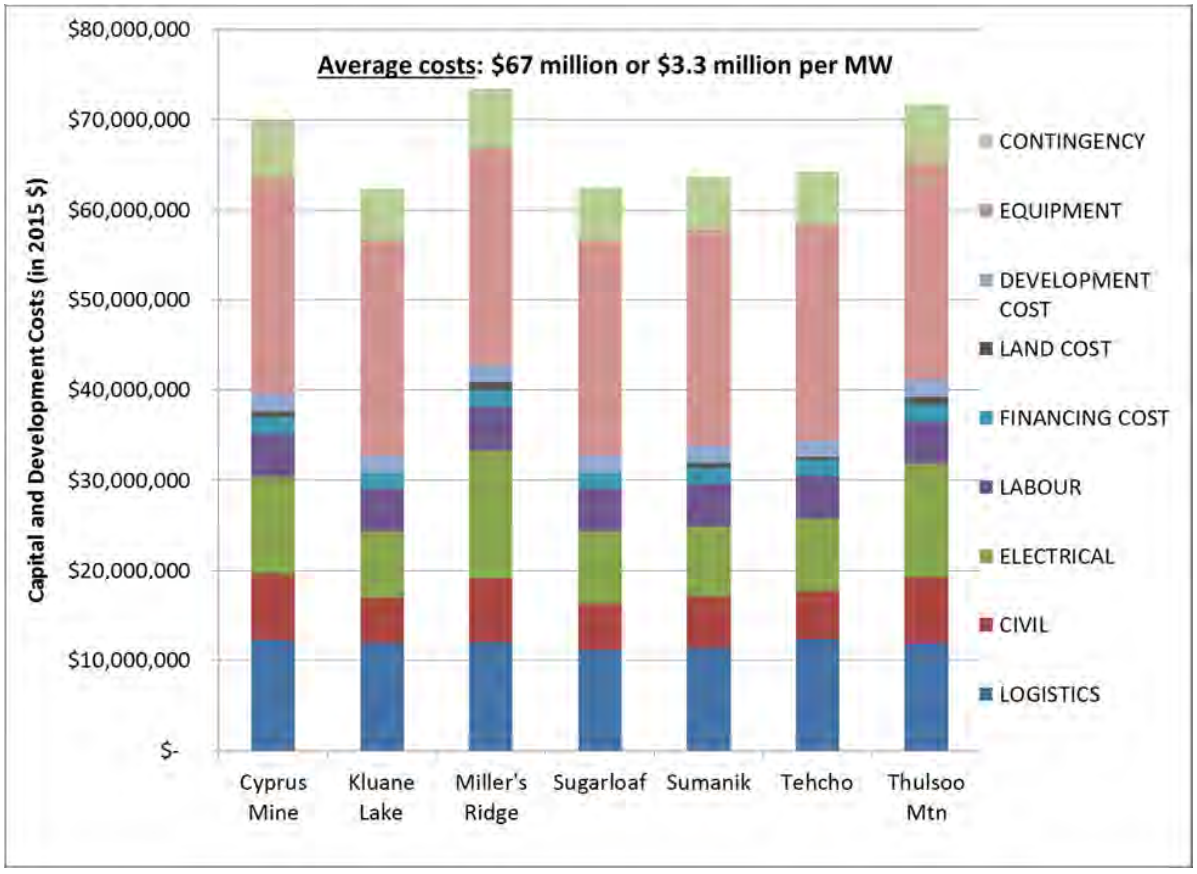


Figure 44 Capital and Development Costs of a 20 MW Wind Farm at Miller's Ridge

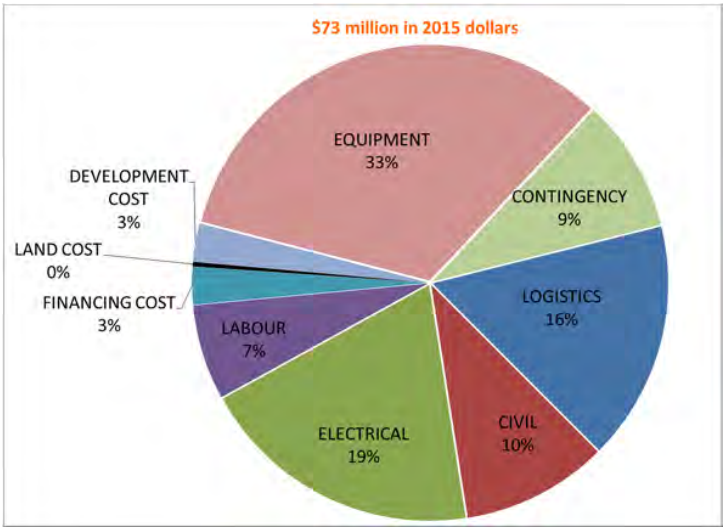
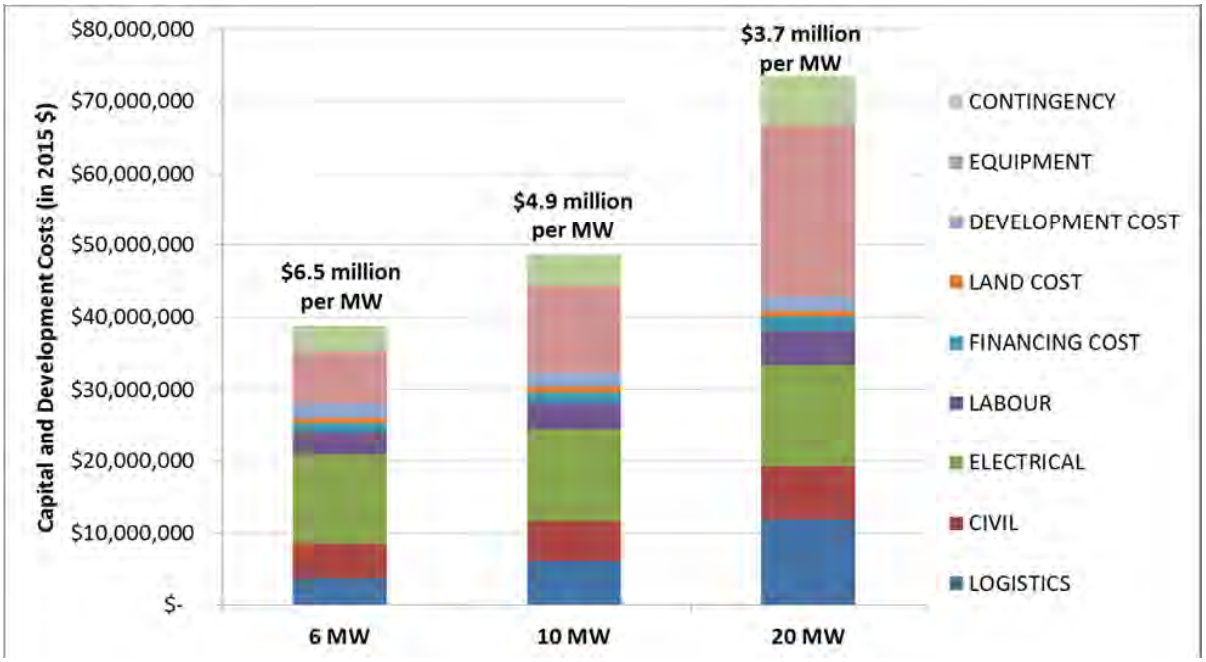


Figure 45 compares the capital cost items for three different wind farm sizes for Miller's Ridge. Since development costs and much of the electrical costs (transmission line) are fixed, their proportion of the capital costs increases as the farm size decreases. Equipment costs are an average of 33% for the 20-MW wind farms, 25% for a 10-MW size and only 20% for the 6-MW wind farms. For this site, the specific capital costs increase from $3.6 million per MW for a 20-MW wind farm to $4.8 million for a 10-MW farm and $6.5 million for a 6-MW wind farm.

Figure 45 Capital and Development Costs of Three Sizes of Wind Farms at Miller's Ridge



5.2 Operational Costs Estimate

5.2.1 Fixed Operational Costs

YEC would have to employ two technicians to be working out of an office near any of the planned wind farms for small maintenance and troubleshooting and other operational purposes. Most sites are within about 200 km from Whitehorse, and the Tehcho farm would likely be serviced out of the existing Mayo office. We therefore assume $60,000 annual office rental costs only for the Cyprus Hill and Kluane sites. The salaries of these technicians have been considered at a cost of $100,000 per year, per person. Other fixed costs include:

- For turbines on aboriginal land, we assume the land will be leased at a cost of 10% of the theoretical purchasing price of $2,500 per acre. [14]
- Insurance costs are estimated at 0.15% of capital costs.
- There is a cost per turbine for its own electricity consumption (mainly for de-icing, some for lighting) but we accounted for this by reducing net output due to icing losses.

We further assume that no property taxes will have to be paid as none of the sites examined lie within municipal administrative borders.

Table 16 Fixed Operational Costs (2015$)

#	Item	Specific Cost	Annual Costs
1.	Operators	Two staff per wind farm	$200,000
2.	Office	$5,000 per month, (only for sites too far from existing YEC offices)	$60,000
3.	Insurance	$0.15 per $100 of CAPEX	$90,000 to $107,000 for 20-MW farm
4.	Land lease	10% of $2,500 per acre = $603/ha [14]	$46,000 (Kluane) to $45,000 (Sugar-loaf) for 20-MW farm

5.2.2 Variable Operational Costs

Wind turbine manufacturers offer service contracts that are calculated based on turbine output. For the Vestas V-90, annual service contracting costs of $15/MWh are assumed. This cost only applies to the first five years, increasing to $25/MWh until year 10, then to $30 after that.[16] This cost would include gearbox replacements every seven years (the Vestas turbine is not gearless; gearless turbines are discussed in Section 4.6).

In addition, royalties will have to be paid for turbines on aboriginal land. We assume that 5% of wind farm revenue would be paid to aboriginal landowners. Revenue is based on net energy output and valued at $120 per MWh, similar to retail electricity prices). We also applied a 5% contingency to variable costs.

[16] Enercon has lower rates that only increase once, after 10 years. This has not been modelled.

Table 17 Operational Costs for a 20 MW Wind Farm (annual, Year 1 -5)

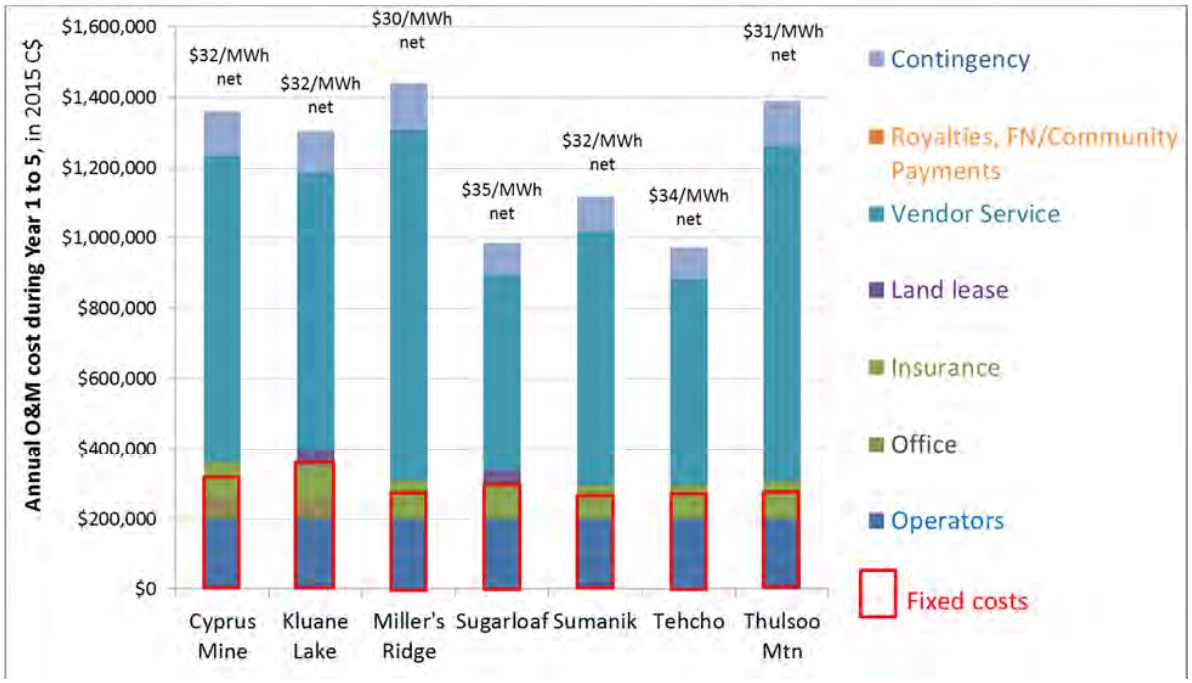
Site	Fixed Costs				Variable Costs		
	Office costs	Operators	Land lease	Insurance	Contin-gency	Royalties	Vendor Service*
Cyprus Mine	$60,000	$200,000		$104,018	$123,661	$0	$871,725
Kluane Lake	$60,000	$200,000	$45,858	$93,560	$118,777	$0	$788,355
Miller's Ridge	n/a	$200,000		$110,238	$131,093	$0	$1,000,695
Sugarloaf	n/a	$200,000	$44,573	$93,649	$89,487	$0	$556,650
Sumanik	n/a	$200,000		$95,476	$101,743	$0	$721,950
Tehcho	n/a	$200,000		$96,460	$88,374	$0	$587,280
Thulsoo Mtn	n/a	$200,000		$107,556	$126,361	$0	$956,055

Note: Sites in *italics* are on aboriginal land; assumes land lease; * Service contracts are based on turbine gross output

The largest share of the O&M costs are the vendor service contract: For a 20 MW turbine 55% of the operational costs are spent on getting the turbines regularly serviced and parts replaced by trained technicians. Because service contracts are based on energy generated, YEC may consider shutting the turbines down during the summer period when no power is required.

Figure 46 illustrates the magnitude of the individual O&M costs.

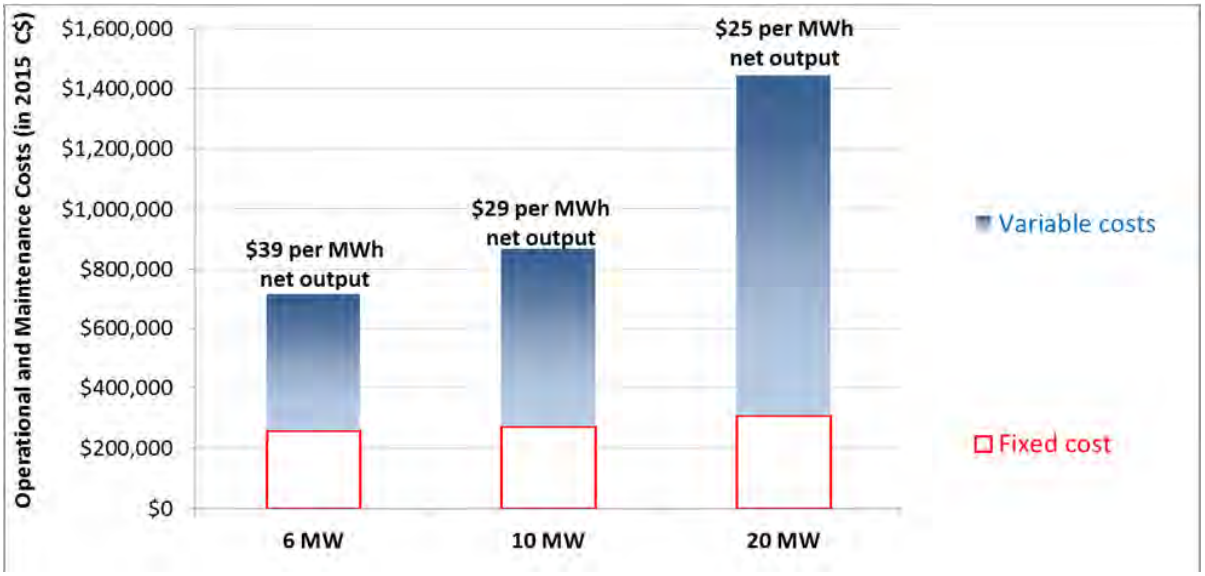
Figure 46 Operation and Maintenance Costs of a 20 MW Wind Farms at the Seven Sites



Operational costs were very similar for each site: fixed costs $265,000 for a 20 MW wind farm to $317,000 per year for a 6 MW wind farm and variable costs of about $24/MWh for all sizes of wind farms. Sugarloaf and Tehcho have low capacity factors (based on net production after losses due to icing, maintenance, etc.), which explain their lower financial performance.

Because the bulk of O&M costs are variable, there is only a small reduction of O&M cost from building larger-size wind farms. Figure 47 illustrates this.

Figure 47 Operation and Maintenance Costs of Three Wind Farms Sizes at Miller's Ridge



5.3 Financial Modelling

Table 18 summarizes the economic modelling results for each site. More detailed results can be found in Appendix D. The values below are based on a real weighted average cost of capital (WACC) of 3.38%. Two more cases (4.61 and 8.82%) can be found in the appendix. The lifetime of each of the wind farms is assumed to be 25 years.

At 3.38% WACC, the levelized cost of energy (at full utilisation, i.e. no curtailment) at almost all sites and all sizes remains under the current Yukon standard offer price of 21¢/kWh [17] but above the residential rate of 12¢/kWh [18] , see the Table 18 and Figure 48 below. For some sites the self-generation costs, the levelized cost of energy, is as low as 12.5¢/kWh. This is not as good as some more southern wind farms, which may produce at between 8 and 10¢/kWh, but highlights the good wind regime at some Yukon sites.

Of the seven sites selected, five show above-average performance in terms of the cost of energy produced. These sites are, in the order of performance, Kluane Lake, Miller's Ridge near Carmacks,

[17] Yukon Energy Mines and Resources: „ENERGY STRATEGY FOR YUKON - Independent Power Production Policy" May 20, 2014, page 7
[18] YEC's Residential Rate Schedule 1160 (Hydro, Non-Government) in May 2016: 12.14 ¢ per kWh for the first 1,000 kWh.

Thulsoo Mountain near the Aishihik hydroelectric facility, a mountain ridge near Cyprus Mine, close to Faro, and Mt. Sumanik near Whitehorse. On the other hand, we notice that both Sugarloaf Mountain and Tehcho have lower performance than the remaining sites, with Kluane Lake and Miller's Ridge showing the best financial performance. There is some, but not a lot of difference in energy production cost between these five sites; non-monetary factors may play an important role in selecting the preferred location.

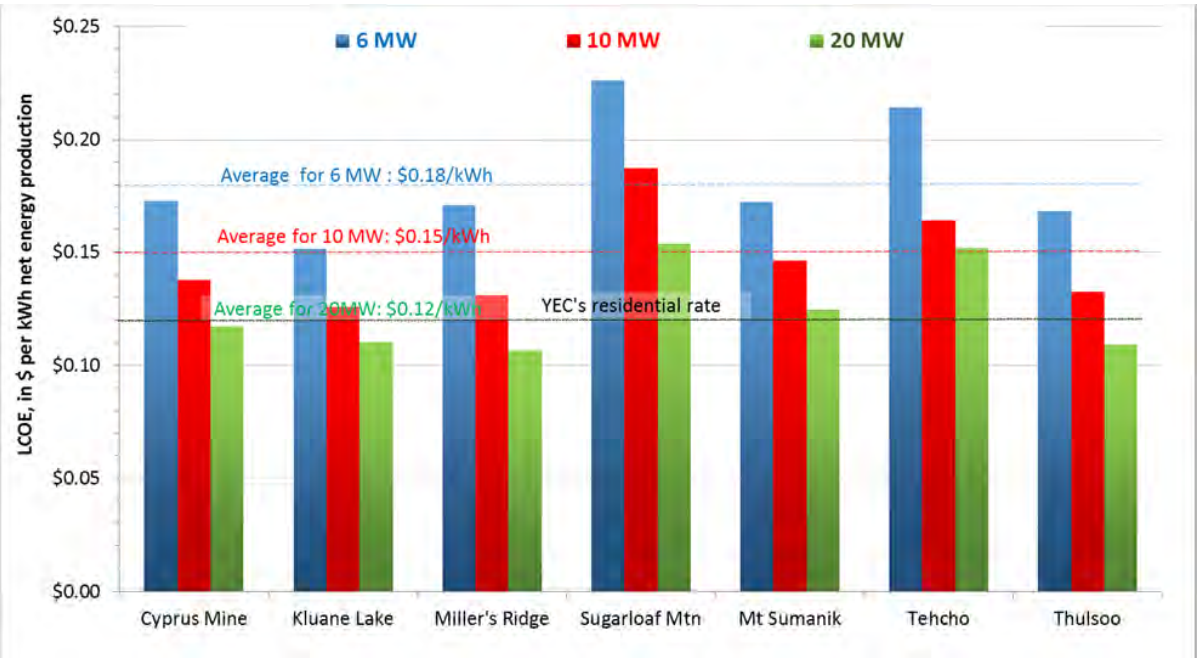
Table 18 Financial Modelling Results

Site	6 MW		10 MW		20 MW	
	Capital Cost (million $)	Levelized Cost of Energy *	Capital Cost (million $)	Levelized Cost of Energy *	Capital Cost (million $)	Levelized Cost of Energy *
Cyprus Mine	34	17.3¢/kWh	44	13.8¢/kWh	69	11.7¢/kWh
Kluane Lake	26	15.1¢/kWh	36	12.6¢/kWh	62	11.0¢/kWh
Miller's Ridge	39	17.1¢/kWh	49	13.1¢/kWh	73	10.7¢/kWh
Sugarloaf Mountain	28	22.6¢/kWh	38	18.7¢/kWh	62	15.3¢/kWh
Mt. Sumanik	30	17.2¢/kWh	39	14.6¢/kWh	64	12.4¢/kWh
Tehcho (Ferry Hill)	28	21.4¢/kWh	39	16.4¢/kWh	64	15.1¢/kWh
Thulsoo Mountain	36	16.8¢/kWh	46	13.2¢/kWh	72	10.9¢/kWh
Average	**32**	**18.2¢/kWh**	**42**	**14.6¢/kWh**	**67**	**12.5¢/kWh**

** at 3.38% real weighted average cost of capital (WACC), 25 years life expectancy, no curtailment*

Financially, the site at Kluane Lake performs best of all seven sites, despite its mediocre wind resources. This can be explained by the very short transmission connection required once the new line is built. Also, less rime icing and less frequent low temperature curtailment helps to increase the net energy generation. Though there are plans, currently there is no transmission line at this site.

Figure 48: Levelized Cost of Energy (LCOE) by Site and Wind Farm Size at 3.38% Real WACC



Due to fixed costs and economies of scale, larger wind farms have lower energy production costs than smaller ones. The cost of energy at the seven sites averages 13 ¢/kWh for a 20-MW wind farm, but increases to 18 ¢/kWh for a 6-MW capacity, see the table below. Our modelling assumes that all energy produced will be used. Curtailment of the operation during the summer when YEC has a surplus of power would increase the cost of energy produced during the rest of the year by more than a third.

5.4 Sensitivity Analyses

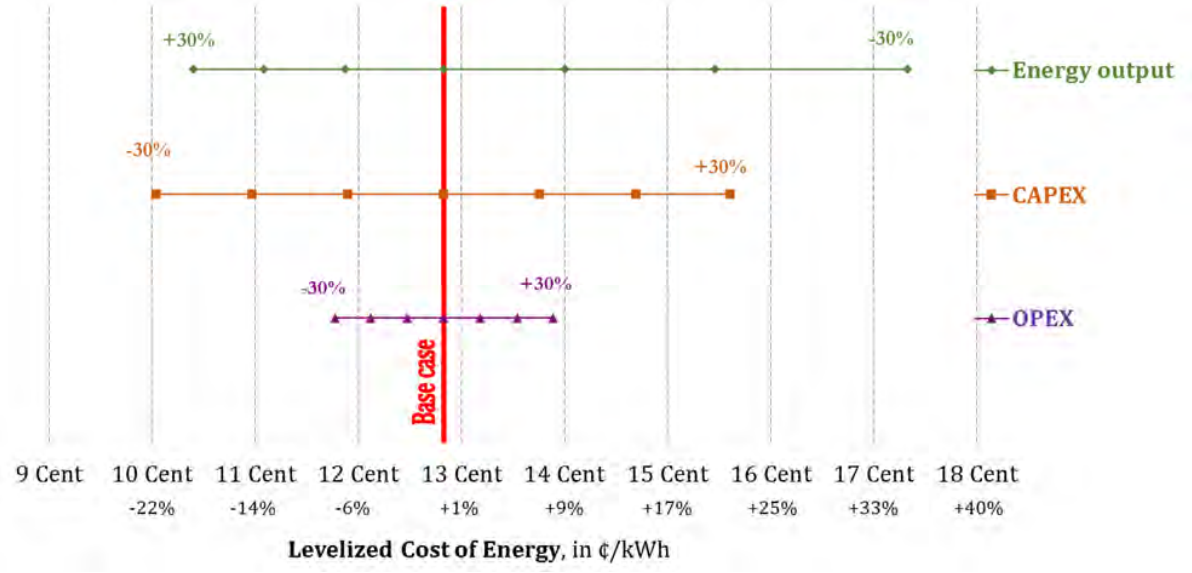
The data above are based on the given assumptions and naturally contain errors. We estimate the margin of error as ±30% for each of the three main inputs: energy production, capital costs and operational costs.

We conducted a sensitivity analysis on key variables affecting the financial results. This involved recalculating the cost of energy (LCOE) for different values of the energy production, capital costs and operational costs. Varying these input parameters, one at a time, by as much as +30% to -30% of the original value, we noted the change in the financial evaluation. The impact of the parameters on the cost of energy is illustrated in the graph below for a 10-MW wind farm at Kluane Lake. The results of the sensitivity analysis for the 20 MW wind farm at Miller's Ridge were comparable. Other sites are likely to show a similar sensitivity.

The results indicate that the project is most sensitive to the forecasted energy production. Assuming a 30% lower net energy production than forecasted would result in energy costs (LCOE) of 16.8 cents per kWh rather than the 12.5 cents determined in the base case. 30% higher operational costs, on the other hand would only increase the cost of energy to 13.5 cents per kWh. A 30% error

in capital costs would yield a 22% error in energy costs. All numbers use weighted average cost of capital (WCAA) of 3.38%.

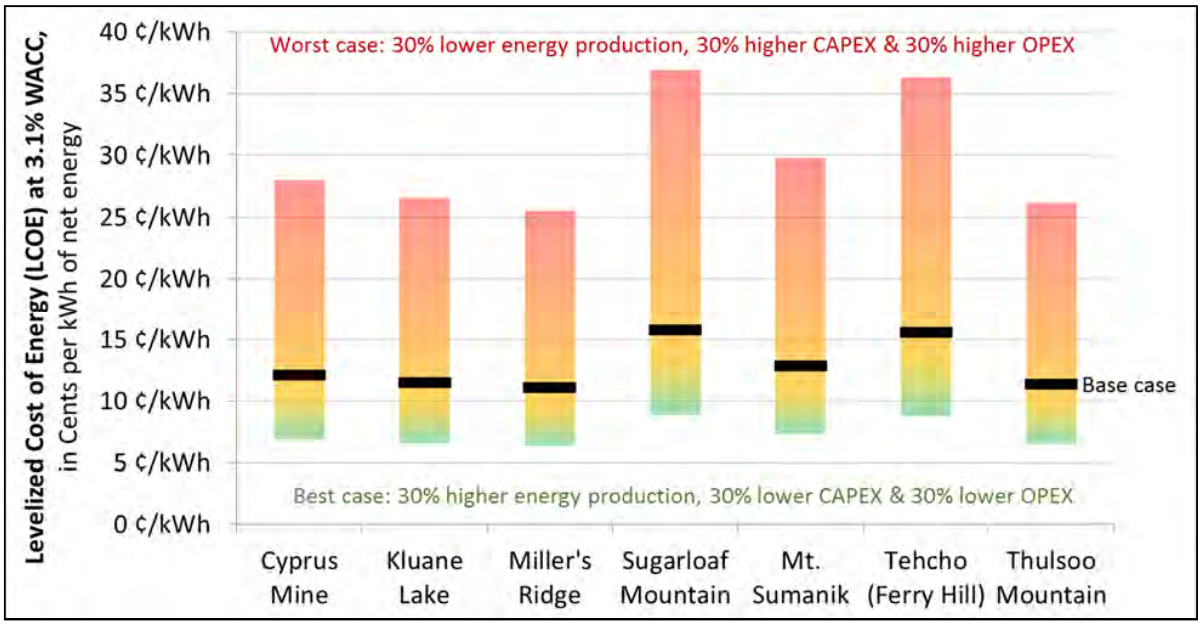
Figure 49 Sensitivity of the Cost of Energy (LCOE) of a 10 MW Wind Farm Size at Kluane Lake at 3.38% Real WACC



This underlines the importance of monitoring wind speed, rime icing, and temperature at selected sites. These are key parameters that will determine the output of a generator and thereby the financial performance of the wind farm.

Because the margin of error is 30% for each of the three main input parameters, a worst-case scenario would be 30% lower annual energy generation and 30% higher capital and 30% higher operational costs then determined in the base case. Conversely, a best-case scenario would be 30% higher energy production and 30% lower capital and operational costs. The resulting margin of error of the cost of energy is + 75%/-43% and is illustrated in Figure 50 below. Further project definition is needed to reduce the error margin.

Figure 50 Margin of Error of the Cost of Energy (LCOE) of the 20 MW Wind Farms



6 ADDITIONAL INFORMATION

6.1 Ice Mitigation Review

Rime icing of concern for wind power forms when small, wind-driven, super-cooled water droplets in clouds rapidly freeze on contact with a surface at sub-freezing temperatures. This often occurs during winter on high elevation mountains and ridges exposed to humid, maritime climate-influenced winds. At sub-arctic latitudes such as in the Yukon, rime icing conditions occur at lower elevations and are of longer seasonal duration than at temperate latitudes.

Figure 51 Rime Icing on Guy Wire of Collapsed Met Tower in Alaska

The frozen droplets contain a mixture of ice and trapped air, are rough surfaced and crystalline in structure, and are opaque to semi-transparent (see Figure 51). Rime ice can be heavy and quite tenacious in its grip on the contact surface and to itself, which can lead to a tremendous accumulation of weight. Rime ice accumulation on the wings, propellers and/or engine nacelles of aircraft has resulted in many aviation fatalities and explains why commercial aircraft are often carefully de-iced (and coated with an anti-icing solution) prior to take-off during the winter when atmospheric icing conditions are anticipated.

Wind turbine rotor blades are rotating airfoils, and can accumulate rime ice on the leading edges during icing conditions. In contrast to an aircraft which flies through an icing risk zone relatively quickly, a wind turbine is fixed in place and for energy production reasons, especially in higher-latitude, mountainous terrain, must be located at sites with considerable environmental rime icing risk. Rime icing adversely affects wind turbine performance in three ways:

- Ice accumulation on the leading edges of the rotor blades reduce aerodynamic efficiency and spoil lift,
- Asymmetric accumulation of ice on the rotor blades leads to vibration and subsequent shutdown,
- Ice accumulation on control sensors results in erroneous control functions, such as maintaining the turbine in shut-down mode even with sufficient wind for energy production.

A number of wind-power studies and journal articles address Yukon icing potential for wind power operations. These papers proved very helpful to the project team for consideration of icing risks and anticipated energy production cost in the Yukon. They include:

- Maissan, John, *Wind Power Development in Sub-Arctic Conditions with Severe Rime Icing*, Circumpolar Climate Change Summit and Exposition, March 2001
- Pinard, Jean-Paul, *Wind Climate in the Whitehorse Area*, Arctic, September 2007
- Pinard, Jean-Paul, *Wind Climate in Yukon Mountainous Terrain*, PhD thesis, University of Alberta, 2008.
- Green, Mark, *Ferry Hill Wind Feasibility Study*: Stage 1, Tasks 1, 2 & 3, Natural Power, September 2010
- *Mt. Sumanik Wind Assessment and Feasibility Study*, AECOM, March 2011
- Maissan, John, *Wind Development in Yukon*, presentation to Yukon Energy wind workshop, March 2013

A number of more recent reports and studies reference a paper presented by Bengt Tammelin and Henry Seifert, *Large Wind Turbines go into Cold Climate Regions,* presented at European Wind Energy Conference 2001 in Copenhagen. This paper notes that at particularly severe rime icing sites, annual energy production losses may range from 20 to 50 percent without de-icing and/or anti-icing features, especially if the turbine is not operated during winter when icing conditions are expected (Figure 52). Note that de-icing refers to active or passive removal of ice from rotor blades while anti-icing refers to prevention or mitigation of ice accumulation.

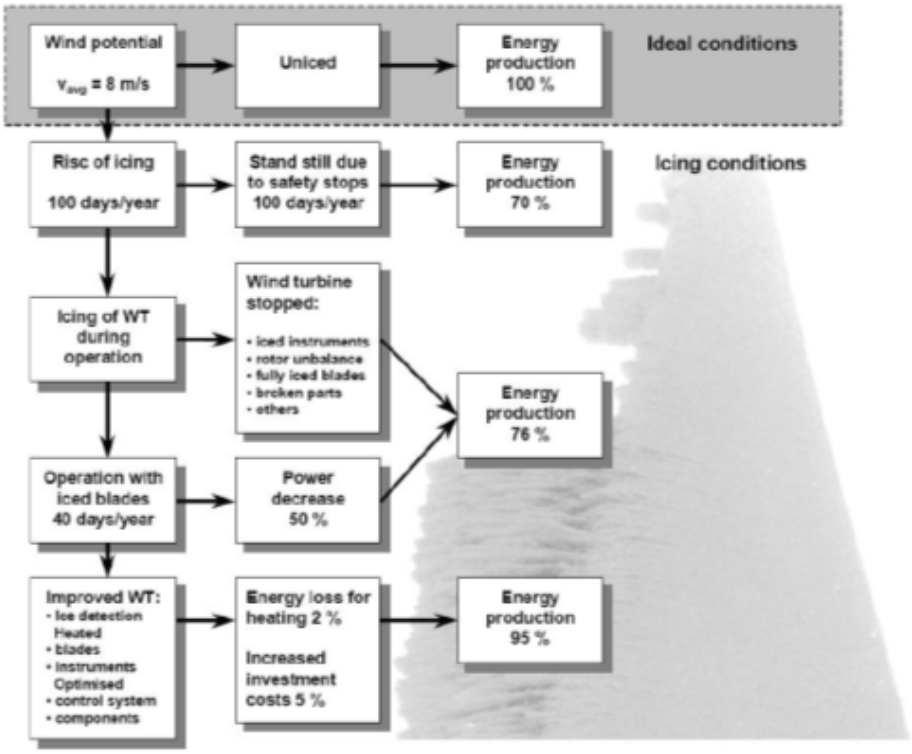
With continued reference to Figure 52, energy production loss decreases somewhat, but nevertheless remains substantial, if wind turbines operate during winter but are shut down during bad icing conditions (instrumentation ice-up, rotor imbalance, power output/wind speed mismatch, etc.). Last, energy loss due to icing can be maintained at acceptable levels with de-icing and anti-icing mitigation measures. These measures come at a cost though in terms of capital expense, energy usage for de-ice heating, and operator involvement to operate ice mitigation systems.

With reference to John Maissan's 2013 Yukon Energy wind workshop presentation and based on YEC's own experience with the two Haeckel Hill wind turbines near Whitehorse, all high elevation sites in the Yukon are at risk of substantial winter energy production loss due to rime icing conditions without mitigation measures. This is the inherent nature of high latitude, mountainous environments exposed to maritime climate-influenced storms.

Rime icing mitigation can be separated into two distinct measures: anti-icing and de-icing. Anti-icing includes heated turbine control instrumentation (this is absolutely critical), software to detect mild icing conditions (power output vs. wind speed mismatch) and retaining the operational status of the turbine as long as there is no rotor imbalance, as well as the use of black hydrophobic blades to allow for passive de-icing. Passive de-icing aside, active de-icing includes direct measures to rid the rotor blades of ice. Primary methods to achieve this are leading edge resistive heaters and internal blade air heating. Both methods have proven effective with wind turbines in North America and Europe, but these methods are not automatic; they require operator involvement and control.

Naturally, there are benefits and costs for any ice-mitigation measure and inclusion of features where not necessary, or where icing is infrequent, would be wasteful. Conversely, exclusion of ice mitigation measures where necessary could be very costly with potentially significant energy production loss due to icing conditions.

Figure 52 Illustration from Tammelin and Seifert, 2001



Naturally, there are benefits and costs for any ice-mitigation measure and inclusion of features where not necessary, or where icing is infrequent, would be wasteful. Conversely, exclusion of ice mitigation measures where necessary could be very costly with potentially significant energy production loss due to icing conditions.

Of the seven potential projects sites profiled in this report, only Kluane Lake is relatively low elevation and likely largely free of significant rime icing potential. Kluane Lake aside, significant rime ice mitigation investment will be necessary for successful wind turbine operations during the all-important winter season when YEC's hydropower resources are less productive. For the remaining six higher-elevation, mountainous sites, anti-icing and de-icing (passive and active) are recommended[19] unless site-specific met tower or Lidar data and modelling prove they would not be necessary, or are not cost effective.

Atmospheric rime icing and wind turbine icing mitigation are complex topics and a truly comprehensive analysis for Yukon wind energy production is beyond the scope of this project. Besides the papers and reports already mentioned in this section, the reader is urged to consult the following additional sources for papers, presentations, and background information. Beyond that, prospective wind turbine site wind data that includes direct or inferred ice detection is highly recommended.

Also recommended is participation in Winterwind International Wind Energy Conference, sponsored by the Swedish Windpower Association and held annually – typically in February – in Swe-

[19] Note that Enercon sells all its turbines in Canada with de-icing kits.

den, and the recently-organized Optimizing Wind Farms in Cold Climate conference, most recently held in Helsinki, Finland in December 2015.

Recommended Reading:

- Lasko, Timo et al, *State-of-the-art of Wind Energy in Cold Climates*, VTT Working Papers 152, October 2010
- Tammelin, Bengt and Seifert, Henry, *Large Wind Turbines go into Cold Climate Regions,* paper presented at European Wind Energy Conference, Copenhagen, Denmark, 2001
- Winterwind 2016 conference presentations: http://winterwind.se/program/presentations-2016/
- Winterwind, previous conferences (navigate to find presentations): http://winterwind.se/previous-conferences/

6.2 Birds and Parks

For any wind farm, a detailed bird and bat impact study needs to be completed. For this assessment, we have merely reviewed a few key sites of interest to highlight potential conflicts with wildlife and parks.

Three major migration routes through the Yukon are identified on birdnature.com:

1. The *Pacific Flyway (*gulls, ducks and other water birds*)* leads from the delta of the Yukon River in Alaska through the southern area of the Yukon (Dawson and Whitehorse) into BC and then the US and Mexico.
2. The *Central Flyway* uses two parallel routes from Alaska through the Yukon and BC/Alberta into the central US.
3. The *Mississippi Flyway* (ducks, geese, shorebirds, blackbirds, sparrows, warbler and thrushes,) stretches all the way from Alaska to the Mississippi Delta, passing by the northern end of the Rocky Mountains and crossing the Prairies.

Many of the birds will fly through the Tintina Trench,[20] which crosses the Yukon diagonally from the southeast to the northwest and lies further north than most of the proposed wind sites. The Trench crosses the Campbell Region in the south-central Yukon, close to the Ross River sites and also along Tehcho and Willow Hill. The area is known as one of the best migration observation sites in the Yukon.[21] No major concerns may exist as the birds usually migrate through the middle of the trench and not along the higher elevations to the side where potential sites were identified.

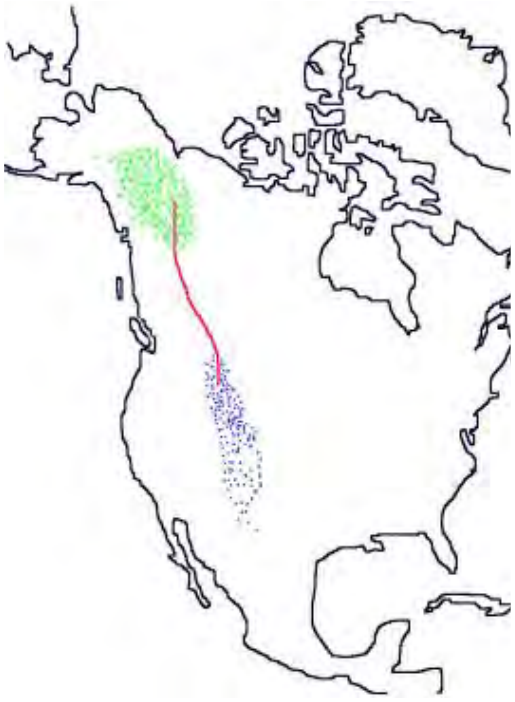
[20] http://sightsandsites.ca/central/site/tintina-trench
[21] A BIrder's Checklist of the Faro and Ross River Region. Yukon Environment, 2003

Further south lies the Shakwak trench, which is also a bird migration pathway. The Shakwak Trench is between eight and 12 km wide and stretches from the southern end of Kluane Lake towards Haines Junction. The Paint and Hard Time Mountain sites are close to this pathway, and the Kluane Lake sites are situated towards its end.

A birdwatching area is situated in the vicinity of the Minto Hill and Sugarloaf Mountain sites, at Tagish Bridge Recreation Site.[22] In the same general area, the Swan Haven Interpretive Centre, about 45 km south of Whitehorse, is located on the shores of M'Clintock Bay on Marsh Lake, YT. This area is one of the first areas of open water every spring and, combined with a delta formed by the M'Clintock River, creates a rich foraging area attracting swans, geese, ducks, gulls, and shorebirds in the spring. At the northern end of Marsh Lake lies the Lewes River Marsh, which is likewise important bird habitat. The turbine sites do, however, appear to be far enough from these sensitive areas.

The Anticline Mountain site lies in the same area as the Aishihik Lake Campground, which is a habitat for waterfowl. Again, the site is somewhat removed from the lake so as to avoid impacts on birds.

Figure 53 Eagle Migration Zones

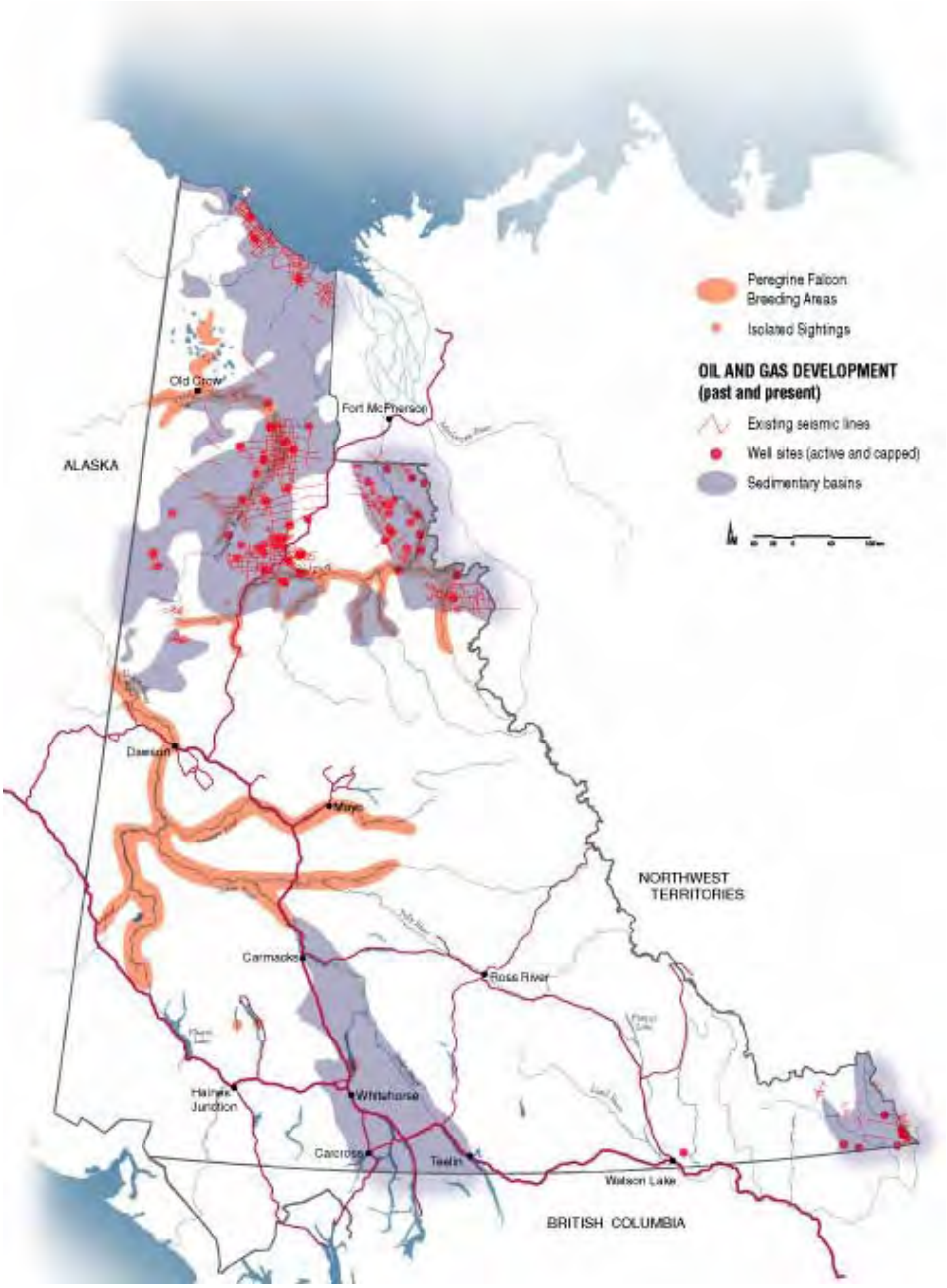


Source: http://eaglewatch.ca/wp/wp-content/uploads/2013/04/migration-sites-ab_1.jpg

The Yukon is also an important area for eagles. Figure 38 shows the general migratory path for eagles and their territory, which stretches from the Yukon into Alaska. Deaths of Golden Eagles and other eagle species due to collisions with wind turbines and cables have been the reason for controversy around wind park development in the US in recent years.[23] As for peregrine falcons, it appears that their habitat around Stewart Crossing lies between the wind sites identified in this area (Wareham/Site 16, Willow Hills) and does not overlap (Figure 54).

[22] http://www.env.gov.yk.ca/animals-habitat/bestviewingsites.php#Hwy8
[23] See http://planetark.org/wen/74421

Figure 54 Peregrine Falcon Habitat[24]



6.3 Comparison to Recent Site-Specific Consultant Reports

Two reports, one on the Tehcho site (full report) and one on the Mt Sumanik site (wind monitoring results for June 2016 only), were either recently prepared or are currently being completed for YEC. As can be expected from the use of different models, there are some differences between the yield estimated between these reports and this one. These cannot be fully explained without more

[24] Source: http://www.cpawsyukon.org/images/map-oilgas-peregrines.jpg

detailed comparisons as to the specific assumptions made and mode inputs used but Table 19 provides a brief appreciation of these differences and offers some high-level conclusions.

Table 19 Comparison of AWS Results to Site-Specific Report Results

Site	This Report	Consulting Reports	Comments
Mount Sumanik	The actual summit of Mt. Sumanik (location of the ZephIR Lidar unit) seemed an unlikely location for wind turbines considering that the best approach route for a road is that quarry on the north side. Plus, winds modeled higher on the ridges north of Mt. Sumanik than on the summit itself, hence also why the AWS data point was not on the actual summit.	In June, the ZephIR wind monitoring report[1] recorded a mean wind speed of 5.88 m/s (at 76 m) and AWS predicts 3.98 m/s (at 80 m).	The ZephIR report covers only the month of June, wind data is not corrected for long-term variability and uses a different location (about 2.2 km from the one used in this report). Data are therefore not directly comparable. Once monitoring data for a complete year is available, AWS model outputs could be compared to the outputs obtained by the model used by ZephIR.
Tehcho	AWS data was used, not monitoring data, to remain consistent with how the other sites were assessed. AWS estimated a wind speed of 5.8m at 80 meters. Annual net output is 33 GWh per year for a 20 MW wind farm. The same GE 1.7-100 turbine was used for modeling.	Average wind speed at 60m is 5.7m, which is in line with about 5.8m at 80m height based on AWS. Annual energy production is higher in the *Natural Power* (NP) report[2] (54 GWh per year for a 25 MW wind farm- considerably higher than what would be expected from the results of this report) than this report but it is not clear why that is so without having access to the underlying data and assumptions.	Data recovery from the met tower – note that this was highlighted as well in the earlier reports that we were sent – was highly problematic with long periods of missing data and lots of icing problems. This data was corrected to create a complete data set, but that is an imperfect process. Generally, the site does not appear to be a good side whether AWS of NP outputs are used.

[1] Post-QC Anemometry Summary: Mt Sumanik (DRAFT), ZephIR-300 Monitoring Results from June 2016
[2] McDonald, Scott: Ferry Hill Wind Project – Indicative Energy Yield Assessment. Natural Power, Saratoga Springs, NY, December 2014

7 PRELIMINARY PROJECT SCHEDULE

Developing a wind farm in the Yukon will likely take three to four years. This includes the following phases:

Year 1: Wind monitoring campaign – a necessary basis for an investment decision. While the campaign will be for two years, one year of data collection should suffice to make a go/no-go decision on whether to proceed.

Year 2: Project development phase: permitting, financial engineering and stakeholder involvement. Except for the geotechnical assessment, all of these tasks are off-site. Based on the results of the assessment during the first half of this phase, a decision to go ahead will have to be taken. Tasks such as detailed engineering and negotiations will only take place after this decision has been taken. Wind monitoring continues during the second year.

Year 3: Site preparation: access to and preparation of the site.

Year 4: Erection of turbines, grid intertie and commissioning. The schedule for this phase is rather tight and may have to be stretched over two years. An early start with pouring concrete for the foundations in April will require covering the area with plastic and heating the interior. If the work started in May there might be scheduling problems with turbine erection by October (a minimum of one month curing should be allowed, pushing the erection of the towers towards the end of the construction season).

The schedule laid down in Figure 55 is for a 20-MW wind farm with no existing access road. The earliest in-service date would be October 2020, provided the wind measurement campaign starts no later than June 2017.

For sites with existing access roads or for smaller wind farms, the schedule may be more relaxed. The wind farms in Kodiak and Kasigluk, Alaska took four years to develop,[25] although subsequent farms may have been realized in shorter timeframes.

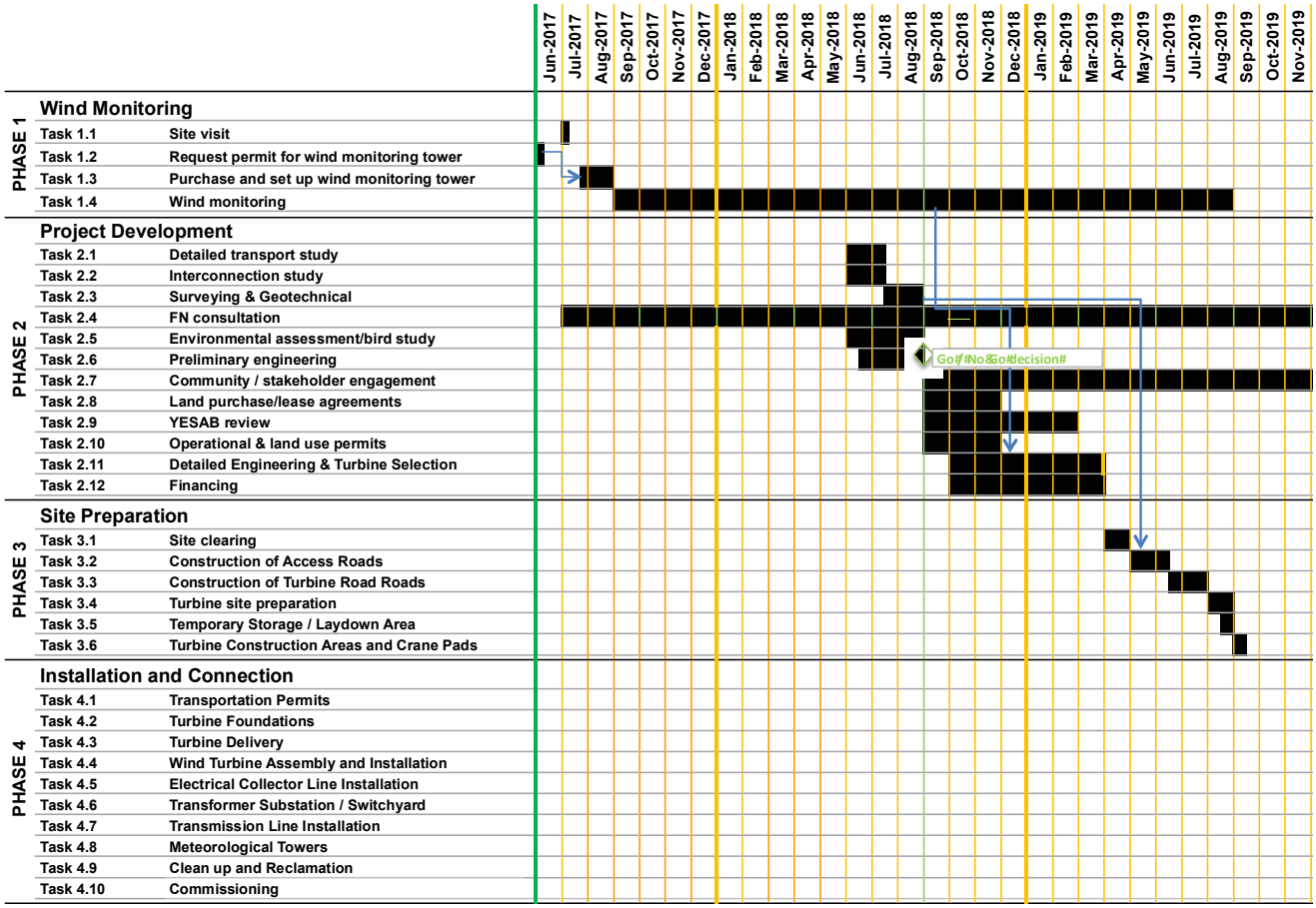
Erecting wind turbines is constrained by weather and wind conditions (wind speeds must be below 10 m/s), i.e. the process for a 20-MW wind farm may take three months due to waiting periods until conditions allow each turbine to be erected. There are also periods when heavy loads may not be allowed on the road (shoulder seasons). Generally, we assume:

- One year of wind monitoring must precede any development;
- Sites with existing good road access could be constructed within a single construction season;
- Sites where extensive road construction is necessary would be built over two construction seasons.

Risks identified in the next chapter may extend the schedule. Notably, it may take up to two years to obtain the necessary permits, which would add to the time required to complete the project.

[25] COMMUNITY WIND TOOLKIT: A Guide to Developing Wind Energy Projects in Alaska Renewable Energy Alaska Project (REAP) March 2011

Figure 55 Preliminary Project Schedule



8 RISK ASSESSMENT

8.1 Introduction

This chapter provides a high-level[26] risk assessment of wind-farm construction. Table 20 summarizes the risks and mitigation measures. Given that YEC would be developing the first commercial-scale wind farm in the Yukon, risks relating to construction expertise and permitting need to be more carefully considered.

8.2 Key Risks

Permitting: Whereas YEC is likely able to obtain all necessary permits for a wind farm, there may be unexpected delays with obtaining permits due to the inexperience of permit authorities with this type of project. Also, projects involving multiple levels of permit authorities (municipal/First Nation, territorial, federal) may incur additional delays as one permit may depend on another, or additional studies and requirements may be imposed. In Alaska, permitting for typical wind projects can take anywhere from two to four years once the site is selected. Permitting should therefore be initiated fairly early in the process (once siting is confirmed and land purchasing is reasonably underway) to reduce this risk. A project development consultant may be of assistance in securing permits and providing project experience from other wind farms in Canada to authorities to facilitate the process, and ensure best practices are applied to project design, construction, and operation.

Stakeholders' opposition: It is best practice to involve stakeholders early in the project development process. This will help identify issues early on and will help design the project so its impacts on stakeholder interests are lessened. Also, land ownership issues can be addressed early to conclude agreements on compensation or land leasing so the project can move forward smoothly. Given that most of the recommended seven sites are on Commissioner's land and the interest by Yukon aboriginal groups in wind power project development, we do not anticipate major resistance against wind projects, and have not classified this as a 'high risk' area. Still, interest groups need to be identified early and included in discussions around project design, also addressing any economic interests stakeholders may legitimately have in the project.

Schedule risk: Due to the short construction season in the Yukon (likely even shorter at the selected locations due to their elevation), there is considerable risk associated with construction activities. We have built extra days into the schedule (Chapter 7) to account for weather-related delays. Nevertheless, several components may cause delays, including turbine and crane transport, availability of key personnel and permitting delays. These risks can be mitigated by contracting out project construction to an experienced EPC company. Usually, turbine vendors will function as EPC contractors for turbine delivery and erection. They will then confirm a realistic schedule, identify the best transport routes and methods, and also look after turbine erection. They may also cooperate with local companies for site preparation, access road and line construction, and the electric and foundational works required. Otherwise, YEC may look after site preparation and civil works based on the specifications provided by the turbine vendor.

[26] For a more in-depth treatment of wind-farm-related project risks, consult http://writepass.com/journal/2012/11/risk-assessment-of-a-wind-farm/

Icing risk: This will essentially be dealt with through de-icing devices integrated into the turbines. However, during the wind monitoring phase, icing should also be monitored to quantify this risk. As mentioned above, the report on the Mt Sumanik wind farm identified a potentially severe icing risk, which may lead to severe power output losses during winter, even with de-icing measures. If icing is too severe and would reduce power output by more than 10% (with de-icing measures), the site may have to be abandoned as unsuitable for wind power production.

Curtailment: This risk is more likely to occur during the summer than during winter, given the Yukon's electricity consumption profile. However, curtailment during the summer will negatively affect the economic performance of the wind farm. This aspect was not the subject of the current study but needs to be assessed when deciding on wind farm siting and size.

8.3 Lesser Risks

Financial: As a utility, YEC is well positioned to develop and finance a wind farm. As such, no major risks are related to financing. We identified currency exchange risk as one potential financial risk. This risk can be monetized by a forward currency purchasing contract. A 30% increase in turbine costs and some labour costs would only result in about an 11% increase in the project budget though.

Transport: Transportation can become a major issue when the existing infrastructure is insufficient. The heavy 550 t crane required to set up large-scale turbines as proposed in this study weighs about 90 tonnes (it can be disassembled; the counterweight alone weighs 36 tonnes). Any weight above 77 tonnes will require a special permit from Yukon Highways and Public Works. It is uncertain that such a permit can be granted for all sites, however. Length is another restriction: trucks transporting turbine blades can be 60 m long or more, making navigation around needle turns difficult or impossible. Also, the access road to be built needs to be smooth and have a gradient no steeper than about 10-14%. Wherever a transport study shows that it is not possible to bring the required equipment to the site, infrastructure must either be specially built, equipment transported in sections and reassembled at the site, or smaller turbines could be selected to reduce transport bottlenecks.

Wildlife and vandalism: Two problems may arise with respect to wildlife. During the environmental assessment, sensitive areas may be identified near the site, which could require changing transmission or access road routes to avoid harming protected species. Wild animals can also be a hazard for workers on site and may have to be deterred from accessing the site either by fencing the area or using other deterrents. Vandalism may also be a risk in some areas. A developer should speak to locals to identify both wildlife and vandalism risks and take countermeasures if need be.

Delivery: Related to schedule risk, deliveries of equipment and turbine sections may be delayed due to vendor-caused delays, weather events or other unforeseen problems with transport, such as accidents or truck breakdowns. Usually, this risk is contractually passed on to the vendor within a turbine purchasing contract that essentially makes the vendor an EPC contractor for timely delivery and turbine erection.

Some other issues have not been included in the tables such as ice throw (turbine sites are remote), budget risks (will be reduced at the detailed engineering stage and are addressed by contingen-

cies), inflation or interest rate changes (thought to be low at this time in Canada), bankability (YEC as the project developer expected to provide value of a PPA), engineering risks/design failures (typically mitigated by assessing company capabilities through an RFP process), and accidents (covered by insurance; adequate on-site worker training presumed).

Table 20 Risk Factors and Mitigation

Risk	Importance	Probability	Impact	Mitigation
Currency exchange increases cost of turbines and some services	Low	High	Low	Obtain binding quotes; rely on Canadian labour and material inputs as much as possible
Icing events reduce turbine output	High	High	**High**	Icing monitoring and de-icing measures
Schedule/weather risk during construction	High	Medium	**High**	Provide conservative timeframes for construction; split up construction over two years; contract out project to an EPC firm to pass on risk to contractor
Operational risk	High	Low	Low	Obtain servicing contracts and warranties; buy new turbines with a cold-weather track record; keep crucial spare parts near site; stall turbines at temperatures below -30 °C
Wind resource variability and turbine choice	Medium	Low	Low	Obtain more than 12 months of monitoring data, select turbine late in project development process based on monitoring results
Local operation/know-how	High	Low	Low	Train two technicians to perform routine turbine maintenance
Curtailment/financial losses	High	High	**High**	Assess capacity of grid to absorb wind farm output and size farm accordingly
Community protest against wind farm	High	Medium	Medium	Engage community and stakeholders early in the process; offer co-benefits to landowners; select sites to avoid scenic, tourist, heritage or recreational locations; confirm low wildlife impacts through environmental assessment
Crane and nacelle transport may exceed permissible weight and length thresholds	High	Medium	Medium	Work with authorities early in the process to determine best routes; provide adequate road access to site; split up components where possible; select smaller turbines if necessary

Risk	Importance	Probability	Impact	Mitigation
Permits take longer than expected	High	High	**High**	Work with authorities early in the process; provide examples from other jurisdictions for authorities; follow best practices in terms of siting, signalization, access road and transmission routing; contract a development consultant to deal with permitting
Wildlife & vandalism risk	Medium	Medium	Medium	Assess potential of appearance of protected and/or hazardous wildlife (e.g., wolves, bears) at planned site and take mitigation measures if needed to ensure worker safety or take precautionary measures to protect wildlife during construction; set up guards if there is a perceived risk of vandalism
Delivery risk	High	Medium	Medium	When purchasing turbines and scheduling machinery, include damage clauses in contracts in case of delays caused by the vendor

9 CONCLUSIONS AND RECOMMENDATIONS

This study identified 26 potential sites for wind farms. Of these, 17 were considered further and seven selected for a detailed analysis. The selection process was tailored to the prerequisites of the project. These prerequisites may change over time. The shortlist should not be taken as final and YEC may want to look further into some of the sites that were not selected.

Of the seven sites selected, five show an above-average performance in terms of the cost of energy produced. These sites are, in the order of performance, Kluane Lake, Miller's Ridge near Carmacks, and a mountain ridge near Cyprus Mine, close to Faro. There is not a lot of difference in energy production cost between these five sites; non-monetary factors may play an important role in selecting the preferred location.

Miller's Ridge near Carmacks and Thulsoo Mountain near the Aishihik hydroelectric facility are the sites with the highest wind resource and a low cost of energy (LCOE). Thulsoo Mountain is near an existing facility, but Miller's Ridge has more expansion potential. Sumanik Mountain is attractive due to its location near Whitehorse. Cyprus Mountain is the furthest from Whitehorse, but appealing due its brownfield nature next to an abandoned mine. Kluane Lake gets a qualified recommendation because of its low elevation and low energy costs (LCOE), but requires a transmission line first. Tehcho and Sugarloaf are not recommended because the other site options clearly are superior, both in terms of annual energy production and energy cost.

The levelized cost of energy (LCOE, assuming no curtailment) at almost all sites and all sizes remains under the standard offer price of 21 ¢/kWh but many are still above the average residential retail price of 12 ¢/kWh. Financially, the sites at Sugarloaf and at Kluane Lake perform best in terms of capital costs. In terms of LCOE, the Miller's Ridge site (20 MW) performs best but is closely followed by the Thulsoo and Kluane Lake sites, despite the mediocre wind regime of the latter. This can be explained by the very short transmission connection required once the new line is built. Also, less rime icing and less frequent low temperature curtailment helps to increase the net energy generation at Kluane Lake. Though there are plans, currently there is no transmission line at this site.

Our modelling assumes that all energy produced will be used. Curtailment of the operation during the summer when YEC has a surplus of power would increase the cost of energy produced during the rest of the year by more than a third. This needs to be considered when assessing the sites. If the update to YEC's 20-year plan yields that wind power is a viable source of electricity, then further research should be done on the five sites mentioned above. We recommend a full-scale feasibility study for one or all of the five top sites. This includes, but is not limited to:

1. Wind velocity, temperature and rime ice monitoring;
2. Determining the maximum size of the wind farm;
3. Modelling of monthly power generation based on monitored data;
4. Modelling and selection of various wind turbine models and sizes;
5. Review of the geotechnical conditions on site and procuring LIDAR elevation maps;
6. Conceptual design of roads and their routing;
7. Capital costing based on quotes;
8. Review of service contracts and costs;
9. Transportation study.

YUKON Wind Site Inventory

Appendices

RFP 2015-060

Prepared for:

YUKON ENERGY

Prepared by:

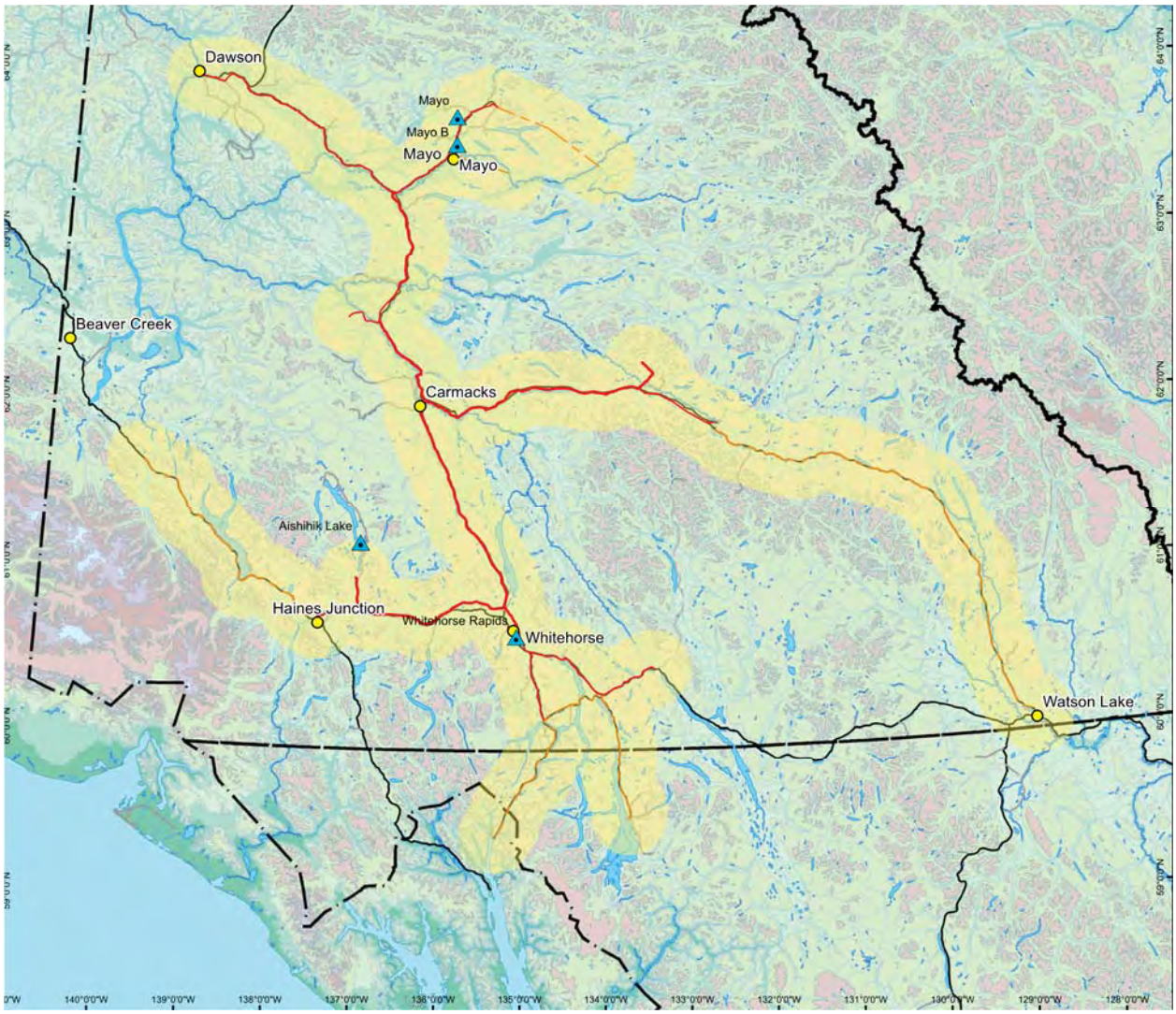
CBER

with

envint Consulting *and* V3 Energy, LLC

August 24, 2016

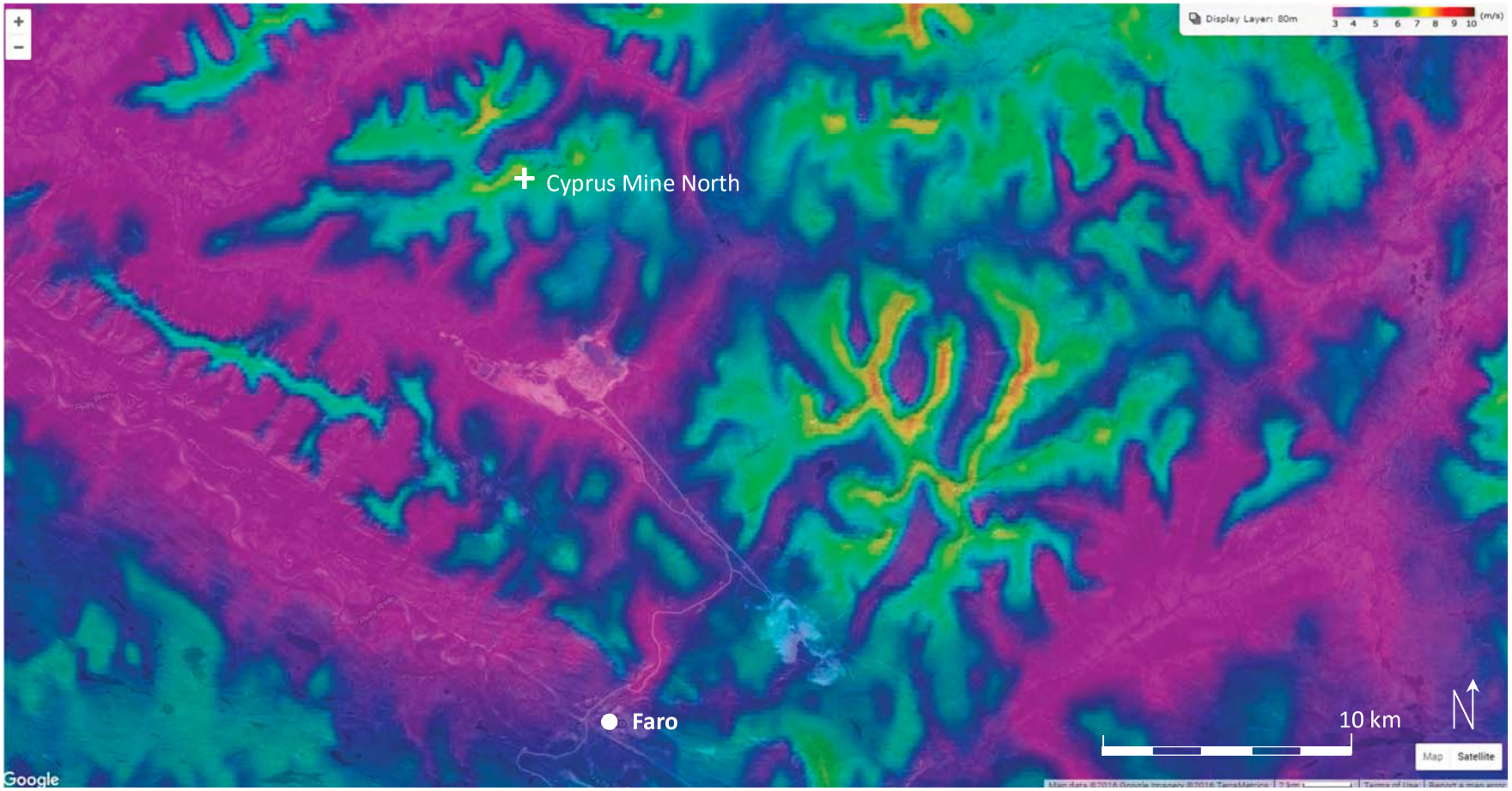
APPENDIX A – YUKON POWER TRANSMISSION INFRASTRUCTURE MAP



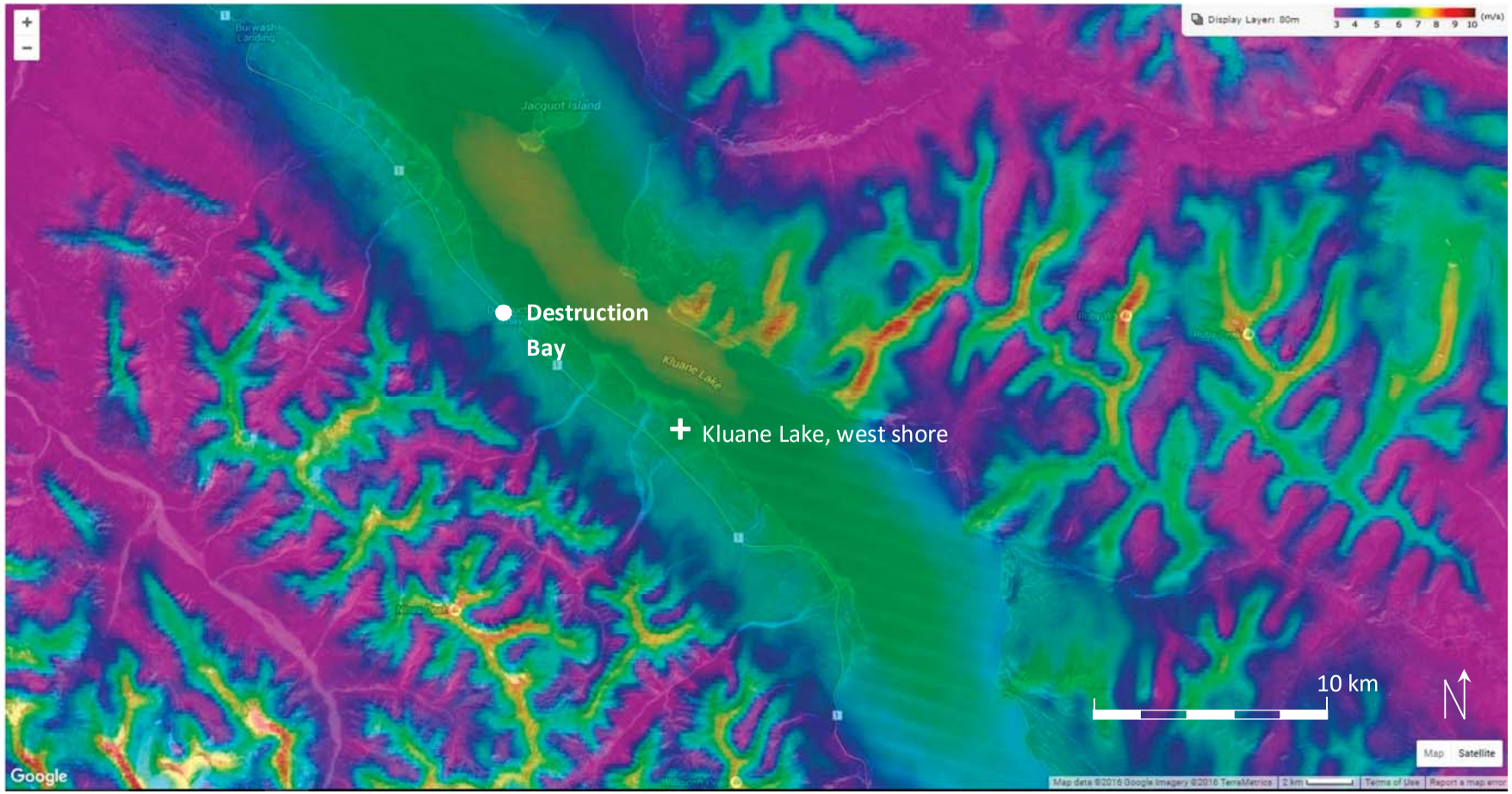
Note: Red lines = existing transmission lines; beige lines = planned lines (Source: YEC)

APPENDIX B – SELECTED SITES AWS TRUEPOWER WIND MAPS

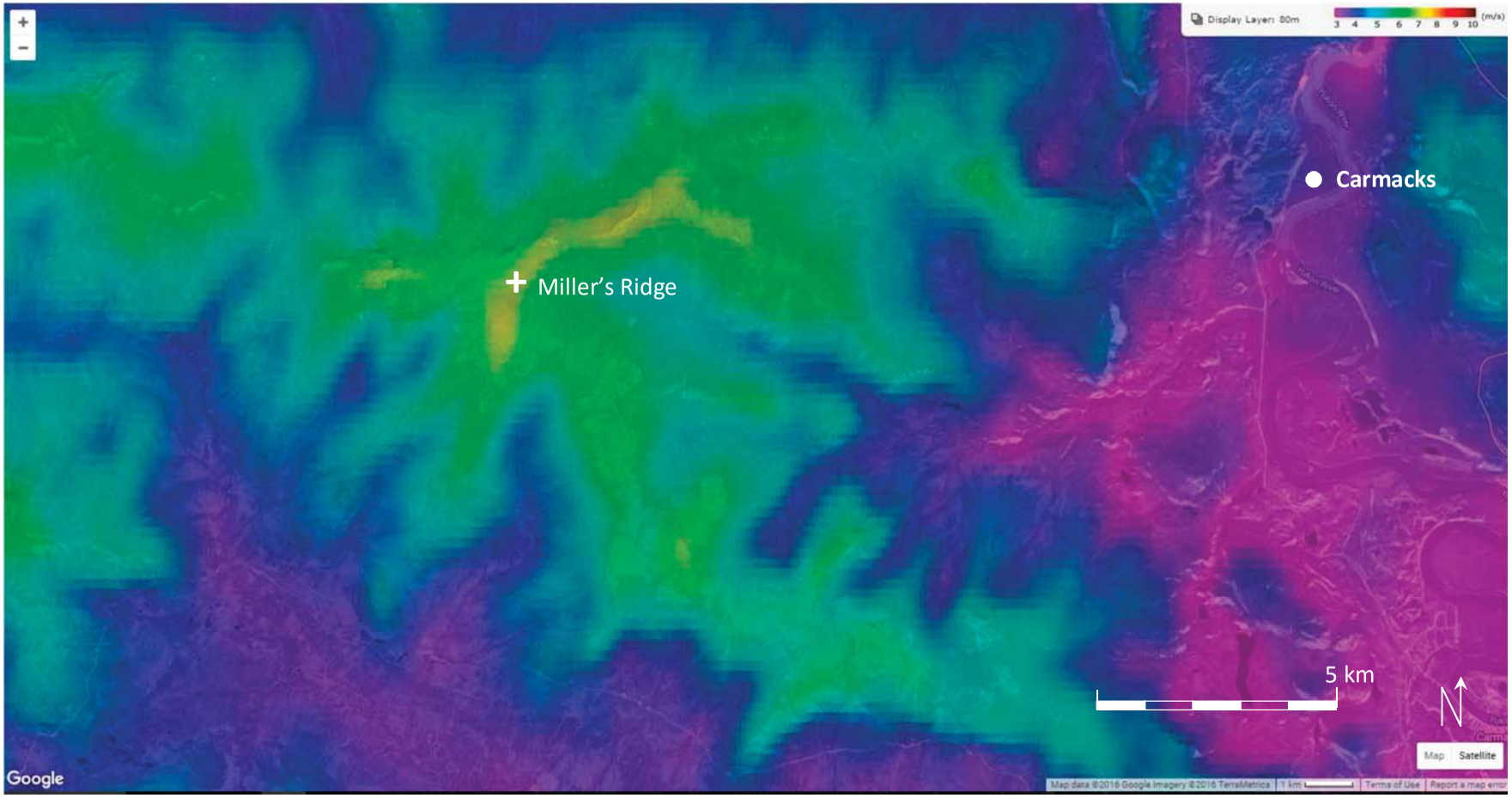
Cyprus Mine



Kluane Lake (West)



Miller's Ridge



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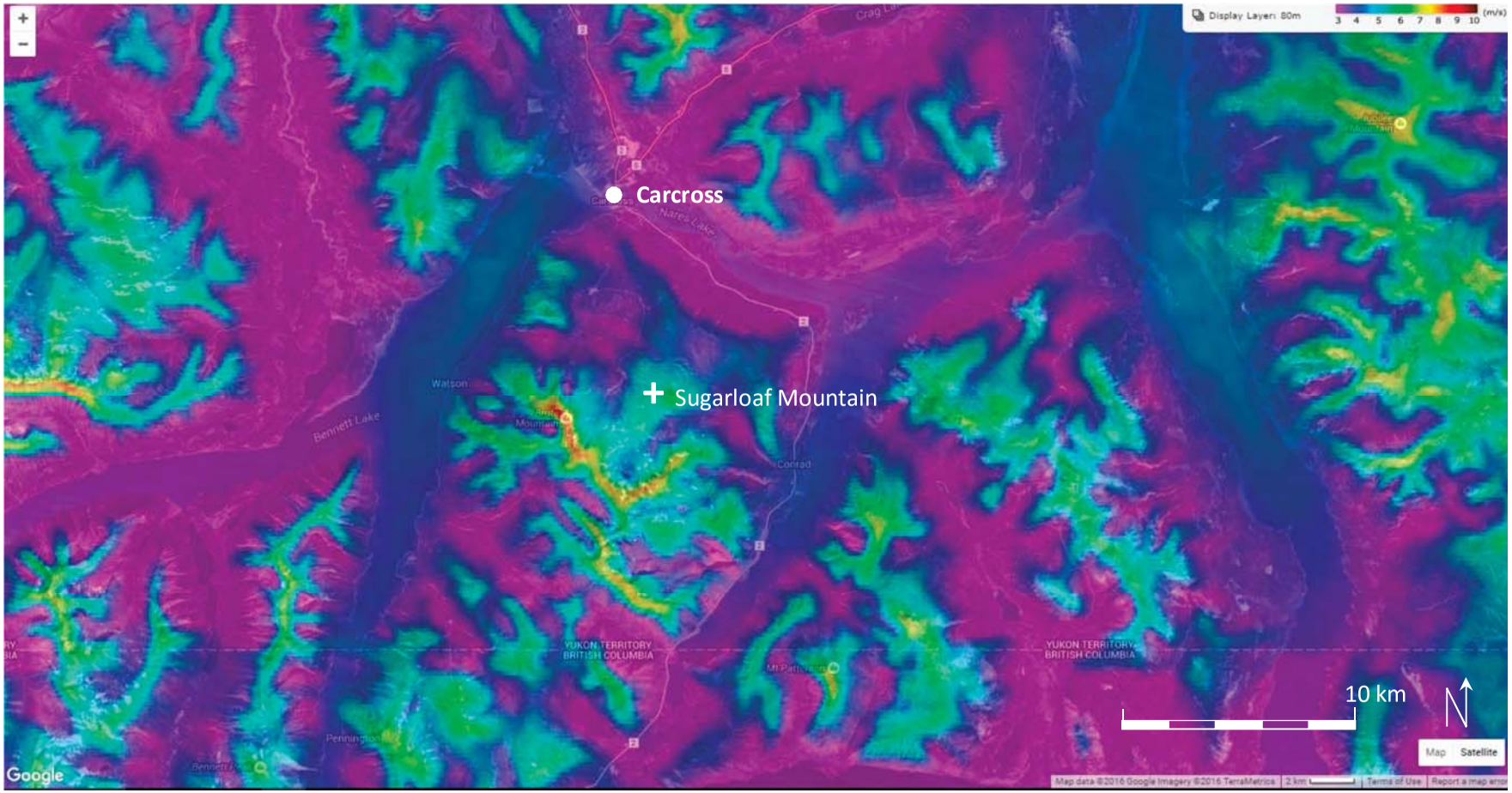
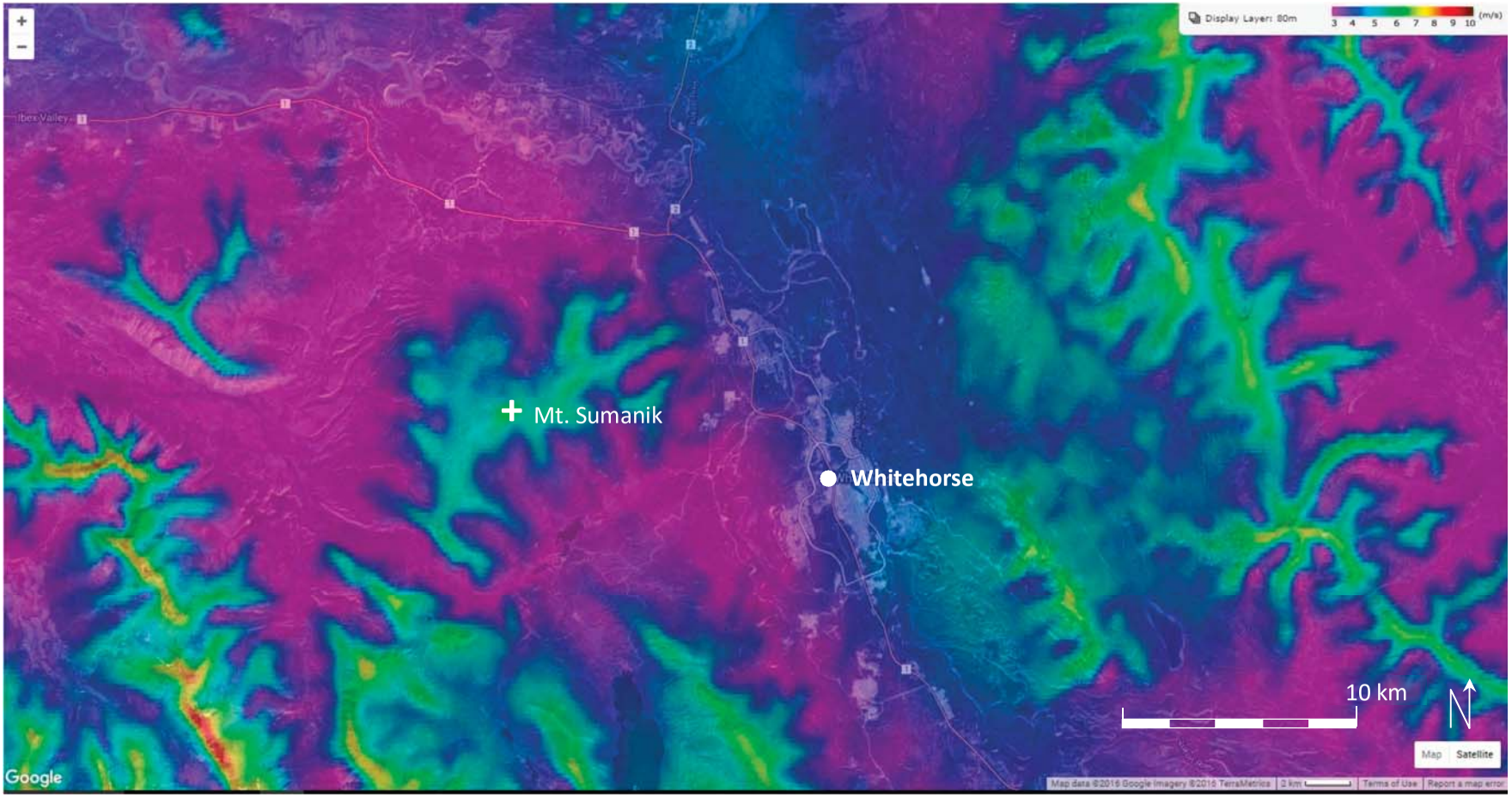
Sugarloaf Mountain



Yukon Energy Corporation
2017-2018 General Rate Application
YUB-YEC-2-29 Attachment 1

Mount Sumanik



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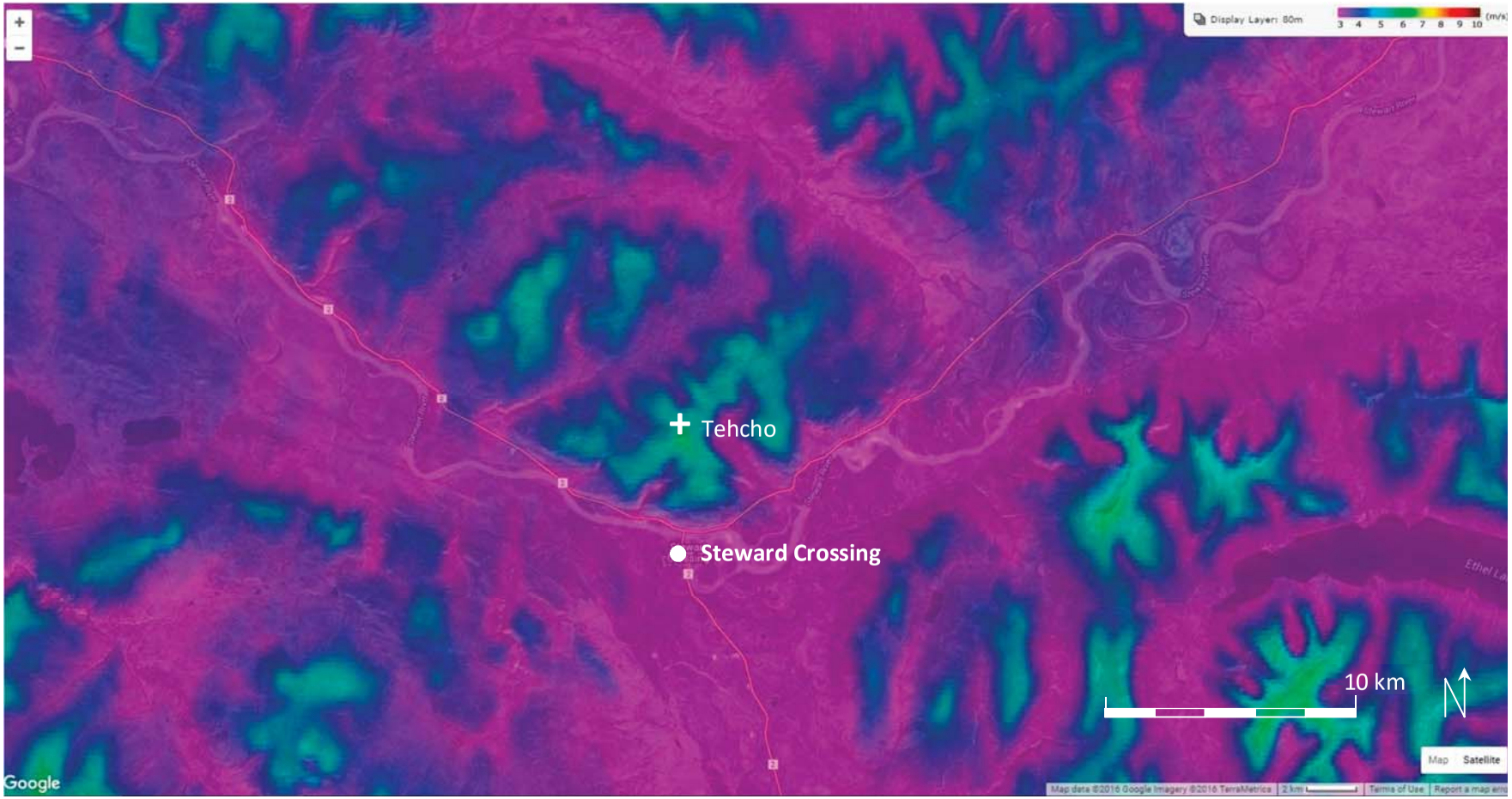
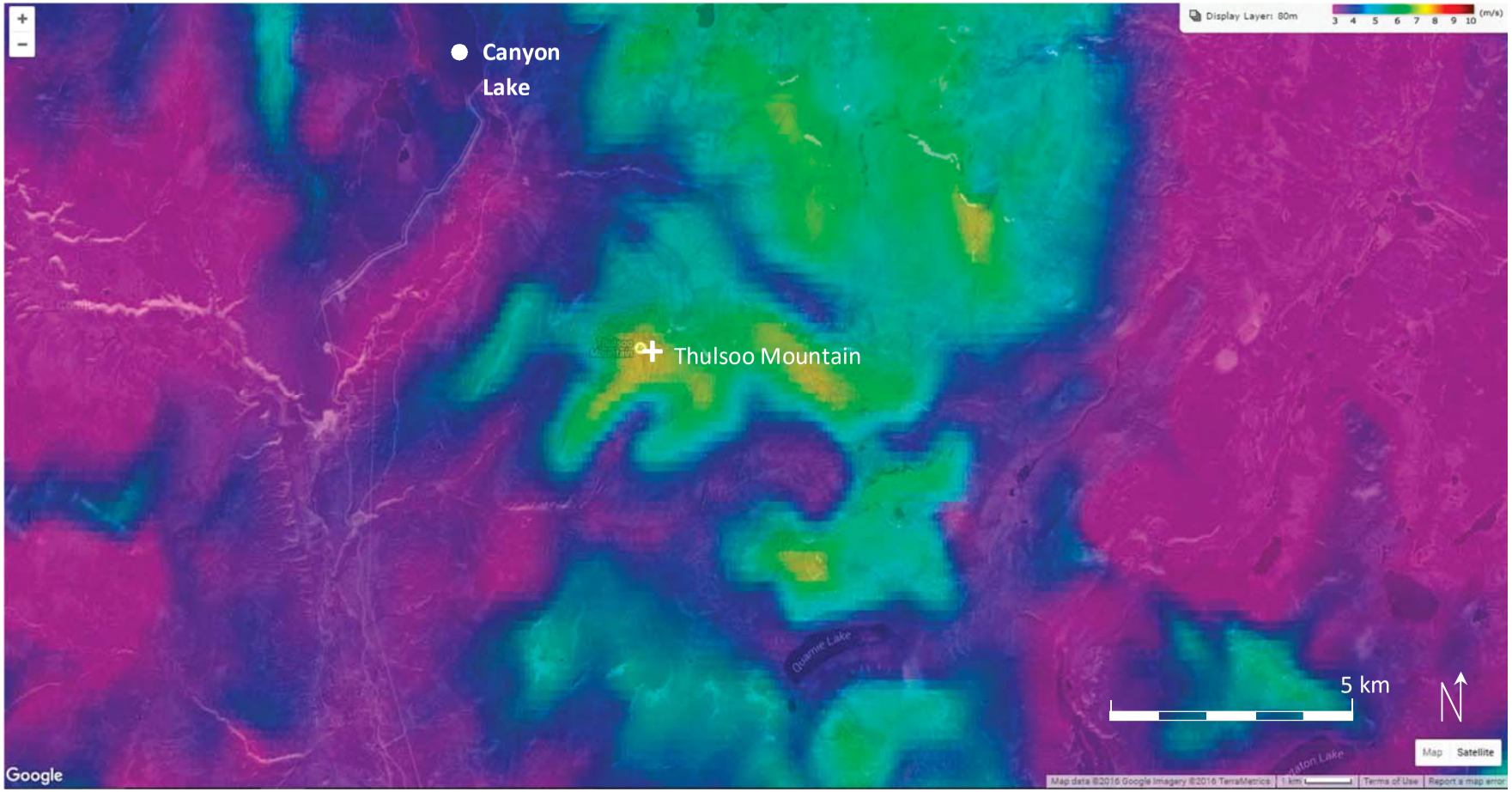
Tehcho


Display Layer: 80m
3 4 5 6 7 8 9 10 (m/s)
Tehcho
Steward Crossing
10 km
Map
Satellite
Google

Thulsoo


Canyon Lake
Thulsoo Mountain
Display Layer: 80m
3 4 5 6 7 8 9 10 (m/s)
5 km
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Map
Satellite
Google

APPENDIX C – CAPITAL AND OPERATIONAL COST SHEETS

SUMMARY

Capacity: 6 MW (3 x 2 MW)

	1 - Cyprus Mine	2 - Kluane Lake	3 - Miller's Ridge	4 - Sugarloaf	5 - Sumanik	6 - Tehcho	7 - Thulsoo Mtn
Nameplate capacity of turbine type	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW
Number of turbines	3	3	3	3	3	3	3
CAPEX AND DEVELOPMENT COSTS							
1 LOGISTICS							
1.1 Transportation cost	$ 1,941,900	$ 1,838,400	$ 1,842,000	$ 1,593,600	$ 1,658,400	$ 1,974,300	$ 1,793,400
1.2 550-tonne crane	$ 470,000	$ 470,000	$ 470,000	$ 470,000	$ 470,000	$ 470,000	$ 470,000
1.3 Erection cost	$ 1,350,000	$ 1,350,000	$ 1,350,000	$ 1,350,000	$ 1,350,000	$ 1,350,000	$ 1,350,000
1.4 90-tonne crane for lay down etc.	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
2 CIVIL							
2.1 Geotech report	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
2.2 Access road	$ 1,712,500	$ 359,000	$ 3,440,250	$ 330,750	$ 1,570,000	$ -	$ 2,963,250
2.3 Turbine road	$ 732,000	$ -	$ 227,000	$ 326,250	$ 221,750	$ 242,250	$ 228,000
2.4 Cement supply for foundation	$ 652,500	$ 517,500	$ 517,500	$ 517,500	$ 342,000	$ 630,000	$ 517,500
2.5 Cost of rebar including delivery	$ 347,228	$ 347,228	$ 347,228	$ 347,228	$ 347,228	$ 347,228	$ 347,228
2.6 Foundation installation cost	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000
3 ELECTRICAL							
3.1 Capacity of site							
3.2 Low voltage step-up transformers	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000
3.3 Collection system	$ 705,600	$ 120,000	$ 301,600	$ 381,000	$ 297,400	$ 313,800	$ 302,400
3.4 Substation (step up transformer & switching yard)	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000
3.5 Interconnection to exising transmission line	$ 4,481,100	$ 785,655	$ 7,897,500	$ 2,234,700	$ 2,558,790	$ 1,959,750	$ 6,047,145
3.6 Line-tap & protection system	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
4 LABOUR							
4.1 Labour/wage for misc. construction-related activities	$ 2,600,000	$ 2,600,000	$ 2,600,000	$ 2,600,000	$ 2,600,000	$ 2,600,000	$ 2,600,000
4.2 Accomodation and per diem	$ 487,500	$ 487,500	$ 487,500	$ 487,500	$ 487,500	$ 487,500	$ 487,500
5 FINANCING COST							
5.1 Legals for financing closing & independent engineer	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000
5.2 Lender charges	$ 510,000	$ 380,000	$ 570,000	$ 420,000	$ 440,000	$ 420,000	$ 540,000
6 SITE COST							
6.1 Land cost	$ 546,646	$ -	$ 827,777	$ -	$ 433,240	$ 138,917	$ 681,297
7 DEVELOPMENT COST	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000
8 EQUIPMENT	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000
9 CONTINGENCY	$ 3,094,697	$ 2,366,528	$ 3,528,835	$ 2,546,853	$ 2,718,631	$ 2,534,374	$ 3,273,772
10 **TOTAL**	$ 34,041,671	$ 26,031,811	$ 38,817,190	$ 28,015,380	$ 29,904,938	$ 27,878,119	$ 36,011,492

OPERATING & MAINTENANCE COSTS

1 ANNUAL NET PRODUCTION	**16,111 MWh/yr.**	**14,955 MWh/yr.**	**18,110 MWh/yr.**	**9,889 MWh/yr.**	**14,180 MWh/yr.**	**10,300 MWh/yr.**	**17,269 MWh/yr.**
2 O&M COSTS PER YEAR	Year 1-5	Year 1-5	Year 1-5	Year 1-5	Year 1-5	Year 1-5	Year 1-5
2.1 Owner Staff	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
2.2 Office	$60,000	$60,000	$0	$0	$0	$0	$0
2.3 Insurance	$51,063	$39,048	$58,226	$42,023	$44,857	$41,817	$54,017
2.4 Land lease	$0	$12,642	$0	$25,668	$0	$0	$0
2.5 Vendor Service	$283,215	$246,660	$316,530	$170,685	$246,765	$181,230	$303,525
2.6 Royalties, land leases, FN/Community Payments	$0	$0	$0	$0	$0	$0	$0
2.7 Contingency	$59,428	$55,835	$57,476	$43,838	$49,162	$42,305	$55,754
2.8 **TOTAL per year**	$653,705	$614,184	$632,231	$482,214	$540,785	$465,352	$613,296
2.9 Fixed cost	$311,063	$311,689	$258,226	$267,691	$244,857	$241,817	$254,017
2.10 Variable costs	$342,643	$302,495	$374,006	$214,523	$295,927	$223,535	$359,279
3 SPECIFIC COSTS							
3.1 Fixed cost per MWh (net)	$19.31	$20.84	$14.26	$27.07	$17.27	$23.48	$14.71
3.2 Variable costs per MWh (net)	$21.27	$20.23	$20.65	$21.69	$20.87	$21.70	$20.81
3.2 Total O&M cost per MWh (net output)	**$40.58**	**$41.07**	**$34.91**	**$48.76**	**$38.14**	**$45.18**	**$35.52**

SUMMARY

Capacity: 10 MW (5 x 2 MW)

	1 - Cyprus Mine	2 - Kluane Lake	3 - Miller's Ridge	4 - Sugarloaf	5 - Sumanik	6 - Tehcho	7 - Thulsoo Mtn
Nameplate capacity of turbine type	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW
Number of turbines	5	5	5	5	5	5	5
CAPEX AND DEVELOPMENT COSTS							
1 LOGISTICS							
1.1 Transportation cost	$ 3,236,500	$ 3,064,000	$ 3,070,000	$ 2,656,000	$ 2,764,000	$ 3,290,500	$ 2,989,000
1.2 550-tonne crane	$ 650,000	$ 650,000	$ 650,000	$ 650,000	$ 650,000	$ 650,000	$ 650,000
1.3 Erection cost	$ 2,250,000	$ 2,250,000	$ 2,250,000	$ 2,250,000	$ 2,250,000	$ 2,250,000	$ 2,250,000
1.4 90-tonne crane for lay down etc.	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000
2 CIVIL							
2.1 Geotech report	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
2.2 Access road	$ 1,710,250	$ 632,000	$ 3,157,500	$ 330,750	$ 1,268,500	$ -	$ 2,743,000
2.3 Turbine road	$ 1,084,750	$ -	$ 575,000	$ 663,500	$ 651,250	$ 797,500	$ 446,500
2.4 Cement supply for foundation	$ 1,087,500	$ 862,500	$ 862,500	$ 862,500	$ 570,000	$ 1,050,000	$ 862,500
2.5 Cost of rebar including delivery	$ 578,713	$ 578,713	$ 578,713	$ 578,713	$ 578,713	$ 578,713	$ 578,713
2.6 Foundation installation cost	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000
3 ELECTRICAL							
3.1 Capacity of site							
3.2 Low voltage step-up transformers	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000	$ 300,000
3.3 Collection system	$ 1,067,800	$ 200,000	$ 660,000	$ 730,800	$ 721,000	$ 838,000	$ 557,200
3.4 Substation (step up transformer & switching yard)	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000
3.5 Interconnection to exising transmission line	$ 4,481,100	$ 1,327,950	$ 7,897,500	$ 2,208,375	$ 1,828,710	$ 1,959,750	$ 6,326,190
3.6 Line-tap & protection system	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
4 LABOUR							
4.1 Labour/wage for misc. construction-related activities	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000
4.2 Accomodation and per diem	$ 562,500	$ 562,500	$ 562,500	$ 562,500	$ 562,500	$ 562,500	$ 562,500
5 FINANCING COST							
5.1 Legals for financing closing & independent engineer	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000
5.2 Lender charges	$ 660,000	$ 530,000	$ 720,000	$ 570,000	$ 590,000	$ 590,000	$ 690,000
6 SITE COST							
6.1 Land cost	$ 607,595	$ -	$ 855,454	$ -	$ 437,686	$ 235,264	$ 707,528
7 DEVELOPMENT COST	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000
8 EQUIPMENT	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000
9 CONTINGENCY	$ 4,045,671	$ 3,313,766	$ 4,431,917	$ 3,454,314	$ 3,535,236	$ 3,528,223	$ 4,184,313
10 **TOTAL**	$ 44,502,378	$ 36,451,429	$ 48,751,083	$ 37,997,452	$ 38,887,595	$ 38,810,450	$ 46,027,444
Check	$ 44,502,378	$ 36,451,429	$ 48,751,083	$ 37,997,452	$ 38,887,595	$ 38,810,450	$ 46,027,444

OPERATING & MAINTENANCE COSTS

1 ANNUAL NET PRODUCTION	**25,983 MWh/yr.**	**24,415 MWh/yr.**	**29,537 MWh/yr.**	**15,947 MWh/yr.**	**21,137 MWh/yr.**	**18,295 MWh/yr.**	**27,467 MWh/yr.**
2 O&M COSTS PER YEAR	Year 1-5	Year 1-5	Year 1-5	Year 1-5	Year 1-5	Year 1-5	Year 1-5
2.1 Operators	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
2.2 Office	$60,000	$60,000	$0	$0	$0	$0	$0
2.3 Insurance	$66,754	$54,677	$73,127	$56,996	$58,331	$58,216	$69,041
2.4 Land lease	$0	$21,914	$0	$32,821	$0	$0	$0
2.5 Vendor Service	$456,750	$402,690	$516,255	$275,250	$367,830	$321,915	$482,775
2.6 Royalties, FN/Community Payments	$0	$0	$0	$0	$0	$0	$0
2.7 Contingency	$78,350	$73,928	$78,938	$56,507	$62,616	$58,013	$75,182
2.8 **TOTAL per year**	$861,854	$813,209	$868,320	$621,573	$688,778	$638,144	$826,998
2.9 Fixed cost	$326,754	$336,591	$273,127	$289,817	$258,331	$258,216	$269,041
2.10 Variable costs	$535,100	$476,618	$595,193	$331,757	$430,446	$379,928	$557,957
3 SPECIFIC COSTS							
3.1 Fixed cost per MWh (net)	$12.58	$13.79	$9.25	$18.17	$12.22	$14.11	$9.80
3.2 Variable costs per MWh (net)	$20.59	$19.52	$20.15	$20.80	$20.36	$20.77	$20.31
3.2 Total O&M cost per MWh (net output)	**$33.17**	**$33.31**	**$29.40**	**$38.98**	**$32.59**	**$34.88**	**$30.11**

SUMMARY

Capacity: 20 MW (10 x Vestas V90 2.0 MW)

	1 - Cyprus Mine	2 - Kluane Lake	3 - Miller's Ridge	4 - Sugarloaf	5 - Sumanik	6 - Tehcho	7 - Thulsoo Mtn
Nameplate capacity of turbine type	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW	2.0 MW
Number of turbines	10	10	10	10	10	10	10
CAPEX AND DEVELOPMENT COSTS							
1 LOGISTICS							
1.1 Transportation cost	$ 6,473,000	$ 6,128,000	$ 6,140,000	$ 5,312,000	$ 5,528,000	$ 6,581,000	$ 5,978,000
1.2 550-tonne crane	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 1,100,000
1.3 Erection cost	$ 4,500,000	$ 4,500,000	$ 4,500,000	$ 4,500,000	$ 4,500,000	$ 4,500,000	$ 4,500,000
1.4 90-tonne crane for lay down etc.	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ 180,000
2 CIVIL							
2.1 Geotech report	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
2.2 Access road	$ 1,710,250	$ 1,407,750	$ 2,157,500	$ 330,750	$ 1,268,500	$ -	$ 2,330,000
2.3 Turbine road	$ 1,645,250	$ -	$ 1,575,000	$ 1,206,000	$ 1,383,500	$ 1,340,500	$ 1,631,500
2.4 Cement supply for foundation	$ 2,175,000	$ 1,725,000	$ 1,725,000	$ 1,725,000	$ 1,140,000	$ 2,100,000	$ 1,725,000
2.5 Cost of rebar including delivery	$ 1,157,426	$ 1,157,426	$ 1,157,426	$ 1,157,426	$ 1,157,426	$ 1,157,426	$ 1,157,426
2.6 Foundation installation cost	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000
3 ELECTRICAL							
3.1 Capacity of site							
3.2 Low voltage step-up transformers	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000
3.3 Collection system	$ 1,716,200	$ 400,000	$ 1,660,000	$ 1,364,800	$ 1,506,800	$ 1,472,400	$ 1,705,200
3.4 Substation (step up transformer & switching yard)	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000
3.5 Interconnection to exising transmission line	$ 4,462,965	$ 2,479,815	$ 7,897,500	$ 2,206,035	$ 1,828,710	$ 2,012,400	$ 6,223,230
3.6 Line-tap & protection system	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
4 LABOUR							
4.1 Labour/wage for misc. construction-related activities	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ 4,000,000
4.2 Accomodation and per diem	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000	$ 750,000
5 FINANCING COST							
5.1 Legals for financing closing & independent engineer	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000
5.2 Lender charges	$ 1,020,000	$ 900,000	$ 1,080,000	$ 950,000	$ 950,000	$ 960,000	$ 1,070,000
6 SITE COST							
6.1 Land cost	$ 703,956	$ -	$ 913,294	$ -	$ 596,511	$ 332,088	$ 860,283
7 DEVELOPMENT COST	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000	$ 1,900,000
8 EQUIPMENT	$ 24,000,000	$ 24,000,000	$ 24,000,000	$ 24,000,000	$ 24,000,000	$ 24,000,000	$ 24,000,000
9 CONTINGENCY	$ 6,356,905	$ 5,670,299	$ 6,681,072	$ 5,675,701	$ 5,786,445	$ 5,846,081	$ 6,518,564
10 **TOTAL**	**$ 69,925,951**	**$ 62,373,290**	**$ 73,491,791**	**$ 62,432,712**	**$ 63,650,891**	**$ 64,306,895**	**$ 71,704,203**
Check	$ 69,925,951	$ 62,373,290	$ 73,491,791	$ 62,432,712	$ 63,650,891	$ 64,306,895	$ 71,704,203

OPERATING & MAINTENANCE COSTS

	Cyprus Mine	Kluane Lake	Miller's Ridge	Sugarloaf	Sumanik	Tehcho	Thulsoo Mtn
1 ANNUAL NET PRODUCTION	**49,589 MWh/yr.**	**47,797 MWh/yr.**	**57,253 MWh/yr.**	**32,250 MWh/yr.**	**41,486 MWh/yr.**	**33,377 MWh/yr.**	**54,393 MWh/yr.**
2 O&M COSTS per year (Year 1 to 5, in 2015 $)	Cyprus Mine	Kluane Lake	Miller's Ridge	Sugarloaf	Sumanik	Tehcho	Thulsoo Mtn
2.1 Operators	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
2.2 Office	$60,000	$60,000	$0	$0	$0	$0	$0
2.3 Insurance	$104,889	$93,560	$110,238	$93,649	$95,476	$96,460	$107,556
2.4 Land lease	$0	$45,858	$0	$44,573	$0	$0	$0
2.5 Vendor Service	$871,725	$788,355	$1,000,695	$556,650	$721,950	$587,280	$956,055
2.6 Royalties, FN/Community Payments	$0	$0	$0	$0	$0	$0	$0
2.7 Contingency	$123,661	$118,777	$131,093	$89,487	$101,743	$88,374	$126,361
2.8 **TOTAL per year**	$1,360,275	$1,306,550	$1,442,026	$984,359	$1,119,169	$972,114	$1,389,972
2.9 Fixed cost	$364,889	$399,418	$310,238	$338,222	$295,476	$296,460	$307,556
2.10 Variable costs	$995,386	$907,132	$1,131,788	$646,137	$823,693	$675,654	$1,082,416
3 SPECIFIC COSTS							
3.1 Fixed cost per MWh (net)	$7.36	$8.36	$5.42	$10.49	$7.12	$8.88	$5.65
3.2 Variable costs per MWh (net)	$20.07	$18.98	$19.77	$20.04	$19.85	$20.24	$19.90
3.2 Total O&M cost per MWh (net output)	**$27**	**$27**	**$25**	**$31**	**$27**	**$29**	**$26**

APPENDIX D – FINANCIAL ANALYSIS

Table 1: Summary Yukon Energy Corporation Wind Power Generation Options

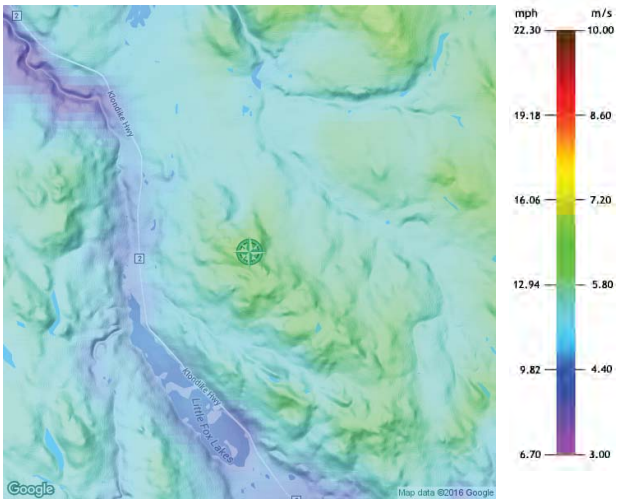
CAPEX +/- 0% OPEX +/- 0% Energy +/- 0%

Wind Power Options	Option Assumptions											Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC)					
	Capital Cost (2015$)			Annual Fixed O&M Costs (2015$)	Annual Variable O&M Costs (2015$)	Capacity	Reliable Winter Capacity	Annual Average Capacity Factor	Annual Average Energy	Expected Life	Expected In-Service Date (January 1)	3.38% Real WACC		4.61% Real WACC		8.82% Real WACC	
	Plant Capital Cost	Transmission Capital Cost	Total Capital Cost									LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)
	$000	$000	$000	$000	$/MW.h	MW	MW	%	GW.h	Years	Year	$/kW.h	$/MW	$/kW.h	$/MW	$/kW.h	$/MW
A	B	C	D=B+C	E	F	G	H	I=J/8.76/G	J	K	L	M	N	O	P	Q	R
Cyprus Mine: 6 MW	$28,061	$5,981	$34,042	$301	$25.54	6.0	-	31%	16.1	25	2021	$0.178		$0.196		$0.264	
Cyprus Mine: 10 MW	$38,521	$5,981	$44,502	$327	$20.59	10.0	-	30%	26.0	25	2021	$0.142		$0.156		$0.211	
Cyprus Mine: 20 MW	$63,963	$5,963	$69,926	$365	$20.07	20.0	-	28%	49.6	25	2021	$0.117		$0.129		$0.174	
Kluane Lake: 6 MW	$23,746	$2,286	$26,032	$291	$24.06	6.0	-	28%	15.0	25	2025	$0.154		$0.168		$0.224	
Kluane Lake: 10 MW	$33,623	$2,828	$36,451	$337	$19.52	10.0	-	28%	24.4	25	2025	$0.128		$0.140		$0.188	
Kluane Lake: 20 MW	$58,393	$3,980	$62,373	$399	$18.98	20.0	-	27%	47.8	25	2025	$0.110		$0.121		$0.163	
Miller's Ridge: 6 MW	$29,420	$9,398	$38,817	$258	$25.18	6.0	-	34%	18.1	25	2021	$0.176		$0.193		$0.262	
Miller's Ridge: 10 MW	$39,354	$9,398	$48,751	$273	$20.15	10.0	-	34%	29.5	25	2021	$0.134		$0.148		$0.201	
Miller's Ridge: 20 MW	$64,094	$9,398	$73,492	$310	$19.77	20.0	-	33%	57.3	25	2021	$0.107		$0.117		$0.159	
Sugarloaf Mtn: 6 MW	$24,281	$3,735	$28,015	$243	$25.39	6.0	-	19%	9.9	25	2021	$0.230		$0.253		$0.344	
Sugarloaf Mtn: 10 MW	$34,289	$3,708	$37,997	$290	$20.80	10.0	-	18%	15.9	25	2021	$0.190		$0.210		$0.287	
Sugarloaf Mtn: 20 MW	$58,727	$3,706	$62,433	$338	$20.04	20.0	-	18%	32.3	25	2021	$0.153		$0.169		$0.232	
Mt Sumanik: 6 MW	$25,846	$4,059	$29,905	$244	$25.22	6.0	-	27%	14.2	25	2021	$0.176		$0.194		$0.262	
Mt Sumanik: 10 MW	$35,559	$3,329	$38,888	$258	$20.36	10.0	-	24%	21.1	25	2021	$0.149		$0.165		$0.224	
Mt Sumanik: 20 MW	$60,322	$3,329	$63,651	$295	$19.85	20.0	-	24%	41.5	25	2021	$0.124		$0.137		$0.186	
Tehcho: 6 MW	$24,418	$3,460	$27,878	$243	$25.81	6.0	-	20%	10.3	25	2021	$0.221		$0.244		$0.331	
Tehcho: 10 MW	$35,351	$3,460	$38,810	$258	$20.77	10.0	-	21%	18.3	25	2021	$0.170		$0.187		$0.255	
Tehcho: 20 MW	$60,794	$3,512	$64,307	$296	$20.24	20.0	-	19%	33.4	25	2021	$0.151		$0.167		$0.229	
Thulsoo: 6 MW	$28,464	$7,547	$36,011	$274	$25.40	6.0	-	33%	17.3	25	2021	$0.174		$0.191		$0.258	
Thulsoo: 10 MW	$38,201	$7,826	$46,027	$269	$20.31	10.0	-	31%	27.5	25	2021	$0.137		$0.150		$0.204	
Thulsoo: 20 MW	$63,981	$7,723	$71,704	$308	$19.90	20.0	-	31%	54.4	25	2021	$0.109		$0.120		$0.163	

APPENDIX E – AWS TRUEPOWER COMPASS REPORTS

Site Characteristics

Site ID: 23



Mean annual wind speed map at 100 m hub height for Anticline Mtn.

Latitude: 61.37173 Longitude: -135.62794

Wind Speed (100.0 m): 6.46 m/s

Roughness: 0.1000 m Elevation: 1,235.4 m (4,053.1 ft)

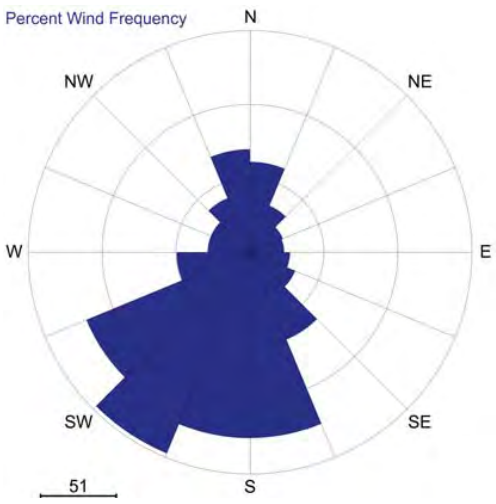
Air Density: 1.111 kg/m3

Mean Power Density: 269 W/m^2

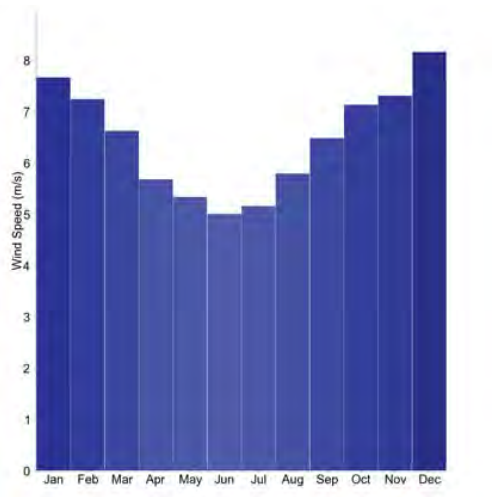
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.29 Weibull k: 2.13

200m Graphs



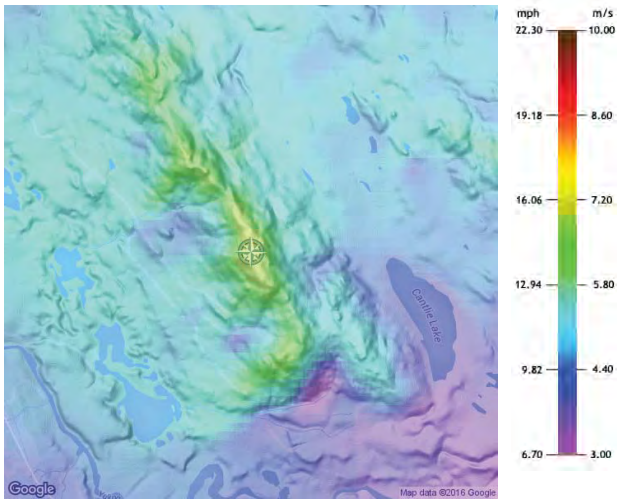
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 9



Mean annual wind speed map at 100 m hub height for Canyon Mtn., Whitehorse.

Latitude: 60.67688 Longitude: -134.90456

Wind Speed (100.0 m): 7.28 m/s

Roughness: 0.0500 m Elevation: 1,416.8 m (4,648.3 ft)

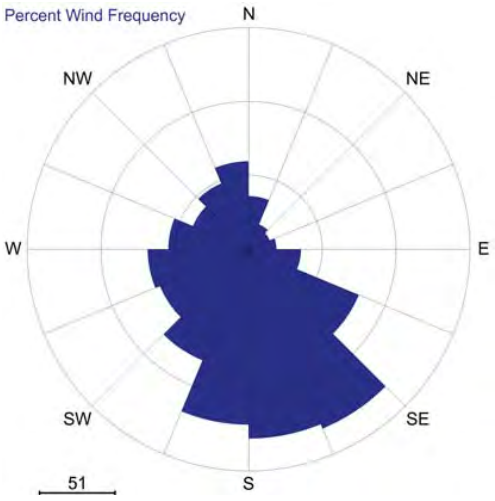
Air Density: 1.105 kg/m3

Mean Power Density: 382 W/m^2

Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.22 Weibull k: 2.14

200m Graphs



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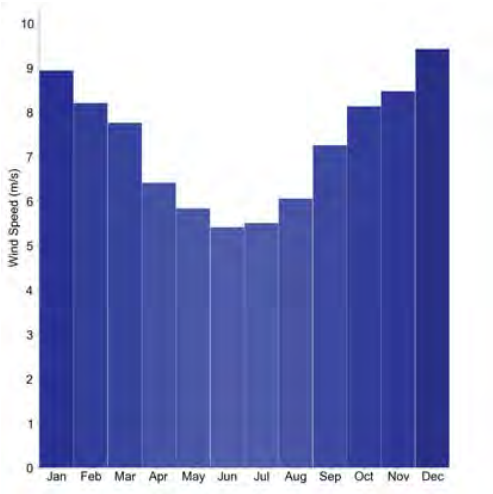
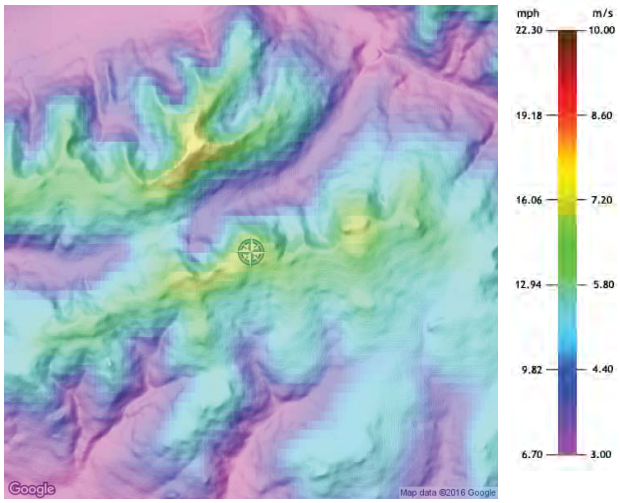


Monthly Distribution

Site Characteristics

Site ID: 1



Mean annual wind speed map at 100 m hub height for Cyprus Mine north.

Latitude: 62.42074 Longitude: -133.42518

Wind Speed (100.0 m): 7.19 m/s

Roughness: 0.0100 m Elevation: 1,849.7 m (6,068.6 ft)

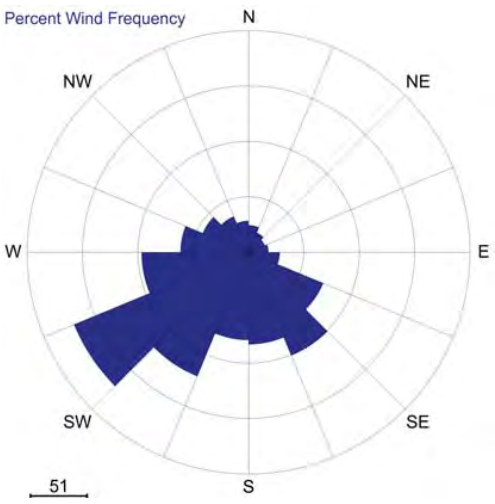
Air Density: 1.081 kg/m3

Mean Power Density: 354 W/m^2

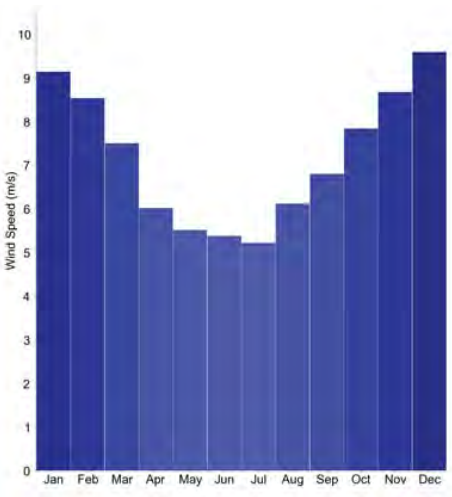
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.12 Weibull k: 2.18

200m Graphs



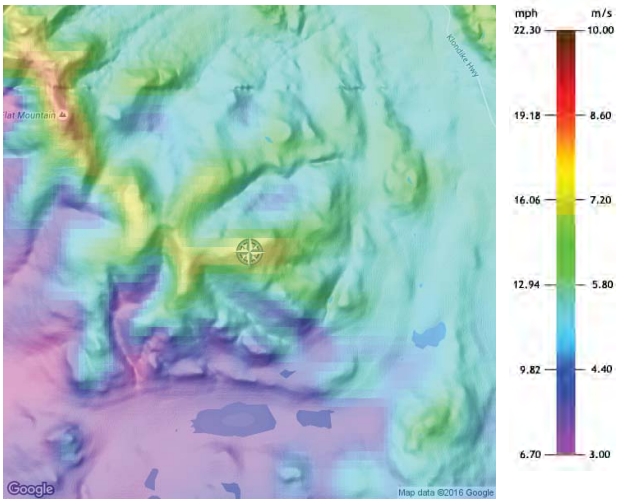
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 15



Mean annual wind speed map at 100 m hub height for Flat Mtn. SE ridge.

Latitude: 60.96678 Longitude: -135.29766

Wind Speed (100.0 m): 7.6 m/s

Roughness: 0.0100 m Elevation: 1,535.1 m (5,036.4 ft)

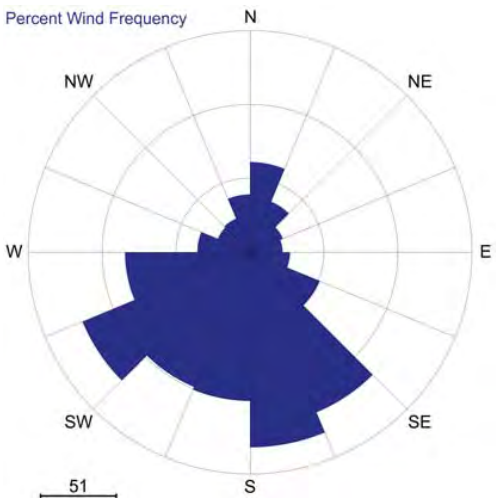
Air Density: 1.097 kg/m3

Mean Power Density: 429 W/m^2

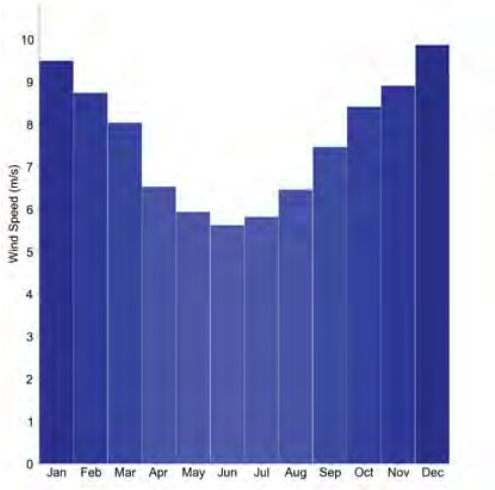
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.58 Weibull k: 2.15

200m Graphs



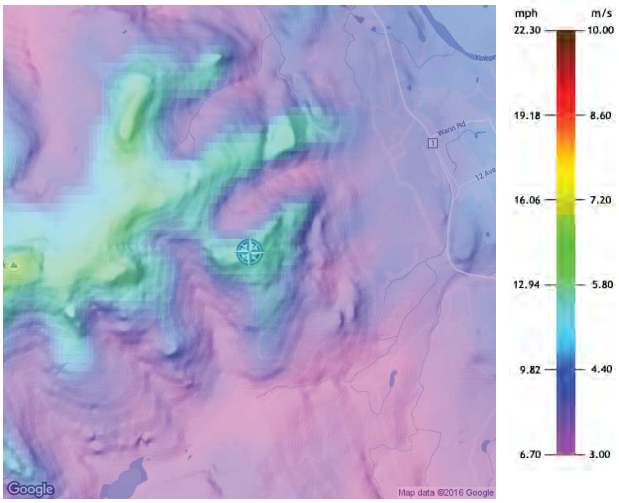
Wind Rose



Monthly Distribution

Site Characteristics

(for comparison only)



Mean annual wind speed map at 100 m hub height for Haeckel Hill.

Latitude: 60.7491 Longitude: -135.22591

Wind Speed (100.0 m): 5.32 m/s

Roughness: 0.1000 m Elevation: 1,374.4 m (4,509.2 ft)

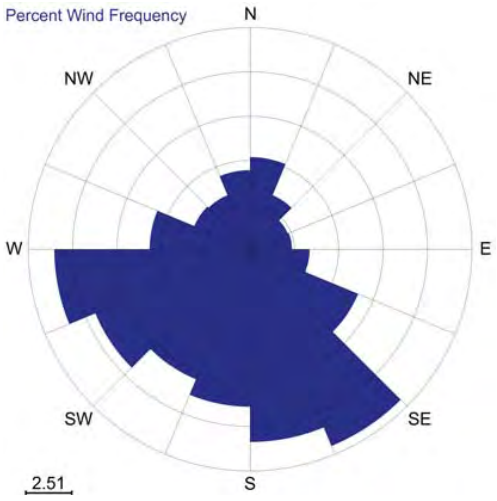
Air Density: 1.107 kg/m3

Mean Power Density: 156 W/m^2

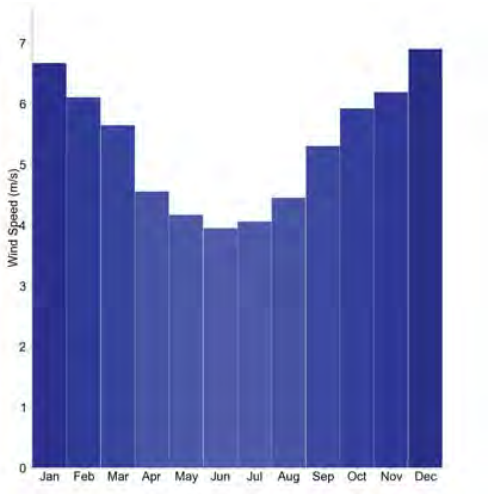
Uncertainty Value: 0.35 +/- m/s

Weibull A: 6.00 Weibull k: 2.04

200m Graphs



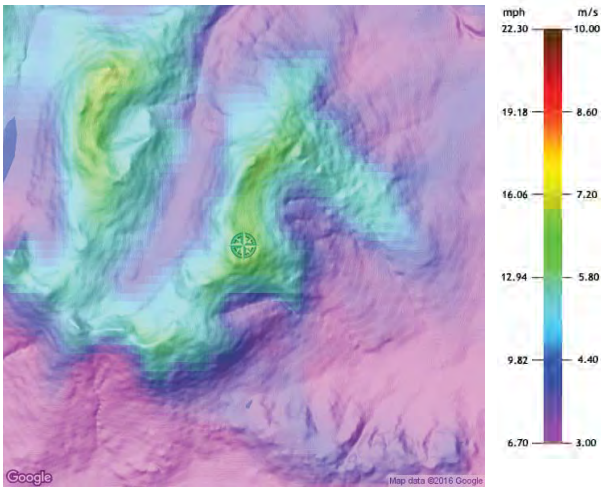
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 20



Mean annual wind speed map at 100 m hub height for Hard Time Mtn.

Latitude: 60.91642 Longitude: -137.17873

Wind Speed (100.0 m): 6.67 m/s

Roughness: 0.0100 m Elevation: 1,844.6 m (6,051.8 ft)

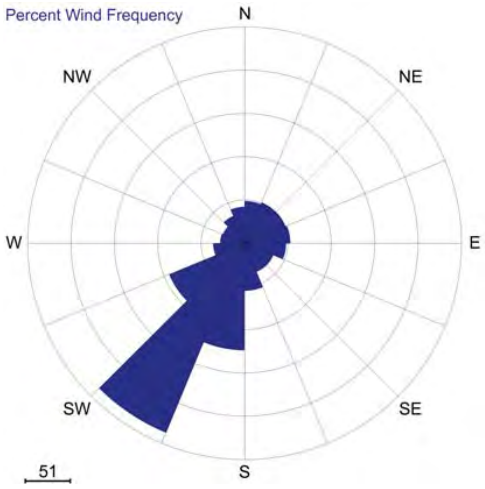
Air Density: 1.071 kg/m3

Mean Power Density: 308 W/m^2

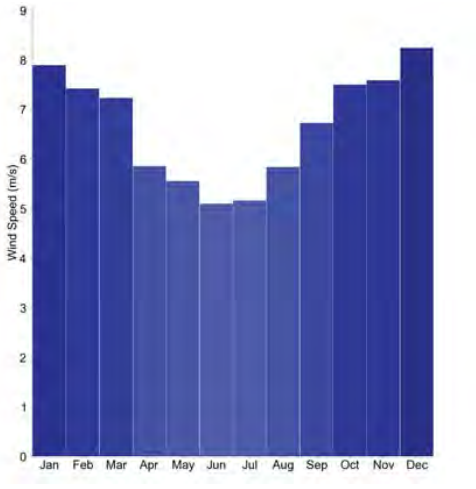
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.52 Weibull k: 1.97

200m Graphs



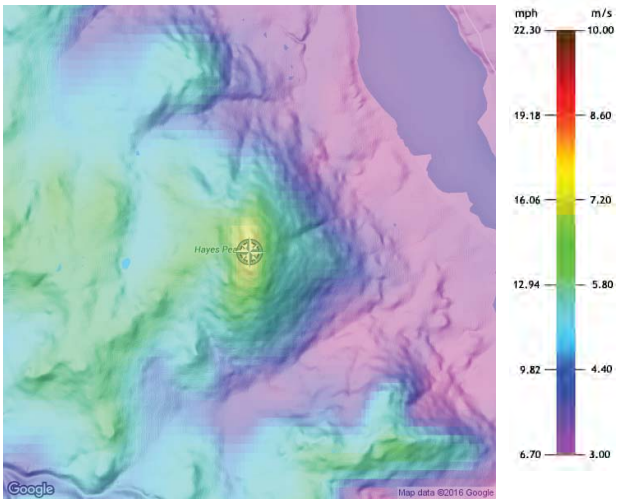
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 13



Mean annual wind speed map at 100 m hub height for Hayes Peak, J. Crossing.

Latitude: 60.39554 Longitude: -133.30605

Wind Speed (100.0 m): 7.53 m/s

Roughness: 0.1000 m Elevation: 1,810.5 m (5,940.0 ft)

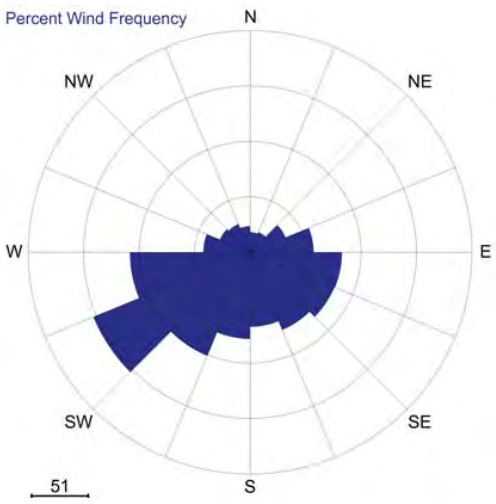
Air Density: 1.070 kg/m3

Mean Power Density: 379 W/m^2

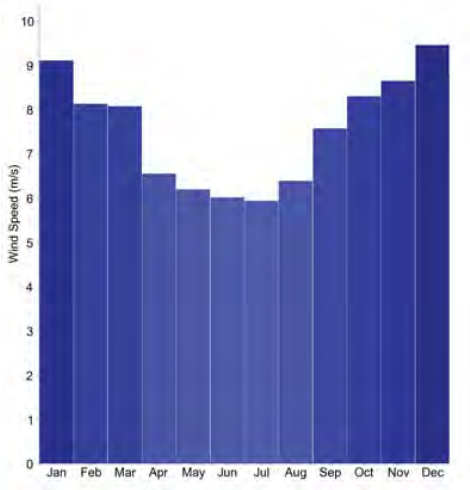
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.50 Weibull k: 2.34

200m Graphs



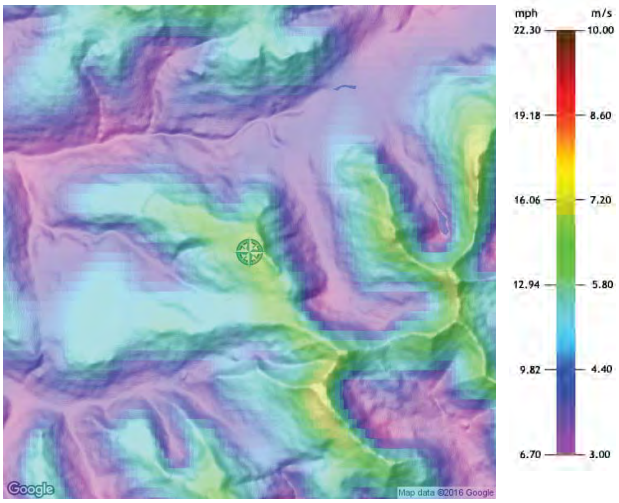
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 16



Mean annual wind speed map at 100 m hub height for Keno City.

Latitude: 63.8948 Longitude: -135.15999

Wind Speed (100.0 m): 6.87 m/s

Roughness: 0.1000 m Elevation: 1,804.6 m (5,920.6 ft)

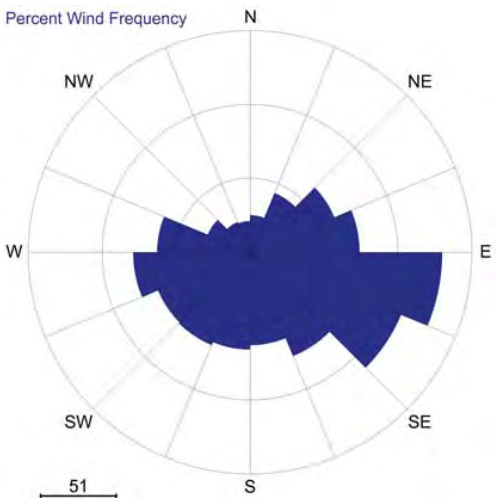
Air Density: 1.104 kg/m3

Mean Power Density: 311 W/m^2

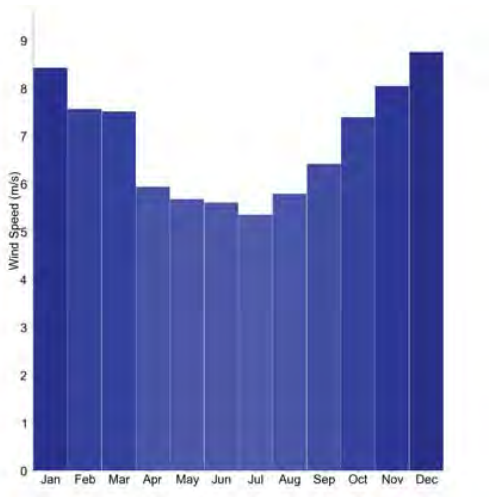
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.76 Weibull k: 2.21

200m Graphs



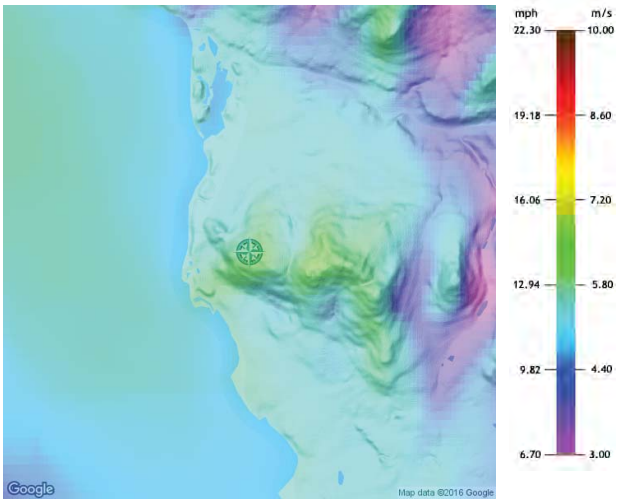
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 14



Mean annual wind speed map at 100 m hub height for Kluane Lake, east shore.

Latitude: 61.12401 Longitude: -138.41125

Wind Speed (100.0 m): 6.35 m/s

Roughness: 1.1250 m Elevation: 1,173.5 m (3,850.1 ft)

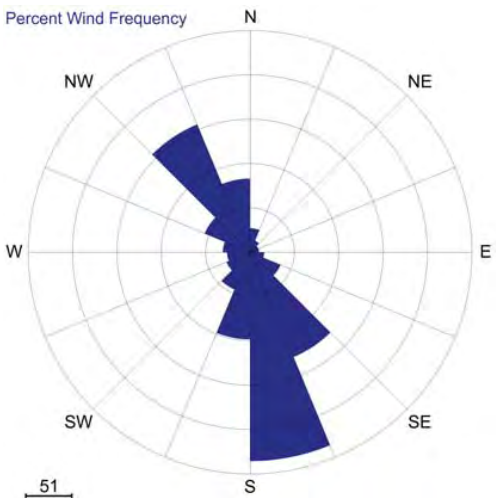
Air Density: 1.132 kg/m3

Mean Power Density: 300 W/m^2

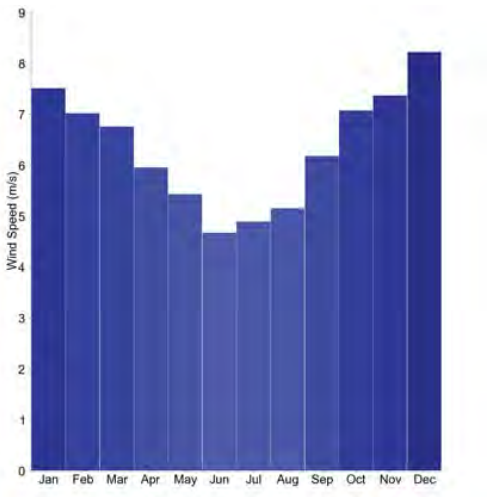
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.15 Weibull k: 1.85

200m Graphs



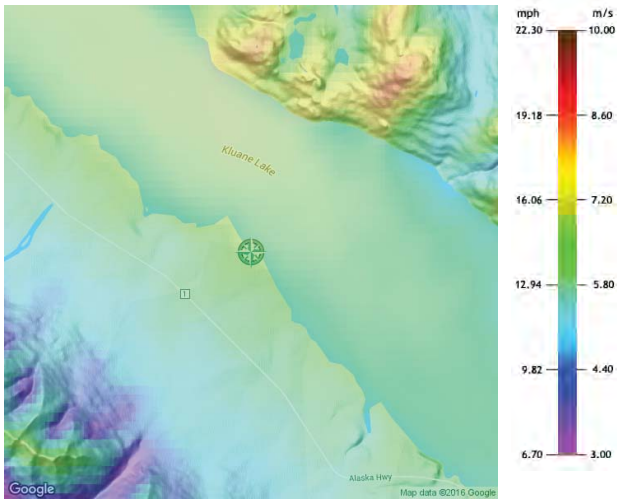
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 2



Mean annual wind speed map at 100 m hub height for Kluane Lake, west shore.

Latitude: 61.2144 Longitude: -138.66531

Wind Speed (100.0 m): 6.75 m/s

Roughness: 0.0010 m Elevation: 765.4 m (2,511.2 ft)

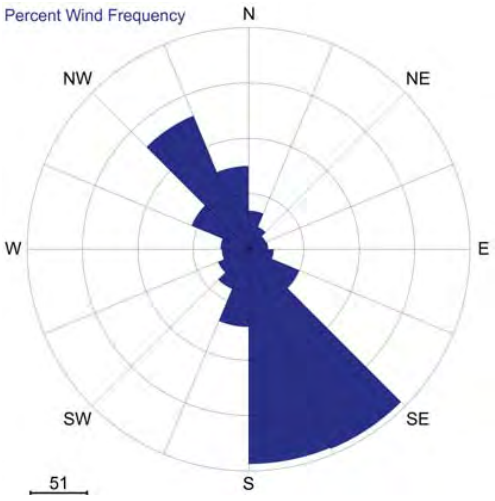
Air Density: 1.167 kg/m3

Mean Power Density: 410 W/m^2

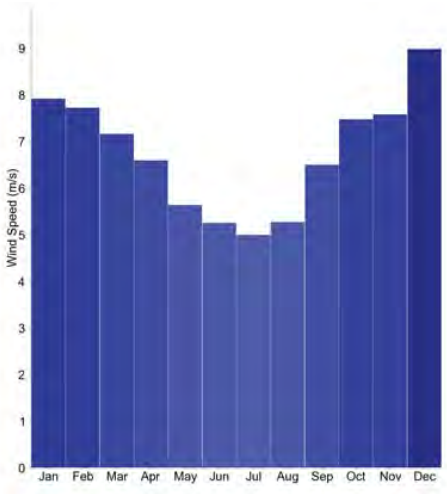
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.57 Weibull k: 1.70

200m Graphs



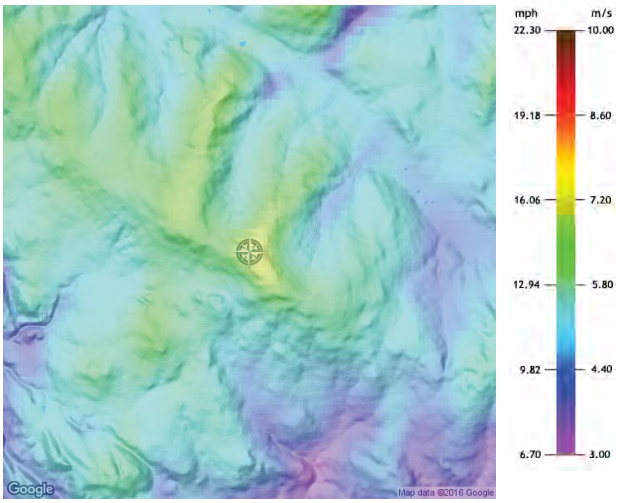
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 18



Mean annual wind speed map at 100 m hub height for Little Salmon hill.

Latitude: 62.14594 Longitude: -135.54794

Wind Speed (100.0 m): 7.41 m/s

Roughness: 0.1000 m Elevation: 1,523.5 m (4,998.4 ft)

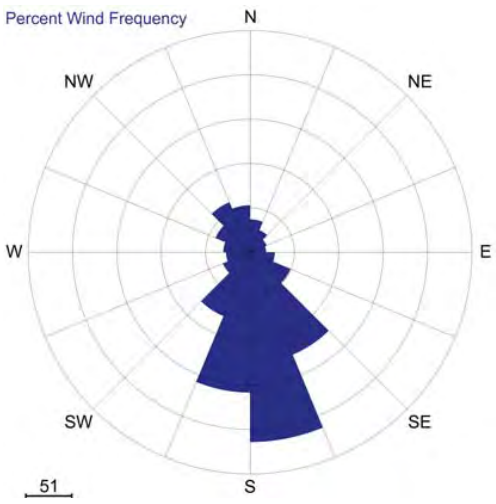
Air Density: 1.090 kg/m3

Mean Power Density: 411 W/m^2

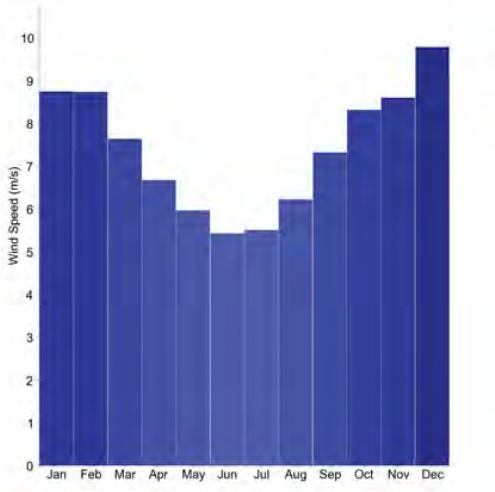
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.36 Weibull k: 2.06

200m Graphs



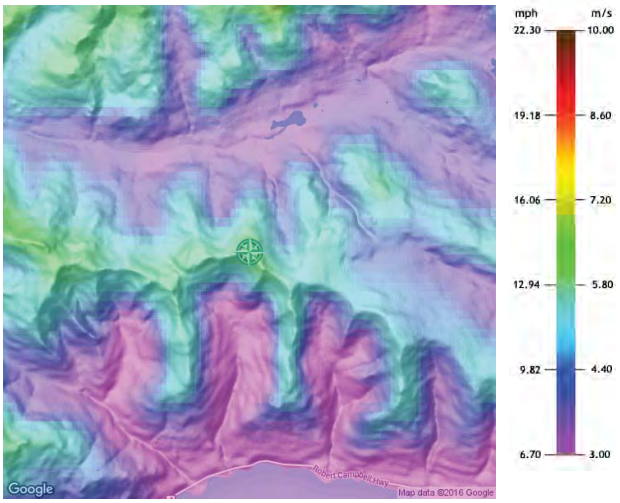
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 22



Mean annual wind speed map at 100 m hub height for Little Salmon/Drury.

Latitude: 62.24811 Longitude: -134.82491

Wind Speed (100.0 m): 6.29 m/s

Roughness: 0.0500 m Elevation: 1,689.2 m (5,542.0 ft)

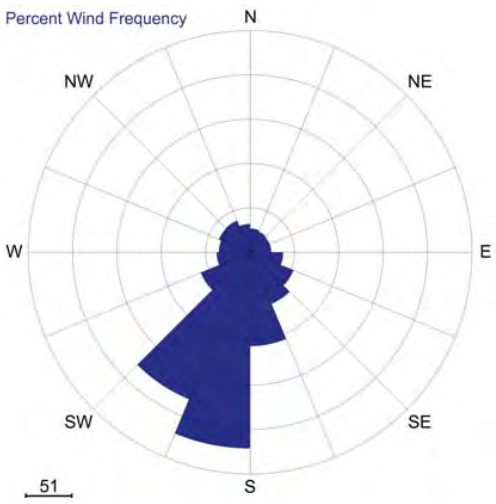
Air Density: 1.174 kg/m3

Mean Power Density: 255 W/m^2

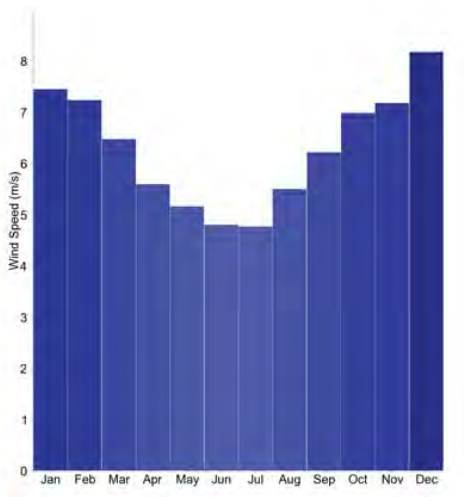
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.11 Weibull k: 2.21

200m Graphs



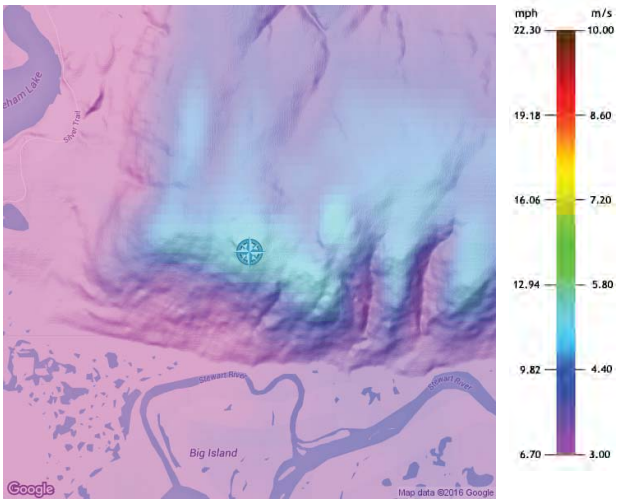
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 10



Mean annual wind speed map at 100 m hub height for Mayo.

Latitude: 63.64839 Longitude: -135.76561

Wind Speed (100.0 m): 4.89 m/s

Roughness: 0.1000 m Elevation: 1,121.5 m (3,679.5 ft)

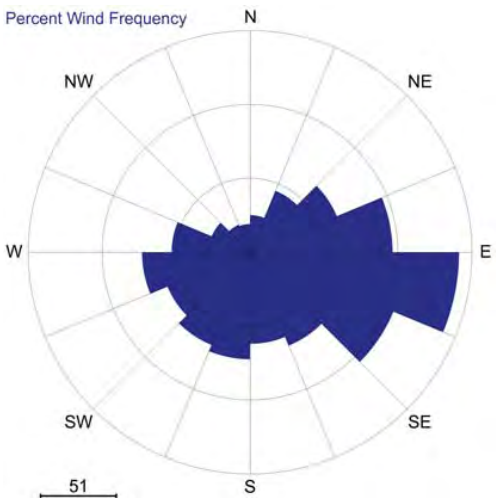
Air Density: 1.156 kg/m3

Mean Power Density: 122 W/m^2

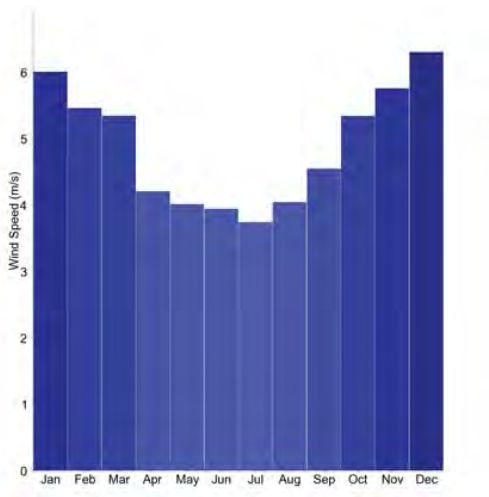
Uncertainty Value: 0.35 +/- m/s

Weibull A: 5.52 Weibull k: 2.13

200m Graphs



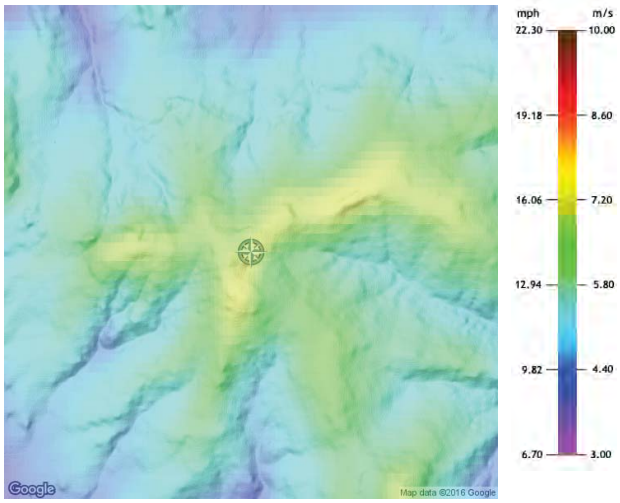
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 3



Mean annual wind speed map at 100 m hub height for Miller's Ridge, Carmacks.

Latitude: 62.16839 Longitude: -136.6555

Wind Speed (100.0 m): 7.32 m/s

Roughness: 1.1250 m Elevation: 1,458.3 m (4,784.4 ft)

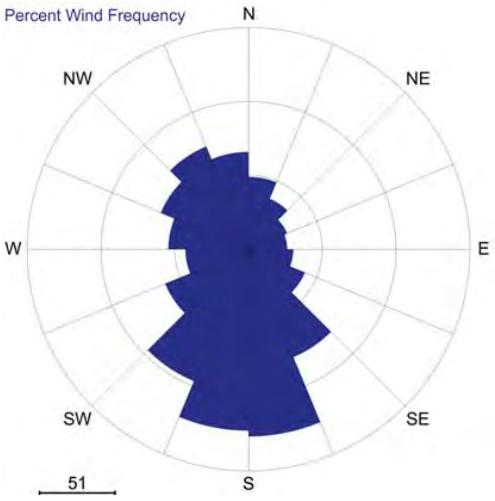
Air Density: 1.092 kg/m3

Mean Power Density: 416 W/m^2

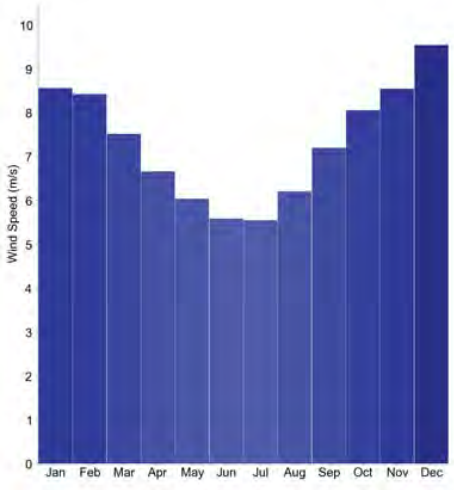
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.26 Weibull k: 1.96

200m Graphs



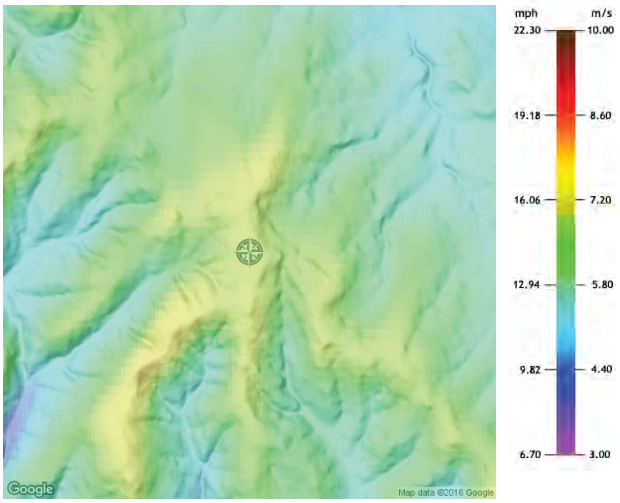
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 17



Mean annual wind speed map at 100 m hub height for Hill E of Minto.

Latitude: 62.54526 Longitude: -136.35544

Wind Speed (100.0 m): 7.15 m/s

Roughness: 0.1000 m Elevation: 1,243.8 m (4,080.7 ft)

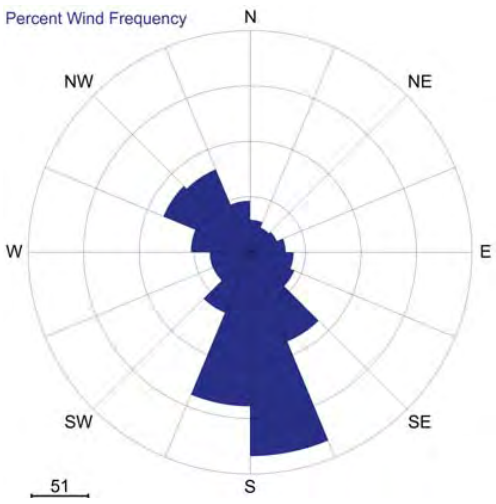
Air Density: 1.108 kg/m3

Mean Power Density: 400 W/m^2

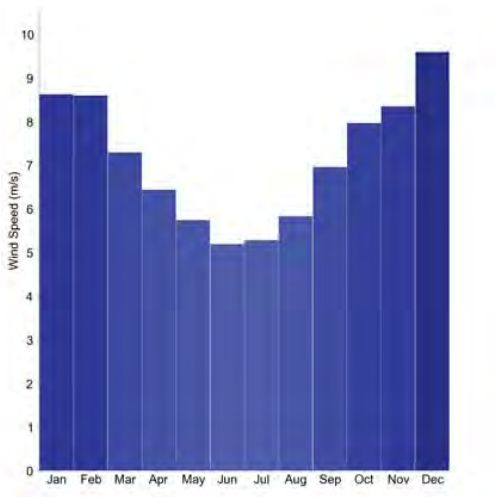
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.06 Weibull k: 1.94

200m Graphs



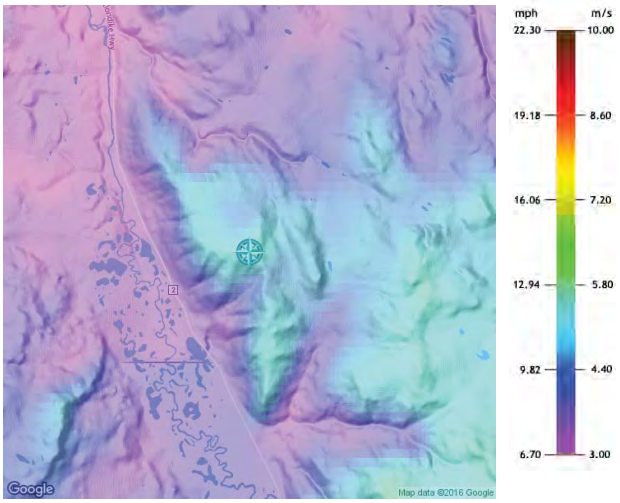
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 21



Mean annual wind speed map at 100 m hub height for Mt. Berdoe.

Latitude: 62.02153 Longitude: -136.22189

Wind Speed (100.0 m): 5.54 m/s

Roughness: 0.1000 m Elevation: 1,051.9 m (3,451.1 ft)

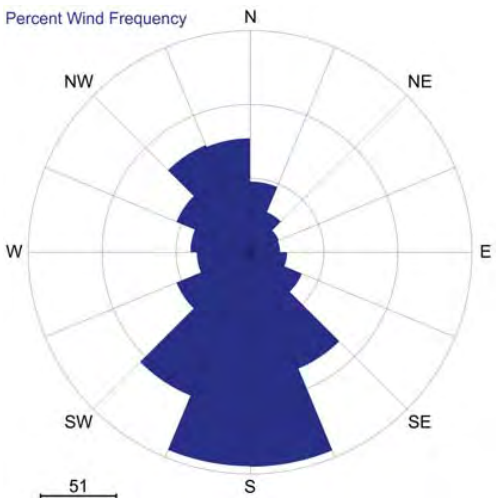
Air Density: 1.145 kg/m3

Mean Power Density: 186 W/m^2

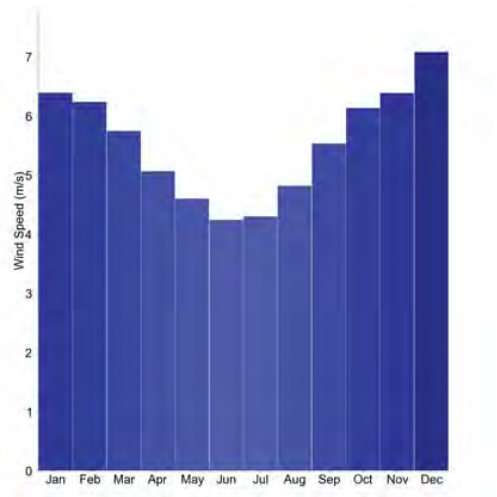
Uncertainty Value: 0.35 +/- m/s

Weibull A: 6.26 Weibull k: 2.01

200m Graphs



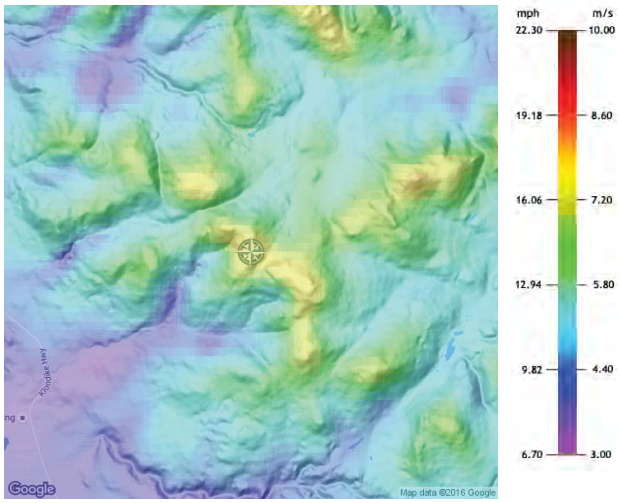
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 8



Mean annual wind speed map at 100 m hub height for Mt. Lorne subpeak.

Latitude: 60.39367 Longitude: -134.69444

Wind Speed (100.0 m): 7.71 m/s

Roughness: 0.1000 m Elevation: 1,703.9 m (5,590.2 ft)

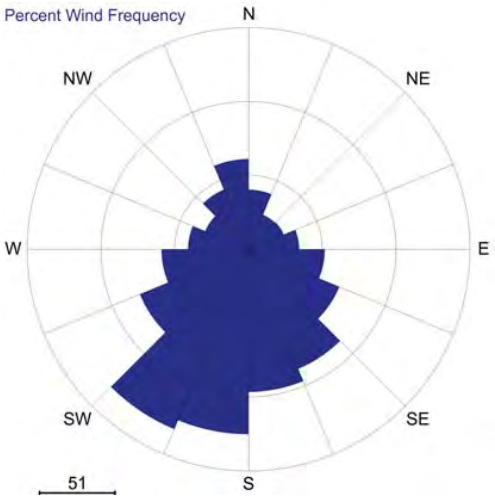
Air Density: 1.078 kg/m3

Mean Power Density: 457 W/m^2

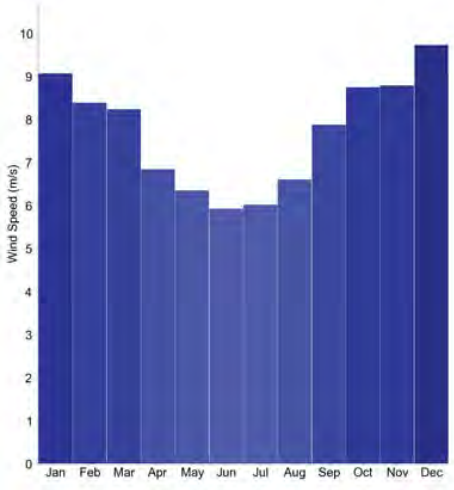
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.70 Weibull k: 2.07

200m Graphs



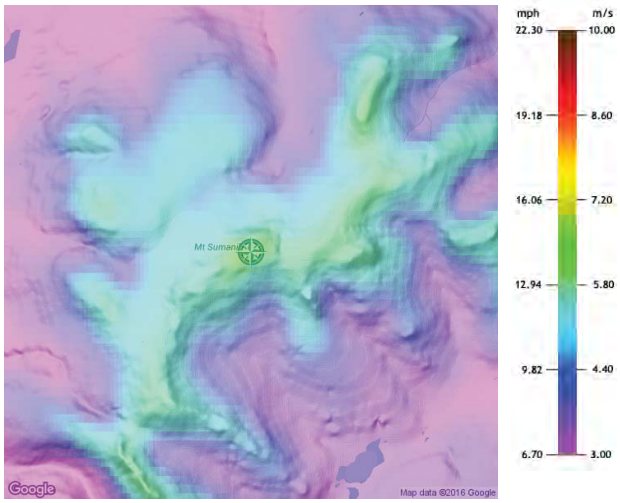
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 4



Mean annual wind speed map at 100 m hub height for Mt. Sumanik.

Latitude: 60.7454 Longitude: -135.3241

Wind Speed (100.0 m): 6.7 m/s

Roughness: 0.0100 m Elevation: 1,674.8 m (5,494.8 ft)

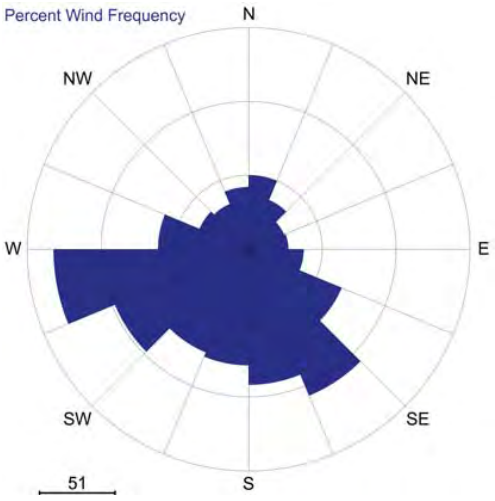
Air Density: 1.084 kg/m3

Mean Power Density: 309 W/m^2

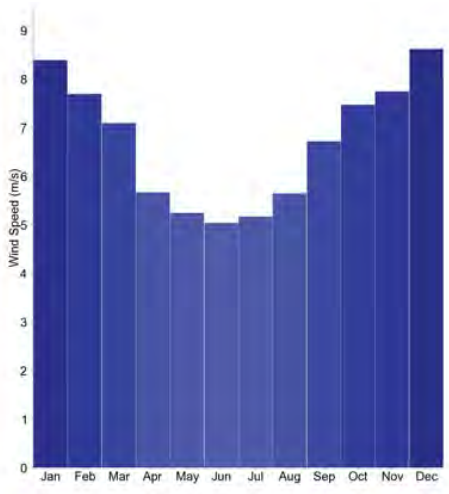
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.57 Weibull k: 2.02

200m Graphs



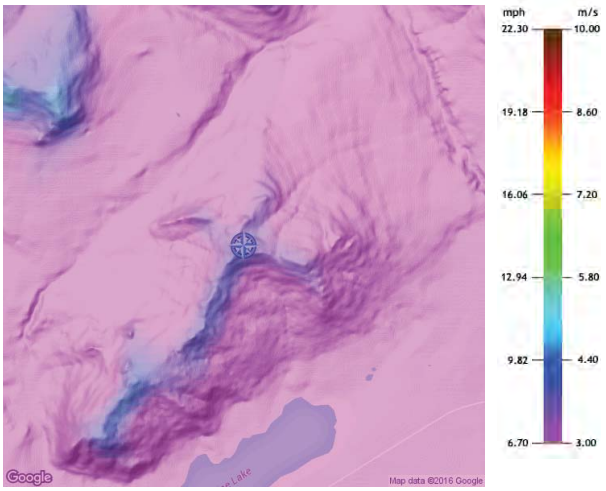
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 24



Mean annual wind speed map at 100 m hub height for Paint Mtn.

Latitude: 60.86631 Longitude: -137.44446

Wind Speed (100.0 m): 3.92 m/s

Roughness: 0.1000 m Elevation: 1,488.4 m (4,883.2 ft)

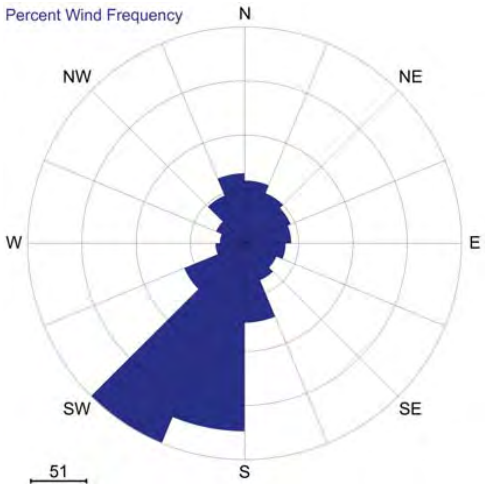
Air Density: 1.102 kg/m3

Mean Power Density: 66 W/m^2

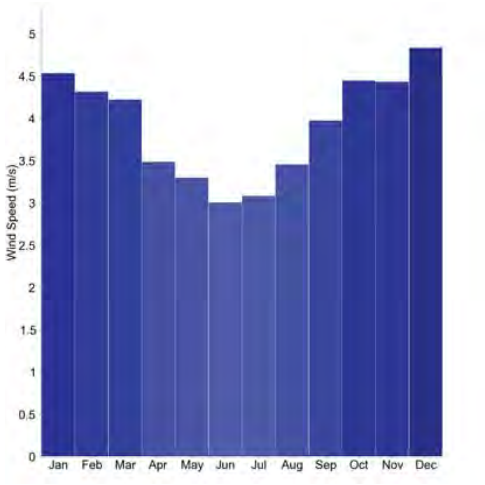
Uncertainty Value: 0.35 +/- m/s

Weibull A: 4.41 Weibull k: 1.92

200m Graphs



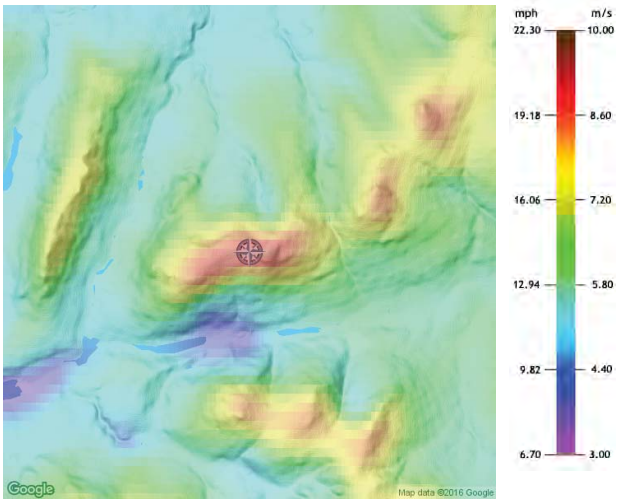
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 26



Mean annual wind speed map at 100 m hub height for Hill 75 km SE Ross River.

Latitude: 61.5649 Longitude: -131.37554

Wind Speed (100.0 m): 9.1 m/s

Roughness: 0.0500 m Elevation: 1,704.7 m (5,592.8 ft)

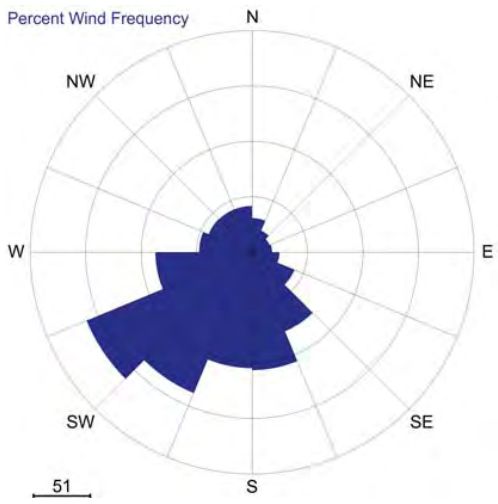
Air Density: 1.124 kg/m3

Mean Power Density: 850 W/m^2

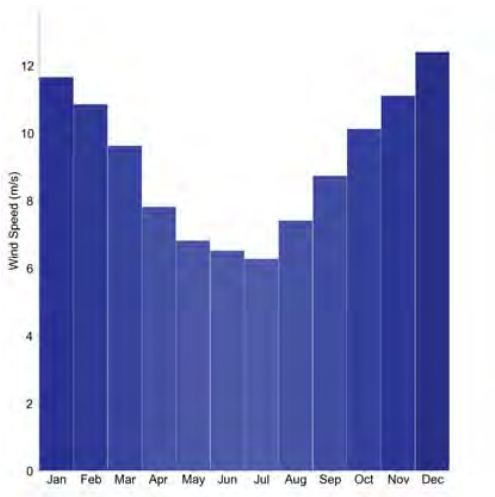
Uncertainty Value: 0.35 +/- m/s

Weibull A: 10.26 Weibull k: 1.91

200m Graphs



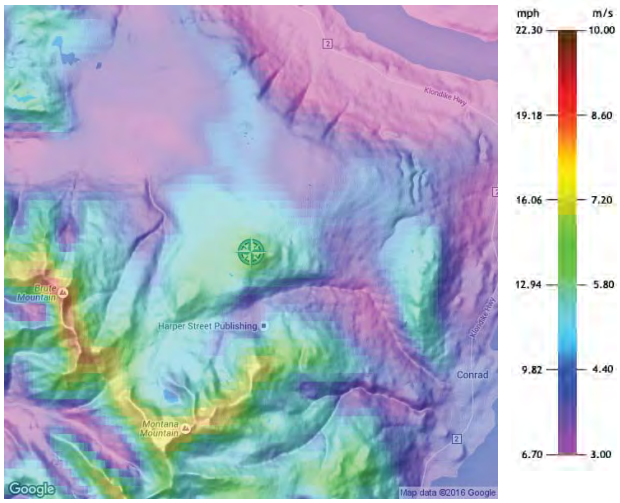
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 5



Mean annual wind speed map at 100 m hub height for Sugarloaf Mtn.

Latitude: 60.09481 Longitude: -134.66389

Wind Speed (100.0 m): 6.45 m/s

Roughness: 0.1000 m Elevation: 1,787.7 m (5,865.2 ft)

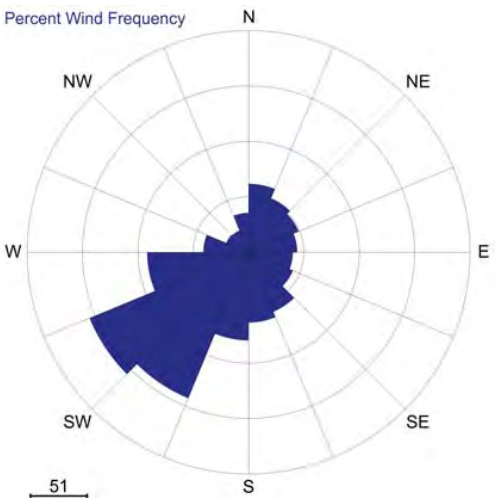
Air Density: 1.062 kg/m3

Mean Power Density: 280 W/m^2

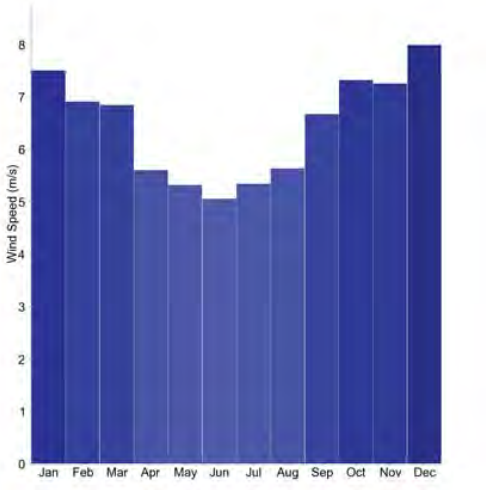
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.28 Weibull k: 1.95

200m Graphs



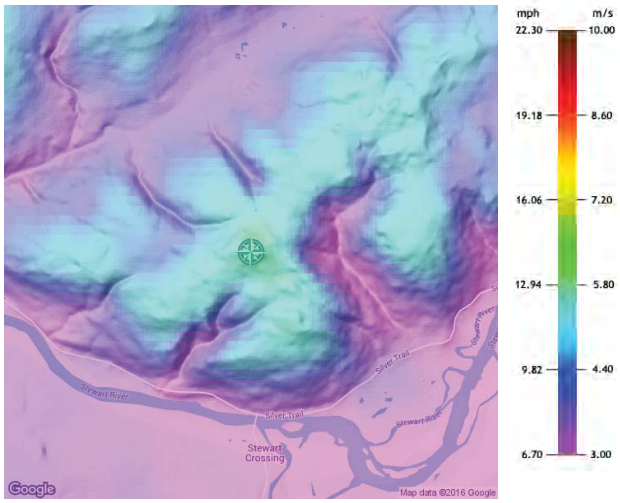
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 6



Mean annual wind speed map at 100 m hub height for Tehcho.

Latitude: 63.41273 Longitude: -136.68365

Wind Speed (100.0 m): 5.97 m/s

Roughness: 0.1000 m Elevation: 1,211.3 m (3,974.1 ft)

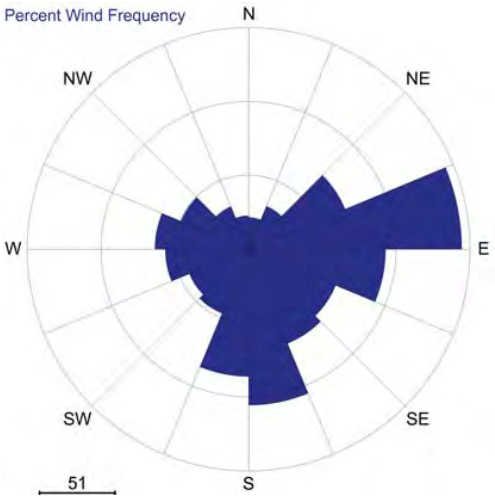
Air Density: 1.135 kg/m3

Mean Power Density: 219 W/m^2

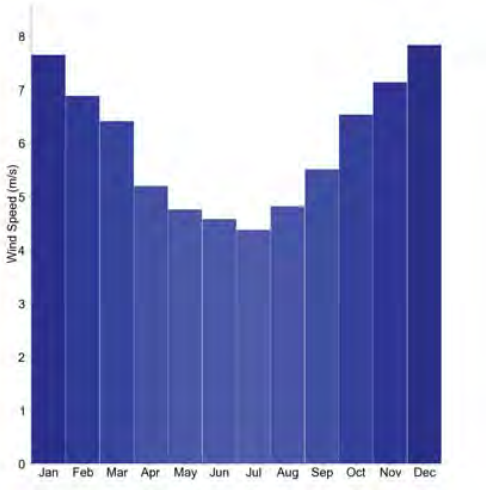
Uncertainty Value: 0.35 +/- m/s

Weibull A: 6.74 Weibull k: 2.11

200m Graphs



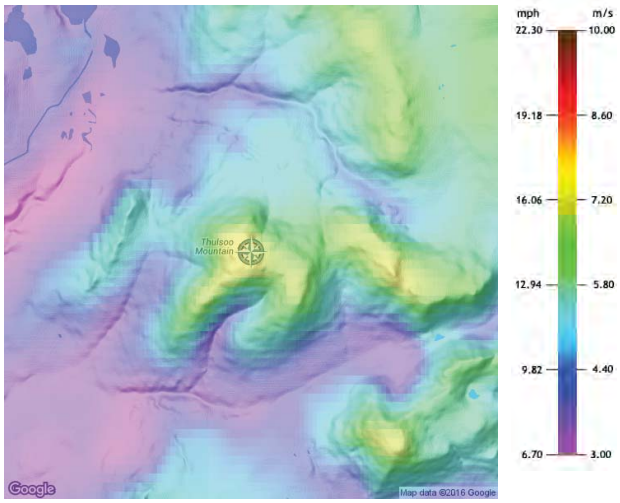
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 7



Mean annual wind speed map at 100 m hub height for Thulsoo Mtn.

Latitude: 61.03419 Longitude: -136.93222

Wind Speed (100.0 m): 7.66 m/s

Roughness: 0.0100 m Elevation: 1,876.5 m (6,156.5 ft)

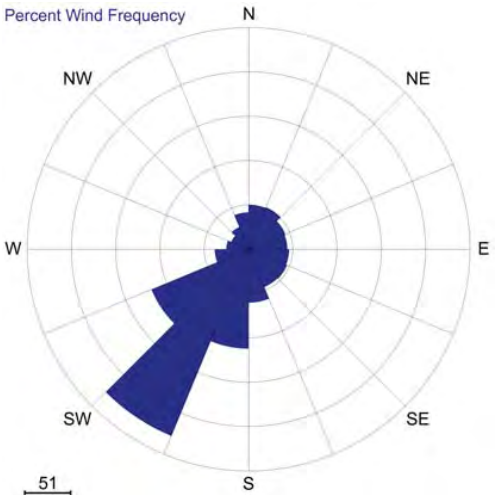
Air Density: 1.065 kg/m3

Mean Power Density: 439 W/m^2

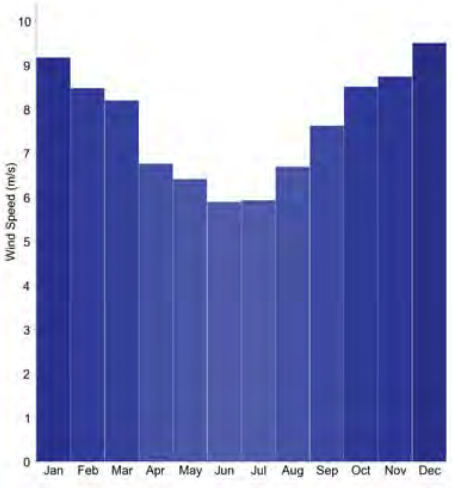
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.65 Weibull k: 2.08

200m Graphs



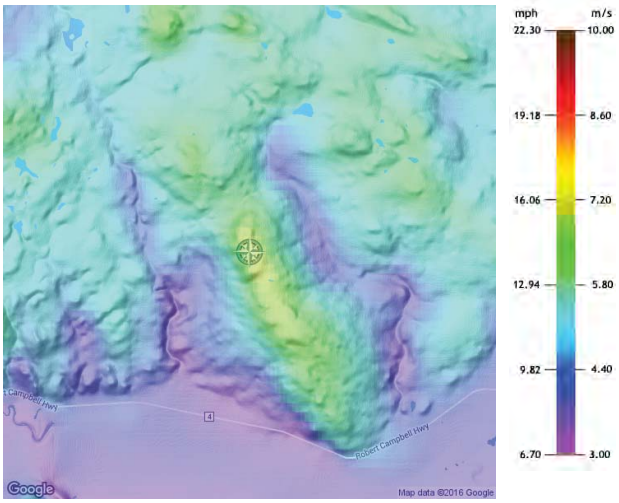
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 11



Mean annual wind speed map at 100 m hub height for West of Faro, N of Hwy 4.

Latitude: 62.20139 Longitude: -133.91785

Wind Speed (100.0 m): 7.31 m/s

Roughness: 0.1000 m Elevation: 1,371.9 m (4,501.0 ft)

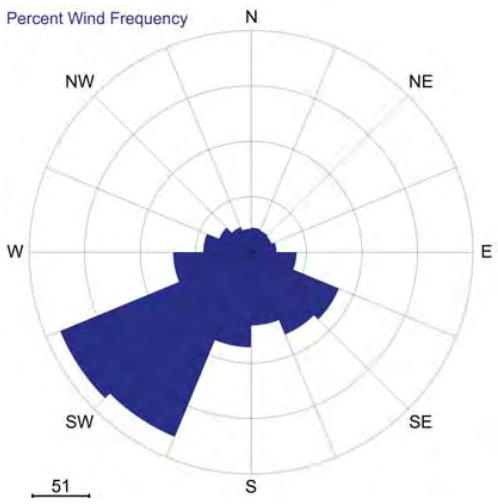
Air Density: 1.142 kg/m3

Mean Power Density: 414 W/m^2

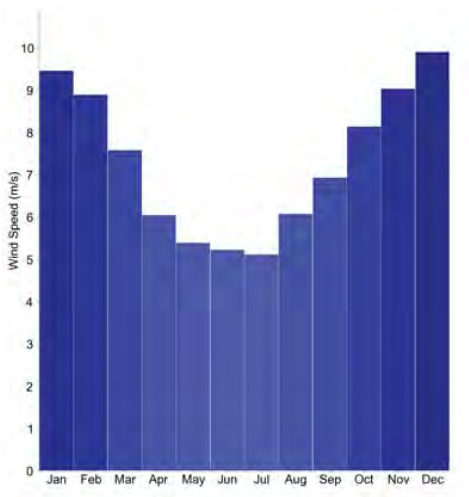
Uncertainty Value: 0.35 +/- m/s

Weibull A: 8.25 Weibull k: 2.06

200m Graphs



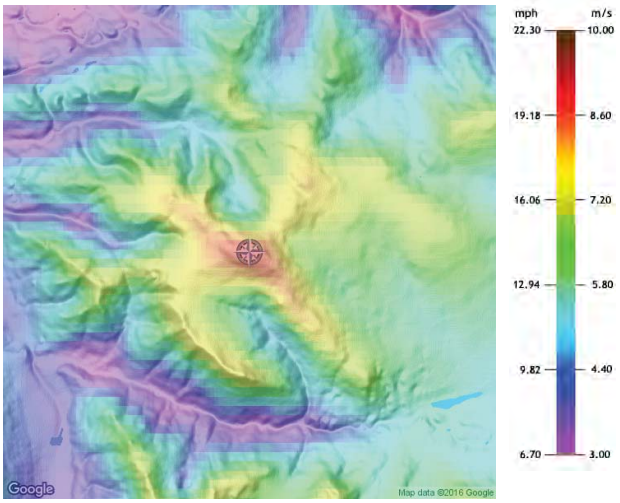
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 12



Mean annual wind speed map at 100 m hub height for West of Faro, S of Hwy 4.

Latitude: 62.07624 Longitude: -133.77022

Wind Speed (100.0 m): 8.83 m/s

Roughness: 0.0100 m Elevation: 1,852.3 m (6,077.1 ft)

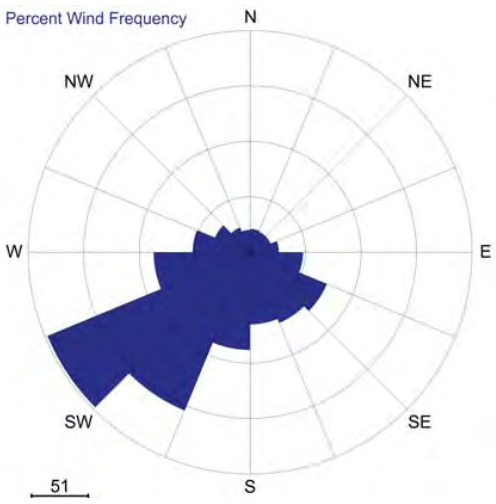
Air Density: 1.054 kg/m3

Mean Power Density: 683 W/m^2

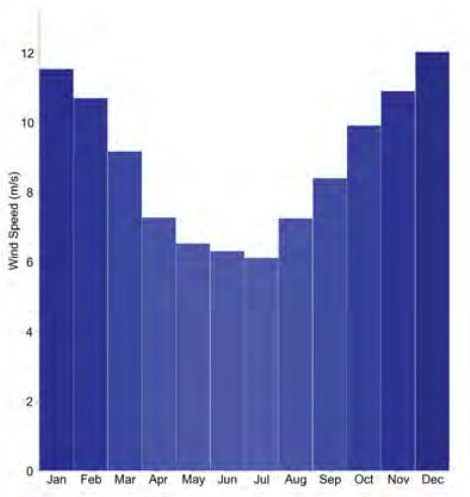
Uncertainty Value: 0.35 +/- m/s

Weibull A: 9.97 Weibull k: 2.03

200m Graphs



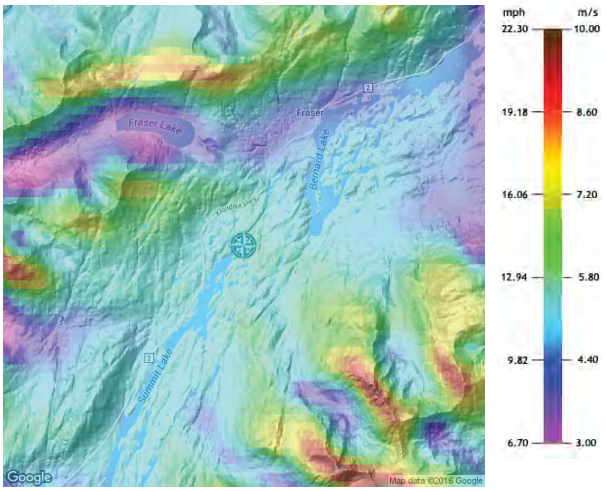
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 25



Mean annual wind speed map at 100 m hub height for White Pass.

Latitude: 59.68854 Longitude: -135.07759

Wind Speed (100.0 m): 5.4 m/s

Roughness: 0.0010 m Elevation: 886.7 m (2,909.1 ft)

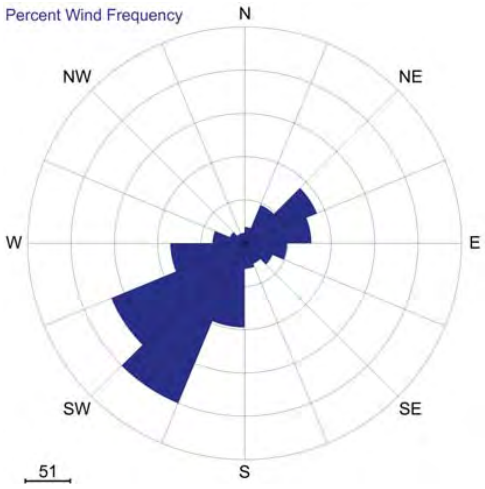
Air Density: 1.137 kg/m3

Mean Power Density: 169 W/m^2

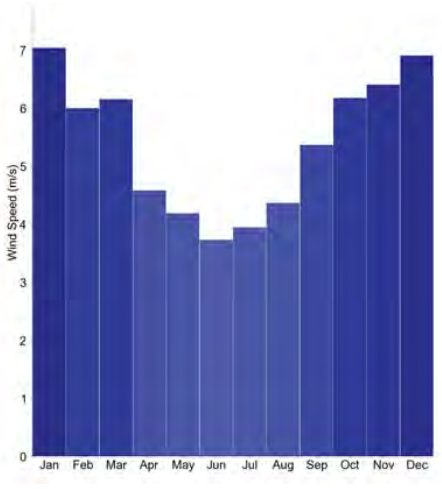
Uncertainty Value: 0.35 +/- m/s

Weibull A: 6.09 Weibull k: 2.02

200m Graphs



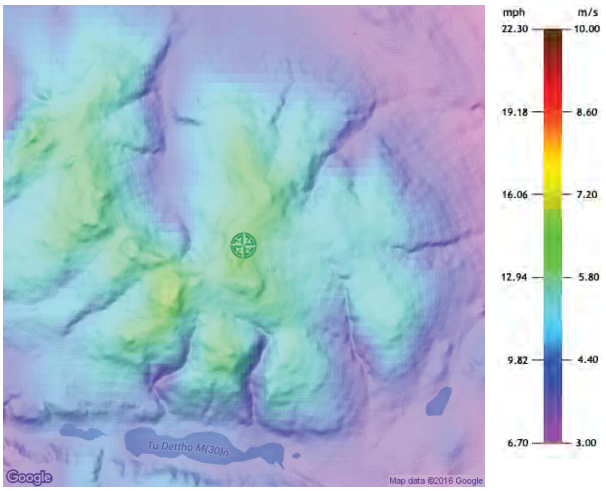
Wind Rose



Monthly Distribution

Site Characteristics

Site ID: 19



Mean annual wind speed map at 100 m hub height for Willow Hills.

Latitude: 63.2262 Longitude: -136.75919

Wind Speed (100.0 m): 6.53 m/s

Roughness: 0.1000 m Elevation: 1,305.6 m (4,283.5 ft)

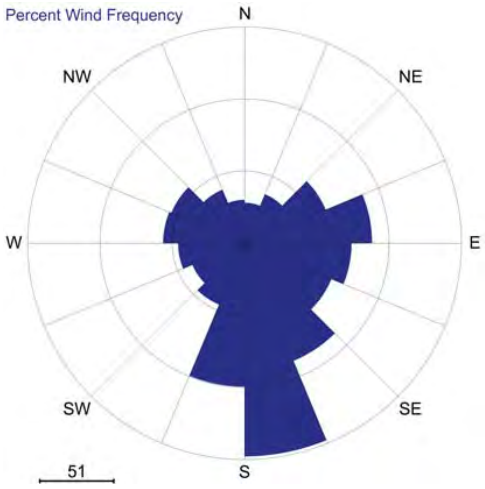
Air Density: 1.115 kg/m3

Mean Power Density: 286 W/m^2

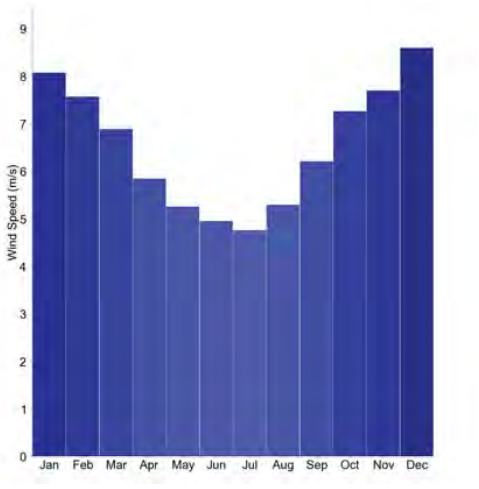
Uncertainty Value: 0.35 +/- m/s

Weibull A: 7.37 Weibull k: 2.07

200m Graphs



Wind Rose



Monthly Distribution

APPENDIX F – ADDITIONAL PHOTOS FROM SITE VISITS

(in alphabetical order)

Anticline Mtn Ridges, view North

Anticline Mtn, South Ridge detail, view NW

Cyprus Mine Hill, alternate SE ridge, view north

Cyprus Mine Hill, north ridge, access point, view SE

Flat Mountain, view north

Flat Mountain complex, view north

Hayes Peak Ride Area, view SW

Hayes Peak, view S

Kluane Lake East Shore, view East

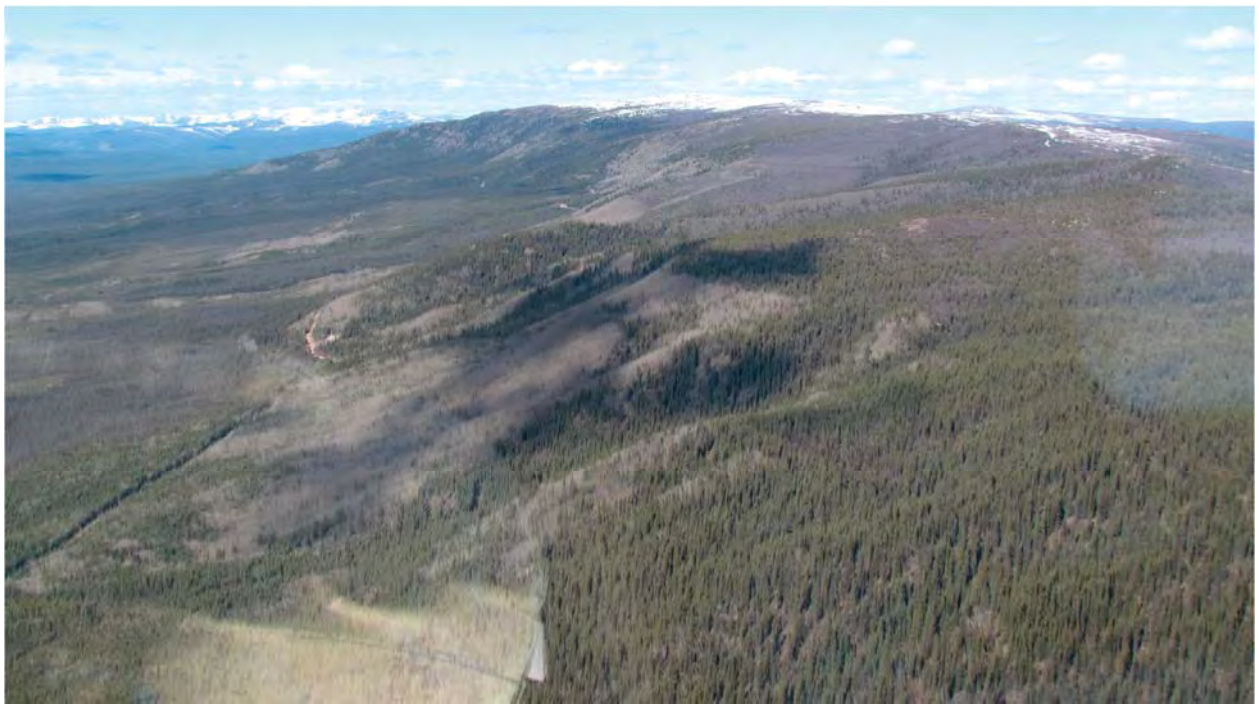
Little Salmon Hill, view west, showing access road

Little Salmon Hill, south ridge, view E

Little Salmon Hill, north ridge, view E

Miller's Ridge, view to Murray Peak, view N

Miller's Ridge, from near Carmacks, view W



Minto Hill, view NW

Mount Berdoe, view North

Mount Berdoe summit, view W

Mount Lorne Subpeak, view NW

Mount Lorne Subpeak, southside, view N

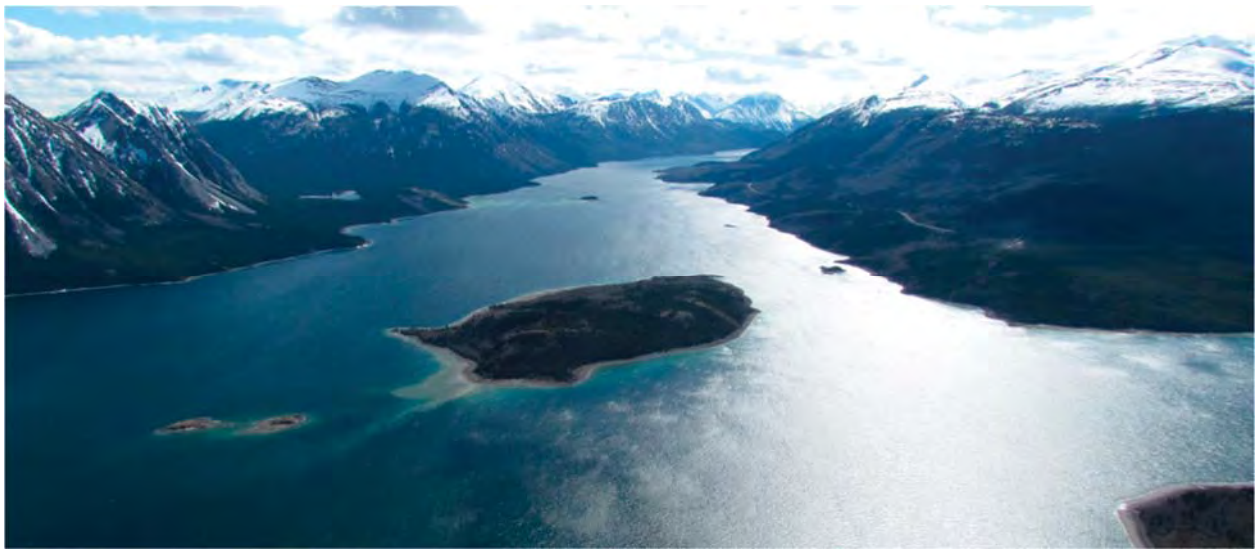
Paint Mountain, view north

Sugarloaf Mtn, Northeast face, view N

Sugarloaf Mtn, Montana Mtn, access road, view S

Mt Sumanik ridge, view N

Tagish Lake and Bowe Mountain, view south



APPENDIX G – WASP WIND FARM REPORTS

Cyprus Mine Hill

Table 1 Cyprus 20 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,810 m	5.44 GWh	0.36%	6.87 m/s	283 W/m²
Turbine #2	1,850 m	5.80 GWh	4.25%	7.23 m/s	330 W/m²
Turbine #3	1,840 m	5.75 GWh	1.73%	7.10 m/s	326 W/m²
Turbine #4	1,850 m	5.88 GWh	2.73%	7.22 m/s	335 W/m²
Turbine #5	1,825 m	5.20 GWh	3.69%	6.83 m/s	277 W/m²
Turbine #6	1,850 m	6.18 GWh	5.94%	7.55 m/s	378 W/m²
Turbine #7	1,822 m	5.89 GWh	1.92%	7.23 m/s	350 W/m²
Turbine #8	1,850 m	6.39 GWh	1.10%	7.46 m/s	353 W/m²
Turbine #9	1,850 m	6.15 GWh	3.32%	7.41 m/s	351 W/m²
Turbine #10	1,784 m	5.44 GWh	1.16%	6.90 m/s	282 W/m²
Average		**5.81 GWh**	**2.62%**	**2.62%**	**2.62%**
Total		**58.12 GWh**			

* Including wake losses, but excluding other losses

Table 2 Cyprus 10 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,850 m	6.48 GWh	1.41%	7.55 m/s	378 W/m²
Turbine #2	1,822 m	5.97 GWh	0.65%	7.23 m/s	350 W/m²
Turbine #3	1,850 m	6.41 GWh	0.85%	7.46 m/s	353 W/m²
Turbine #4	1,850 m	6.16 GWh	3.22%	7.41 m/s	351 W/m²
Turbine #5	1,784 m	5.44 GWh	1.10%	6.90 m/s	282 W/m²
Average		**6.09 GWh**	**1.45%**	**7.31 m/s**	**343 W/m²**
Total		**30.45 GWh**			

* Including wake losses, but excluding other losses

Table 3 Cyprus 6 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,850 m	6.48 GWh	1.38%	7.55 m/s	378 W/m²
Turbine #2	1,822 m	5.97 GWh	0.62%	7.23 m/s	350 W/m²
Turbine #3	1,850 m	6.43 GWh	0.47%	7.46 m/s	353 W/m²
Average		**6.29 GWh**	**0.82%**	**7.41 m/s**	**360 W/m²**
Total		**18.88 GWh**			

* Including wake losses, but excluding other losses

Kluane Lake (West shore)

Table 4 Kluane Lake 20 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	821 m	5.34 GWh	3.42%	6.57 m/s	310 W/m²
Turbine #2	816 m	5.18 GWh	5.25%	6.53 m/s	305 W/m²
Turbine #3	821 m	5.21 GWh	5.69%	6.57 m/s	310 W/m²
Turbine #4	828 m	5.37 GWh	4.00%	6.61 m/s	316 W/m²
Turbine #5	815 m	5.32 GWh	1.63%	6.49 m/s	301 W/m²
Turbine #6	803 m	5.25 GWh	4.60%	6.55 m/s	309 W/m²
Turbine #7	800 m	5.10 GWh	6.22%	6.52 m/s	303 W/m²
Turbine #8	801 m	5.14 GWh	5.89%	6.53 m/s	306 W/m²
Turbine #9	808 m	5.27 GWh	4.95%	6.58 m/s	313 W/m²
Turbine #10	806 m	5.37 GWh	2.89%	6.57 m/s	312 W/m²
Average		**5.26 GWh**	**4.45%**	**6.55 m/s**	**309 W/m²**
Total		**52.56 GWh**			

* Including wake losses, but excluding other losses

Table 5 Kluane Lake 10 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	821 m	5.34 GWh	3.49%	6.57 m/s	310 W/m²
Turbine #2	828 m	5.41 GWh	3.33%	6.61 m/s	316 W/m²
Turbine #3	815 m	5.33 GWh	1.42%	6.49 m/s	301 W/m²
Turbine #4	808 m	5.38 GWh	3.13%	6.58 m/s	313 W/m²
Turbine #5	806 m	5.40 GWh	2.31%	6.57 m/s	312 W/m²
Average		**5.37 GWh**	**2.74%**	**6.56 m/s**	**310 W/m²**
Total		**26.85 GWh**			

* Including wake losses, but excluding other losses

Table 6 Kluane Lake 6 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	821 m	5.40 GWh	2.29%	6.57 m/s	310 W/m²
Turbine #2	828 m	5.53 GWh	1.06%	6.61 m/s	316 W/m²
Turbine #3	808 m	5.51 GWh	0.69%	6.58 m/s	313 W/m²
Average		**5.48 GWh**	**1.35%**	**6.59 m/s**	**313 W/m²**
Total		**16.44 GWh**			

* Including wake losses, but excluding other losses

Miller's Ridge

Table 7 Miller's Ridge 20 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electric-ity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,404 m	6.99 GWh	1.48%	7.86 m/s	511 W/m²
Turbine #2	1,417 m	6.90 GWh	1.78%	7.80 m/s	498 W/m²
Turbine #3	1,441 m	7.06 GWh	1.85%	7.88 m/s	504 W/m²
Turbine #4	1,450 m	6.81 GWh	2.19%	7.70 m/s	461 W/m²
Turbine #5	1,450 m	6.47 GWh	2.50%	7.51 m/s	426 W/m²
Turbine #6	1,450 m	6.28 GWh	2.65%	7.40 m/s	407 W/m²
Turbine #7	1,450 m	6.40 GWh	2.01%	7.48 m/s	432 W/m²
Turbine #8	1,450 m	6.58 GWh	1.06%	7.57 m/s	456 W/m²
Turbine #9	1,500 m	6.76 GWh	2.18%	7.70 m/s	456 W/m²
Turbine #10	1,500 m	6.46 GWh	2.58%	7.47 m/s	404 W/m²
Average		**6.67 GWh**	**2.03%**	**7.64 m/s**	**456 W/m²**
Total		**66.71 GWh**			

* Including wake losses, but excluding other losses

Table 8 Miller's Ridge 10 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,404 m	7.00 GWh	1.43%	7.86 m/s	511 W/m²
Turbine #2	1,417 m	6.91 GWh	1.64%	7.80 m/s	498 W/m²
Turbine #3	1,441 m	7.07 GWh	1.69%	7.88 m/s	504 W/m²
Turbine #4	1,450 m	6.84 GWh	1.70%	7.70 m/s	461 W/m²
Turbine #5	1,450 m	6.60 GWh	0.53%	7.51 m/s	426 W/m²
Average		**6.88 GWh**	**1.40%**	**7.75 m/s**	**480 W/m²**
Total		**34.42 GWh**			

* Including wake losses, but excluding other losses

Table 9 Miller's Ridge 6 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,404 m	7.00 GWh	1.31%	7.86 m/s	511 W/m²
Turbine #2	1,417 m	6.93 GWh	1.36%	7.80 m/s	498 W/m²
Turbine #3	1,441 m	7.17 GWh	0.32%	7.88 m/s	504 W/m²
Average		**7.03 GWh**	**1.00%**	**7.85 m/s**	**504 W/m²**
Total		**21.10 GWh**			

* Including wake losses, but excluding other losses

Sugarloaf Mountain

Table 10 Sugarloaf 20 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,203 m	3.96 GWh	0.58%	5.84 m/s	205 W/m²
Turbine #2	1,206 m	3.60 GWh	0.95%	5.57 m/s	187 W/m²
Turbine #3	1,306 m	3.78 GWh	1.15%	5.70 m/s	199 W/m²
Turbine #4	1,303 m	3.43 GWh	1.17%	5.52 m/s	174 W/m²
Turbine #5	1,397 m	3.53 GWh	1.36%	5.60 m/s	183 W/m²
Turbine #6	1,406 m	3.68 GWh	1.39%	5.70 m/s	191 W/m²
Turbine #7	1,402 m	3.88 GWh	0.90%	5.81 m/s	207 W/m²
Turbine #8	1,403 m	3.74 GWh	1.12%	5.73 m/s	198 W/m²
Turbine #9	1,402 m	3.80 GWh	1.30%	5.77 m/s	203 W/m²
Turbine #10	1,395 m	3.71 GWh	0.56%	5.70 m/s	196 W/m²
Average		**3.71 GWh**	**1.05%**	**5.69 m/s**	**194 W/m²**
Total		**37.11 GWh**			

* Including wake losses, but excluding other losses

Table 11 Sugarloaf 10 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,203 m	3.96 GWh	0.52%	5.84 m/s	205 W/m²
Turbine #2	1,206 m	3.60 GWh	0.87%	5.57 m/s	187 W/m²
Turbine #3	1,306 m	3.79 GWh	1.06%	5.70 m/s	199 W/m²
Turbine #4	1,303 m	3.44 GWh	0.84%	5.52 m/s	174 W/m²
Turbine #5	1,397 m	3.56 GWh	0.58%	5.60 m/s	183 W/m²
Average		**3.67 GWh**	**0.77%**	**5.65 m/s**	**190 W/m²**
Total		**18.35 GWh**			

* Including wake losses, but excluding other losses

Table 12 Sugarloaf 6 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,203 m	3.96 GWh	0.50%	5.84 m/s	205 W/m²
Turbine #2	1,206 m	3.61 GWh	0.69%	5.57 m/s	187 W/m²
Turbine #3	1,306 m	3.81 GWh	0.42%	5.70 m/s	199 W/m²
Average		**3.79 GWh**	**0.54%**	**5.70 m/s**	**197 W/m²**
Total		**11.38 GWh**			

* Including wake losses, but excluding other losses

Mount Sumanik

Table 13 Mount Sumanik 20 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,470 m	5.66 GWh	1.70%	6.89 m/s	324 W/m²
Turbine #2	1,500 m	5.54 GWh	1.86%	6.83 m/s	325 W/m²
Turbine #3	1,500 m	5.14 GWh	1.82%	6.57 m/s	290 W/m²
Turbine #4	1,500 m	4.83 GWh	1.46%	6.38 m/s	258 W/m²
Turbine #5	1,543 m	4.38 GWh	2.90%	6.15 m/s	232 W/m²
Turbine #6	1,553 m	4.45 GWh	2.59%	6.17 m/s	246 W/m²
Turbine #7	1,563 m	4.25 GWh	2.89%	6.05 m/s	229 W/m²
Turbine #8	1,581 m	4.18 GWh	3.25%	6.03 m/s	222 W/m²
Turbine #9	1,583 m	4.85 GWh	4.62%	6.50 m/s	263 W/m²
Turbine #10	1,600 m	4.86 GWh	0.92%	6.39 m/s	252 W/m²
Average		**4.81 GWh**	**2.40%**	**6.40 m/s**	**264 W/m²**
Total		**48.13 GWh**			

* Including wake losses, but excluding other losses

Table 14 Mount Sumanik 10 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,500 m	5.56 GWh	1.52%	6.83 m/s	325 W/m²
Turbine #2	1,500 m	5.15 GWh	1.72%	6.57 m/s	290 W/m²
Turbine #3	1,500 m	4.84 GWh	1.16%	6.38 m/s	258 W/m²
Turbine #4	1,543 m	4.42 GWh	2.03%	6.15 m/s	232 W/m²
Turbine #5	1,553 m	4.55 GWh	0.27%	6.17 m/s	246 W/m²
Average		**4.90 GWh**	**1.34%**	**6.42 m/s**	**270 W/m²**
Total		**24.52 GWh**			

* Including wake losses, but excluding other losses

Table 15 Mount Sumanik 6 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,470 m	5.67 GWh	1.53%	6.89 m/s	324 W/m²
Turbine #2	1,500 m	5.56 GWh	1.51%	6.83 m/s	325 W/m²
Turbine #3	1,500 m	5.22 GWh	0.34%	6.57 m/s	290 W/m²
Average		**5.48 GWh**	**1.13%**	**6.76 m/s**	**313 W/m²**
Total		**16.45 GWh**			

* Including wake losses, but excluding other losses

Tehcho (Ferry Hill)

Table 16 Tehcho 20 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,145 m	3.35 GWh	7.60%	5.65 m/s	167 W/m²
Turbine #2	1,186 m	4.00 GWh	4.83%	5.94 m/s	192 W/m²
Turbine #3	1,196 m	4.07 GWh	7.22%	6.03 m/s	201 W/m²
Turbine #4	1,124 m	3.63 GWh	6.19%	5.71 m/s	176 W/m²
Turbine #5	1,101 m	4.25 GWh	4.28%	5.99 m/s	209 W/m²
Turbine #6	1,061 m	3.87 GWh	3.44%	5.80 m/s	182 W/m²
Turbine #7	1,098 m	3.56 GWh	8.15%	5.71 m/s	177 W/m²
Turbine #8	1,093 m	4.27 GWh	4.53%	6.03 m/s	207 W/m²
Turbine #9	1,061 m	4.36 GWh	1.38%	6.03 m/s	203 W/m²
Turbine #10	970 m	3.82 GWh	0.66%	5.71 m/s	174 W/m²
Average		**3.92 GWh**	**4.83%**	**5.86 m/s**	**189 W/m²**
Total		**39.15 GWh**			

* Including wake losses, but excluding other losses

Table 17 Tehcho 10 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,186 m	4.07 GWh	3.15%	5.94 m/s	192 W/m²
Turbine #2	1,196 m	4.24 GWh	3.15%	6.03 m/s	201 W/m²
Turbine #3	1,101 m	4.38 GWh	1.26%	5.99 m/s	209 W/m²
Turbine #4	1,093 m	4.36 GWh	2.46%	6.03 m/s	207 W/m²
Turbine #5	1,061 m	4.41 GWh	0.23%	6.03 m/s	203 W/m²
Average		**4.29 GWh**	**2.05%**	**6.00 m/s**	**202 W/m²**
Total		**21.46 GWh**			

* Including wake losses, but excluding other losses

Table 18 Tehcho 6 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,186 m	4.08 GWh	2.86%	5.94 m/s	192 W/m²
Turbine #2	1,196 m	4.21 GWh	3.99%	6.03 m/s	201 W/m²
Turbine #3	1,124 m	3.80 GWh	1.83%	5.71 m/s	176 W/m²
Average		**4.03 GWh**	**2.89%**	**5.89 m/s**	**190 W/m²**
Total		**12.08 GWh**			

* Including wake losses, but excluding other losses

Thulsoo Mountain

Table 19 Thulsoo 20 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,850 m	7.05 GWh	1.39%	7.91 m/s	459 W/m²
Turbine #2	1,850 m	6.50 GWh	1.40%	7.55 m/s	407 W/m²
Turbine #3	1,826 m	6.60 GWh	0.90%	7.62 m/s	438 W/m²
Turbine #4	1,811 m	6.14 GWh	1.09%	7.31 m/s	380 W/m²
Turbine #5	1,803 m	5.84 GWh	0.68%	7.10 m/s	332 W/m²
Turbine #6	1,781 m	6.38 GWh	1.30%	7.50 m/s	419 W/m²
Turbine #7	1,800 m	5.97 GWh	3.78%	7.32 m/s	381 W/m²
Turbine #8	1,800 m	6.53 GWh	2.68%	7.67 m/s	447 W/m²
Turbine #9	1,789 m	6.59 GWh	1.15%	7.65 m/s	448 W/m²
Turbine #10	1,769 m	6.14 GWh	0.30%	7.28 m/s	366 W/m²
Average		**6.37 GWh**	**1.47%**	**7.49 m/s**	**408 W/m²**
Total		**63.74 GWh**			

* Including wake losses, but excluding other losses

Table 20 Thulsoo 10 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,850 m	7.06 GWh	1.30%	7.91 m/s	459 W/m²
Turbine #2	1,850 m	6.50 GWh	1.34%	7.55 m/s	407 W/m²
Turbine #3	1,826 m	6.61 GWh	0.82%	7.62 m/s	438 W/m²
Turbine #4	1,811 m	6.15 GWh	0.90%	7.31 m/s	380 W/m²
Turbine #5	1,803 m	5.87 GWh	0.29%	7.10 m/s	332 W/m²
Average		**6.44 GWh**	**0.93%**	**7.50 m/s**	**403 W/m²**
Total		**32.18 GWh**			

* Including wake losses, but excluding other losses

Table 21 Thulsoo 6 MW Wind Farm Site-Specific Data at 80 m Hub Height; Generic Turbine

Site	Elevation above sea level	Annual electricity production*	Wake loss	Wind speed	Wind energy
Turbine #1	1,850 m	7.06 GWh	1.19%	7.91 m/s	459 W/m²
Turbine #2	1,850 m	6.52 GWh	1.13%	7.55 m/s	407 W/m²
Turbine #3	1,826 m	6.66 GWh	0.11%	7.62 m/s	438 W/m²
Average		**6.75 GWh**	**0.81%**	**7.69 m/s**	**435 W/m²**
Total		**20.24 GWh**			

* Including wake losses, but excluding other losses

APPENDIX H – ENERGY PERFORMANCE OF THE SELECTED SITES

1 CYPRUS MINE HILL

Wind turbines at Cyprus Mine would perform well. A 2.0 MW turbine would produce between 5.2 and 6.5 GWh of energy annually, depending on the size of the wind farm and the particular location of the turbine within the site. This is 14% to 17% less than the same turbine at Miller's Ridge, the top wind resource site.

1.1 Annual Energy Production

WAsP modeling of the three wind farm capacity options – 20 MW, 10 MW and 6 MW – indicates an approximate 33% wind turbine net capacity factor based on the net annual energy production (AEP) given in Table 22 below.[1] A 33% capacity factor is very good but perhaps could be slightly improved upon with a wind turbine model more attuned to this site, in place of the generic 2 MW model for the modeling exercise. Chapter 1.2 below describes the impact of various turbine models.

Figure 1 and Table 22 below state the key production parameters. Given are the potential energy output, the gross energy production and the net energy production. The gross energy production is representative of the wind energy resource were there no wake losses due to terrain roughness and neighbouring turbines. Subtracting these wake losses yields the gross energy production. Conversion or efficiency losses, curtailment, downtime and parasitic energy consumption further reduce the annual output. The remaining net energy production is what will be fed into YEC's grid.

[1] Capacity factor of a wind turbine is defined as the mean annual power output divided by rated power or the total annual power output divided by the capacity and by 8760, the number of hours in a year.

Table 22 Cyprus Mine Hill Wind Farm Annual Energy Production, 2 MW generic turbine

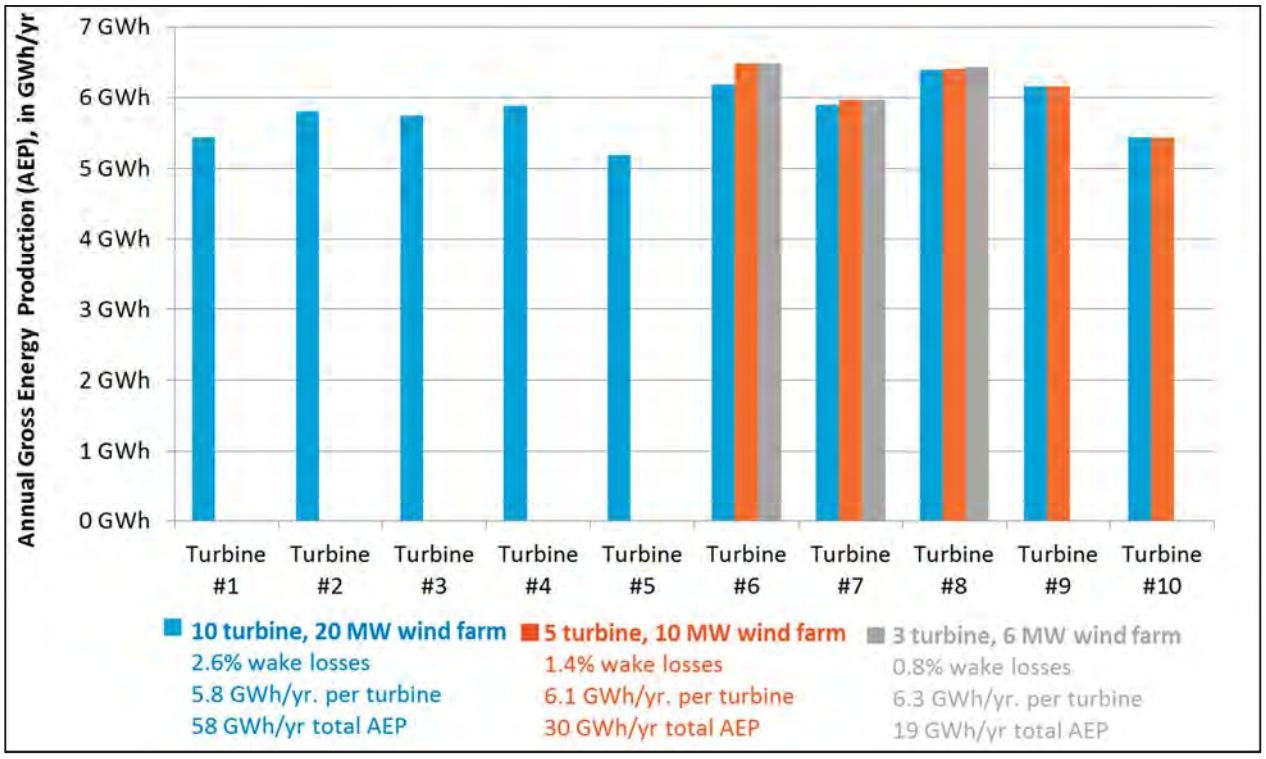
Wind Farm Capacity	Parameter	Total all turbines (GWh)	Average turbine (GWh)	Lowest turbine (GWh)	Best turbine (GWh)
20 MW	Gross Annual Energy Production (AEP)	59.7	5.97	5.40	6.57
	Wake loss	2.7%	-	-	-
	AEP after Wake Loss	58.1	5.81	5.20	6.39
	Additional Losses and Downtime	14.7%			
	Net AEP	**49.6**			
10 MW	Gross AEP	30.9	6.18	5.50	6.57
	Wake loss	1.5%	-	-	-
	AEP after Wake Loss	30.5	6.09	5.44	6.48
	Additional Losses and Downtime	14.7%			
	Net AEP	**26.0**			
6 MW	Gross AEP	19.0	6.35	6.01	6.57
	Wake loss	0.8%	-	-	-
	AEP after Wake Loss	18.9	6.29	5.97	6.48
	Additional Losses and Downtime	14.7%			
	Net AEP	**16.1**			

Losses and downtime are calculated as a percentage and are therefore proportionally smaller for a small wind farm than for large wind farm. The difference in relative losses between the three sizes of wind farms modeled is solely due to wake losses. These tend to increase with the size of a wind farm because the individual turbines start to 'shade' each other or create a wake, turbulences or reduced wind speed that effects a downwind or adjacent turbine.

Figure 1 indicates the annual gross energy output of the site turbines. The ten turbine 20 MW capacity turbine layout was developed first and selected turbines were removed for the 10 MW (five turbine) and 6 MW (three turbine) capacity wind farm options. Retained turbines were chosen to reduce the site footprint *and* retain the higher performing locations. This approach applies to all seven selected sites.

For the five-turbine (10 MW) option at Cyprus Mine, Turbines 6 through 10 were retained (refer to Figure 10 in Chapter 3.1 of the body of the report). For the three-turbine (6 MW) wind farm location, Turbines 6, 7 and 8 were retained as the model demonstrates high energy production for turbines at these locations and the turbines are near each other, minimizing infrastructure costs.

Figure 1 Annual Net (wake loss only) Energy Generation, Cyprus Mine Hill



For a detailed wind farm design of a lower capacity option, one may wish to reconsider turbine locations with just the intended number in mind as possibly this may yield higher performance. Detailed WAsP wind farm reports for the three capacity alternatives can be found in Appendix G.

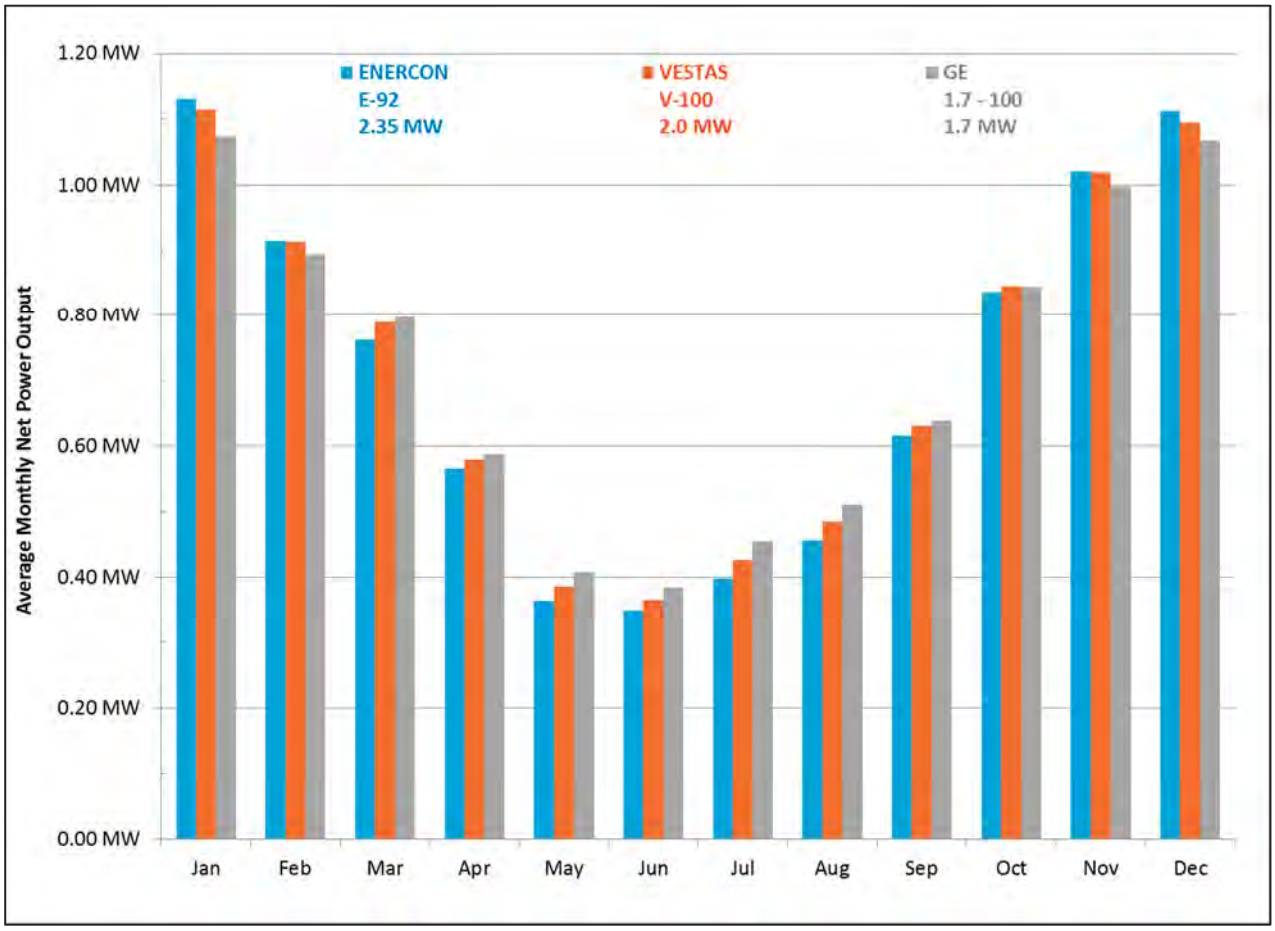
1.2 Turbine Choice

The numbers presented above are based on a generic 2.0 MW turbine. This may not be the best choice for this site. To gauge the impact of different types and sizes of turbines we compared three alternate types of turbines. Modeling of an Enercon E-92, a Vestas V-100 and a GE-1.7-100 turbine showed that a smaller General Electric 1.7 MW turbine yields a slightly higher (1%) output than the larger capacity 2.3 MW Enercon E-92. In the higher wind speed period from October to April, however, the Vestas V-100 performs slightly better than the other two turbines, see Figure 2 below.

1.3 Monthly Generation Profile

As for all sites selected, a wind farm at Cyprus Mine generates more energy in winter than summer, as one would expect. Modeling indicates that 69% to 71% of annual energy production will occur October to April (see Figure 2).

Figure 2 Monthly Generation Profile of a three types of wind turbines at Cyprus Mine Hill

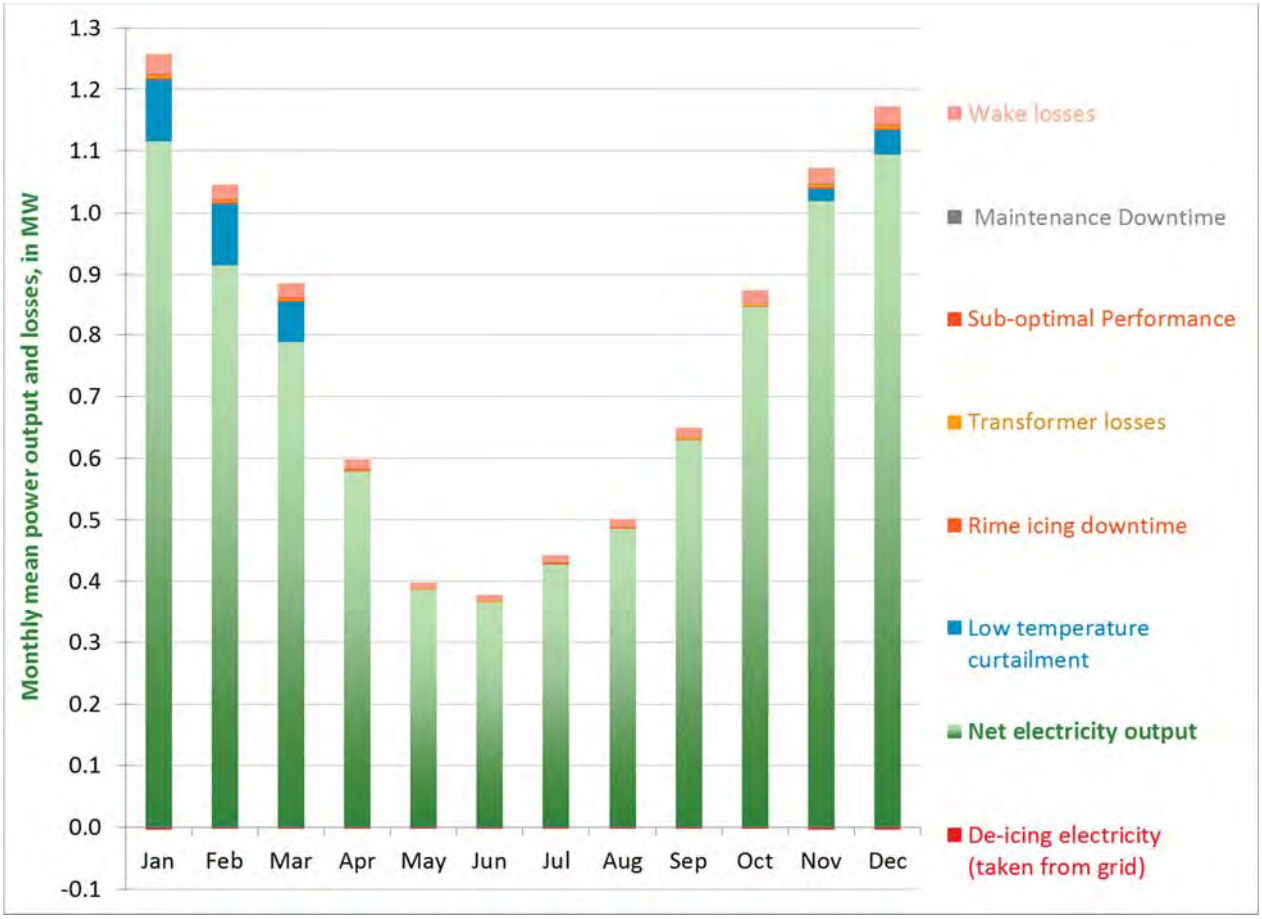


The numbers presented above are the net energy production delivered to the grid of a single turbine. Wake losses from terrain features or nearby turbines are not taken into account. The mean power outputs to the grid presented above are relevant in terms of turbine selection and monthly generation profile rather than as absolute numbers. AWS software does not take the impact of terrain features and nearby turbines into account the way WAsP modeling does.

Just as power output, monthly losses, curtailment, and downtime described in Chapter 4.2 of the body of the report vary over the course of the year. Figure 2 below displays monthly losses in relation to the monthly mean power that will be fed into the grid assuming a Vestas V-100 turbine at Cyprus Mine. Energy production is higher during the winter months and so are losses. De-icing energy is shown as negative because it will actually draw power from the grid. Over the course of the year 14.7% of the annual energy that could be generated at Cyprus Mine will be lost due to downtime, curtailment, losses or energy consumption for de-icing.

This scheme is similar for all seven sites, though there are differing losses depending on the air temperature over the course of the year and the elevation of the site.

Figure 3: Monthly Mean Net Power Output for a GE-100-1.7 MW Turbine at Cyprus Mine



For the purpose of creating data of monthly net electricity output we combined the annual gross energy production forecasted by the WAsP model with the monthly distribution of energy production of the AWS report. We then subtracted all other losses described in the main report to obtain monthly net electricity production data.

Table 23 Cyprus Mine Hill: Losses and Net Annual Energy Production of the Three Wind Farm Sizes

Annual Energy Production of a 20 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	8.0 GWh	0.4 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	1.1 GWh	**7.0 GWh**
Feb	6.1 GWh	0.5 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	1.1 GWh	**5.0 GWh**
Mar	5.7 GWh	0.4 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	1.0 GWh	**4.6 GWh**
Apr	3.7 GWh	0.0 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**3.1 GWh**
May	2.5 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**2.1 GWh**
Jun	2.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.0 GWh**
Jul	2.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.6 GWh	0.9 GWh	**1.9 GWh**
Aug	3.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.9 GWh**
Sep	4.0 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**3.5 GWh**
Oct	5.6 GWh	0.0 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**4.9 GWh**
Nov	6.6 GWh	0.1 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.7 GWh	**5.9 GWh**
Dec	7.5 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.8 GWh	**6.7 GWh**
Overall	**58.1 GWh**	**1.6 GWh**	**1.5 GWh**	**1.5 GWh**	**2.3 GWh**	**0.6 GWh**	**1.2 GWh**	**8.5 GWh**	**49.6 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**
Annual Energy Production of a 10 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	4.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**3.7 GWh**
Feb	3.2 GWh	0.3 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**2.6 GWh**
Mar	3.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**2.4 GWh**
Apr	1.9 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.6 GWh**
May	1.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.1 GWh**
Jun	1.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.1 GWh**
Jul	1.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.3 GWh	0.5 GWh	**1.0 GWh**
Aug	1.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.5 GWh**
Sep	2.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.8 GWh**
Oct	2.9 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.6 GWh**
Nov	3.5 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**3.1 GWh**
Dec	3.9 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**3.5 GWh**
Overall	**30.5 GWh**	**0.8 GWh**	**0.8 GWh**	**0.8 GWh**	**1.2 GWh**	**0.3 GWh**	**0.6 GWh**	**4.5 GWh**	**26.0 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**
Annual Energy Production of a 6 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	2.6 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.3 GWh**
Feb	2.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**1.6 GWh**
Mar	1.8 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.5 GWh**
Apr	1.2 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.0 GWh**
May	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**0.7 GWh**
Jun	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.7 GWh**
Jul	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.2 GWh	0.3 GWh	**0.6 GWh**
Aug	1.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.9 GWh**
Sep	1.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.1 GWh**
Oct	1.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.6 GWh**
Nov	2.2 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.9 GWh**
Dec	2.4 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.2 GWh**
Overall	**18.9 GWh**	**0.5 GWh**	**0.5 GWh**	**0.5 GWh**	**0.8 GWh**	**0.2 GWh**	**0.4 GWh**	**2.8 GWh**	**16.1 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**

2 KLUANE LAKE (WEST SHORE)

2.1 Annual Gross Energy Production

Despite its low elevation Kluane Lake features a reasonable wind resource and good energy production compared to the other six, high-elevation sites. A generic 2.0 MW turbine would generate between 5.1 and 5.6 GWh a year, mainly depending on the size of the wind farm and resulting wake loses.

Wind farm (WAsP) modeling of the three wind farm capacity options – 20 MW, 10 MW and 6 MW – indicates an approximate 30% wind turbine net capacity factor based on the gross annual energy production in Table 24 below.

Kluane Lake is unique of the seven sites profiled in this report in that icing loss and/or icing-related operational challenges is expected to be relatively low. Apart from wake losses only 9.1% of the gross energy production are lost due factors such as icing, operations and maintenance, and electrical efficiency.

Table 24 Kluane Lake Wind Farm Annual Energy Production, 2 MW generic turbine

Wind Farm Capacity	Parameter	Total all turbines (GWh)	Average turbine (GWh)	Lowest turbine (GWh)	Best turbine (GWh)
20 MW	Gross Annual Energy Production (AEP)	55.0	5.50	5.40	5.59
	Wake loss	4.5%	-	-	-
	AEP after Wake Loss	52.6	5.26	5.10	5.37
	Additional Losses and Downtime	9.1%			
	Net AEP	**47.8**			
10 MW	Gross AEP	27.6	5.52	5.40	5.59
	Wake loss	2.7%	-	-	-
	AEP after Wake Loss	26.8	5.37	5.33	5.41
	Additional Losses and Downtime	9.1%			
	Net AEP	**24.4**			
6 MW	Gross AEP	16.7	5.56	5.53	5.59
	Wake loss	1.4%	-	-	-
	AEP after Wake Loss	16.4	5.48	5.40	5.53
	Additional Losses and Downtime	9.1%			
	Net AEP	**14.9**			

As for all other sites the ten turbine, 20 MW capacity, turbine layout was developed first and turbines were removed for the 10 MW (five turbine) and 6 MW (three turbine) capacity wind farm options. Wind turbines selected for removal for the lower capacity options were chosen to reduce the site footprint *and* retain the higher performing locations.

Due to the prevailing wind parallel to the shoreline there are higher wake losses than for other 20 MW wind farm sites considered in this report. This could be mitigated by either locating the turbines further apart or reducing the size of the wind farm. A 6 MW wind farm has only 1.35% wake losses, a 20 MW farm almost three times as much.

For a detailed wind farm design of a lower capacity option, one may wish to reconsider turbine locations with just the intended number in mind as possibly this may yield higher performance. Detailed WAsP wind farm reports for the three capacity alternatives can be found in Appendix G.

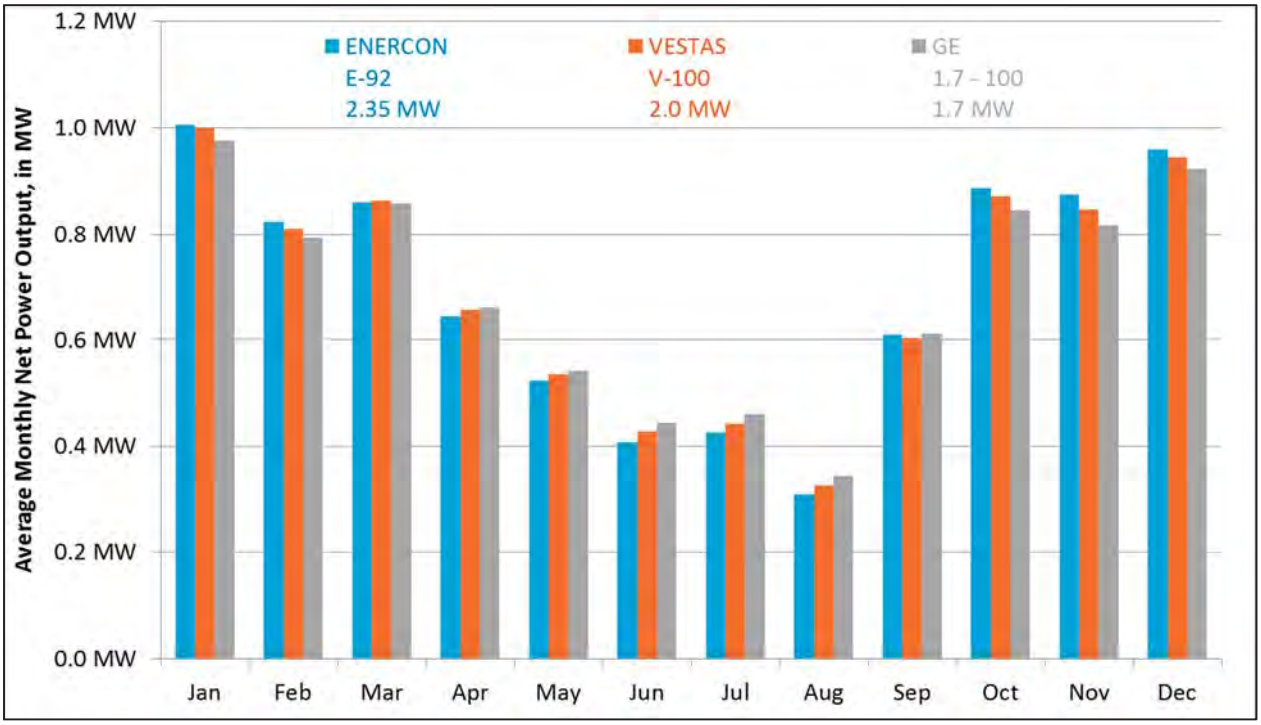
2.2 Monthly Generation Profile

Peak production for a turbine at Kluane Lake is December and January. As at all the selected sites, a wind farm at Kluane Lake would generate more energy in winter than summer. According to AWS modeling, 71% to 73% of the energy will be produced from October to April, see Figure 4 below.

2.3 Turbine Choice

Kluane Lake should have fewer rime ice problems than the other sites. Temperatures at Kluane Lake also tend to be higher and hence present less of a cold weather operational concern than the other sites. Geared drive turbines could be considered for Kluane Lake. Modeling of alternative turbines shows, however, that the gearless 2.35 MW Enercon E-92 model has 1% to 3% better performance in the period from October to April than the other two, smaller, but geared turbines. Considering that the site is next to the Alaska Highway and that there are no steep access roads, a larger turbine may also be considered from a logistics point of view.

Figure 4 Monthly Generation Profile of a three types of wind turbines at Kluane Lake



Data on the monthly losses and net production is provided below.

Table 25 Kluane Lake: Losses and Net Annual Energy Production of the three sizes of a wind farm

Annual Energy Production of a 20 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	NET ELECTRICITY PRODUCTION
Jan	7.3 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.5 GWh	6.8 GWh
Feb	5.5 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.4 GWh	5.1 GWh
Mar	5.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.5 GWh	4.7 GWh
Apr	3.3 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.4 GWh	3.0 GWh
May	2.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	2.0 GWh
Jun	2.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	1.8 GWh
Jul	2.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.6 GWh	0.8 GWh	1.8 GWh
Aug	2.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	2.6 GWh
Sep	3.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	3.4 GWh
Oct	5.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	4.7 GWh
Nov	6.0 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.4 GWh	5.6 GWh
Dec	6.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.4 GWh	6.3 GWh
Overall	**52.6 GWh**	**0.0 GWh**	**0.5 GWh**	**0.5 GWh**	**2.1 GWh**	**0.5 GWh**	**1.1 GWh**	**4.8 GWh**	**47.8 GWh**
	100%	**0%**	**1%**	**1%**	**4%**	**1%**	**2%**	**9%**	**91%**
Annual Energy Production of a 10 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	3.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**3.5 GWh**
Feb	2.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**2.6 GWh**
Mar	2.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**2.4 GWh**
Apr	1.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.5 GWh**
May	1.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.0 GWh**
Jun	1.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.9 GWh**
Jul	1.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.3 GWh	0.4 GWh	**0.9 GWh**
Aug	1.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.3 GWh**
Sep	1.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.7 GWh**
Oct	2.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**2.4 GWh**
Nov	3.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**2.9 GWh**
Dec	3.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**3.2 GWh**
Overall	**26.8 GWh**	**0.0 GWh**	**0.3 GWh**	**0.3 GWh**	**1.1 GWh**	**0.3 GWh**	**0.5 GWh**	**2.4 GWh**	**24.4 GWh**
	100%	**0%**	**1%**	**1%**	**4%**	**1%**	**2%**	**9%**	**91%**
Annual Energy Production of a 6 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	2.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**2.1 GWh**
Feb	1.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.6 GWh**
Mar	1.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.5 GWh**
Apr	1.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.9 GWh**
May	0.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
Jun	0.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
Jul	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.2 GWh	0.2 GWh	**0.6 GWh**
Aug	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.8 GWh**
Sep	1.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.1 GWh**
Oct	1.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.5 GWh**
Nov	1.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.7 GWh**
Dec	2.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**2.0 GWh**
Overall	**16.4 GWh**	**0.0 GWh**	**0.2 GWh**	**0.2 GWh**	**0.7 GWh**	**0.2 GWh**	**0.3 GWh**	**1.5 GWh**	**15.0 GWh**
	100%	**0%**	**1%**	**1%**	**4%**	**1%**	**2%**	**9%**	**91%**

3 MILLER'S RIDGE

Miller's Ridge has the best wind resource of all sites reviewed.

3.1 Annual Energy Production

With its excellent wind conditions, Miller's Ridge has the highest gross energy production of all sites. A 2.0 MW turbine would be able to generate 6.3 to 7.2 GWh of energy, depending on the size of the wind farm and the particular location of the individual turbine, see Table 26 below.

WAsP modeling of the three wind farm capacity options – 20, 10 and 6 MW – indicates an approximate 39% wind turbine net capacity factor based on the gross annual energy production given in Table 26 below. A 39% capacity factor is extraordinarily good. If a larger capacity turbine more suitable for higher energy winds is chosen, overall net capacity factor will decrease slightly.

Table 26 Miller's Ridge Wind Farm Annual Energy Production, 2 MW generic turbine

Wind Farm Capacity	Parameter	Total all turbines (GWh)	Average turbine (GWh)	Lowest turbine (GWh)	Best turbine (GWh)
20 MW	Gross Annual Energy Production (AEP)	68.1	6.81	6.45	7.19
	Wake loss	2.0%	-	-	-
	AEP after Wake Loss	66.7	6.67	6.28	7.06
	Additional Losses and Downtime	14.2%			
	Net AEP	**57.2**			
10 MW	Gross AEP	34.9	6.98	6.63	7.19
	Wake Loss	1.4%	-	-	-
	AEP after Wake Loss	34.4	6.88	6.60	7.07
	Additional Losses and Downtime	14.2%			
	Net AEP	**29.5**			
6 MW	Gross AEP	21.3	7.10	7.03	7.19
	Wake Loss	1.0%	-	-	-
	AEP after Wake Loss	21.1	7.03	6.93	7.17
	Additional Losses and Downtime	14.2%			
	Net AEP	**18.1**			

The ten turbine, 20 MW capacity, turbine layout was developed first and turbines were removed for the 10 MW (five turbine) and 6 MW (three turbine) capacity wind farm options. Wind turbines selected for removal for the lower capacity options were chosen to reduce the site footprint *and* retain the higher performing locations.

For a detailed wind farm design of a lower capacity option, one may wish to reconsider turbine locations with just the intended number in mind as possibly this may yield higher performance. Detailed WAsP wind farm reports for the three capacity alternatives can be found in Appendix G.

Miller's Ridge is long and oriented perpendicular to the prevailing wind direction, south-south-west. Additional four turbines could be installed southeast of turbine #1 (WTG1) without creating significant additional wake losses (refer to Figure 18 in Chapter 3.3 of the body of the report). This would bring the maximum capacity up to 28 MW.

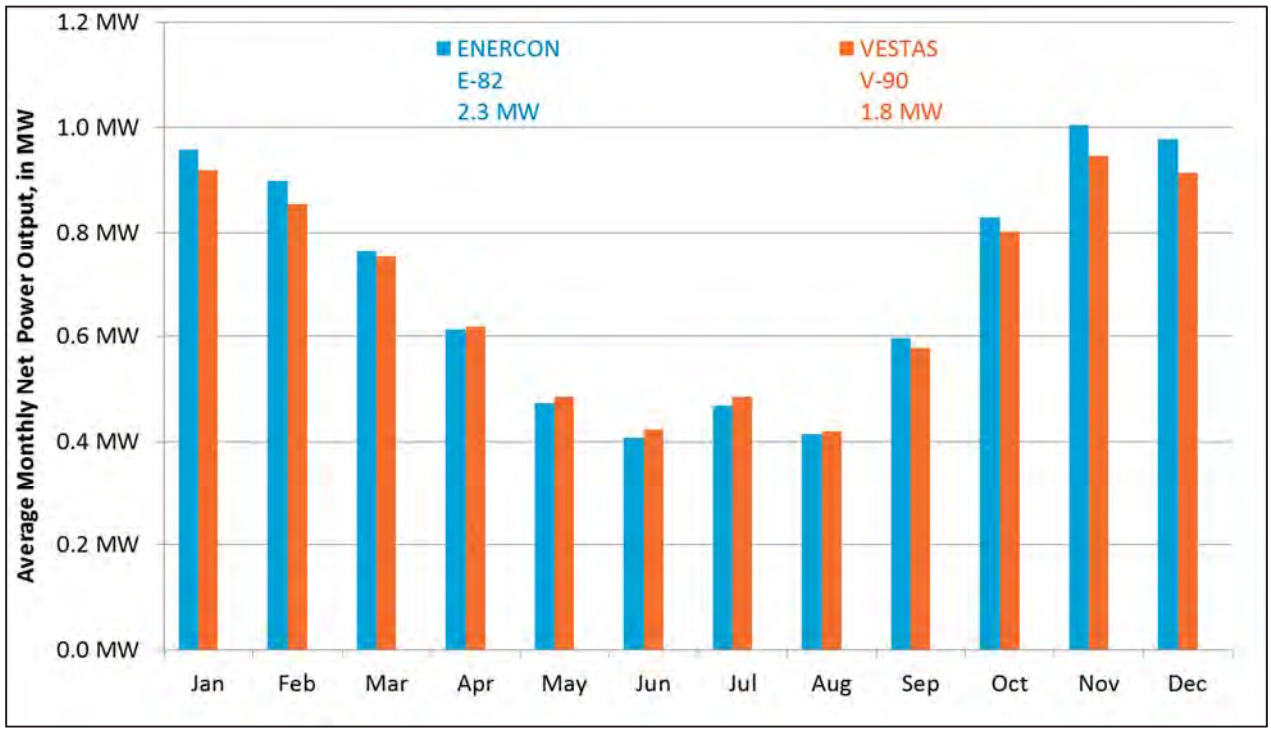
3.2 Monthly Generation Profile

As for all sites selected a wind farm at Miller's Ridge produces more energy in winter than in summer. According to AWS modeling 71% to 72% of the energy will be produced from October to April, see Figure 5 below.

3.3 Turbine Choice

From a wind speed and wind direction point of view Miller's Ridge is likely one of the best sites in Yukon. AWS' advanced reports model the highest yield for the Enercon E-92 turbine. A larger IEA Class II turbine, such as the E-82 with 2.3 MW rated capacity can be expected to perform better at Miller's Ridge than the smaller 1.8 MW Class III Vestas V-90 model. The E-82 series performs better during the high wind speed winter months and worse during the summer with generally lower wind speed, see Figure 5 below. A decision regarding turbine choice, however, would require site-specific wind monitoring data.

Figure 5 Monthly Production Profile for three types of turbines at Miller's Ridge Site



Data on the monthly losses and net production is provided below.

Table 27 Miller's Ridge: Losses and Net Annual Energy Production of the Three Wind Farm Sizes

Annual Energy Production of a 20 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	NET ELECTRICITY PRODUCTION
Jan	9.2 GWh	0.5 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	1.3 GWh	7.9 GWh
Feb	7.0 GWh	0.6 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	1.4 GWh	5.6 GWh
Mar	6.5 GWh	0.0 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.8 GWh	5.6 GWh
Apr	4.2 GWh	0.0 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.7 GWh	3.5 GWh
May	2.9 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.5 GWh	2.5 GWh
Jun	2.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.3 GWh	2.3 GWh
Jul	3.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.1 GWh	0.7 GWh	1.0 GWh	2.2 GWh
Aug	3.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.3 GWh	3.3 GWh
Sep	4.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.4 GWh	4.2 GWh
Oct	6.4 GWh	0.0 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.7 GWh	5.7 GWh
Nov	7.6 GWh	0.1 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.9 GWh	6.7 GWh
Dec	8.6 GWh	0.1 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.9 GWh	7.7 GWh
Overall	**66.7 GWh**	**1.5 GWh**	**1.7 GWh**	**1.7 GWh**	**2.7 GWh**	**0.7 GWh**	**1.3 GWh**	**9.5 GWh**	**57.3 GWh**
	100%	**2%**	**3%**	**3%**	**4%**	**1%**	**2%**	**14%**	**86%**
Annual Energy Production of a 10 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	4.8 GWh	0.3 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.7 GWh	**4.1 GWh**
Feb	3.6 GWh	0.3 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.7 GWh	**2.9 GWh**
Mar	3.3 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**2.9 GWh**
Apr	2.2 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**1.8 GWh**
May	1.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.3 GWh**
Jun	1.4 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.2 GWh**
Jul	1.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.4 GWh	0.5 GWh	**1.2 GWh**
Aug	1.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.7 GWh**
Sep	2.4 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**2.2 GWh**
Oct	3.3 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**2.9 GWh**
Nov	3.9 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**3.5 GWh**
Dec	4.4 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**4.0 GWh**
Overall	**34.4 GWh**	**0.8 GWh**	**0.9 GWh**	**0.9 GWh**	**1.4 GWh**	**0.3 GWh**	**0.7 GWh**	**4.9 GWh**	**29.5 GWh**
	100%	**2%**	**3%**	**3%**	**4%**	**1%**	**2%**	**14%**	**86%**
Annual Energy Production of a 6 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	2.9 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**2.5 GWh**
Feb	2.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**1.8 GWh**
Mar	2.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.8 GWh**
Apr	1.3 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.1 GWh**
May	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.8 GWh**
Jun	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.7 GWh**
Jul	1.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.2 GWh	0.3 GWh	**0.7 GWh**
Aug	1.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.0 GWh**
Sep	1.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.3 GWh**
Oct	2.0 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.8 GWh**
Nov	2.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.1 GWh**
Dec	2.7 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.4 GWh**
Overall	**21.1 GWh**	**0.5 GWh**	**0.5 GWh**	**0.5 GWh**	**0.8 GWh**	**0.2 GWh**	**0.4 GWh**	**3.0 GWh**	**18.1 GWh**
	100%	**2%**	**3%**	**3%**	**4%**	**1%**	**2%**	**14%**	**86%**

4 SUGARLOAF MOUNTAIN

Of all sites selected, Sugarloaf Mountain is the site with the lowest wind resource

WAsP modeling of the three wind farm capacity options – 20, 10 and 6 MW – indicates an approximate 21% wind turbine net capacity factor based on the Gross Annual Energy Production given in Table 28 below. A 21% capacity factor is low and could be improved upon with a wind turbine model more attuned to this site in place of the generic 2 MW model for the modeling exercise. A decision for the latter, however, would require site-specific wind monitoring data to verify a likely IEC Class III wind regime, i.e. a low wind speed class.

4.1 Annual Energy Production

As expected from the wind resource, modeling of three wind farm sizes at Sugarloaf Mountain yields lower energy production than the remaining six sites selected. The annual mean gross energy production of a single 2.0 MW turbine is only 3.7 to 3.8 GWh. This is 39% to 51% less than the mean output of the same turbine at Miller's Ridge.

These numbers are the gross energy production and only reflect wake, or wind turbine array efficiency, loss though. Other loss factors such as icing, operations and maintenance, and electrical losses are determined in Chapter 4.2 in the body of the report.

Table 28 Sugarloaf Mountain Wind Farm Annual Energy Production, 2 MW generic turbine

Wind Farm Capacity	Parameter	Total all turbines (GWh)	Average turbine (GWh)	Lowest turbine (GWh)	Best turbine (GWh)
20 MW	Gross Annual Energy Production (AEP)	37.5	3.75	3.47	3.98
	Wake Loss	1.0%	-	-	-
	AEP after Wake Loss	37.1	3.71	3.43	3.96
	Additional Losses and Downtime	13.1%			
	Net AEP	**32.2**			
10 MW	Gross AEP	18.5	3.70	3.47	3.98
	Wake Loss	0.8%	-	-	-
	AEP after Wake Loss	18.4	3.67	3.44	3.96
	Additional Losses and Downtime	13.1%			
	Net AEP	**15.9**			
6 MW	Gross AEP	11.4	3.81	3.63	3.98
	Wake Loss	0.5%	-	-	-
	AEP after Wake Loss	11.4	3.79	3.61	3.96
	Additional Losses and Downtime	13.1%			
	Net AEP	**9.9**			

The ten turbine, 20 MW capacity, turbine layout was developed first and turbines were removed for the 10 MW (five turbine) and 6 MW (three turbine) capacity wind farm options. Wind turbines selected for removal for the lower capacity options were chosen to reduce the site footprint *and*

retain the higher performing locations. For Sugarloaf, a reduction of the site footprint was paramount and the lower capacity turbine layouts successively removed the southern-most turbines.

For a detailed wind farm design of a lower capacity option, one may wish to reconsider turbine locations with just the intended number in mind as possibly this may yield higher performance. Detailed WAsP wind farm reports for the three capacity alternatives can be found in Appendix G.

4.2 Monthly Generation Profile

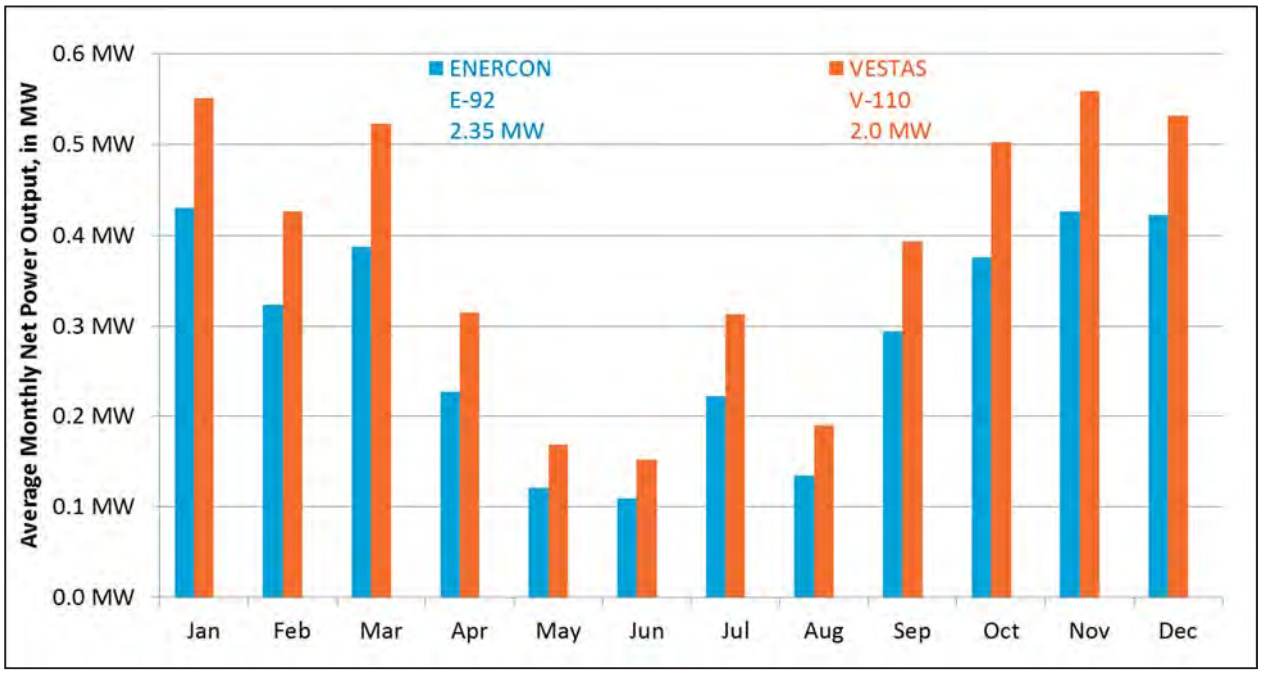
Sugarloaf Mountain is a site with medium to low wind speeds. There is a more pronounced difference between winter and summer than for other sites; especially during the summer months the output and capacity factor is low, see Figure 6 below.

Despite the generally favorable monthly production profile the site is low performing: During the winter months the sites produces only 55% of a wind turbine during the same period at the best performing site, Miller's Ridge.

4.3 Turbine Choice

Being a low-wind speed site, a IEA Class III turbine, such as the Vestas V-110 is a better choice than a Class II Enercon E-92 model. AWS models that the 2.35 MW Enercon E-92 produces 25% less energy annually than the less powerful (2.0 MW) Vestas V-110.

Figure 6 Monthly Production Profile for three Turbine Types at Sugarloaf Mountain



Data on the monthly losses and net production is provided below.

Table 29 Sugarloaf Mountain: Losses and Net Annual Energy Production of the Three Wind Farm Sizes

Annual Energy Production of a 20 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	5.1 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**4.5 GWh**
Feb	3.9 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**3.3 GWh**
Mar	3.6 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**3.2 GWh**
Apr	2.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**1.9 GWh**
May	1.6 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.3 GWh**
Jun	1.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.3 GWh**
Jul	1.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.4 GWh	0.6 GWh	**1.2 GWh**
Aug	2.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.8 GWh**
Sep	2.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.3 GWh**
Oct	3.6 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**3.2 GWh**
Nov	4.2 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**3.8 GWh**
Dec	4.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**4.3 GWh**
Overall	**37.1 GWh**	**0.4 GWh**	**0.9 GWh**	**0.9 GWh**	**1.5 GWh**	**0.4 GWh**	**0.7 GWh**	**4.9 GWh**	**32.3 GWh**
	100%	**1%**	**3%**	**3%**	**4%**	**1%**	**2%**	**13%**	**87%**
Annual Energy Production of a 10 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	2.5 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.2 GWh**
Feb	1.9 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.6 GWh**
Mar	1.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.6 GWh**
Apr	1.2 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.0 GWh**
May	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.7 GWh**
Jun	0.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
Jul	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.2 GWh	0.3 GWh	**0.6 GWh**
Aug	1.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.9 GWh**
Sep	1.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.1 GWh**
Oct	1.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.6 GWh**
Nov	2.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.9 GWh**
Dec	2.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**2.1 GWh**
Overall	**18.4 GWh**	**0.2 GWh**	**0.5 GWh**	**0.5 GWh**	**0.7 GWh**	**0.2 GWh**	**0.4 GWh**	**2.4 GWh**	**15.9 GWh**
	100%	**1%**	**3%**	**3%**	**4%**	**1%**	**2%**	**13%**	**87%**
Annual Energy Production of a 6 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	1.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.4 GWh**
Feb	1.2 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.0 GWh**
Mar	1.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.0 GWh**
Apr	0.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
May	0.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.4 GWh**
Jun	0.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.4 GWh**
Jul	0.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.2 GWh	**0.4 GWh**
Aug	0.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
Sep	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.7 GWh**
Oct	1.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.0 GWh**
Nov	1.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.2 GWh**
Dec	1.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.3 GWh**
Overall	**11.4 GWh**	**0.1 GWh**	**0.3 GWh**	**0.3 GWh**	**0.5 GWh**	**0.1 GWh**	**0.2 GWh**	**1.5 GWh**	**9.9 GWh**
	100%	**1%**	**3%**	**3%**	**4%**	**1%**	**2%**	**13%**	**87%**

5 MOUNT SUMANIK

Compared to the other sites reviewed Mount Sumanik has an average wind resource. Consequently, the energy production is below the average of the seven sites.

5.1 Annual Gross Energy Production

Modeling of three wind farm sizes at Mount Sumanik yields lower energy production than the remaining six sites selected. The annual mean gross energy production of a single 2.0 MW turbine is 4.8 to 5.5 GWh. This is 21% to 29% less than the output of the same turbine at Miller's Ridge.

WAsP modeling of the three wind farm capacity options – 20, 10 and 6 MW – indicates an approximate 27% wind turbine net capacity factor based on the Gross Annual Energy Production in Table 30 below. A 27% capacity factor is good but perhaps could be improved upon with a wind turbine model more attuned to this site, in place of the generic 2 MW model for the modeling exercise. A decision for the latter, however, would require a review of the site data collected to date and more detailed terrain wind flow modeling to confirm the suitability of the northern and lower elevation ridges of Mount Sumanik for turbines.

Table 30 Mount Sumanik Wind Farm Annual Energy Production, 2 MW generic turbine

Wind Farm Capacity	Parameter	Total all turbines (GWh)	Average turbine (GWh)	Lowest turbine (GWh)	Best turbine (GWh)
20 MW	Gross Annual Energy Production (AEP)	49.3	4.93	4.32	5.76
	Wake Loss	2.4%	-	-	-
	AEP after Wake Loss	48.1	4.81	4.18	5.66
	Additional Losses and Downtime	13.8%			
	Net AEP	**41.5**			
10 MW	Gross AEP	24.9	4.97	4.51	5.65
	Wake Loss	1.4%	-	-	-
	AEP after Wake Loss	24.5	4.90	4.42	5.56
	Additional Losses and Downtime	13.8%			
	Net AEP	**21.1**			
6 MW	Gross AEP	16.6	5.55	5.24	5.76
	Wake Loss	1.2%	-	-	-
	AEP after Wake Loss	16.5	5.48	5.22	5.67
	Additional Losses and Downtime	13.8%			
	Net AEP	**14.2**			

The ten turbine, 20 MW capacity, turbine layout was developed first and turbines were removed for the 10 MW (five turbine) and 6 MW (three turbine) capacity wind farm options. Wind turbines selected for removal for the lower capacity options were chosen to reduce the site footprint *and* retain the higher performing locations.

Detailed WAsP wind farm reports for the three capacity alternatives can be found in Appendix G.

For a detailed wind farm design of a lower capacity option, one may wish to reconsider turbine locations with just the intended number in mind as possibly this may yield higher performance.

5.2 Monthly Generation Profile

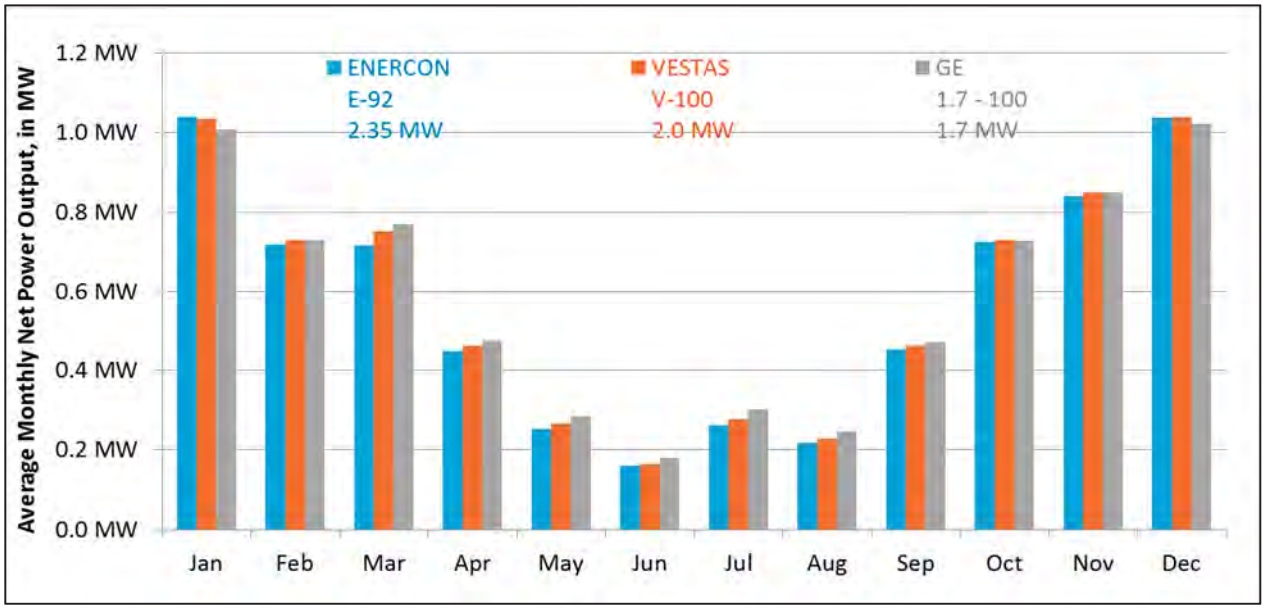
Mount Sumanik has a good power output in January and December, but rather low wind resources during the summer period. Moreover, wind direction changes by 90° from winter to summer, increasing wake losses in summer as the turbines start shading each other.

According to AWS modeling 79% to 81% of the energy will be produced from October to April, see Figure 7 below.

5.3 Turbine Choice

Comparing three options of turbine choices, AWS modeling yields that over the course of the year the GE-1.7-100 model with a rated capacity of only 1.7 MW yields slightly higher annual output than the 2.0 MW Vestas V-100 or the 2.3 MW Enercon E-92 turbine. In the period from October to April the Vestas V-100 turbine slightly outperforms the other two models.

Figure 7 Monthly Production Profile for three Turbine Types at Mount Sumanik Site



Data on the monthly losses and net production is provided below.

Table 31 Mt. Sumanik: Losses and Net Annual Energy Production of the Three Wind Farm Sizes

Annual Energy Production of a 20 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	NET ELECTRICITY PRODUCTION
Jan	6.6 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.7 GWh	5.9 GWh
Feb	5.1 GWh	0.4 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.9 GWh	4.1 GWh
Mar	4.7 GWh	0.1 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.6 GWh	4.1 GWh
Apr	3.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.5 GWh	2.5 GWh
May	2.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.4 GWh	1.7 GWh
Jun	1.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	1.7 GWh
Jul	2.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.5 GWh	0.7 GWh	1.6 GWh
Aug	2.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.2 GWh	2.4 GWh
Sep	3.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.3 GWh	3.0 GWh
Oct	4.6 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.5 GWh	4.1 GWh
Nov	5.5 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.7 GWh	4.8 GWh
Dec	6.2 GWh	0.1 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.0 GWh	0.0 GWh	0.6 GWh	5.6 GWh
Overall	**48.1 GWh**	**0.9 GWh**	**1.2 GWh**	**1.2 GWh**	**1.9 GWh**	**0.5 GWh**	**1.0 GWh**	**6.6 GWh**	**41.5 GWh**
	100%	**2%**	**3%**	**3%**	**4%**	**1%**	**2%**	**14%**	**86%**
Annual Energy Production of a 10 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	3.4 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**3.0 GWh**
Feb	2.6 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**2.1 GWh**
Mar	2.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.1 GWh**
Apr	1.6 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.3 GWh**
May	1.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**0.9 GWh**
Jun	1.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.9 GWh**
Jul	1.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.3 GWh	0.4 GWh	**0.8 GWh**
Aug	1.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.2 GWh**
Sep	1.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.5 GWh**
Oct	2.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.1 GWh**
Nov	2.8 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**2.4 GWh**
Dec	3.2 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.8 GWh**
Overall	**24.5 GWh**	**0.4 GWh**	**0.6 GWh**	**0.6 GWh**	**1.0 GWh**	**0.2 GWh**	**0.5 GWh**	**3.4 GWh**	**21.1 GWh**
	100%	**2%**	**3%**	**3%**	**4%**	**1%**	**2%**	**14%**	**86%**
Annual Energy Production of a 6 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	2.3 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.0 GWh**
Feb	1.7 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.4 GWh**
Mar	1.6 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.4 GWh**
Apr	1.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**0.9 GWh**
May	0.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
Jun	0.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
Jul	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.2 GWh	0.2 GWh	**0.6 GWh**
Aug	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.8 GWh**
Sep	1.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.0 GWh**
Oct	1.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.4 GWh**
Nov	1.9 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.6 GWh**
Dec	2.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.9 GWh**
Overall	**16.5 GWh**	**0.3 GWh**	**0.4 GWh**	**0.4 GWh**	**0.7 GWh**	**0.2 GWh**	**0.3 GWh**	**2.3 GWh**	**14.2 GWh**
	100%	**2%**	**3%**	**3%**	**4%**	**1%**	**2%**	**14%**	**86%**

6 TEHCHO (FERRY HILL)

6.1 Annual Gross Energy Production

Tehcho is a site with an average wind resource compared to the remaining six sites. Modeling of three wind farm sizes at Mount Sumanik yields lower energy production than the remaining six sites selected. The annual mean gross energy production of a single 2.0 MW turbine is 3.4 to 4.4 GWh, depending on the size of the wind farm and the location of the individual turbine. This is 41% to 46% less than the output of the same turbine at Miller's Ridge.

These numbers are the gross energy production and only reflect wake, or wind turbine array efficiency, loss though. On a net energy basis a wind farm at Tehcho has a 39% to 43% lower output than the same size wind farm with the same turbine at Miller's Ridge.

WAsP modeling of the three wind farm capacity options – 20, 10 and 6 MW – indicates an approximate 22% wind turbine net capacity factor based on the Gross Annual Energy Production in Table 32 below. A 22% capacity factor is low and could be improved upon with a wind turbine model more attuned to this site in place of the generic 2 MW model for the modeling exercise. A decision for the latter, however, would require additional site data, or re-review of the older met tower data, to verify a likely IEC Class III wind regime.

Table 32 Tehcho Wind Farm Annual Energy Production, 2 MW generic turbine

Wind Farm Capacity	Parameter	Total all turbines (GWh)	Average turbine (GWh)	Lowest turbine (GWh)	Best turbine (GWh)
20 MW	Gross Annual Energy Production (AEP)	41.1	4.11	3.63	4.47
	Wake Loss	4.8%	-	-	-
	AEP after Wake Loss	39.2	3.92	3.35	4.36
	Additional Losses and Downtime	14.8%			
	Net AEP	**33.4**			
10 MW	Gross AEP	21.9	4.38	4.20	4.47
	Wake Loss	2.0%	-	-	-
	AEP after Wake Loss	21.5	4.29	4.07	4.41
	Additional Losses and Downtime	14.8%			
	Net AEP	**18.3**			
6 MW	Gross AEP	12.4	4.15	3.87	4.38
	Wake Loss	2.9%	-	-	-
	AEP after Wake Loss	12.1	4.03	3.80	4.21
	Additional Losses and Downtime	14.8%			
	Net AEP	**10.3**			

The ten turbine, 20 MW capacity, turbine layout was developed first and turbines were removed for the 10 MW (five turbine) and 6 MW (three turbine) capacity wind farm options. Wind turbines selected for removal for the lower capacity options were chosen to reduce the site footprint *and* retain the higher performing locations.

Detailed WAsP wind farm reports for the three capacity alternatives can be found in Appendix G.

For a detailed wind farm design of a lower capacity option, one may wish to reconsider turbine locations with just the intended number in mind as possibly this may yield higher performance.

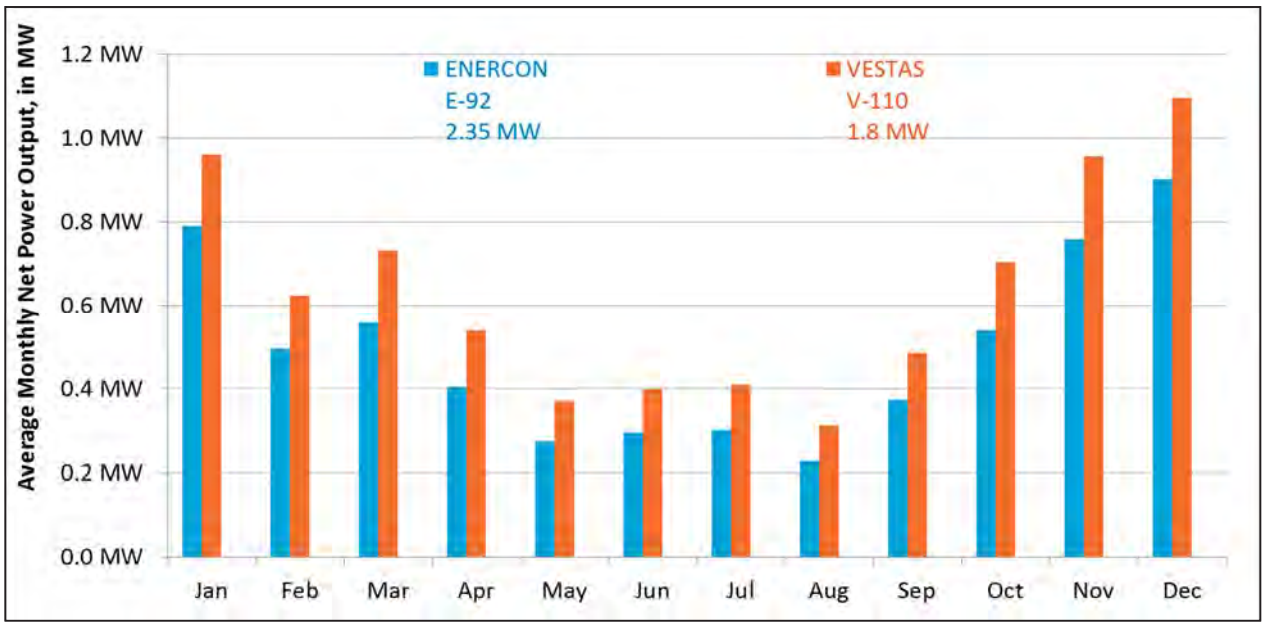
6.2 Monthly Generation Profile

As for all sites selected a wind farm at Tehcho produces more energy in winter than in summer. According to AWS modeling 75% to 76% of the energy will be produced from October to April, see Figure 8 below.

6.3 Turbine Choice

AWS modeling shows that for Tehcho (Ferry Hill) the 1.8 MW Vestas V-110 turbine yields 28% higher annual output than the 2.35 MW Enercon E-92 model. During the period from October to April the Vestas turbine still outperforms the Enercon turbine by 25%.

Figure 8 Monthly Production Profile for three Types of Turbines at Tehcho Site



Data on the monthly losses and net production is provided below.

Table 33 Techho: Losses and Net Annual Energy Production of the Three Wind Farm Sizes

Annual Energy Production of a 20 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	NET ELECTRICITY PRODUCTION
Jan	5.4 GWh	0.3 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.8 GWh	4.6 GWh
Feb	4.1 GWh	0.4 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.9 GWh	3.2 GWh
Mar	3.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	3.3 GWh
Apr	2.5 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	2.1 GWh
May	1.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	1.5 GWh
Jun	1.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	1.4 GWh
Jul	1.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.4 GWh	0.6 GWh	1.3 GWh
Aug	2.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	1.9 GWh
Sep	2.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	2.5 GWh
Oct	3.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	3.3 GWh
Nov	4.5 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.7 GWh	3.8 GWh
Dec	5.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.6 GWh	4.4 GWh
Overall	**39.2 GWh**	**1.1 GWh**	**1.0 GWh**	**1.0 GWh**	**1.6 GWh**	**0.4 GWh**	**0.8 GWh**	**5.8 GWh**	**33.4 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**
Annual Energy Production of a 10 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	3.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**2.5 GWh**
Feb	2.3 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**1.8 GWh**
Mar	2.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.8 GWh**
Apr	1.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.2 GWh**
May	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.8 GWh**
Jun	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.8 GWh**
Jul	1.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.2 GWh	0.3 GWh	**0.7 GWh**
Aug	1.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.1 GWh**
Sep	1.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.4 GWh**
Oct	2.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.8 GWh**
Nov	2.5 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**2.1 GWh**
Dec	2.8 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.4 GWh**
Overall	**21.5 GWh**	**0.6 GWh**	**0.5 GWh**	**0.5 GWh**	**0.9 GWh**	**0.2 GWh**	**0.4 GWh**	**3.2 GWh**	**18.3 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**
Annual Energy Production of a 6 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	1.7 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.4 GWh**
Feb	1.3 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.0 GWh**
Mar	1.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.0 GWh**
Apr	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
May	0.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.5 GWh**
Jun	0.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.4 GWh**
Jul	0.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.2 GWh	**0.4 GWh**
Aug	0.7 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.6 GWh**
Sep	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.8 GWh**
Oct	1.2 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.0 GWh**
Nov	1.4 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.2 GWh**
Dec	1.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.4 GWh**
Overall	**12.1 GWh**	**0.3 GWh**	**0.3 GWh**	**0.3 GWh**	**0.5 GWh**	**0.1 GWh**	**0.2 GWh**	**1.8 GWh**	**10.3 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**

7 THULSOO MOUNTAIN

Thulsoo Mountain has excellent wind resources, the second best wind resource of the seven sites selected. The mean annual wind speed is almost as high as for Miller's Ridge and consistently SSW, perpendicular to the turbine array of (see Figure 35 in Chapter 3.7 of the body of the report)

7.1 Annual Gross Energy Production

Modeling of a 6 MW, a 10 MW and a 20 MW wind farm yields almost the same energy as Miller's Ridge, the site with the highest mean wind velocity. The annual mean gross energy production of a single 2.0 MW turbine is 5.8 to 7.1 GWh, depending on the size of the wind farm and the location of the individual turbine. This is only 5% to 8% less than the output of the same turbine at Miller's Ridge.

WAsP wind farm modeling indicates an approximate 36% wind turbine net capacity factor based on the Gross Annual Energy Production in Table 34 below. This applies to all three wind farm sizes. A 36% capacity factor is extraordinarily good.

Table 34 Thulsoo Mountain Wind Farm Annual Energy Production, 2 MW generic turbine

Wind Farm Capacity	Parameter	Total all turbines (GWh)	Average turbine (GWh)	Lowest turbine (GWh)	Best turbine (GWh)
20 MW	Gross Annual Energy Production (AEP)	64.7	6.47	5.88	7.15
	Wake Loss	1.5%	-	-	-
	AEP after Wake Loss	63.7	6.37	5.84	7.05
	Additional Losses and Downtime	14.7%			
	Net AEP	**54.4**			
10 MW	Gross AEP	32.5	6.50	5.88	7.15
	Wake Loss	1.0%	-	-	-
	AEP after Wake Loss	32.2	6.44	5.87	7.06
	Additional Losses and Downtime	14.7%			
	Net AEP	**27.5**			
6 MW	Gross AEP	20.4	6.80	6.59	7.15
	Wake Loss	0.8%	-	-	-
	AEP after Wake Loss	20.2	6.75	6.52	7.06
	Additional Losses and Downtime	14.7%			
	Net AEP	**17.3**			

As for the previous six sites the ten turbine, 20 MW capacity, turbine layout was developed first and turbines were removed for the 10 MW (five turbine) and 6 MW (three turbine) capacity wind farm options. Wind turbines selected for removal for the lower capacity options were chosen to reduce the site footprint *and* retain the higher performing locations.

For a detailed wind farm design of a lower capacity option, one may wish to reconsider turbine locations with just the intended number in mind as possibly this may yield higher performance. Detailed WAsP wind farm reports for the three capacity alternatives can be found in Appendix G.

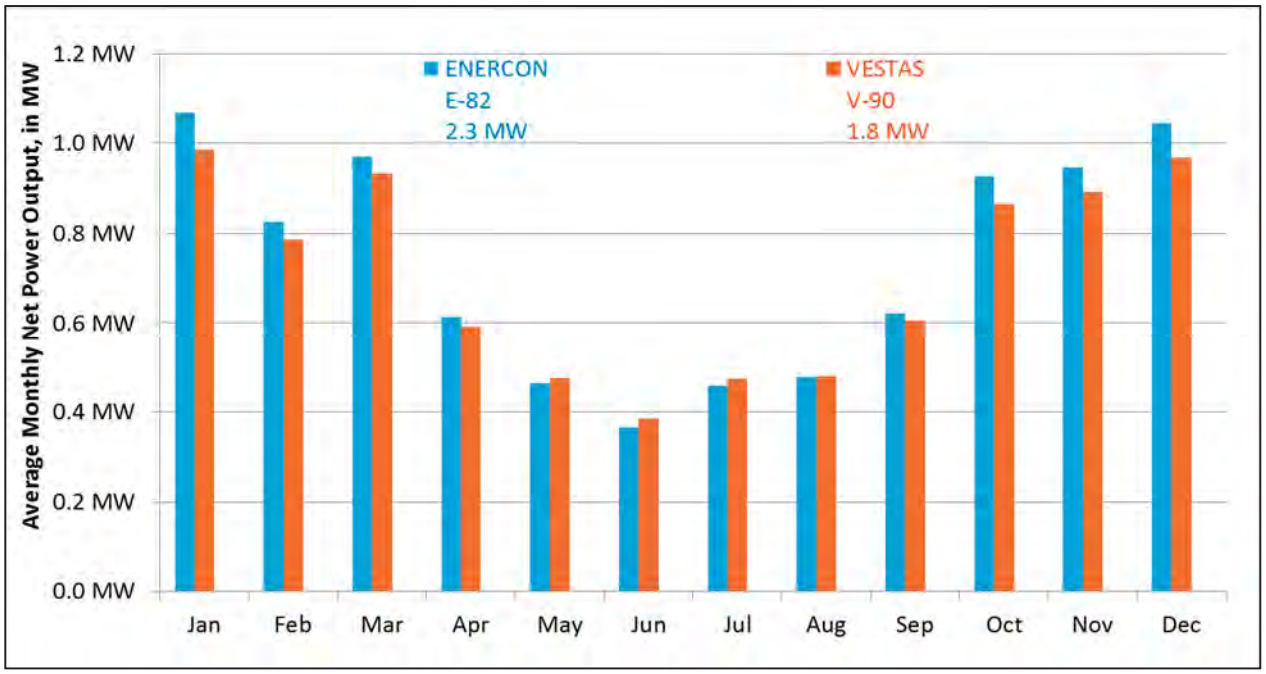
7.2 Monthly Generation Profile

As for all selected sites, a wind farm at Thulsoo Mountain produces more energy in winter than in summer. According to AWS modeling 72% to 74% of the energy will be produced from October to April, see Figure 9 below.

7.3 Turbine Choice

According to AWS modeling a larger (2.35 MW) Enercon E-92 turbine yields 6% to 8% higher annual energy production than the medium-sized 2.0 MW Vestas V-90 and the smaller size 1.7 MW GE 1.7-100 model. Thulsoo is a high wind speed site and a larger IEA Class II turbine, such as the E-92 can be expected to perform 4% better than the Class III GE-model.

Figure 9 Monthly Production Profile for Thulsoo Mountain Site



Data on the monthly losses and net production is provided below.

Table 35 Thulsoo Mountain: Losses and Net Annual Energy Production of the Three Wind Farm Sizes

Annual Energy Production of a 20 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	NET ELECTRICITY PRODUCTION
Jan	8.8 GWh	0.5 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	1.2 GWh	7.6 GWh
Feb	6.7 GWh	0.6 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	1.3 GWh	5.5 GWh
Mar	6.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.9 GWh	5.3 GWh
Apr	4.1 GWh	0.0 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.7 GWh	3.4 GWh
May	2.8 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.6 GWh	2.2 GWh
Jun	2.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.4 GWh	2.2 GWh
Jul	3.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.1 GWh	0.7 GWh	1.0 GWh	2.1 GWh
Aug	3.5 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.4 GWh	3.1 GWh
Sep	4.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.5 GWh	3.9 GWh
Oct	6.1 GWh	0.0 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.7 GWh	5.4 GWh
Nov	7.3 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.9 GWh	6.4 GWh
Dec	8.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.9 GWh	7.3 GWh
Overall	**63.7 GWh**	**1.7 GWh**	**1.6 GWh**	**1.6 GWh**	**2.5 GWh**	**0.6 GWh**	**1.3 GWh**	**9.3 GWh**	**54.4 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**
Annual Energy Production of a 10 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	4.4 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**3.9 GWh**
Feb	3.4 GWh	0.3 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.6 GWh	**2.8 GWh**
Mar	3.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**2.7 GWh**
Apr	2.0 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.7 GWh**
May	1.4 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.1 GWh**
Jun	1.3 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.1 GWh**
Jul	1.6 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.3 GWh	0.5 GWh	**1.1 GWh**
Aug	1.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.6 GWh**
Sep	2.2 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.9 GWh**
Oct	3.1 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.7 GWh**
Nov	3.7 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**3.2 GWh**
Dec	4.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.5 GWh	**3.7 GWh**
Overall	**32.2 GWh**	**0.9 GWh**	**0.8 GWh**	**0.8 GWh**	**1.3 GWh**	**0.3 GWh**	**0.6 GWh**	**4.7 GWh**	**27.5 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**
Annual Energy Production of a 6 MW WINDFARM									
Month	Production after wake losses	Low temperature curtailment	Rime icing downtime	De-icing electricity	Transformer losses	Sub-optimal Performance	Maintenance Downtime	TOTAL LOSSES	**NET ELECTRICITY PRODUCTION**
Jan	2.8 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**2.4 GWh**
Feb	2.1 GWh	0.2 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.4 GWh	**1.7 GWh**
Mar	2.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**1.7 GWh**
Apr	1.3 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.1 GWh**
May	0.9 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**0.7 GWh**
Jun	0.8 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**0.7 GWh**
Jul	1.0 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.2 GWh	0.3 GWh	**0.7 GWh**
Aug	1.1 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.1 GWh	**1.0 GWh**
Sep	1.4 GWh	0.0 GWh	0.0 GWh	0.0 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.2 GWh**
Oct	1.9 GWh	0.0 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.2 GWh	**1.7 GWh**
Nov	2.3 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.0 GWh**
Dec	2.6 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.1 GWh	0.0 GWh	0.0 GWh	0.3 GWh	**2.3 GWh**
Overall	**20.2 GWh**	**0.5 GWh**	**0.5 GWh**	**0.5 GWh**	**0.8 GWh**	**0.2 GWh**	**0.4 GWh**	**3.0 GWh**	**17.3 GWh**
	100%	**3%**	**3%**	**3%**	**4%**	**1%**	**2%**	**15%**	**85%**

APPENDIX I – AWS ADVANCED REPORTS

Separate PDF documents:

Cyprus Advanced Report.pdf

Kluane Advanced Report.pdf

Milers Advanced Report.pdf

Sugarloaf Advanced Report.pdf

Sumanik Advanced Report.pdf

Tehcho Advanced Report.pdf

Thulsoo Advanced Report.pdf

Appendix 5.10
Geothermal Review and Site Inventory
(KGS 2016)

YUKON ENERGY

Geothermal Review and Site Inventory

FINAL – REV 0

KGS Group 16-1404-001
August 2016

Prepared By

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Sept 8, 2016

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September 8, 2016 File No. 16-1404-001

Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, Yukon
Y1A 6S7

ATTENTION: Mr. Marc-André Lavigne
Resource Planner

RE: Geothermal Review and Site Inventory
Final – Rev 0

Dear Mr. Lavigne:

Please find enclosed a PDF version of our revised draft report for the Yukon Energy Corporation Geothermal Review and Site Inventory. The primary objective of this study was to develop potential geothermal projects at a conceptual level. This study included identifying potential sites and providing economic analysis for these sites to determine whether a geothermal project was feasible in the Yukon. This revision addresses the comments received from Yukon Energy Corporation on the Draft B report.

After reviewing past reports and performing a volumetric assessment; the Vista Mountain and McArthur Springs locations were determined to have the largest production capacity for sites located near Yukon Energy Corporation's existing or planned infastructure. As the exact amount of production capacity is unknown, we have considered alternatives for both sites. The best and worst case senario in terms of production from the geothermal wells were considered for our analysis. For each alternative, we have developed monthly generation profiles and cost estimates including the construction and long term costs for developing these geothermal projects.

Please review the report and provide any comments you may have. We thank you for the opportunity to work on this project.

Sincerely,

Joel Lambert, P.Eng.
Senior Mechanical Engineer

JCL/ama
Enclosure

EXECUTIVE SUMMARY

Yukon Energy Corporation retained the engineering services of KGS Group to develop conceptual designs for geothermal projects in the Yukon. KGS Group retained Mannvit hf from Iceland to perform the final review of the site selections, assessment of geothermal well field needs, plant sizing, and determination of the appropriate technology and process to be used for the selected sites. KGS Group also retained InterGroup Consultants to perform the economic evaluation of the concepts developed. The study includes identifying potential sites and providing cost estimates and energy generation profiles for these sites to determine whether a geothermal project is feasible.

KGS Group and Mannvit hf reviewed the memoranda and reports provided by YEC and established a ranking of the sites from most favourable to least. The terms of reference for the project were to consider only sites that were located within 25 km from existing or future planned infrastructure.

Of the sites within the geographic location criteria, the Vista Mountain site was the most attractive because it is located on crown lands, close to the load centre of Whitehorse, has a relatively high inferred temperature, and it is very close to the North Klondike Highway and the Takhini substation.

The most promising site reviewed was McArthur Springs. Although it does not lie within the corridor 25 km on either side of existing or planned infrastructure, it has the highest inferred temperature. Unfortunately, the length of the access road and transmission lines required to develop this site increase the expected project costs considerably.

Since no exploration wells have been drilled at any of the sites reviewed, including the Vista Mountain and McArthur Springs sites, there is considerable uncertainty regarding the actual reservoir temperature, chemistry and production index (PI) of the geothermal wells. This report presents optimistic and pessimistic cases for the PI at each site and the resulting plant capacities were determined using the geothermal fluid temperature that was inferred using geothermometer calculations.

The expected plant capacities from the Vista Mountain site range from 0.9 MW net output to 2.3 MW net output. The expected plant capacities from the McArthur Springs site range from 2.1 MW net output to 5.5 MW net output. The actual plant capacity that can be developed will be dependant on the actual geothermal fluid temperature and the PI values encountered once the wells are drilled. The plant capacities being limited by the estimated capacity of the geothermal resource.

The Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC) for the Vista Mountain site are shown in the Table below.

Geothermal Cases	Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC)					
	3.38% Real WACC		4.61% Real WACC		8.82% Real WACC	
	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)
	$/kW.h	$/MW	$/kW.h	$/MW	$/kW.h	$/MW
A	B	C	D	E	F	G
Vista Mountain Case 1: 0.9 MW	$0.368	$2,330,074	$0.412	$2,658,409	$0.577	$3,901,681
Vista Mountain Case 2: 2.3 MW	$0.194	$1,094,589	$0.214	$1,248,829	$0.290	$1,832,876

The Vista Mountain Case 1 with 0.9 MW net development scale shows about two times higher LCOE and LCOC under each WACC scenario compared to the higher scale capacity and energy Case 2 [with 2.3 MW]. This highlights that any small scale version of the project is likely not financially attractive.

The Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC) for the McArthur Springs site are shown in the Table below.

Geothermal Cases	Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC)					
	3.38% Real WACC		4.61% Real WACC		8.82% Real WACC	
	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)
	$/kW.h	$/MW	$/kW.h	$/MW	$/kW.h	$/MW
A	B	C	D	E	F	G
McArthur Springs Case 3: 2.1 MW	$0.469	$3,220,803	$0.527	$3,674,652	$0.746	$5,393,197
McArthur Springs Case 4: 5.5 MW	$0.225	$1,388,937	$0.250	$1,584,655	$0.343	$2,325,759

The McArthur Springs Case 3 with 2.1 MW net development scale shows more than two times higher LCOE and LCOC under each of the WACC scenarios compared to the higher scale Case 4 capacity and energy. This highlights that any small scale version of the project is likely not financially attractive.

TABLE OF CONTENTS

PAGE

1.0 INTRODUCTION 1
1.1 TERMS OF REFERENCE 1
1.2 MODIFICATION TO THE ORIGINAL TERMS OF REFERENCE 2

2.0 REVIEW OF EXISTING INFORMATION AND RANKING OF SITES 3
2.1 COMMENT ON AVAILABLE INFORMATION 3
2.2 SITE LOCATION CRITERIA 5
2.3 SITE RANKINGS 6
2.4 PREFERRED SITES AND POTENTIAL PLANT CAPACITIES 8

3.0 VISTA MOUNTAIN 13
3.1 SITE DESCRIPTION 13
3.1.1 REGIONAL GEOLOGY AND SITE OBSERVATIONS 13
3.1.2 AVAILABILITY OF CONSTRUCTION MATERIAL 14
3.2 PLANT ARRANGEMENT 14
3.2.1 ORGANIC RANKINE CYCLE (ORC) POWER PLANT 14
3.2.2 TRANSMISSION LINE 15
3.3 POWER AND ENERGY POTENTIAL 16
3.3.1 ESTIMATES OF POTENTIAL ENERGY 16
3.3.2 CASE 1 - MONTHLY GENERATION PROFILE 17
3.3.3 CASE 2 - MONTHLY GENERATION PROFILE 18
3.4 COST ESTIMATES 19
3.5 CONSTRUCTION SCHEDULE & LIFE OF THE PROJECT 21
3.6 OPERATION AND MAINTENANCE COSTS 21
3.7 LEVELIZED COSTS 22

4.0 MCARTHUR SPRINGS 24

4.1 SITE DESCRIPTION 24
4.1.1 REGIONAL GEOLOGY AND SITE OBSERVATIONS 24
4.1.2 AVAILABILITY OF CONSTRUCTION MATERIAL 25
4.2 PLANT ARRANGEMENT 26
4.2.1 ORGANIC RANKINE CYCLE (ORC) POWER PLANT 26
4.2.2 TRANSMISSION LINE 26
4.3 POWER AND ENERGY POTENTIAL 27
4.3.1 ESTIMATES OF POTENTIAL ENERGY 27
4.3.2 CASE 3 - MONTHLY GENERATION PROFILE 28
4.3.3 CASE 4 - MONTHLY GENERATION PROFILE 29
4.4 COST ESTIMATES 30
4.5 CONSTRUCTION SCHEDULE & LIFE OF THE PROJECT 32
4.6 OPERATION AND MAINTENANCE COSTS 32
4.7 LEVELIZED COSTS 33

5.0 REVIEW OF RISKS AND SHOWSTOPPERS 35

6.0 CONCLUSIONS AND RECOMMENDATIONS 36
6.1 CONCLUSIONS 36
6.2 RECOMMENDATIONS 37

TABLE OF CONTENTS CONTINUED

7.0 STATEMENT OF LIMITATIONS AND CONDITIONS 39
7.1 THIRD PARTY USE OF REPORT 39
7.2 CAPITAL COST ESTIMATE STATEMENT OF LIMITATIONS 39

FIGURES
DRAWINGS
APPENDICES

LIST OF TABLES

1. Sites Located Within 25 km of Existing or Planned Infrastructure
2. Sites Located Close to Location Criteria
3. Water Treatment Mitigations
4. Case 1 Summary of Initial Average Monthly Energy
5. Case 2 Summary of Initial Average Monthly Energy
6. Vista Mountain Summarized Costs
7. LCOE and LCOC for Vista Mountain Cases
8. Case 3 Summary of Initial Average Monthly Energy
9. Case 4 Summary of Initial Average Monthly Energy
10. McArthur Springs Summarized Costs
11. LCOE and LCOC For McArthur Springs Cases
12. Risks Identified With The Geothermal Developments

LIST OF FIGURES

1. Yukon Energy Grid Overview and Potential Transmission Options
2. Vista Mountain Site Location Plan
3. Case 1 Organic Rankine Cycle Flow Chart
4. Case 2 Organic Rankine Cycle Flow Chart
5. Vista Mountain Case 1 Plant Layout
6. Vista Mountain Case 2 Plant Layout
7. Case 1 Initial Monthly Generation Profile
8. Case 2 Initial Monthly Generation Profile
9. Preliminary Development Schedule For Vista Mountain
10. McArthur Springs Site Location Plan
11. Case 3 Organic Rankine Cycle Flow Chart
12. Case 4 Organic Rankine Cycle Flow Chart
13. McArthur Springs Case 3 Plant Layout
14. McArthur Springs Case 4 Plant Layout
15. Case 3 Initial Monthly Generation Profile
16. Case 4 Initial Monthly Generation Profile
17. Preliminary Development Schedule For McArthur Springs
18. Drilling Cost as a Function of Well Depth
19. Energy and Capacity Degradation Case 1 Vista Mountain
20. Energy and Capacity Degradation Case 2 Vista Mountain
21. Energy and Capacity Degradation Case 3 McArthur
22. Energy and Capacity Degradation Case 4 McArthur

LIST OF APPPENDICES

A. Bibliography
B. Site Ranking Summary
C. Detailed Cost Estimates
D. Financial Tables

1.0 INTRODUCTION

Yukon Energy Corporation (YEC), established in 1987, is a publicly owned electrical utility which provides reliable electricity to close to 15,000 consumers. The hydro facilities at Whitehorse, Mayo, and Aishihik Lake provide 92 megawatts of power to the surrounding communities. With 39 megawatts produced by diesel generators (currently used for back up) and 0.65 megawatts by a small wind turbine on Haeckel Hill near Whitehorse, Yukon Energy has the capacity to generate close to 132 megawatts. In support of Yukon's long term load forecast, YEC seeks to refine the knowledge and determine the feasiblity of potential geothermal generation projects in the Territory.

Yukon Energy Corporation retained the engineering services of KGS Group and indirectly, KGS Group's subconsultants, Mannvit hf of Iceland and InterGroup Consultants, to review existing reports and data, identify preferred sites, and develop conceptual designs for geothermal projects in the Yukon. The study includes cost estimates and energy generation profiles for these sites as well as the expected levelized costs of energy and capacity. The results of this study will be used to support Yukon Energy Corporation's planning process to look at potential resource options to meet the long term load forecast for 2016-2035.

1.1 TERMS OF REFERENCE

The scope of work for this study included the following:

- Attend a project kickoff meeting with YEC by conference call.
- Project Management.
- Review the 26 memoranda and reports previously completed by YEC on the available geothermal resources available in the Yukon.
- Identify all potential geothermal sites within 25 km of existing and/or planned infrastructure as illustrated by Figure 1 from the RFP.
- Employing the above information, select the best three (3) sites. Evaluate the site-specific requirements (procurement of land, # of wells, and type of equipment and cost of transmission/distribution) and develop conceptual level geothermal projects for various generation capacities, namely 5 MW, 10 MW and 20 MW.

- Develop monthly generation profiles for the three sites based on the projected capacities.
- Develop AACE Class V cost estimates (-50% to +100%) for the three sites based on the projected capacities.
- Identify preliminary risks and potential "Show Stoppers" for the three sites. However, it is noted that the evaluation of the three geothermal projects against the environmental and socio-economic attributes will be completed as a separate project.
- Identify and evaluate potential O&M costs for operation of the three sites based on the various generation capacities.
- Generate high-level project schedules (including provisions for further exploratory work, data collection, effects assessment, permitting and the like) from the early planning/exploration phase through to the project commissioning phase.
- Evaluate the earliest possible in-service date and potential project life for each of the three sites.
- Prepare a report detailing the study process and findings.

The items identified below were excluded from the scope of work:

- Collection of any additional environmental, geotechnical, or physical data; and
- Evaluation of the three geothermal projects against any environmental and socio-economic project attributes.

1.2 MODIFICATION TO THE ORIGINAL TERMS OF REFERENCE

Given the budget set aside by Yukon Energy Corporation to complete the study, the KGS Group proposal indicated that there would be greater value to Yukon Energy Corporation in developing fewer concept designs and providing a more in-depth review of fewer design options, than could be done if the 9 scenarios requested in the RFP were pursued. It was decided at the kick-off meeting that the existing data would be reviewed and the sites ranked from most to least attractive. From these intial rankings, a determination was made as to the number of total sites to be evaluated, and for the range in generating capacity for each site.

As described in Section 2, two sites were selected for concept design development and two different capacity levels were considered at each site; thus resulting in a total of four concept designs and cost evaluations.

2.0 REVIEW OF EXISTING INFORMATION AND RANKING OF SITES

KGS Group collected and reviewed pertinent documentation, reports, drawings, surveys and other data, assessed the available information, and identified the additional information required to effectively complete the study. The reports received from Yukon Energy Corporation are listed in Appendix A – Bibliography**.**

Information from CanGEA/Energy Branch was also used in this assessment. The information had not yet been published but Yukon Energy Corporation provided “early access” to assist with this work.

2.1 COMMENT ON AVAILABLE INFORMATION

In general, the reports provided by YEC were compiled over a number of years of study (typically between 2009 and 2012), and for the most part by the same engineering consultant. Some of the reports, such as more broadly based, sub-regional to regional aerial photography interpretation reports and/or other geophysical studies, for example, are of general interest in defining possible geothermal source signatures over larger areas, but did not factor directly into assessments and calculations necessary for completion of the current study. As such, these more regionally based reports were not reviewed in detail, other than to provide some context if/as necessary in relation to site terrain or general geological conditions of the region of interest.

Key data sources necessary for developing the current study included:

- Basic details associated with the overall geological setting and geological structure(s) of the potential geothermal resource;
- Measured surface spring temperature data;
- Measured water quality data to infer the possible relationship of the flow system(s) to deeper seated plutonic heat sources;
- Calculation of geothermal source temperatures via geothermometer calculations (typically SiO2 geothermometer techniques);
- Isotope signatures of source waters to infer residence times and possible deep-seated geothermal sources;

- Measured or estimated geothermal gradients (if any were available); and
- Typical ground temperatures for the region, and climate normal data, used to assess heat exchange processes necessary with the power generation schemes assessed in the study.

Each of the potential geothermal resources, ranked into the project shortlist during the course of this study, included some basic understanding of the geological framework and hydrogeological setting within which the possible geothermal resourse is hosted. This is of importance as there must be a conduit through which groundwaters can circulate to depth, become heated, and return back toward surface, to provide a signature for a possible geothermal resource target. The geochemistry of these heated spring waters will vary, depending on the geology, residence times, and flow path length/depths to which these groundwaters circulate. These signatures, in absence of direct measurements of a possible geothermal resource, are important in deducing the potential for a viable geothermal system.

Those resources in the vicinity of Whitehorse (e.g. Vista Mountain, Takhini, Stinky Lake and Versluce) are hosted within fault zones and ancillary fault zones of the “Whitehorse Trough”. The Whitehorse Trough is associated with an intermontane setting, comprised of an intensely folded, faulted and metamorphosed geology, and is juxtaposed along the Nahlin Fault zone, and south of the Tintina Fault, which is a significant, territory-wide structural feature.

Other short-listed geothermal features, namely Jarvis River, Partridge Creek, and the McArthur spring, are associated with a valley setting comprised of thick sediment cover, though bounded by assumed deep and sub-vertical fault zones; a zone of intense fracturing, faulting, and shearing along the Tintina Trench; and within the Selwyn Fold Belt, respectively. The Tintina Trench is associated with a massive Territory-wide fault zone, extending continuously for hundreds of kilometers, and the Selwyn Fold Belt formed during a phase of basin folding and during large scale mobilization of regional fault structures.

It is important to note that the evaluation of all of these potential geothermal resource sites as necessary for the current study are being completed using inferred data. None of these geothermal resources have been measured directly, and it is possible that direct measurement of these geological and geothermal features at depth could result in a different conclusion.

Site rankings and interpretations of possible geothermal resources are discussed in the following report sections.

2.2 SITE LOCATION CRITERIA

The terms of reference for this study stipulated that sites located within a 25 kilometre range of existing and planned future Yukon Energy Corporation infrastructure (i.e. transmission & distribution lines, substations, switchyards, etc.) would be considered for evaluation. This is due to the relatively high additonal costs of support infrastructure such as construction of access roads and interconnections via new transmission lines. This was the first screening criteria applied to all target geothermal resources, and several of the sites discussed in the reports and memos were eliminated from consideration based only on this proximity criteria. Figure 1 is a map of the geographical area in question, which includes the locations of the potential geothermal sites. Table 1 lists the longitude and latitude of the sites that meet the location criteria, as well as the "straight-line" distance to the existing or planned infrastructure and estimates of the transmission line and access road lengths that would be necessary to develop the site.

TABLE 1
SITES LOCATED WITHIN 25 KM OF EXISTING OR PLANNED INFRASTRUCTURE

NAME OF SPRING	LATITUDE	LONGITUDE	STRAIGHT LINE DISTANCE TO TRANSMISSION LINE	ESTIMATED ACCESS ROAD LENGTH	ESTIMATED TRANSMISSION LINE LENGTH
	[deg - min]	[deg - min]	[km]	[km]	[km]
Takhini	60 52	135 22	1	1	1
Versluce	60 46	135 09	1	1	1
Mayo well	63 36	135 53	1	1	1
Stinky Lake	60 45	135 08	1	1	1
Vista Mountain	60 55	135 11	4	2	5
Jarvis Creek	60 54	137 57	5	5	5
Partridge Creek	63 41	137 18	15	20	20
Atlin	59 24	133 35	20	1	22
Morin North	59 59	134 13	22	33	33
Morin Middle	59 58	134 13	22	33	33
Jones Lake	59 53	134 00	22	22	22
Morin South	59 58	134 13	25	30	30

Of these sites, the Takhini, Versluce, Vista Mountain and Stinky Lake sites are attractive from a geographical location point of view because of their proximity to Whitehorse and the major load centre in the Territory.

There were a few sites that, while not within the area of interest, were reviewed. These sites are listed in Table 2.

TABLE 2
SITES LOCATED CLOSE TO LOCATION CRITERIA

NAME OF SPRING	LATITUDE	LONGITUDE	STRAIGHT LINE DISTANCE TO TRANSMISSION LINE	ESTIMATED ACCESS ROAD LENGTH	ESTIMATED TRANSMISSION LINE LENGTH
	[deg - min]	[deg - min]	[km]	[km]	[km]
McArthur	63 04	135 42	37	43	43
McPherson	61 52	129 37	41	50	50
Volcano Mountain	62 54	137 20	33	35	35

2.3 SITE RANKINGS

Once the location screening criteria was applied, the available information for the remaining sites was reviewed. This amount of information available for each site varied. Some sites had almost no information at all (e.g. Volcano Mountain and the Sites near Atlin), while reports contained water temperature, groundwater chemistry, spring flow rates and isotope analyses for some of the other sites.

The following sites were eliminated from consideration from this study based on the lack of available information.

- Volcano Mountain.
- Atlin.
- Jones Lake.
- Morin (South, Middle and North).
- Mayo Well.

Further investigation/exploration may indicate geothermal resources worth developing at these sites, but there is not sufficient information available at this time to make this determination. The remaining sites, each including enough base information for a cursory resource evaluation, were ranked as follows (Refer to Appendix B – Site Ranking Summary for further details):

- Vista Mountain Warm Spring.
- Takhini.
- Stinky Lake Warm Springs.
- Versluce.
- Jarvis Creek (Jarvis River) Warm Spring.
- Partridge Creek.
- McArthur Spring.

Interestingly, based on the available data, the McArthur Spring, although not in accordance with the proximity to existing/future infrastructure criteria, appears overall to be the site with the greatest inferred potential for a “low temperature” geothermal source. It was ranked at 7 due to its distance from the nearest transmission line (Carmacks-Stewart line), and associated complexities in constructing road access and power transmission interconnections in a rugged terrain setting.

Vista Mountain ranks high due to its close proximity to infrastructure and the main load center of Whitehorse, location on Crown lands, and relatively high inferred resource temperature (110°C, or “low temperature” geothermal) in comparison to other possible Whitehorse region sites which have an inferred temperature of <100°C (Klump and Dennett, December 2012). The Takhini geothermal resource is also in a good geographical location, however it is situated on private land and it is currently being operated as a recreational “Hot Spring” business, which is a major destination in the Whitehorse area. The inferred temperature of the Takhini geothermal resource is just below the “low temperature” geothermal resource threshold cutoff, at an inferred resource temperature of approximately 96°C (Klump and Dennett, December 2012).

It should be noted that, of the remaining sites in the Whitehorse region (i.e. Stinky Lake, Versluce, and Jarvis River), there is not one site that is siginificantly better than the others, and

the associated inferred maximum resource temperature of these sites is approximately 100°C. Partridge Creek, while in accordance with the transmission right-of-way screening criteria, is further from the main Territory load center of Whitehorse, located approximately 115 km southeast of Dawson City. The inferred resource temperature of Partridge Creek is somewhat low, with geothermometer readings as low as 95°C, though depending on the geothermometer calculation used, reported estimates on reseource temperature vary between approximately 100°C and 120°C (Klump and Dennett, April 2012). Access/transmission construction to Partridge Creek is overall within rugged terrain, thus increasing site development logistical complexities, and overall associated costs as compared to possible geothermal resources located closer to Whitehorse. The difference in the current site rankings is within the expected margin of error, and given more information from further investigations or explorations, the site ranking order may vary.

All the reviewed sites for this report are low/medium temperature resources. Low/medium temperature resources have temperature less than 150°C. The fluid is usually pumped from the wells as a liquid. The heat from the fluid is used for generating electrical power in a binary power cycle as described in Section 3.2.1. For comparison, the temperature in high temperature resources are typically over 200°C. The fluid from the wells is usually in two phases, liquid and steam, but in some cases dry steam. The steam can be used directly in turbines. The efficiency and feasibility of such power plant is usually better than for a power plant using low/medium temperature resource in a binary power cycle.

2.4 PREFERRED SITES AND POTENTIAL PLANT CAPACITIES

Given that there was not a marked difference between the attractiveness of the Whitehorse region potential geothermal resource sites (other than for inferred resource temperature), the KGS Group team and Yukon Energy Corporation decided to develop concept designs for only one of these sites. Due to the limited baseline data available, there is little to no difference in the concept design that would apply to any of these sites. However, it was decided that a site with the highest inferred geothermal resource temperature, and relatively straightforward construction considerations (i.e. Vista Mountain), would form the best base case for assessment in the Whitehorse region. The Vista Mountain concept design is in general representative of the concept that could be developed for the remainder of these Whitehorse region sites.

The Vista Mountain Warm Spring site was selected because it:

- Ranked better that the other Whitehorse region sites, based on inferred geothermal resource temperature.
- Is geographically located near Whitehorse and near the Takhini substation.
- Is located near the North Klondike Highway.
- Has a relatively gentle surrounding terrain with good access; and
- Is located on public (Crown) land.

Regarding the resource capabilities, the main assumption for the preferred sites is that each geothermal resource capacity declines annually by 2%, as a "natural" decline. As a face value, the lifetime of each project is just over 30 years, if no new make-up wells are drilled. For the range of the selected Productivity Indices (PI) and temperatures, as well as assuming the power generating processes presented in the following report sections, each well power output was estimated to be 0.6 to 3.5 MW_e. The annual well decline would be approximately 0.02 to 0.1, depending on the PI and temperature.

The annual production decline of 2% is taken from the world literature and it applies to high temperature geothermal projects with successful reinjection. For the Yukon projects which are assumed to be operated at much lower temperature, the 2% annual decline is a reasonable estimation.

For this type of reservoir, reinjection will boost the reservoir pressure by providing an extra mass flow. Ideally the reinjection strategy is to locate the injection and production wells close together to provide pressure support, but far enough apart to prevent premature thermal breakthrough. Without any reservoir simulations in hand, the minimum distance between a production and a reinjection well is considered to be about 1,000 m. The world average between production and reinjection wells for this type of reservoir is about 1,300 m.

The two cases at Vista Mountain are primarily based on two assumptions for PI. Case 1 has a PI of 1 kg/s/bar, producing 1.2 MW gross and 0.9 MW net. Case 2 has PI of 5 kg/s/bar, producing 3.1 MW gross and 2.3 MW net. The number of wells and completion depth of the wells are the same for both the cases and the expected geothermal resource temperature is

estimated at 120°C. The only difference between the cases is the PI value which results in different mass flow from the production wells. Wells with less mass flow like in Case 1 do not need as powerful well pumps as Case 2 and other parasitic load for such a plant (e.g. power to run well pumps and condenser fans, etc.) is also less. The two PI values are estimates of likely ranges estimated for the McArthur reservoir as well.

The McArthur Warm Spring site was also selected for assessment. Although it is situated outside the geographical proximity to transmission tie-in screened within this study, and while the terrain/access conditions appear difficult, it was the only site where the available raw data showed a geothermal resource that was of significantly higher temperature than all other potential geothermal resource sites studied to date. In fact, based on the raw water quality data provided, a recalcuation of the silica geothermometer for this resource indicates it may be inferred to be as high as approximately 155°C – 160°C. While not included in the current assessment, it is important to note that the site is located on land that has significance to the local First Nations community.

The two cases at McArthur are, as in the Vista Mountain case, primarily based on two assumptions for PI. Case 3 has PI of 1 kg/s/bar, producing 2.8 MW gross and 2.1 MW net. Case 4 has PI of 5 kg/s/bar, producing 7.0 MW gross and 5.5 MW net. The number of wells and depth of the wells are the same for both the cases, and the expected temperature value is estimated at 160°C. The only difference betweem the cases is the PI value which results in different mass flow from the production wells. Wells with less mass flow like in Case 3 do not need as powerful well pumps as Case 4 and other parasitic load for such a plant is also less.

Drilling of make-up wells is usually a part of the normal operation of a geothermal power plant in order to replenish the reduced capacity of the production wells. How frequently make-up wells are drilled depends on the decline rate as well as number of wells. The cost of drilling one make-up well can, however, be a large part of the total cost for power projects with few wells making the make-up drilling less feasible. In the case of the Vista Mountain and McArthur Springs sites, it is expected that the drawdown in the wells will be governed by the general drawdown in the resource. As the temperature decline and degradation of equipment are also independent of the wells, we conclude that make-up wells will not remedy the output degradation.

Due to lack of geophysical data, the actual size of the geothermal resource could not be delineated. Therefore, a conventional volumetric capacity estimate was not possible. The approach here was to use the length of the mapped faults to determine how many wells could be drilled in each area. The assumption is that the faults are the main providers of the necessary permeability to sustain the proposed geothermal production. The second assumption is that 1000 m spacing is required between the wells. These assumptions lead to the conclusion that both the areas (Vista Mountain and McArthur Springs) could each sustain two production wells and one injection well. The limited number of wells that could be sustained at each site limit the plant capacities that could be developed at these sites to the values included in this report.

Dissolved solids and/or gases may require water treatment mitigations, such as relatively high plant operation pressure and/or necessary chemical treatment. The nature of geothermal plants is such that these problems are normally inherited and unavoidable, but mitigatable. The mitigation methods depend on the nature of the geothermal fluid (like chemical composition, temperature and pressure). Since little is known about the nature of the geothermal fluid in these resources which are being dealt with here, the extent of the mitigation process is unknown. Possible problems and mitigations for geothermal fluids are listed in Table 3.

TABLE 3

WATER TREATMENT MITIGATIONS

PROBLEM	MITIGATION
High CO_2 gas content of the fluid leads to high CO_2 emission into the atmosphere.	Keep the CO_2 dissoved in water by relatvely high wel head pressures and reinject it back into the reservoir.
Low pH (acid geothermal fluid) which can be corrosive for wells and pipelines.	Injecting a solution with high pH value into the well to neutralize its acidity.
Mineral scaling due to silica (SiO_2) and/or calcite ($CaCO_3$).	Inhibitors injected into the well, high operation pressures, repeated cleaning.

2.5 FURTHER EXPLORATION

The geological information available for the Vista Mountain site is general and further work is needed to assess the geothermal potential of the area. The assessment should be divided into two phases.

The first phase should focus on the surface geology, structural arrangements and geochemistry in the Vista Mountain area. The target of the work is to estimate the resource temperature and to delineate the geothermal area. With this information, the power capacity can be estimated. The estimated power capacity value will be used as a go/no-go decision for further work.

If the decision is to continue the investigation, the assessment will move to phase two. The work in this phase mainly focuses on geophysical surveys. There are several geophysical surveys which can be utilized. Normally two to three individual surveys are recommended. Typical surveys are resistivity surveys (for this area, Transient Electro-Magnetic (TEM) surveys are ideal and Magnetotelluric (MT) surveys are less so due to the low probability of adding information on the resistivity structure of the area), gravity surveys and magnetic surveys. Surface surveys, like soil temperature and soil gas mapping are also ideal, as well as thermal gradient drilling. The soil/gas temperature mapping measures the temperature and the gas flow in the soil down to 1 meter depth. Soil temperature/gas mapping will find anomalously hot areas, which are normally tied to permeable structures. These permeable structures could be then targeted at greater depths. Prior to drilling thermal gradient wells, the regional gradient must be known so anomalous areas can be delineated. In other words, the proposed thermal gradient survey will focus on finding anomalously hot areas. In low temperature areas, the thermal gradient wells only need be 30-60 meters deep, if the permeability is low. The number of wells will vary greatly, but 10-15 wells are not an unrealistic number of thermal gradient wells.

If after the completion of the assessment, deep drilling is still considered too risky, one option is to drill “slim” exploration wells (i.e. test boreholes with diameters less than 150 mm, or 6 inches) which are deep enough to penetrate into the top of the geothermal resource. Slim wells offer cost effective solution compared to a full diameter research well. The resource temperature can be measured in slim wells and short production/injection testing can be carried out as well. Nevertheless, slim well drilling is risky, particularly with deep wells, and it is highly unlikely they can be used as either production wells or reinjection wells.

3.0 VISTA MOUNTAIN

3.1 SITE DESCRIPTION

Vista Mountain is located approximately 4 km North of Takhini Substation and approximately 1 km West of the North Klondike Highway, as shown on Figure 2. Access to the site is good. Most of the distance between the North Klondike Highway and the spring is generally flat, with a rise in elevation on approach to the spring site itself. It is estimated that the optimum transmission line route will follow the access road from the plant to the North Klondike Highway. The line would then follow the existing right of way to the Takhini substation.

3.1.1 Regional Geology and Site Observations

Site visits were not included in the scope of this project, therefore the Vista Mountain site, and any geological observations are based on the available reports (e.g. Klump and Dennett, December, 2012), and satellite/aerial images of the surrounding landscape. Review of aerial photography indicates a relatively flat (+/- 2 m elevation variation) rock outcrop south of the spring site suitable for construction of the powerhouse and condenser. There is strong evidence of glacial scouring, with most exposed outcrops with a smooth and rounded morphology. The rock is generally of low relief, with fluted outcrops trending in a northwest-southeast orientation, separated by narrow shallow depression areas. Limited overburden stripping and minimal bedrock excavation is estimated to be necessary to prepare the preferred construction site, south of the spring. Based on the extents of visible bedrock, it is estimated that all major structures can be founded on concrete slabs cast directly on the prepared bedrock surface, with smaller components such as pipe supports or doweled directly to the rock surface. Rock types in the area include massive to thickly bedded limestones, and sandstones, shales, and conglomerates. Specifically, outcrops of limestones and shales are observed at the spring site itself. As reported by Klump and Dennett (December, 2012), typical slopes are gentle (e.g. 15% to 26%), to moderate in other site areas (i.e. 27% to 49%) away from the relatively flat location that would be targeted for construction of any facility, and as described above.

As described by Klump and Dennett (December, 2012), two regional fault trends are typical in the study area, subsidiary zones associated with the more regional Whitehorse Trough. These

faults trend in a northwesterly direction, and in a north-northeast, to northerly direction. The spring site itself is located at the intersection of two prominent faults. Dominant jointing directions measured at the site are generally in a north-south direction, dipping to the west, with secondary discontinuity orientations northwest-southeast (dipping southwest) and/or oriented northeast-southwest with a sub-vertical dip. The project area includes zones of glaciolacustrine deposits, overlying the bedrock.

The project site as well lies within the zone of discontinuous permafrost in Canada, where frozen ground is scattered throughout these kinds of glaciolacustrine fine sediments. In general permafrost is most common within poorly drained and low-lying bog areas where layers of peat and vegetation insulate the ground and prevent permaforst thaw. At this time, permafrost design issues are not included within the conceptual assessments. However, based on the extents of visible bedrock at the site it is not estimated that permafrost issues would be significant for development at this site.

3.1.2 Availability of Construction Material

Construction materials would need to be sourced to provide for aggregates for access road construction as well as concrete production. From a review of satellite photography, established aggregate sources are located within 15 km of the site which could likely provide all aggregate needs for the project. If the available local aggregate sources are not sufficient or accessible, other established aggregate sources in the Whitehorse area would provide the required construction materials.

3.2 PLANT ARRANGEMENT

3.2.1 Organic Rankine Cycle (ORC) Power Plant

The Vista Mountain site was estimated to produce geothermal liquid at 120°C. The design concepts for the site are comprised of ORC geothermal plants for both cases where the geothermal fluid is kept as single phase liquid. An ORC plant uses the high temperature steam and/or water from the production wells to heat a binary fluid, which most often is a hydrocarbon, with a low boiling point in a heat exchanger. The heat absorbed from the geothermal source

causes the hydrocarbon fluid to evaporate, producing the high-pressure vapor that is then expanded through a turbine. The turbine drives a generator to produce electrical power. The low pressure turbine exhaust vapor is then condensed to be recirculated through the system repeatedly. The lower boiling point and higher molecular weight of the hydrocarbon fluid allows the use of smaller equipment than a conventional steam cycle operating at low temperatures. After the geothermal fluid has heated the hydrocarbon fluid in the heat exchanger, it is reinjected into the reservoir through a reinjection well. Figures 3 and 4 demonstrate schematically how an organic rankine cycle (ORC) functions for different PI values.

For both Case 1 and Case 2, it is proposed that the arrangement consist of two production wells and one injection well. All wells were assumed to be 2700 metres deep and they would be located approximately 1000 m apart. The wells will have ø13 ⅜" anchor casings down to approximately 400 m depth and a ø9 ⅝" production liner from 300 m down to approximately 1000 m. The production part of the wells will be drilled with a ø8 ½" drill bit and a ø7" slotted liner will be run in the production part down to the bottom of the well or 2700 m depth. Installed in the wells will be ø8" line-shaft pumps. A small building covering the well head and associated equipment would be equipped with either a roof hatch or a completely removable roof to allow for easy installation and maintenance of the pumps. Buried insulated pipe would connect the wells to the plant. Although the exact location of the plant relative the wells cannot be determined without further field investigations, the preferred option is to locate the plant close to the reinjection well, even within the well field.

Figure 5 and Figure 6 show the proposed plant layout. The turbine, generator and control rooms will be housed in a powerhouse due to the local climate. The heat exchangers and condensing equipment are located outdoors adjacent to the powerhouse.

3.2.2 Transmission Line

The transmission line for the Case 1 and 2 is 34.5kV which will follow the Vista Mountain access road until it dead ends to Highway #2. It will then follow Highway #2 and interconnect with the transmission line at the Takhini Substation. The proposed transmission line path does not interfere with any Ta'an Kwach'an First Nation settlement land.

With little site specific geological or terrain information evaluated, the exact construction location within the Vista Mountain region may vary along with the required transmission line alignment. For cost estimating purposes, the transmission line length is estimated to be 5 km from the geothermal plant to the Takhini Substation.

There has been no consideration to the overall grid capacity at the tie-in locations, and any constraints or limitations of the existing or future grid extensions have not be evaluated. Costs for upgrades that may be required have not been carried in the estimates in this report.

3.3 POWER AND ENERGY POTENTIAL

3.3.1 Estimates of Potential Energy

The efficiency of an ORC geothermal power plant is inversely proportional to the ambient temperature. In other words; the efficiency of the plant decreases as the the ambient temperature increases. Also, as the ambient temperature increases, more power is needed to condense the working fluid. This results in a lower plant capacity during the summer. In the winter months, the efficiency increases and less power is required to condense and a higher plant capacity is achieved. The following tables show the gross and net plant capacity ranges for both cases.

CASE #1

	T_{amb} [°C]	P_{gross} [MW]	P_{net} [MW]
	15	1,1	0,7
Design case:	**8**	**1,2**	**0,9**
	0	1,4	1,1

CASE #2

	T_{amb} [°C]	P_{gross} [MW]	P_{net} [MW]
	15	2,7	1,9
Design case:	**8**	**3,1**	**2,3**
	0	3,6	2,8

As mentioned earlier, a constant decrease of 2% per year has been assumed. The actual performance of the wells would depend on the local conditions. Monitoring of the well production rates and drawdown values would be required during the operation of the station.

3.3.2 Case 1 - Monthly Generation Profile

The energy production was estimated using monthly climate normals recorded from 1981 to 2010 at the Whitehorse A station which were provided by weather records of Government of Canada.

The assumptions used for this estimation of the average annual energy production are:

- The plant net capacity was linearly interpolated between 1.1 MW – 0.9 MW for monthly climate normals between 0°C - 8°C.
- The plant net capacity was linearly interpolated between 0.9 MW – 0.7 MW for normals between 8°C and 15°C.
- The plant net capacity is 1.1MW for any monthly climate normal under 0°C.
- Plant availability of approximately 95%.

The monthly generation profile for Case 1 is shown in Figure 7.

The maximum energy production would occur in between the months of December and March. The following table summarizes the monthly generation profile resulting with an initial yearly total of 8.15 GWh. As discussed, the capacity and yearly energy production of the plant decreases over time; therefore, after 30 years, it is expected that the annual energy production will be decreased to 4.54 GWh.

TABLE 4
CASE 1 SUMMARY OF INITIAL AVERAGE MONTHLY ENERGY

	MONTHLY AVERAGE ENERGY (MWh)
January	777
February	702
March	777
April	735
May	648
June	532
July	509
August	543
September	629
October	769
November	752
December	777
Yearly Total (MWh)	**8150**

3.3.3 Case 2 - Monthly Generation Profile

For Case 2, the plant net capacity was linearly interpolated between 2.8MW – 2.3MW for monthly climate normals between 0°C - 8°C and 2.3MW – 1.9MW for normals between 8°C and 15°C.

The assumptions used for this estimation of the average annual energy production are:

- The plant net capacity was linearly interpolated between 2.8 MW – 2.3 MW for monthly climate normals between 0°C - 8°C
- The plant net capacity was linearly interpolated between 2.3 MW – 1.9 MW for normals between 8°C and 15°C
- The plant net capacity is 2.8MW for any monthly climate normal under 0°C.
- Plant availability of approximately 95%, to account for inspection/repair time.

The monthly generation profile for Case 2 is shown on Figure 8.

The maximum average energy production would occur in between the December and March months. Table 4 summarizes the monthly generation profile resulting with a yearly total of 20.95 GWh. The capacity and yearly energy production of the plant decreases over time; therefore, after 30 years, it is expected that the annual energy production will be decreased to 11.66 GWh.

TABLE 5
CASE 2 SUMMARY OF INITIAL AVERAGE MONTHLY ENERGY

	MONTHLY AVERAGE ENERGY (MWh)
January	1,979
February	1,788
March	1,979
April	1,872
May	1,657
June	1,405
July	1,371
August	1,440
September	1,607
October	1,957
November	1,915
December	1,979
Yearly Total (MWh)	**20,950**

3.4 COST ESTIMATES

Costing for both cases was completed for comparison. The total 0.9 MW net plant, Case 1, is estimated at approximately $37,800,000, as summarized in Table 5. The total 2.3 MW net project cost, Case 2, is estimated at approximately $45,200,000, as summarized in Table 5. Detailed estimates of the project direct costs have been provided in Appendix C – Detailed Cost Estimates. This appendix also include a brief discussion of the basis for the cost estimate.

TABLE 6
VISTA MOUNTAIN SUMMARIZED COSTS

ITEM			CASE 1 0.9 MW COST (2015 $)	CASE 2 2.3 MW COST (2015 $)
Contractor Direct Costs			**$15,130,000**	**$18,160,000**
Site Work			$100,000	$120,000
Structures & Excavation			$930,000	$1,190,000
Power Plant			$2,900,000	$5,400,000
Wells & Water Supply System			$9,070,000	$9,320,000
Transmission Line & Interconnection			$990,000	$990,000
Access			$640,000	$640,000
Environmental & Mitigation Items			$500,000	$500,000
General Contractor Indirect Costs	*35%*	of Directs	**$5,300,000**	**$6,360,000**
Travel and Accommodation Costs	*6%*	of Directs	**$910,000**	**$1,090,000**
Subtotal			**$21,340,000**	**$25,610,000**
Contingency	*30%*	*of Subtotal*	**$6,400,000**	**$7,680,000**
Total Construction Cost			**$27,740,000**	**$33,290,000**
Contractor Markups			**$5,600,000**	**$6,720,000**
Profit	12%	of Const.	$3,329,000	$3,995,000
Head Office Overhead	7.0%	of Const.	$1,942,000	$2,330,000
Bonding & Insurance	1.2%	of Const.	$333,000	$399,000
Total Contractor Price			**$33,340,000**	**$40,010,000**
Owner Costs			**$4,440,000**	**$5,180,000**
Environmental Licencing/Consulting	3.0%	of Directs	$454,000	$545,000
Prefeasibility Study	0.5%	of Directs	$76,000	$91,000
Feasibility Study	1.5%	of Directs	$227,000	$272,000
Final Design	9.0%	of Directs	$1,362,000	$1,634,000
Site Assistance & Quality Assurance	6.0%	of Directs	$908,000	$1,090,000
Owner's Administration	2.0%	of Contract	$667,000	$800,000
Pre-Drilling Go/No Go Exploration			$750,000	$750,000
Total Project Cost			**$37,800,000**	**$45,200,000**

The total project costs shown are expected to be inclusive of all project costs. Given the limited amount of design work performed to date, a contingency of 30% has been included. Also, the allowances for contractor indirect costs, travel and accommodation, profit, overhead, etc. are based on KGS Group's recent experience on hydroelectric development projects in various remote locations in Canada (including the Mayo B Hydroelectric project).

3.5 CONSTRUCTION SCHEDULE & LIFE OF THE PROJECT

The preliminary construction schedule is shown on Figure 9. A pre-design phase including the test well drilling and confirmation of plant capacity has been considered in the context of the total project schedule. If the pre-design phase where to start immediately, site works and transmission line construction would start 1ST quarter 2018. The earliest possible in service date would be 1ST quarter 2019.

The potential life span for both Case 1 and 2 are estimated at 30 years.

3.6 OPERATION AND MAINTENANCE COSTS

At this early stage of design, it is difficult to estimate the operation and maintenance costs, but generally, an ORC geothermal plant of the sizes in question here can be operated by one person working approximately half-time. On top of this, scheduled and unscheduled maintenance needs to occur. The O&M cost includes all expenses that are related to the operation and maintenance of the power plant like overhead costs, supervision of equipment (turbine, generator, heat exchangers, buildings, pipes, wellhead etc.), maintenance (both work and material) and monitoring. Besides the labor cost, the other costs include some consumable goods (lubricants, spare parts, etc.), taxes and other expenses such as waste disposal.

To estimate yearly average maintenance costs, published data for ORC geothermal plants was used. Costs per kW of capacity from the report “Assessment of Current Costs of Geothermal Power Generation in New Zealand (2007 Basis)”, by Sinclair Knight Merz, 2009, was used as a basis. The published data was for 20 MW plants, therefore, the values obtained were scaled up to account for the anticipated increase cost per kW for the significantly smaller Vista Mountain cases. The O&M costs were estimated at:

- Case 1 (0.9 MW net plant): $350,000 per year.
- Case 2 (2.3 MW net plant): $800,000 per year.

3.7 LEVELIZED COSTS

The Levelized Cost of Energy ("LCOE") and Levelized Cost of Capacity ("LCOC") are a useful means of comparing energy options based on financial attributes, providing the levelized cost of a unit of energy or capacity of a resource option at the point of interconnection with the Yukon power grid. The LCOE and LCOC estimates adopted for this assessment assume a full utilization of the energy and capacity of the reviewed option.

The following financial assumptions are used for LCOE and LCOC analysis ($2015) of the Vista Mountain geothermal resource option:

- The capital costs, including transmission/interconnection costs identified during the review and provided in this report;
    - Vista Mountain case 1 at $37.0 million.
    - Vista Mountain case 2 at $44.4 million.
- Annual fixed operating and maintenance costs identified during the review and provided in this report;
    - Vista Mountain case 1 at $0.350 million/year.
    - Vista Mountain case 2 at $0.800 million/year.
- Annual energy output [KWHr] and capacity [MW] outputs are based on evaluation of each option provided in this report, including the assumed 2% yearly degradation over the life;
- Expected life of all options is assumed to be 30 years and the in-service date is assumed to be the start of 2019.
- Inflation rate of 2%.
- Weighted average cost of capital (WACC) as specified by YEC.
- Rate of 5.45% (nominal) and 3.38% (real), assuming 2% inflation.
- The options are also reviewed using higher WACC (assumed to be used in the assessments of independent power producers [IPP] options):
    - Rate of 6.7% (nominal) and 4.61% (real).
    - Rate of 11% (nominal) and 8.82% (real).

Table 7 below provides a summary of the LCOE and LCOC for each scale of Vista Mountain development cases under each of the WACC scenarios.

TABLE 7
LCOE AND LCOC FOR VISTA MOUNTAIN CASES

Geothermal Cases	Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC)					
	3.38% Real WACC		4.61% Real WACC		8.82% Real WACC	
	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)
	$/kW.h	$/MW	$/kW.h	$/MW	$/kW.h	$/MW
A	B	C	D	E	F	G
Vista Mountain Case 1: 0.9 MW	$0.368	$2,330,074	$0.412	$2,658,409	$0.577	$3,901,681
Vista Mountain Case 2: 2.3 MW	$0.194	$1,094,589	$0.214	$1,248,829	$0.290	$1,832,876

The Vista Mountain Case 1 with 0.9 MW net development scale shows about two times higher LCOE and LCOC under each WACC scenarios compared to the higher scale capacity and energy Case 2 [with 2.3 MW]. This highlights that any small scale version of the project is likely not financially attractive.

Refer to Appendix D - Financial Tables for further details.

4.0 McARTHUR SPRINGS

4.1 SITE DESCRIPTION

McArthur Springs is located approximately 42 km East of North Klondike Highway southeast of Stewart Crossing, and approximately 75 km south of Mayo, as shown on Figure 10. The site is located within the Ddhaw Ghro Habitat Protection Area, and is designated for mineral exporation development by the Selkirk First Nation. With the remote location of the springs, current site access conditions are challenging, due to overall rugged terrain. As a result of this, a longer access road is necessary to access the geothermal plant site. It is therefore assumed that the optimum transmission line route will follow the access road from the plant to interconnection along the North Klondike Highway.

4.1.1 Regional Geology and Site Observations

Site visits were not included in the scope of this project, therefore the McArthur Springs site and geology observations are based on available reports (e.g. Schillereff, Johnston, and Dennett, February, 2009; Dennett and Klump, April, 2010; Menzies and Dennett, October, 2009; Carlson and Zondervan, September, 2009; Carlson and Zondervan, June, 2009), and satellite/aerial images of the surrounding landscape. The springs are associated with an intensely folded geological terrane, within the Selwyn Fold Belt. The McArthur Pluton, a major intrusive body, is also a significant feature in the McArthur springs area, and is oriented relatively parallel to the Tintina Trench (which is located 8 km south of the spring site). The springs exit at the southwest margin of the pluton, where it had intruded sedimentary and meta-sedimentary bedrock at the margin of the basin. These bedrock units include siltstones, mudstones and chert, with interbedded sandstones and schists. Based on the orientation of the creek where the springs are located, the spring site is assumed to be hosted within a subsidiary fault zone, trending at approximately 60° to the main regional fault trend.

The spring discharges at 18 individual vents, distributed over an area of approximately 150 m x150 m, and exiting from river valley fill overburden deposits. Variation in the preciptates from groundwater flows at the discharge areas, suggest that there have been changes in flows, or variation in discharge sites, over the life of this spring. Unique to this site is the relatively fesh

spring groundwater geochemistry, which suggests short residence times within the subsurface circulation system.

A relatively flat area will be selected near the spring site, suitable for construction of the powerhouse and condenser. Limited overburden stripping and rock excavation in the form of local chipping rather than blasting is anticipated to prepare the site for construction. Due to the extents of bedrock visible, it is expected that all major structures can be founded on slabs cast directly to rock with smaller components such as pipe supports or doweled directly to the rock surface.

While the project site lies within the zone of discontinuous permafrost in Canada, in general permafrost is most common within fine grained glaciolacustine soils that are poorly drained and where layers of peat and vegetation insulate the ground and prevent permaforst thaw. At this time, permafrost design issues are not included within the conceptual assessments.

4.1.2 Availability of Construction Material

Construction materials would need to be sourced to provide for access road construction, as well as for concrete production. From a review of satellite photography, existing rock outcrops and talus materials could be developed to produce all aggregate needs for the project. Importantly, the cut-fill balance of the road design would require optimization, as best possible, to mitigate the need for significant importation of construction materials, and enhance efficient and cost effective utilization of materials available within the project footprint and along the access road alignment. A Geotechnical investigation of the surrounding area could be required to optimize the road alignment, and also confirm sources of additional construction materials, if the available local sources are insufficient, or otherwise difficult to develop for construction use. Some photos of the McArthur site that show the typical valley rockfills and bedrock outcrops in the project area are contained within reference reports such as Schillereff, Johnston, and Dennett (February, 2009).

4.2 PLANT ARRANGEMENT

4.2.1 Organic Rankine Cycle (ORC) Power Plant

The McArthur Springs site was estimated to produce geothermal fluid at 160°C; which is significantly higher than Vista Mountain. The higher water temperature delivers more heat for the hydrocarbon fluid to absorb in the heat exchanger. The more heat absorbed by the working fluid, the higher pressure flowing through the turbine-generator unit which results in a higher plant capacity. The ORC components are similar to both cases at Vista Mountain, only the system size is larger. For further details on functionality of the ORC, refer to Section 3.2.1. Figures 11 and 12 demonstrate the organic rankine cycle schematic for the different PI values.

For both Case 3 and Case 4, it is proposed that the arrangement consist of two production wells and one injection well. All wells were assumed to be 2700 metres deep and they would be located approximately 1000 m apart. The wells will have ø13 ⅜" anchor casings down to approximately 400 m depth and a ø9 ⅝" production liner from 300 m down to approximately 1000 m. The production part of the wells will be drilled with a ø8 ½" drill bit and a ø7" slotted liner will be run in the production part down to the bottom of the well or 2700 m depth. Installed in the wells will be ø8" line-shaft pumps. A small building covering the well head and associated equipment would be equipped with either a roof hatch or a completely removable roof to allow for easy installation and maintenance of the pumps. Buried insulated pipe would connect the wells to the plant.

Figure 13 and Figure 14 show the proposed plant layout. The turbine, generator and control rooms will be housed in a powerhouse due to the local climate. The heat exchangers and condensing equipment are located outdoors adjacent to the powerhouse.

4.2.2 Transmission Line

The transmission line for Case 3 and 4 is 138kV which will follow the McArthur Springs access road until it dead ends onto the North Klondike Highway. Located north of the Pelly and MacMillan rivers, the proposed transmission line path lies entirely within Nacho Nyak Dun First

Nation and Selkirk First Nation traditional territory and the westernmost portion of the line is within the Selkirk First Nation settlement land.

With relatively little geological or site specific information, the exact transmission line corridor within the McArthur Springs region is undetermined at this time, along with the required length of transmission line. For cost estimating purposes, an approximated transmission line length of 42 km is assumed.

Similar to the Vista Mountain location; there has been no consideration to the overall grid capacity at the tie-in locations, and any constraints or limitations of the existing or future grid extensions have not be evaluated. Costs for upgrades that may be required have not been carried in the estimates in this report.

4.3 POWER AND ENERGY POTENTIAL

4.3.1 Estimates of Potential Energy

The efficiency of an ORC geothermal power plant is inversely proportional to the ambient temperature. In other words; the higher the ambient temperature, the lower the efficiency and more power is needed to condense the working fluid. This results in a lower plant capacity during the summer. In the winter months, the efficiency increases and less power is required to condense and a higher plant capacity is achieved. The following tables show the gross and net plant capacity ranges for both cases.

CASE #3

	T_{amb} [°C]	P_{gross} [MW]	P_{net} [MW]
	15	2,6	1,9
Design case:	**8**	**2,8**	**2,1**
	0	3,1	2,4

CASE #4

	T_{amb} [°C]	P_{gross} [MW]	P_{net} [MW]
	15	6,4	4,9
Design case:	**8**	**7,0**	**5,5**
	0	7,7	6,2

As mentioned earlier, a constant decrease of 2% per year has been assumed. The actual performance of the wells would depend on the local conditions. Monitoring of the well production rates and drawdown values would be required during the operation of the station.

4.3.2 Case 3 - Monthly Generation Profile

The energy production was estimated using monthly climate normals recorded from 1981 to 2010 at the Whitehorse A station which were provided by weather records of Government of Canada.

The assumptions used for this estimation of the average annual energy production are:

- The plant net capacity was linearly interpolated between 2.4 MW – 2.1 MW for monthly climate normals between 0°C - 8°C
- The plant net capacity was linearly interpolated between 2.1 MW – 1.9 MW for normals between 8°C and 15°C.
- The plant net capacity is 2.4 MW for any monthly climate normal under 0°C.
- Plant availability of approximately 95%.

The monthly generation profile for Case 3 is shown on Figure 15.

The maximum energy production would occur in between the months of December and March. Table 8 summarizes the monthly generation profile resulting with an initial yearly total of 18.62 GWh. As discussed, the capacity and yearly energy production of the plant decreases over time; therefore, after 30 years, it is expected that the annual energy production will be decreased to 10.37 GWh.

TABLE 8
CASE 3 SUMMARY OF INITIAL AVERAGE MONTHLY ENERGY

	MONTHLY AVERAGE ENERGY (MWh)
January	1,696
February	1,532
March	1,696
April	1,616
May	1,503
June	1,352
July	1,357
August	1,391
September	1,457
October	1,683
November	1,642
December	1,696
Yearly Total (MWh)	**18,620**

4.3.3 Case 4 - Monthly Generation Profile

The assumptions used for this estimation of the average annual energy production are:

- The net plant capacity was linearly interpolated between 6.2 MW – 5.5 MW for monthly climate normals between 0°C - 8°C
- The plant net capacity was linearly interpolated between 5.5 MW – 4.9 MW for normals between 8°C and 15°C
- The plant net capacity is 6.2 MW for any monthly climate normal under 0°C.
- Plant availability of approximately 95%, to account for inspection/repair time.

The monthly generation profile for Case 4 is shown on Figure 16.

The maximum average energy production would occur in between the December and March months. Table 9 summarizes the monthly generation profile resulting with a yearly total of 48.24 GWh. The capacity and yearly energy production of the plant decreases over time; therefore, after 30 years, it is expected that the annual energy production will be decreased to 26.85 GWh.

TABLE 9
CASE 4 SUMMARY OF INITIAL AVERAGE MONTHLY ENERGY

	MONTHLY AVERAGE ENERGY (MWh)
January	4,382
February	3,958
March	4,382
April	4,181
May	3,931
June	3,510
July	3,506
August	3,609
September	3,810
October	4,351
November	4,241
December	4,382
Yearly Total (MWh)	**48,240**

4.4 COST ESTIMATES

Costing for both cases was completed for comparison. The total 2.1 MW net plant, Case 3, is estimated at approximately $114,000,000, as summarized in Table 10. The total 5.5 MW project cost, Case 4, is estimated at approximately $127,000,000, as summarized in Table 9. Detailed estimates of the project direct costs have been provided in Appendix C – Detailed Cost Estimates. This appendix also include a brief discussion of the basis for the cost estimate.

TABLE 10
McARTHUR SPRINGS SUMMARIZED COSTS

ITEM			CASE 3 2.1 MW COST (2015 $)	CASE 4 5.5 MW COST (2015 $)
Contractor Direct Costs			**$45,010,000**	**$50,170,000**
Site Work			$110,000	$130,000
Structures & Excavation			$1,660,000	$2,550,000
Power Plant			$4,400,000	$8,400,000
Wells & Water Supply System			$8,800,000	$9,050,000
Transmission Line & Interconnection			$11,120,000	$11,120,000
Access			$18,420,000	$18,420,000
Environmental & Mitigation Items			$500,000	$500,000
General Contractor Indirect Costs	35%	of Directs	**$15,750,000**	**$17,560,000**
Travel and Camp Costs	10%	of Directs	**$4,500,000**	**$5,020,000**
Subtotal			**$65,260,000**	**$72,750,000**
Contingency	30%	of Subtotal	**$19,580,000**	**$21,830,000**
Total Construction Cost			**$84,840,000**	**$94,580,000**
Contractor Markups			**$17,140,000**	**$19,110,000**
Profit	12%	of Const.	$10,181,000	$11,350,000
Head Office Overhead	7.0%	of Const.	$5,939,000	$6,621,000
Bonding & Insurance	1.2%	of Const.	$1,018,000	$1,135,000
Total Contractor Price			**$101,980,000**	**$113,690,000**
Owner Costs			**$12,040,000**	**$13,310,000**
Environmental Licencing/Consulting	3.0%	of Directs	$1,350,000	$1,505,000
Prefeasibility Study	0.5%	of Directs	$225,000	$251,000
Feasibility Study	1.5%	of Directs	$675,000	$753,000
Final Design	9.0%	of Directs	$4,051,000	$4,515,000
Site Assistance & Quality Assurance	6.0%	of Directs	$2,701,000	$3,010,000
Owner's Administration	2.0%	of Contract	$2,040,000	$2,274,000
Pre-Drilling Go/No Go Exploration			$1,000,000	$1,000,000
Total Project Cost			**$114,000,000**	**$127,000,000**

The total project costs shown are expected to be inclusive of all project costs. Given the limited amount of design work performed to date, a contingency of 30% has been included. Also, the allowances for contractor indirect costs, travel and accommodation, profit, overhead, etc. are based on KGS Group's recent experience on hydroelectric development projects in various remote locations in Canada (including the Mayo B Hydroelectric project).

4.5 CONSTRUCTION SCHEDULE & LIFE OF THE PROJECT

The preliminary construction schedule is shown on Figure 17. A pre-design phase including the test well drilling and confirmation of plant capacity has been considered in the context of the total project schedule. If the pre-design phase where to start immediately, site works would start 3rd quarter 2018. The earliest possible in service date would be 4th quarter 2019.

The potential life span for both Case 3 and 4 are estimated at 30 years.

4.6 OPERATION AND MAINTENANCE COSTS

At this early stage of design, it is difficult to estimate the operation and maintenance costs, but generally, an ORC geothermal plant of the sizes in question here can be operated by one person working approximately half-time. On top of this, scheduled and unscheduled maintenance needs to occur. The O&M cost includes all expenses that are related to the operation and maintenance of the power plant like overhead costs, supervision of equipment (turbine, generator, heat exchangers, buildings, pipes, wellhead etc.), maintenance (both work and material) and monitoring. Besides the labor cost the other costs include some consumable goods (lubricants, spare parts, etc.), taxes, and other expenses such as waste disposal.

To estimate yearly average maintenance costs, published data for ORC geothermal plants was used. Costs per kW of capacity from the report "*Assessment of Current Costs of Geothermal Power Generation in New Zealand (2007 Basis)", by Sinclair Knight Merz, 2009,* was used as a basis. The published data was for 20 MW plants, therefore, the values obtained were scaled up to account for the anticipated increase cost per kW for the significantly smaller Vista Mountain cases. The O&M costs were estimated at:

- Case 3 (0.9 MW plant): $800,000 per year.
- Case 4 (2.3 MW plant): $1,800,000 per year.

4.7 LEVELIZED COSTS

The Levelized Cost of Energy ("LCOE") and Levelized Cost of Capacity ("LCOC") are a useful means of comparing energy options based on financial attributes, providing the levelized cost of a unit of energy or capacity of a resource option at the point of interconnection with the Yukon power grid. The LCOE and LCOC estimates adopted for this assessment assume a full utilization of the energy and capacity of the reviewed option.

The following financial assumptions are used for LCOE and LCOC analysis ($2015) of the McArthur Springs geothermal resource options:

- The capital costs, including transmission/interconnection costs identified during the review and provided in this report:
    - McArthur Springs Case 3 at $113.0 Million.
    - McArthur Springs Case 4 at $126.0 Million.
- Annual fixed operating and maintenance costs identified during the review and provided in this report:
    - McArthur Springs Case 3 at $0.8 Million/Year.
    - McArthur Springs Case 4 at $1.8 Million/Year.
- Annual energy output [KWHr] and capacity [MW] outputs are based on evaluation of each option provided in this report, including the assumed 2% yearly degradation over the life.
- Expected life of all options assumed to be 30 years [assumed in-service by the start of 2020].
- Inflation rate of 2%.
- Weighted average cost of capital (WACC) as specified by YEC:
    - Rate of 5.45% (nominal) and 3.38% (real), assuming 2% inflation.
- The options are also reviewed using higher WACC (assumed to be used in the assessments of independent power producers [IPP] options):
    - Rate of 6.7% (nominal) and 4.61% (real).
    - Rate of 11% (nominal) and 8.82% (real).

Table 11 below provides a summary of the LCOE and LCOC for each scale of McArthur Springs development cases under each of the WACC scenarios.

TABLE 11

LCOE AND LCOC FOR McARTHUR SPRINGS CASES

Geothermal Cases	Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC)					
	3.38% Real WACC		4.61% Real WACC		8.82% Real WACC	
	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)
	$/kW.h	$/MW	$/kW.h	$/MW	$/kW.h	$/MW
A	B	C	D	E	F	G
McArthur Springs Case 3: 2.1 MW	$0.469	$3,220,803	$0.527	$3,674,652	$0.746	$5,393,197
McArthur Springs Case 4: 5.5 MW	$0.225	$1,388,937	$0.250	$1,584,655	$0.343	$2,325,759

The McArthur Springs Case 3 with 2.1 MW net development scale shows more than two times higher LCOE and LCOC under each of the WACC scenarios compared to the higher scale Case 4 capacity and energy. This highlights that any small scale version of the project is likely not financially attractive.

The detailed tables are provided in Appendix D – Financial Tables.

5.0 REVIEW OF RISKS

The process proposed for the geothermal generating plants is well established and it is not expected that there are significant risks with the availability of equipment or the technology.

The risks identified with the geothermal developments discussed in this report are related to the unknowns with the geothermal field. Namely, the temperature of the fluid, the production index of the wells, the depth of the wells required, the size of the geothermal field and the chemical properties of the geothermal fluid. Table 12 discusses the effects of these parameters.

TABLE 12
RISKS IDENTIFIED WITH THE GEOTHERMAL DEVELOPMENTS

PARAMETER	IMPACT
Temperature of fluid	Efficiency and feasibility of the power plant is directly related to temperature
Production Index	Higher the yield from the wells (L/s) results in more efficient utilization of wells (i.e. reduced drawdown and thus reduced associated pumping costs) and this makes the plant more feasible
Temperature gradient	Well depth is related to the temperature gradient and the well depth affects the cost of drilling
Size of geothermal field	The size of the power plant relative to the size of the geothermal field and can also affect life time of the plant.
Chemical properties	Dissolved solids and/or gases may require mitigation by higher plant operating pressures, and may effect a limitation on cooling of the fluid, or necessitate chemical treatment. This may increase parasitic load, reduce plant power efficiency, and/or increase operating/maintenance costs

As shown in the preliminary project schedule, one or two wells should be drilled prior to detailed design to confirm the available resource. Once the results from the exploration wells are known, a GO – NO GO decision would have to be made. The cases presented are expected to be the estimated upper and lower bounds of the potential geothermal well production capacities.

As mentioned in Table 12, the well depth affects the cost of drilling. Figure 18 shows how the drilling cost developes with the depth when drilling a vertical 2000 m deep well where the production section is drilled with a ø8 ½" drill bit. The cost does not include preparation for the drilling such as roads, drill pad, water supply, surface casingetc. From the graph, one can read that the marginal cost for depth is rather small and will be still smaller when the cost of preparation is included. The drilling risk will however increase with increased depth and the depth and strength of anchor and production castings limits the maximum depth of the well.

6.0 CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSIONS

Frorm the information to date within the reports and information provided by Yukon Energy, it is concluded that there is a modest geothermal resource available for development in the Yukon. The inferred temperatures at all of the sites reviewed are relatively low and would therefore require the use of a binary geothermal plant arrangement (organic rankine cycle).

Of the sites reviewed that are within the 25 km corridor on either side of existing or planned transmission infrastructure, the Vista Mountain site appears to be the most promising. It is located on crown lands, close to the load centre of Whitehorse, has a relatively high inferred temperature, and is very close to the North Klondike Highway and the Takhini substation

The most promising site reviewed was McArthur Springs. Although it does not lie within the 25 km corridor on either side of existing or planned transmission infrastructure, it has the highest inferred resource temperature. Unfortunately, the length of the access road and transmission lines required to develop this site increase the estimated project costs considerably.

Since no exploration wells have been drilled at any of the sites reviewed, including the Vista Mountain and McArthur Springs sites, there is considerable uncertainty regarding the actual reservoir temperature, fluid chemistry, and production index (PI) of the geothermal wells. This report presents optimistic and pessimistic cases for the PI at each site. The resulting plant capacities were determined using the geothermal fluid temperature that was inferred using from existing geothermometer calculations. Further surveys and geophysical investigation would be required to refine the estimates presented herein.

The expected plant capacities from the Vista Mountain site range from 0.9 MW net output to 2.3 MW net output. The expected plant capacities from the McArthur Springs site range from 2.1 MW net output to 5.5 MW net output. The actual plant capacity that can be developed will be dependant on the actual geothermal fluid temperature and the PI values encountered once the production test wells are drilled and assessed.

The LCOE and LCOC analyses in this report were performed assuming full utilization of the energy option throughout each year during the 30 year life assumed under each scale of development. The following compares the financial attribute analysis of the resource options reviewed:

- The McArthur Springs option is materially larger than Vista Mountain at each of the two scales examined for each option, i.e., the smallest McArthur Springs case (Case 3) is roughly the same scale as the largest Vista Mountain case (Case 2).
- Both of these geothermal resource options are not economically attractive if the larger scale development case is not confirmed for the option through further studies, i.e., levelized unit costs per kW.h (LCOE) or per MW (LCOC) are more than twice as high for the smallest scale case versus the largest scale case for each option. McArthur Springs case (Case 3) shows the highest LCOE and LCOC reflecting high capital cost [more than 2.5 times the capital cost compared to roughly the same scale for the Vista Mountain case].
- The real LCOE ($2015) for the largest scale cases examined for each option is in the range of 19-22 cents/kW.h, i.e., $0.194/kW.h for Vista Mountain Case 2 (2.3 MW) and $0.225/kW.h for McArthur Springs Case 4 (5.3 MW). However, the McArthur Springs Case 4 option requires the larger load demand for fossil energy displacement in order to be competitive financially with the Vista Mountain Case 2 option.

McArthur Springs requires a much longer transmission line (assumed at 138 kV) to connect to the Yukon electrical grid. There could be potential financial benefits not considered in this analysis if the new transmission could be utilized by other loads or resource options.

6.2 RECOMMENDATIONS

The cost of drillling exploration wells at either of these sites is substantial. This is especially true for the McArthur Springs site, given its distance from any established access road. Therefore, further studies should be perfomed to quantify and delineate the resource at each site. The first studies should focus on the surface geology and structural arrangements and geochemistry in each area. With this, the estimated power capacity value can be used as a go/no-go decision for further work. If then, it is decided to proceed further, geophysical surveys and other surface mapping, as well as shallow drilling of smaller diamater test wells to determine thermal gradients would be required.

Following the additional studies, should either of these sites be considered further for development, at least one exploration well should be drilled at that site prior to making a final GO/NO GO decision. Since an exploration well could be developed into a production well if the project proceeds, the cost of the exploration is implicitly included in the cost estimates provided herein.

Once more precise information is known for resource temperature, fluid chemistry and well production index, the ORC process could be refined, preliminary equipment selections could be completed and the cost estimates for the project refined.

7.0 STATEMENT OF LIMITATIONS AND CONDITIONS

7.1 THIRD PARTY USE OF REPORT

This report has been prepared for Yukon Energy Corporation to whom this report has been addressed and any use a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

7.2 CAPITAL COST ESTIMATE STATEMENT OF LIMITATIONS

The cost estimates included with this report have been prepared by KGS Group using its professional judgment and exercising due care consistent with the level of detail required for the stage of the project for which the estimate has been developed. These estimates represent KGS Group's opinion of the probable costs and are based on factors over which KGS Group has no control. These factors include, without limitation, site conditions, availability of qualified labour and materials, present workload of the Bidders at the time of tendering and overall market conditions. KGS Group does not assume any responsibility to Yukon Energy Corporation, in contract, tort or otherwise in connection with such estimates and shall not be liable to Yukon Energy Corporation if such estimates prove to be inaccurate or incorrect.

FIGURES

Document Path: \\fs1\GIS Data\Project Data\Aishihik Water Licence Renewal\FIG_1_Yukon Power Grid_28Sept2015.mxd
United States
Yukon
Northwest Territories
British Columbia
Alberta
Larson Creek
Nash Creek
Dawson
Partridge Creek
Mayo
Mayo B
Mayo
Mayo
Volcano
McArthur
Beaver Creek
Carmacks
McPherson Lake
Aishihik Lake
Vista Mountain
Takhini
Stinky Lake
Jarvis Creek
Haines Junction
Whitehorse Rapids
Whitehorse
Versluce Warm Springs
Beaver River
Watson Lake
Swift River
Morin
Jones Lake
Atlin
Data Source -Main Map: Coordinate System: NAD83 UTM Zone 8
Roads -YTG SVW Roads
YEC Transmission Lines from Yukon Energy
Water 1:2M GeoYukon Dataset
Data Source -Overview Map: Coordinate System: Yukon Albers
Geobase 1:1,000,000 Place Names
*All data are limited by the date the map was printed. All spatial data subject to change.
1:3,000,000
This drawing has been prepared for the use of Yukon Energy and may not be used, reproduced or relied upon by third parties, except as agreed to by Yukon Energy and its Partners, as required by law or for use by governmental reviewing agencies. Yukon Energy accepts no responsibility, and denies any liability whatsoever, to any party that modifies this drawing without Yukon Enery's express written consent.
Legend
Existing Hydro Sites
YEC Transmission Lines
138kV Transmission Line
69kV Transmission Line
Proposed Transmission Line
25km Buffer
Roads
Primary Highway
Road
Secondary Highway
Watercourses
Waterbodies
YUKON ENERGY
20 Year Resource Plan
Yukon Electrical Grid Overview
and
Potential Transmission Options
Date Produced: 01/12/2015
Fig 1

Portions of data Produced by KGS Group, under Licence with Yukon Territory
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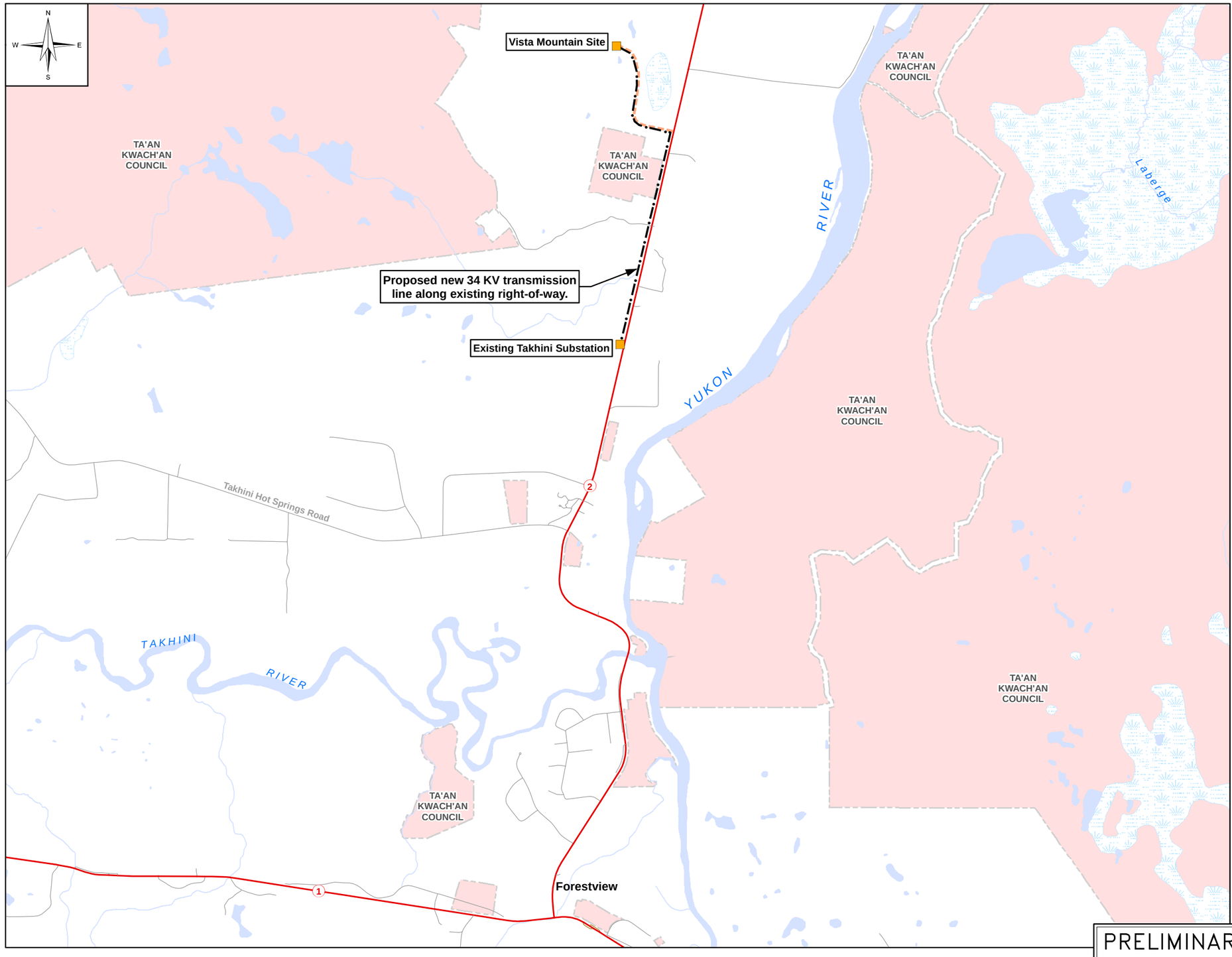


LEGEND:

- Proposed All–Weather Access Road
- Proposed 34.5 KV Transmission Line
- Highway
- Secondary Road
- Watercourse
- Waterbody
- Wetland
- First Nation Boundary

NOTES:
1. Wetland, Watercourse and Waterbody layers shown were obtained from GeoYukon base data.
2. All units are metric and in metres unless otherwise specified. Transverse Mercator Projection, NAD 1983, Zone 8. Elevations are in metres above sea level (MSL).

DRAFT

0.5 0 0.5 1 1.5 2
Kilometres

SCALE: 1:50,000 METRIC 11"x17"

NO.	YY/MM/DD	DESCRIPTION	ISSUED BY	CHECK BY
A	16/05/09	ISSUED WITH REPORT	JCL	MSW

REVISIONS / ISSUE

KGS GROUP CONSULTING ENGINEERS

YUKON ENERGY

GEOTHERMAL REVIEW AND SITE INVENTORY

VISTA MOUNTAIN
SITE LOCATION PLAN

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

MAY 2016 | FIGURE 2 | REV: A

FileName: P:\Projects\2016\16-1404-001\Dwg\GIS\MXDs\RevA\16-1404-001_Fig2_RevA.mxd
11"x17" PLOT SCALE 1:1

FIGURE 3
CASE 1 ORGANIC RANKINE CYLE FLOW CHART

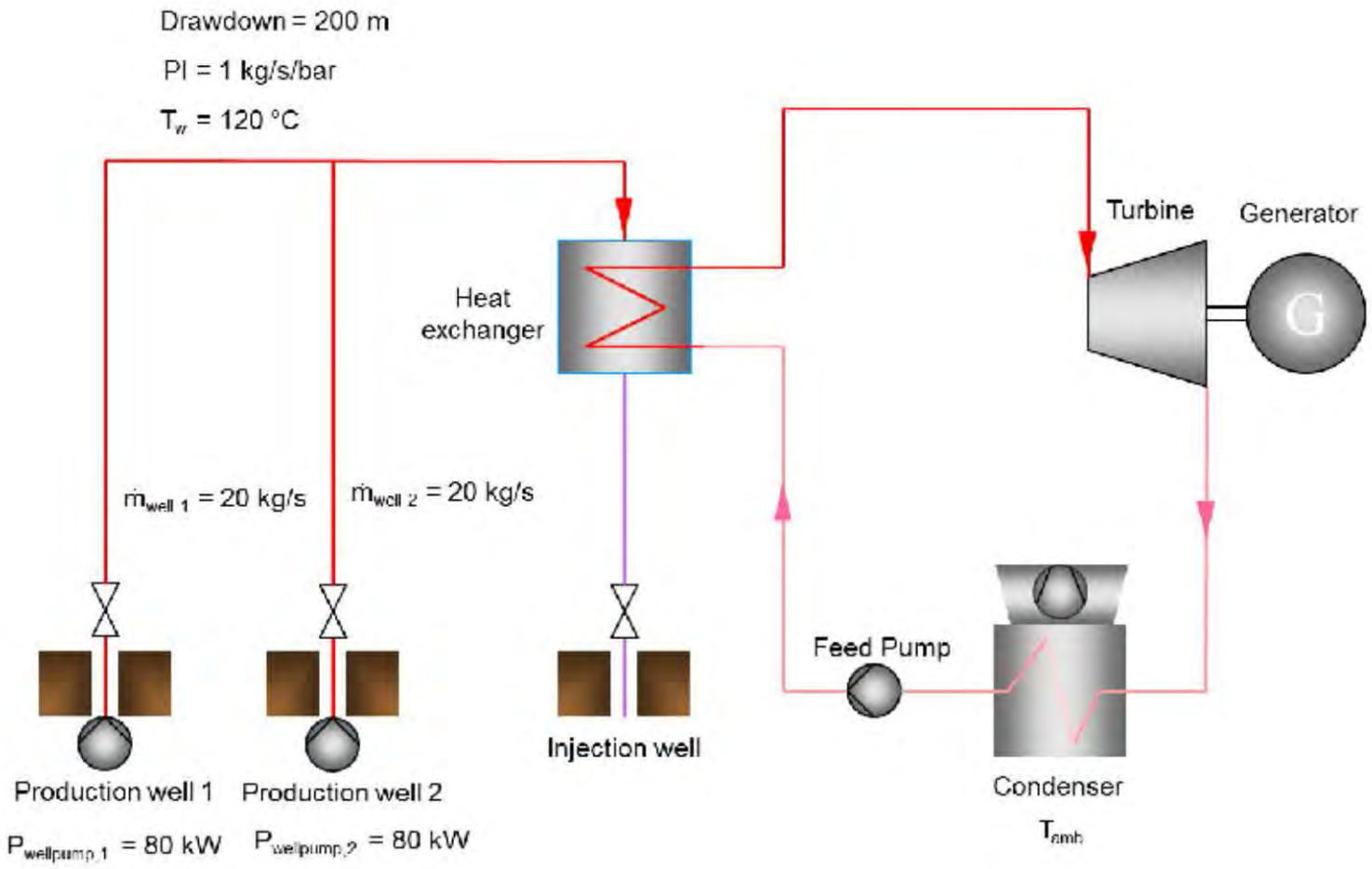
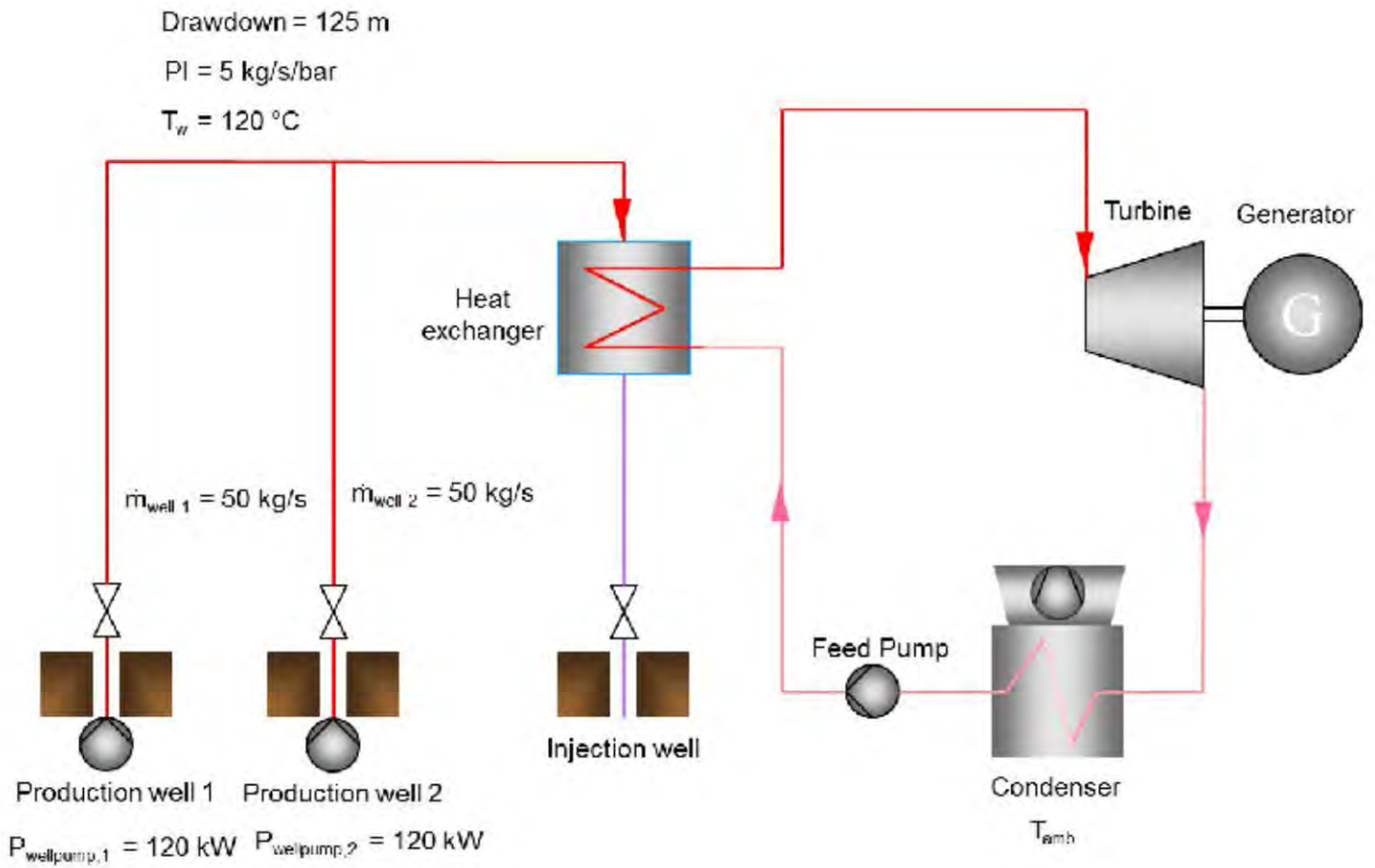
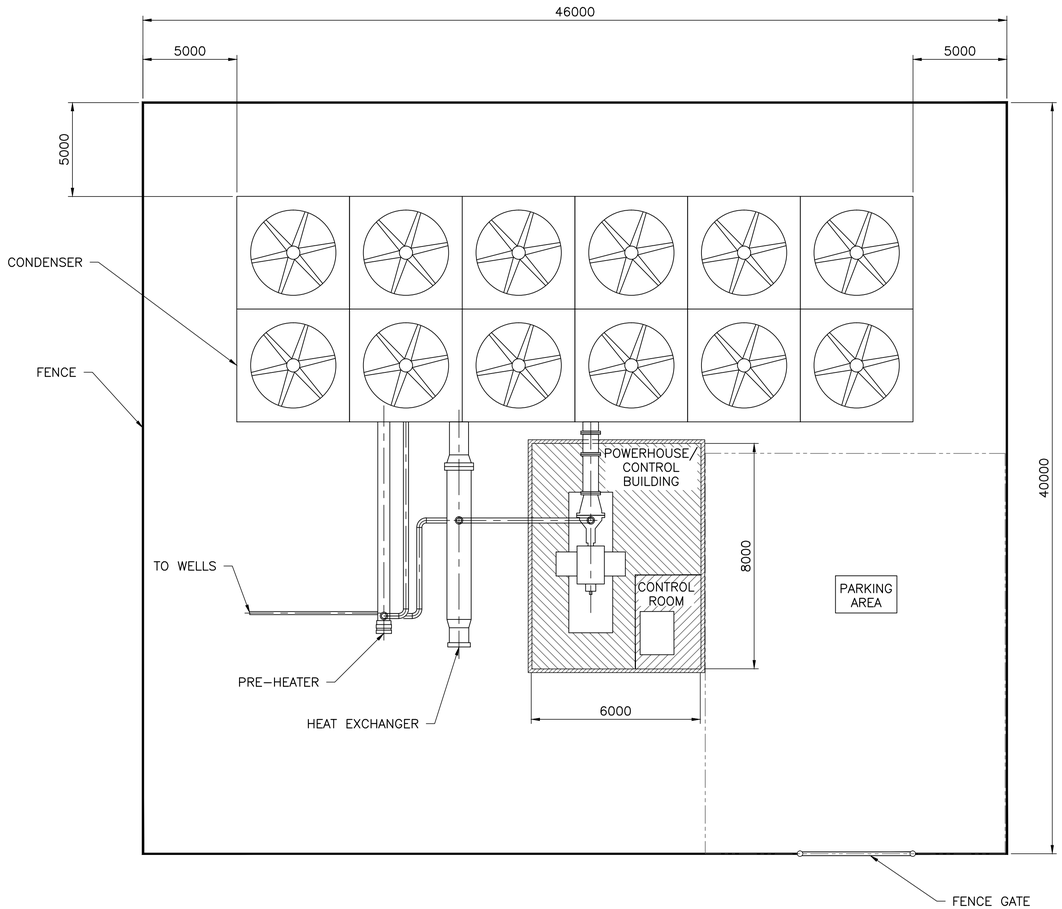


FIGURE 4
CASE 2 INITIAL MONTHLY GENERATION PROFILE



11x17



VISTA MOUNTAIN GEOTHERMAL ORC PLANT (1.2 MW)

3000 0 3000 6000 9000 12000

SCALE: 1:150mm (24"x36")

LEGEND:

ORC ORGANIC RANKINE CYCLE

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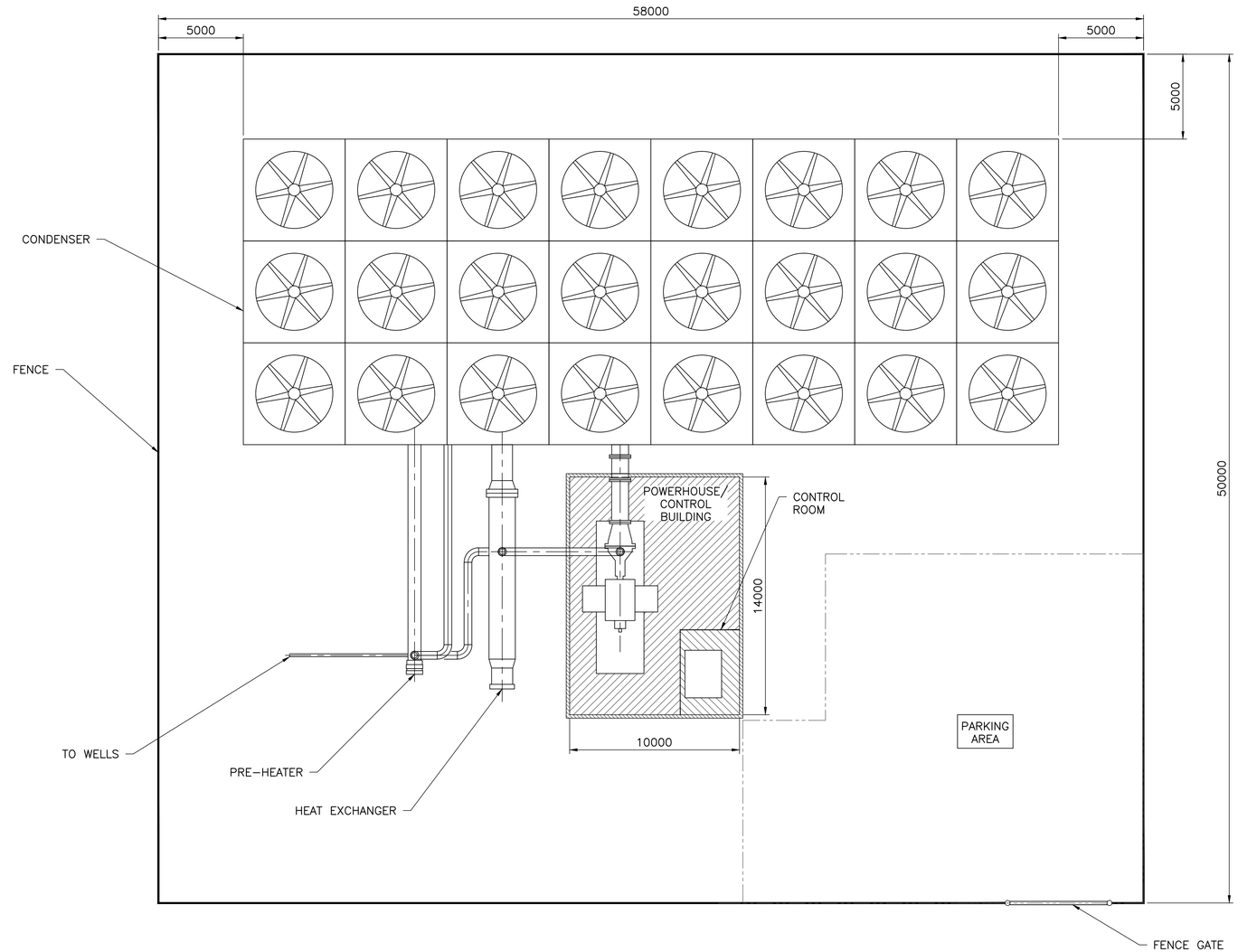
GEOTHERMAL REVIEW AND SITE INVENTORY

PLANT LAYOUT
CASE 1 (1.2 MW)
VISTA MOUNTAIN

MAY_2016 | FIGURE 5 | REV: A

FileName: U:\PMS\16-1404-001\16-1404-001_FIGURE 5.dwg - Tab: Rev A Plotted By: Cabellanosa 16/05/09 [Mon 2:10pm]
11"x17" PLOT SCALE: 1:2

11x17



VISTA MOUNTAIN GEOTHERMAL ORC PLANT (3.1 MW)

3000 0 3000 6000 9000 12000

SCALE: 1:150mm (24"x36")

LEGEND:

ORC ORGANIC RANKINE CYCLE

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GEOTHERMAL REVIEW AND SITE INVENTORY

PLANT LAYOUT
CASE 2 (3.1 MW)
VISTA MOUNTAIN

MAY_2016 | FIGURE 6 | REV: A

FileName: U:\PMS\16-1404-001\16-1404-001_FIGURE 6.dwg - Tab: Rev A Plotted By: Cabellanosa 16/05/09 [Mon 2:11pm]
11"x17" PLOT SCALE: 1:2

FIGURE 7

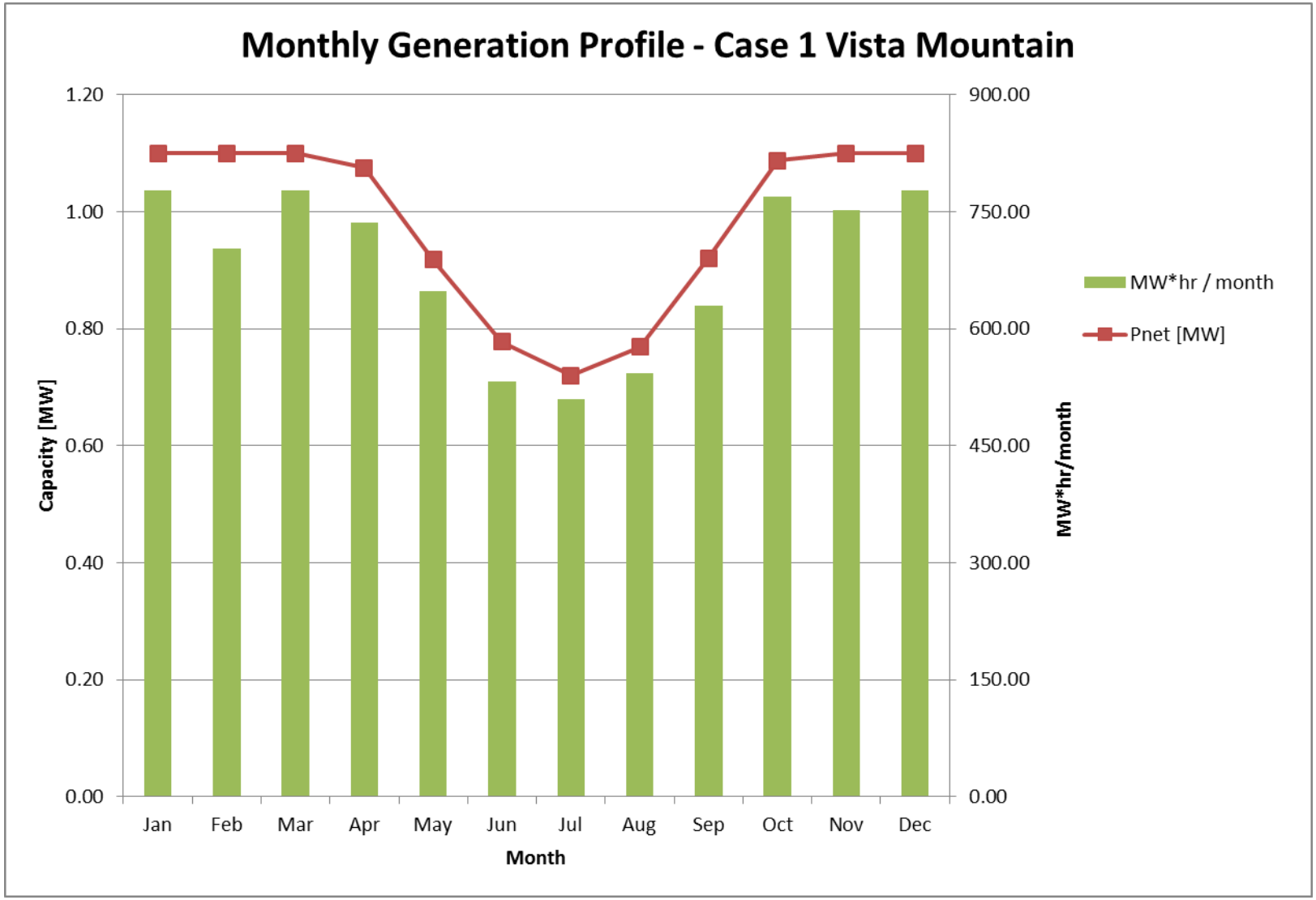

Monthly Generation Profile - Case 1 Vista Mountain
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Capacity [MW]
900.00
750.00
600.00
450.00
300.00
150.00
0.00
MW*hr/month
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
MW*hr / month
Pnet [MW]

FIGURE 8

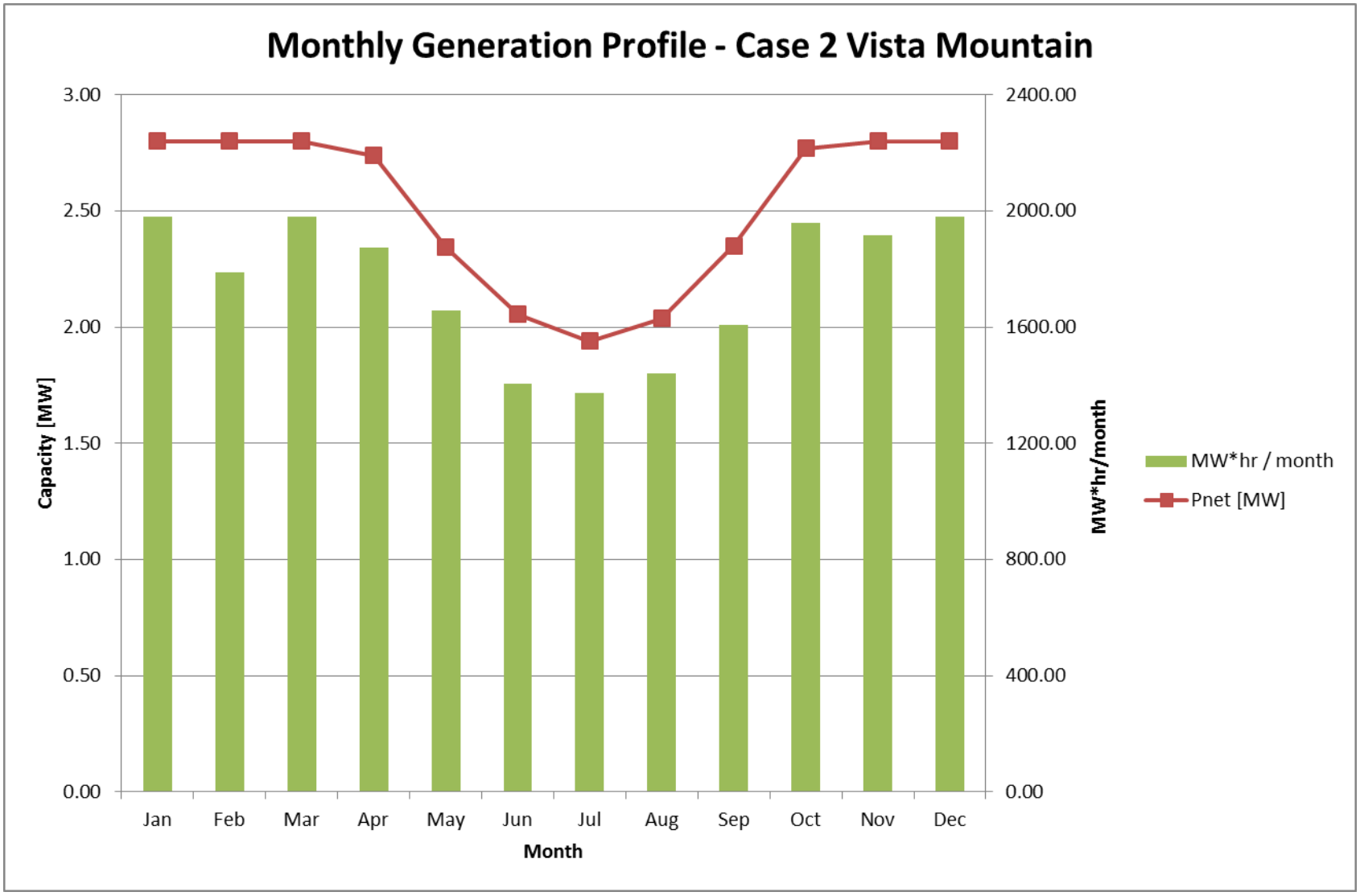
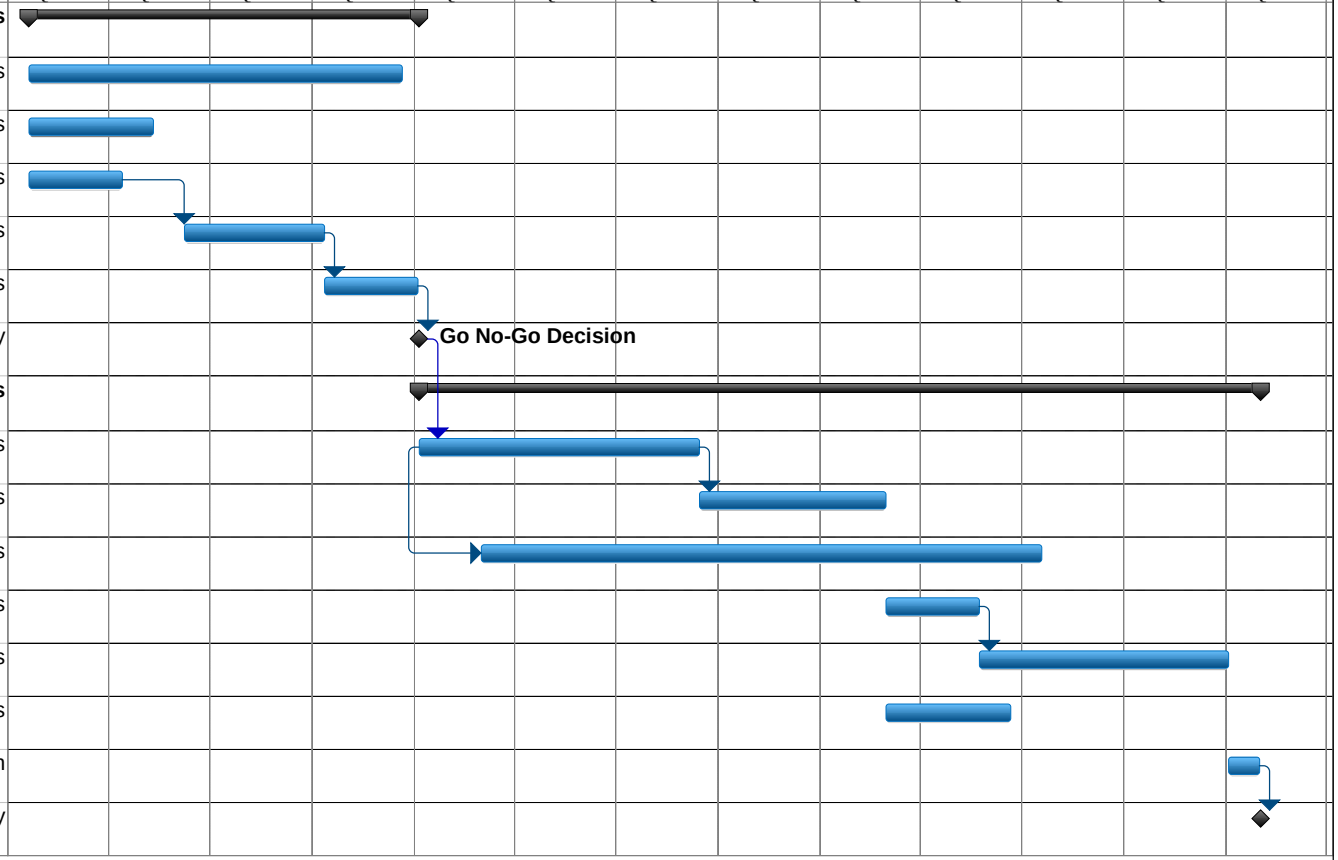

Monthly Generation Profile - Case 2 Vista Mountain
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Capacity [MW]
2400.00
2000.00
1600.00
1200.00
800.00
400.00
0.00
MW*hr/month
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
MW*hr / month
Pnet [MW]

Figure 9: Vista Mountain Geothermal Plant - Preliminary Schedule

ID	Task Name	Duration
1	**Pre-design Phase**	**251 days**
2	Environmental Approval & Licensing	12 mons
3	Land acquisition	4 mons
4	Preliminary design	3 mons
5	Drilling of test well(s)	90 days
6	Confirmation of plant capacity & cost estimate	60 days
7	Go-No-Go Decision	1 day
8	**Detailed Design & Construction**	**541 days**
9	Detailed design	9 mons
10	complete wells & steamfield piping	6 mons
11	Power plant & pumps procure & manufacture	18 mons
12	Site works	3 mons
13	Plant & steamfield construction	8 mons
14	Transmission line construction	4 mons
15	Testing and commissioning	1 mon
16	Commercial operation	1 day



Date: 09/05/2016

Summary Task Milestone

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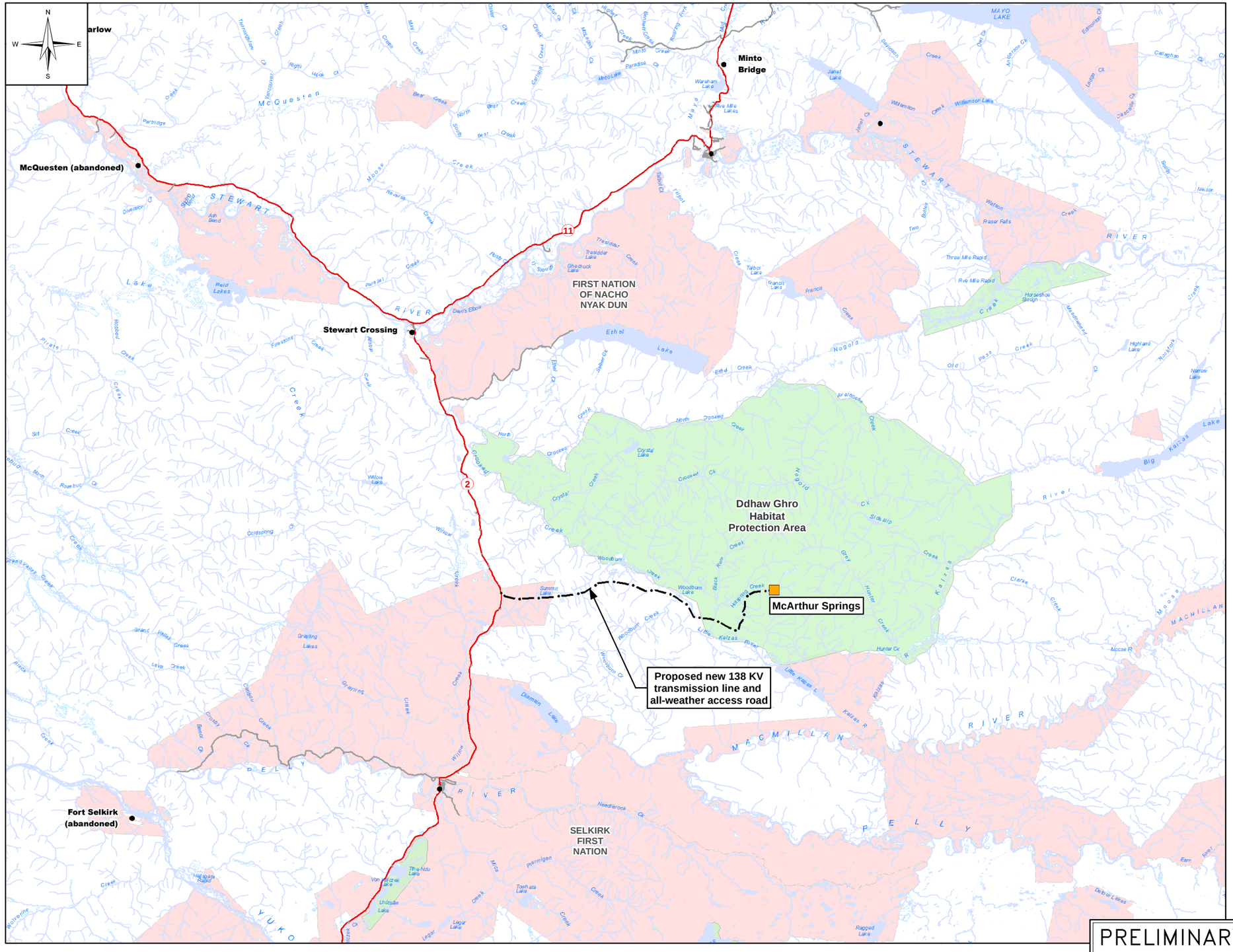

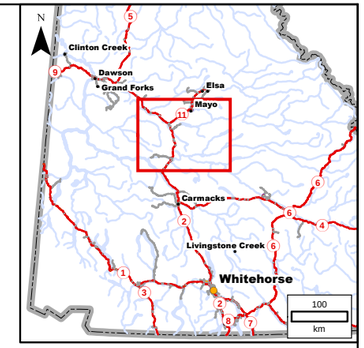

LEGEND:

- Proposed New 138 KV Transmission Line and All-Weather Access Road
- Highway
- Secondary Road
- Watercourse
- Waterbody
- Wetland
- Park
- First Nation Boundary

NOTES:
1. Wetland, Watercourse and Waterbody layers shown were obtained from GeoYukon base data.
2. All units are metric and in metres unless otherwise specified. Transverse Mercator Projection, NAD 1983, Zone 8. Elevations are in metres above sea level (MSL).

DRAFT

5 0 5 10 15 20
Kilometres

SCALE: 1:500,000 METRIC 11"x17"

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GEOTHERMAL REVIEW AND SITE INVENTORY

McARTHUR SPRINGS
SITE LOCATION PLAN

PRELIMINARY
NOT TO BE USED FOR CONSTRUCTION

MAY 2016 | FIGURE 10 | REV: A

FileName: P:\Projects\2016\16-1404-001\Dwg\GIS\MXDs\RevA\16-1404-001_Fig10_RevA.mxd
11"x17" PLOT SCALE 1:1

FIGURE 11
CASE 3 ORGANIC RANKINE CYCLE FLOW CHART

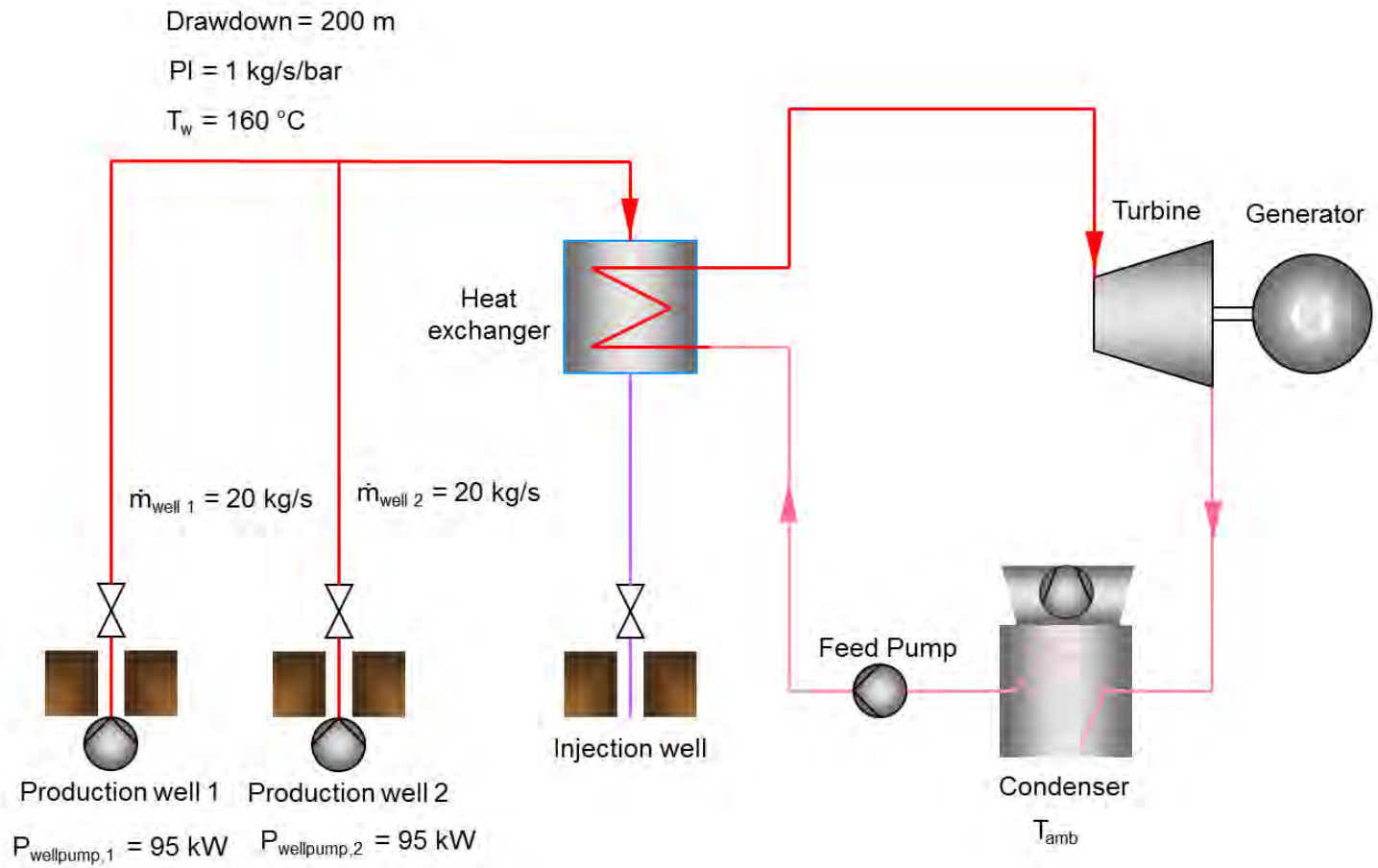
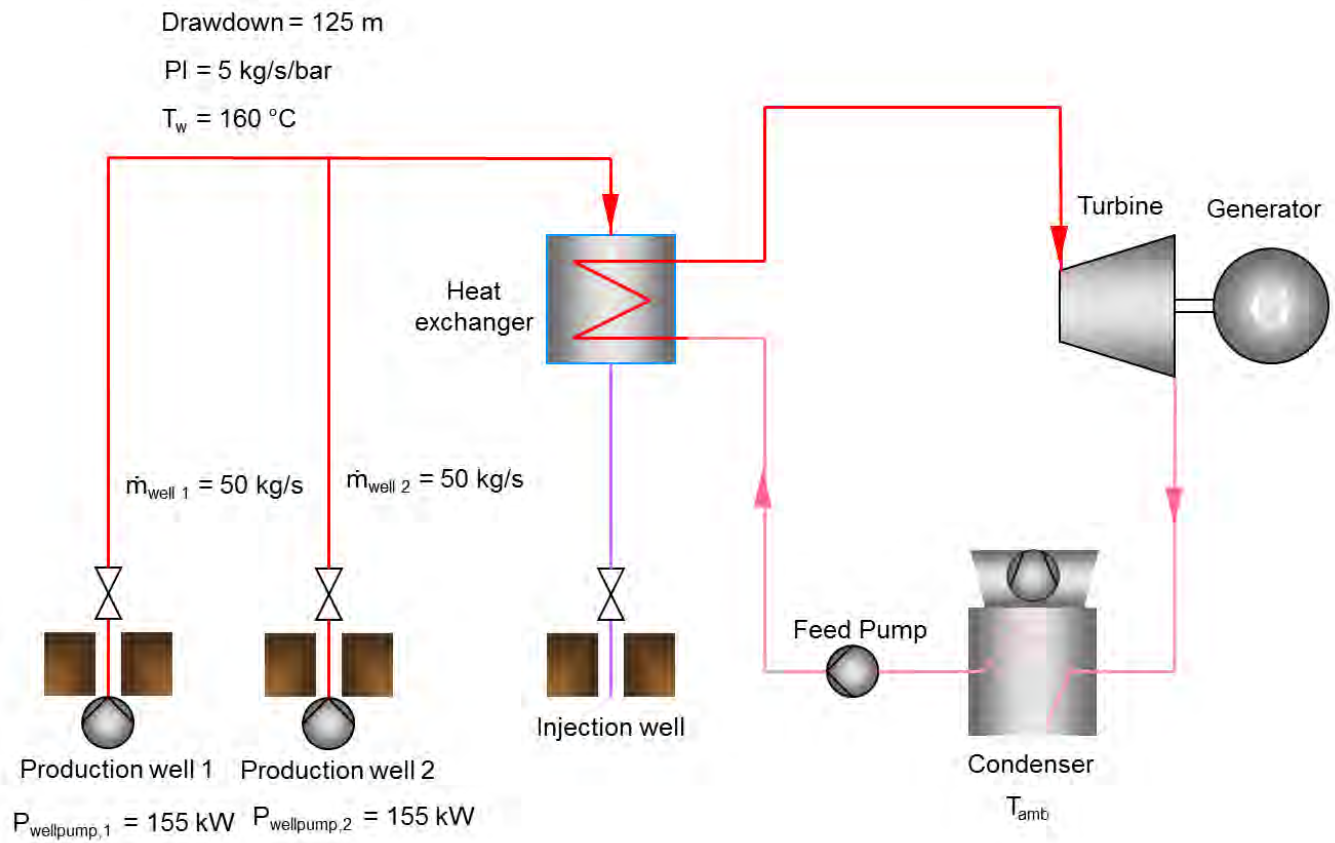
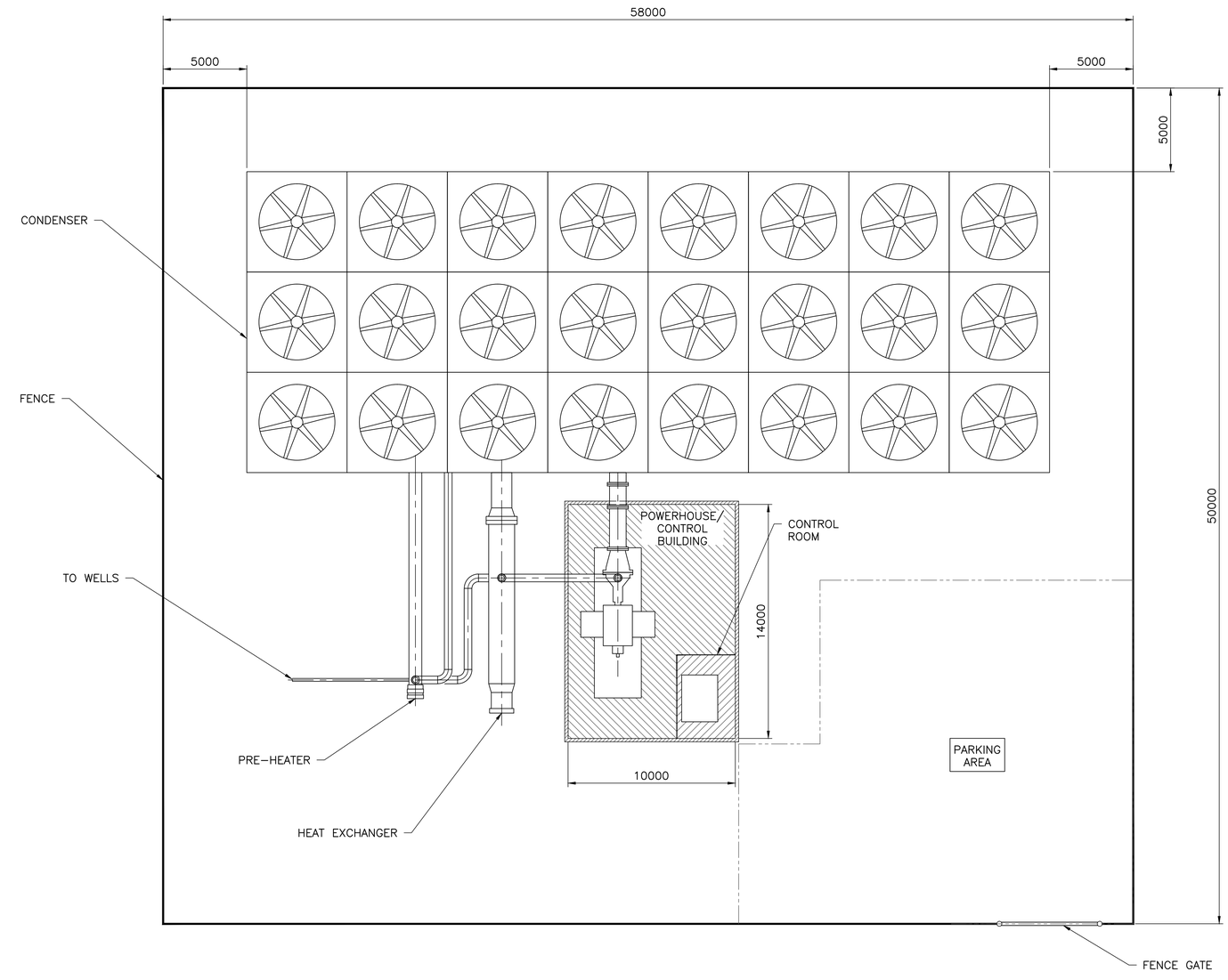


FIGURE 12
CASE 4 ORGANIC RANKINE CYCLE FLOW CHART



11x17



McARTHUR SPRINGS GEOTHERMAL ORC PLANT (2.8 MW)

3000 0 3000 6000 9000 12000

SCALE: 1:150mm (24"x36")

LEGEND:

ORC ORGANIC RANKINE CYCLE

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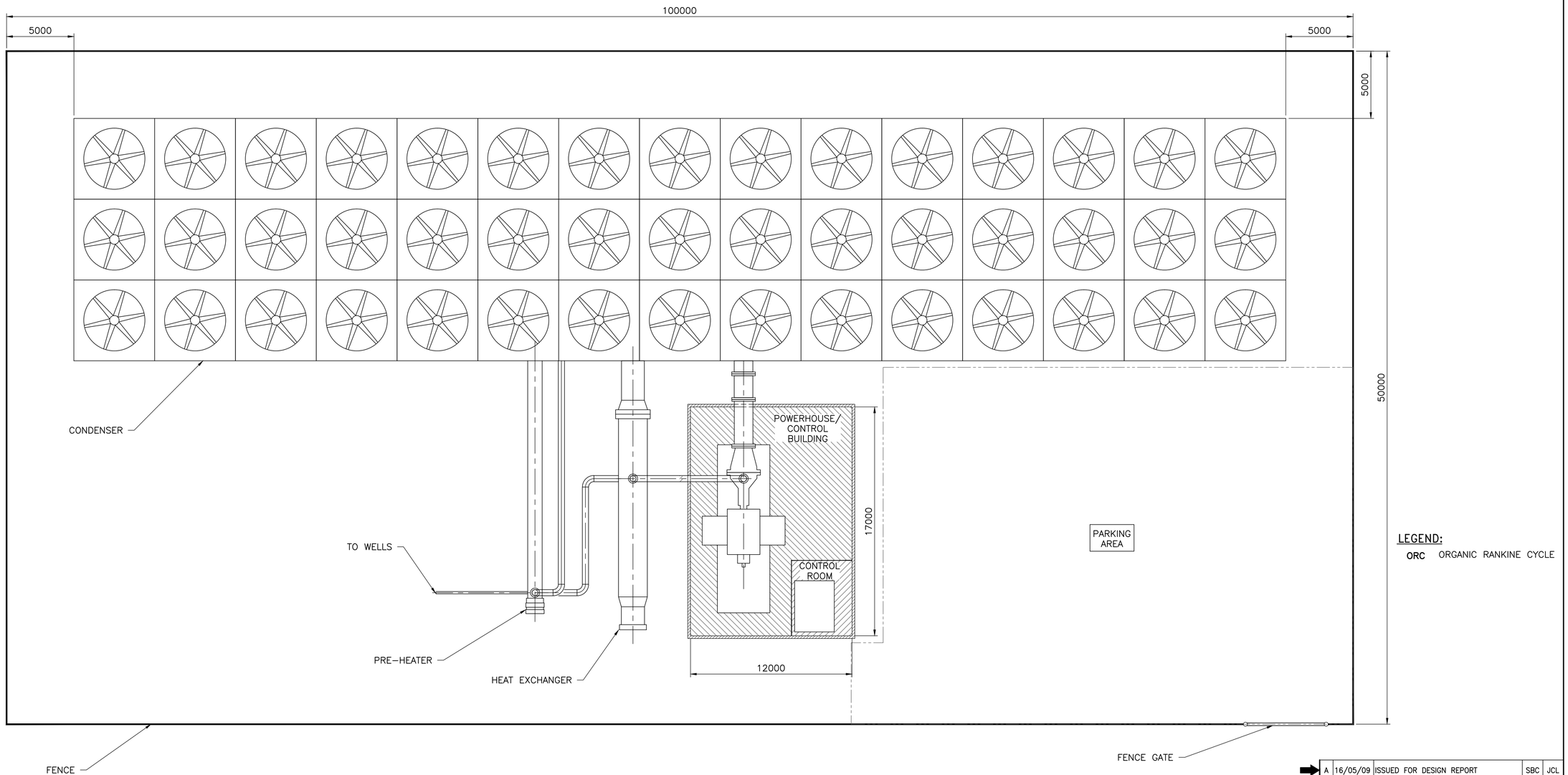
GEOTHERMAL REVIEW AND SITE INVENTORY

PLANT LAYOUT
CASE 3 (2.8 MW)
McARTHUR SPRINGS

MAY_2016 | FIGURE 13 | REV: A

FileName: U:\PMS\16-1404-001\16-1404-001_FIGURE 13.dwg - Tab: Rev A Plotted By: Cabellanosa 16/05/09 [Mon 2:11pm]
11"x17" PLOT SCALE: 1:2

11x17



McARTHUR SPRINGS GEOTHERMAL ORC PLANT (7.0 MW)

3000 0 3000 6000 9000 12000

SCALE: 1:150mm (24"x36")

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GEOTHERMAL REVIEW AND SITE INVENTORY

PLANT LAYOUT
CASE 4 (7.0 MW)
McARTHUR SPRINGS

MAY_2016 | FIGURE 14 | REV: A

FileName: U:\PMS\16-1404-001\16-1404-001_FIGURE 14.dwg - Tab: Rev A Plotted By: Cabellanosa 16/05/09 [Mon 2:11pm]
11"x17" PLOT SCALE: 1:2

FIGURE 15

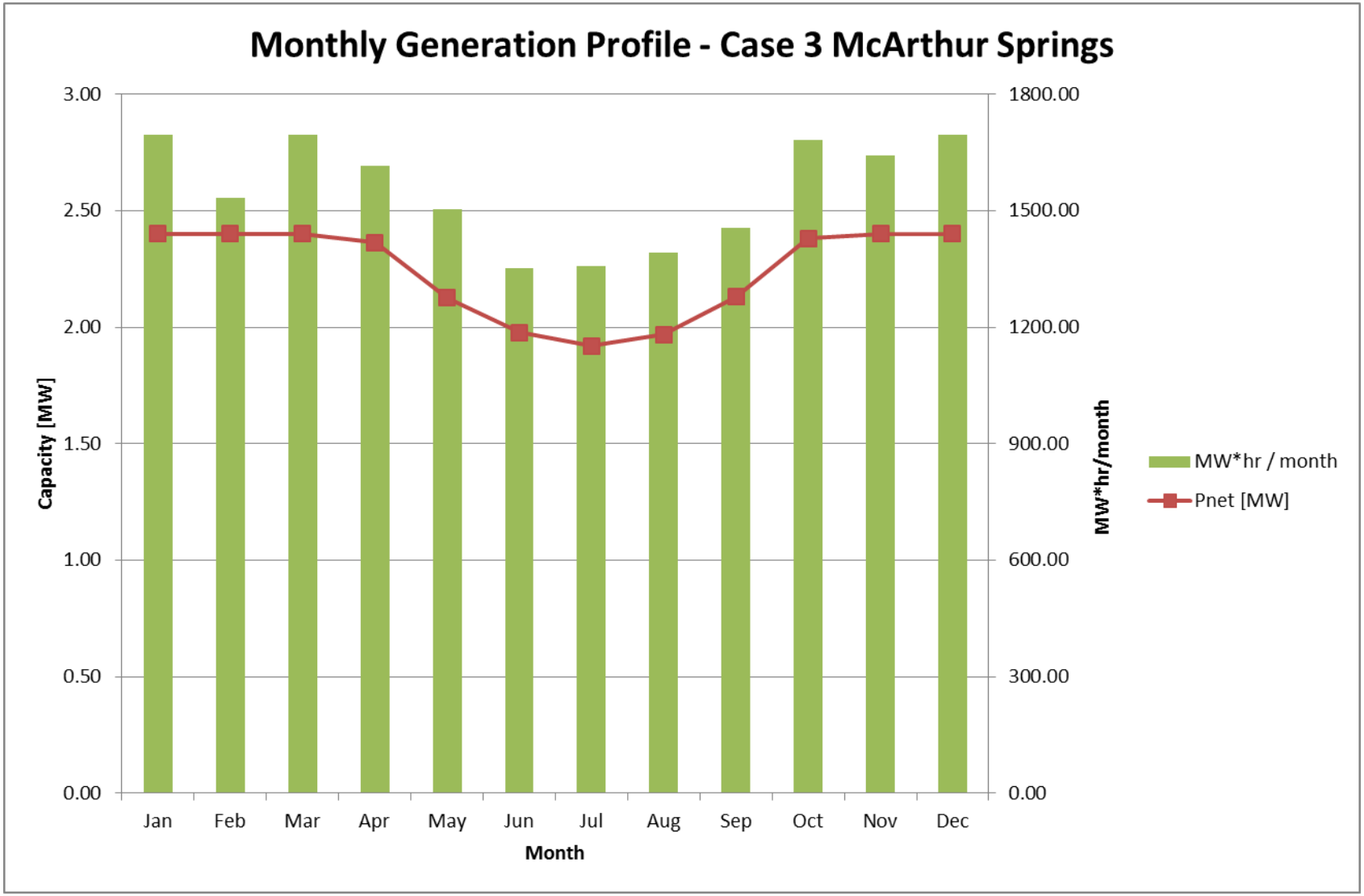

Monthly Generation Profile - Case 3 McArthur Springs
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Capacity [MW]
1800.00
1500.00
1200.00
900.00
600.00
300.00
0.00
MW*hr/month
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
MW*hr / month
Pnet [MW]

FIGURE 16

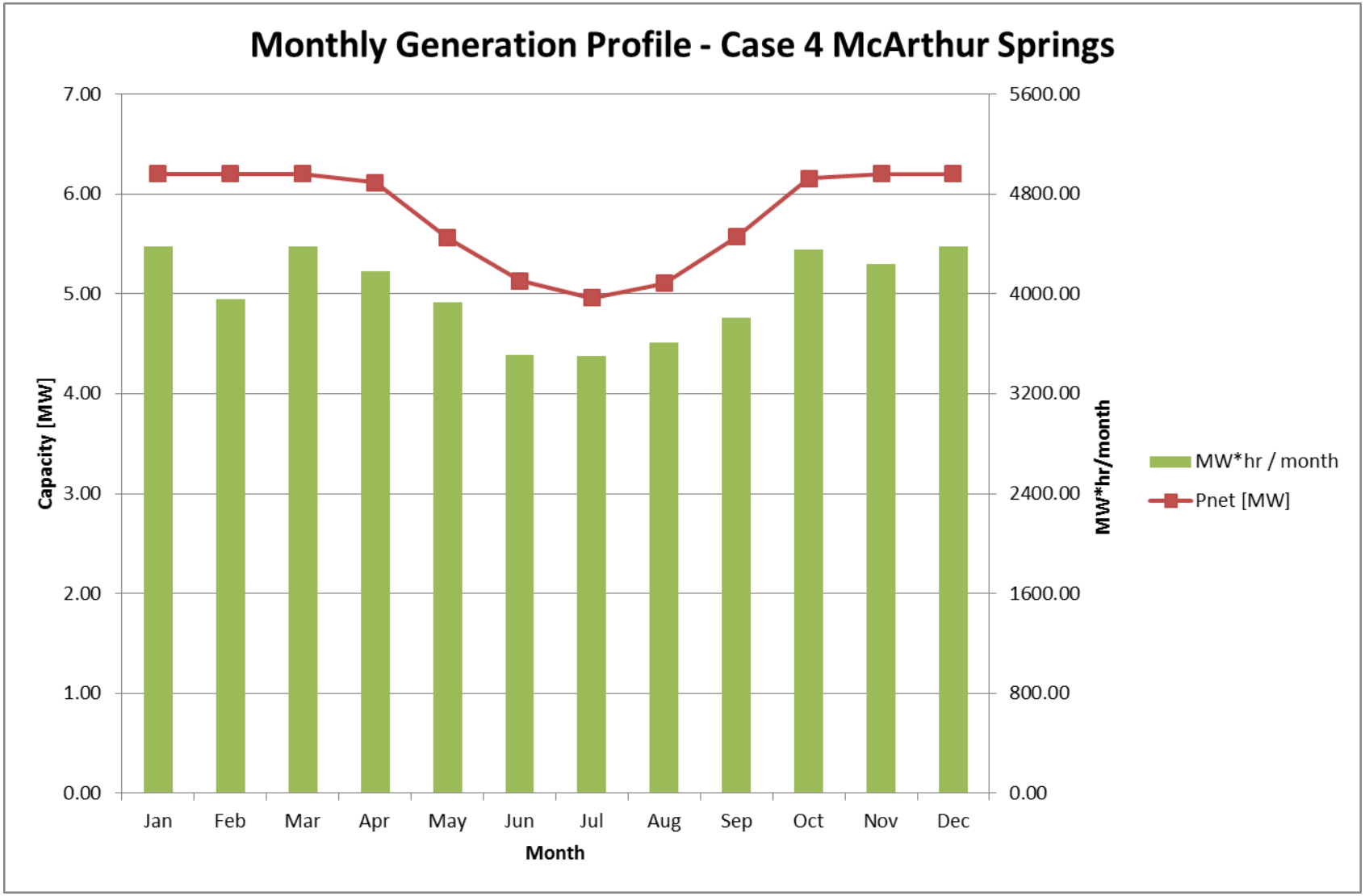
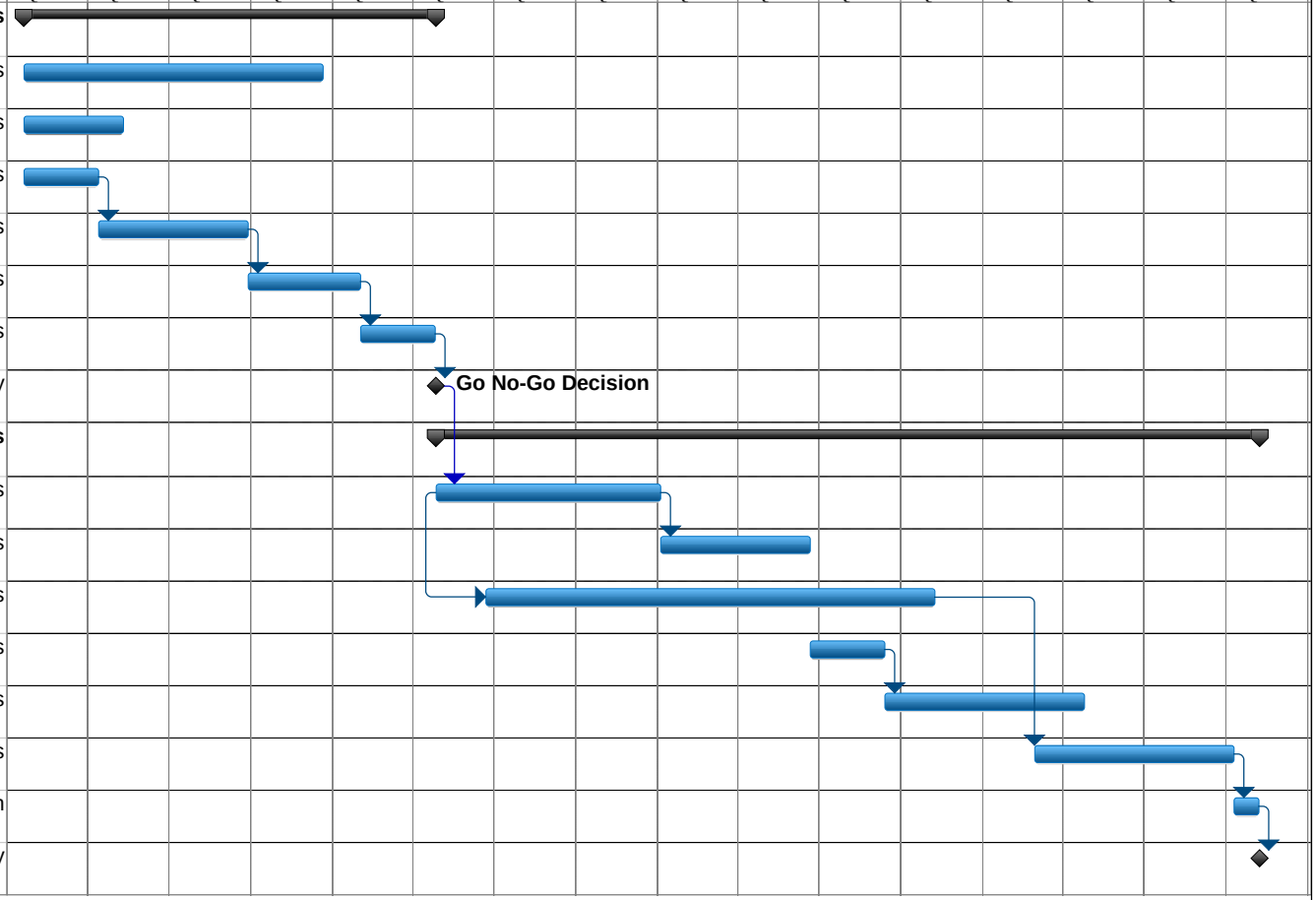

Monthly Generation Profile - Case 4 McArthur Springs
Capacity [MW]
MW*hr/month
Month
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
0.00
1.00
2.00
3.00
4.00
5.00
6.00
7.00
0.00
800.00
1600.00
2400.00
3200.00
4000.00
4800.00
5600.00
MW*hr / month
Pnet [MW]

Figure 17: McArthur Springs Geothermal Plant - Preliminary Schedule

ID	Task Name	Duration
1	**Pre-design Phase**	**331 days**
2	Environmental Approval & Licensing	12 mons
3	Land acquisition	4 mons
4	Preliminary design	3 mons
5	Construct access road	6 mons
6	Drilling of test well(s)	90 days
7	Confirmation of plant capacity & cost estimate	60 days
8	Go-No-Go Decision	1 day
9	**Detailed Design & Construction**	**661 days**
10	Detailed design	9 mons
11	complete wells & steamfield piping	6 mons
12	Power plant & pumps procure & manufacture	18 mons
13	Site works	3 mons
14	Plant & steamfield construction	8 mons
15	Transmission line construction	8 mons
16	Testing and commissioning	1 mon
17	Commercial operation	1 day



Date: 09/05/2016

Summary Task Milestone

FIGURE 18
DRILLING COST AS A FUNCTION OF WELL

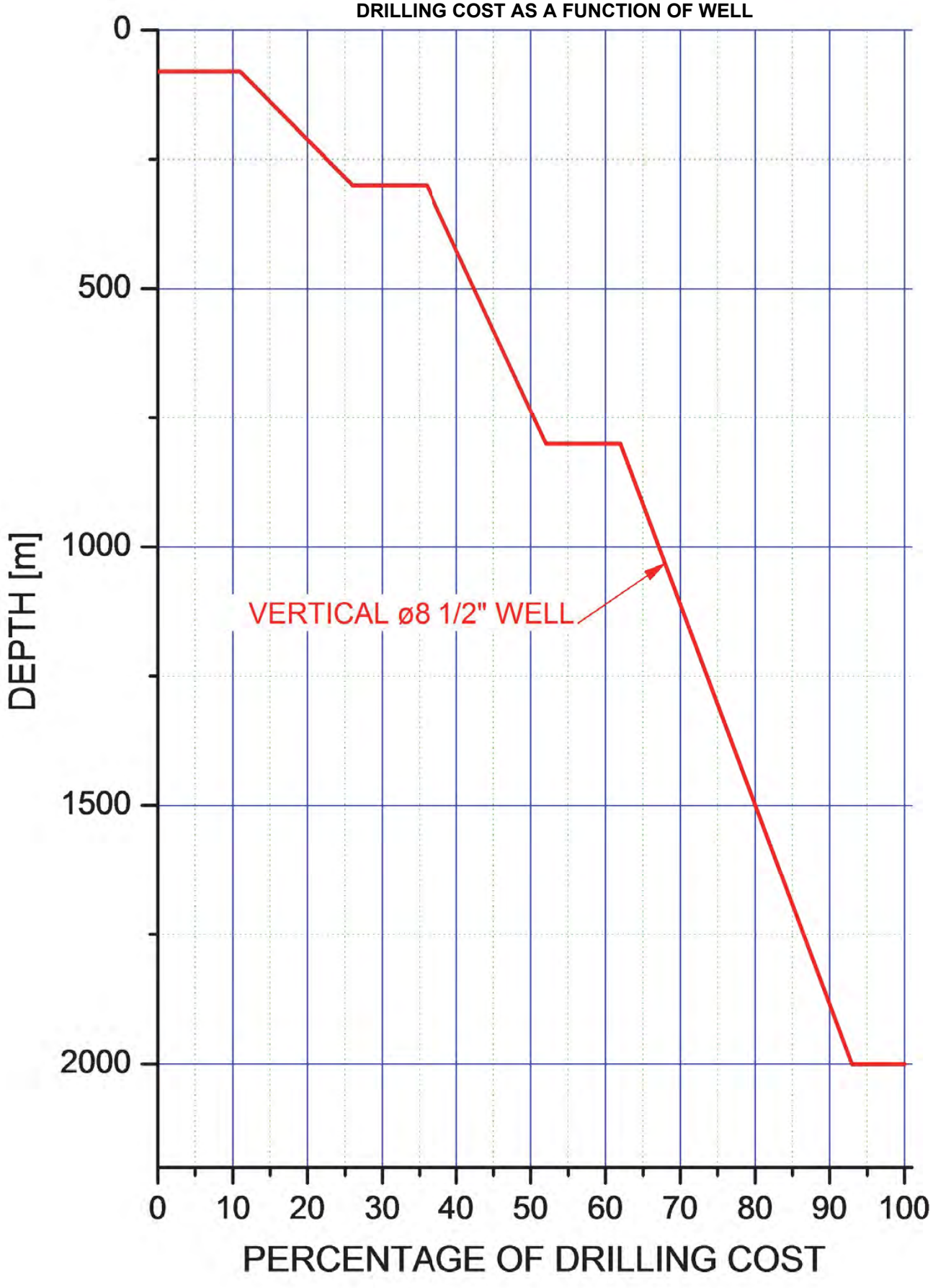
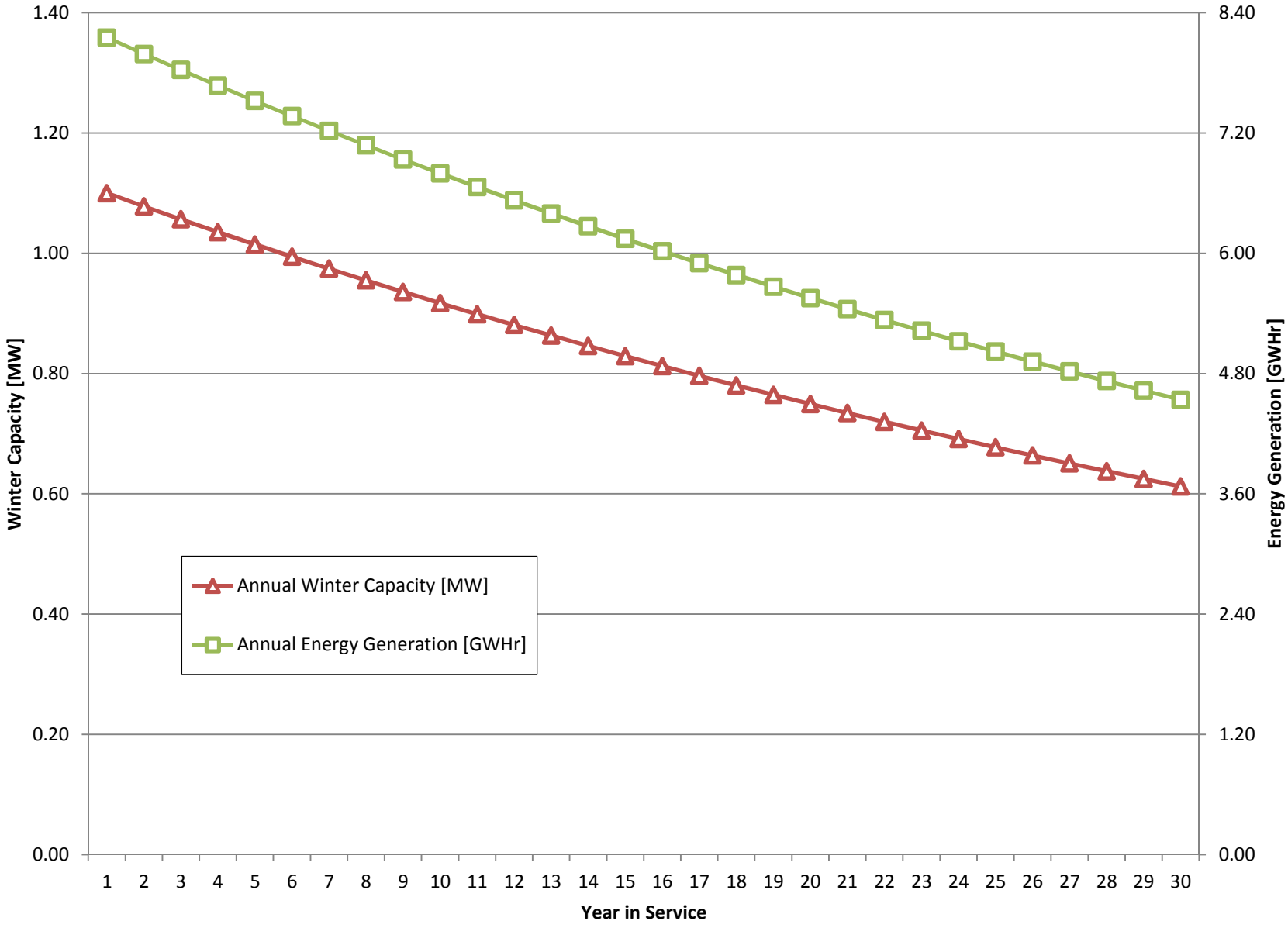


Figure 19: Energy and Capacity Degradation - Case 1 Vista Mountain



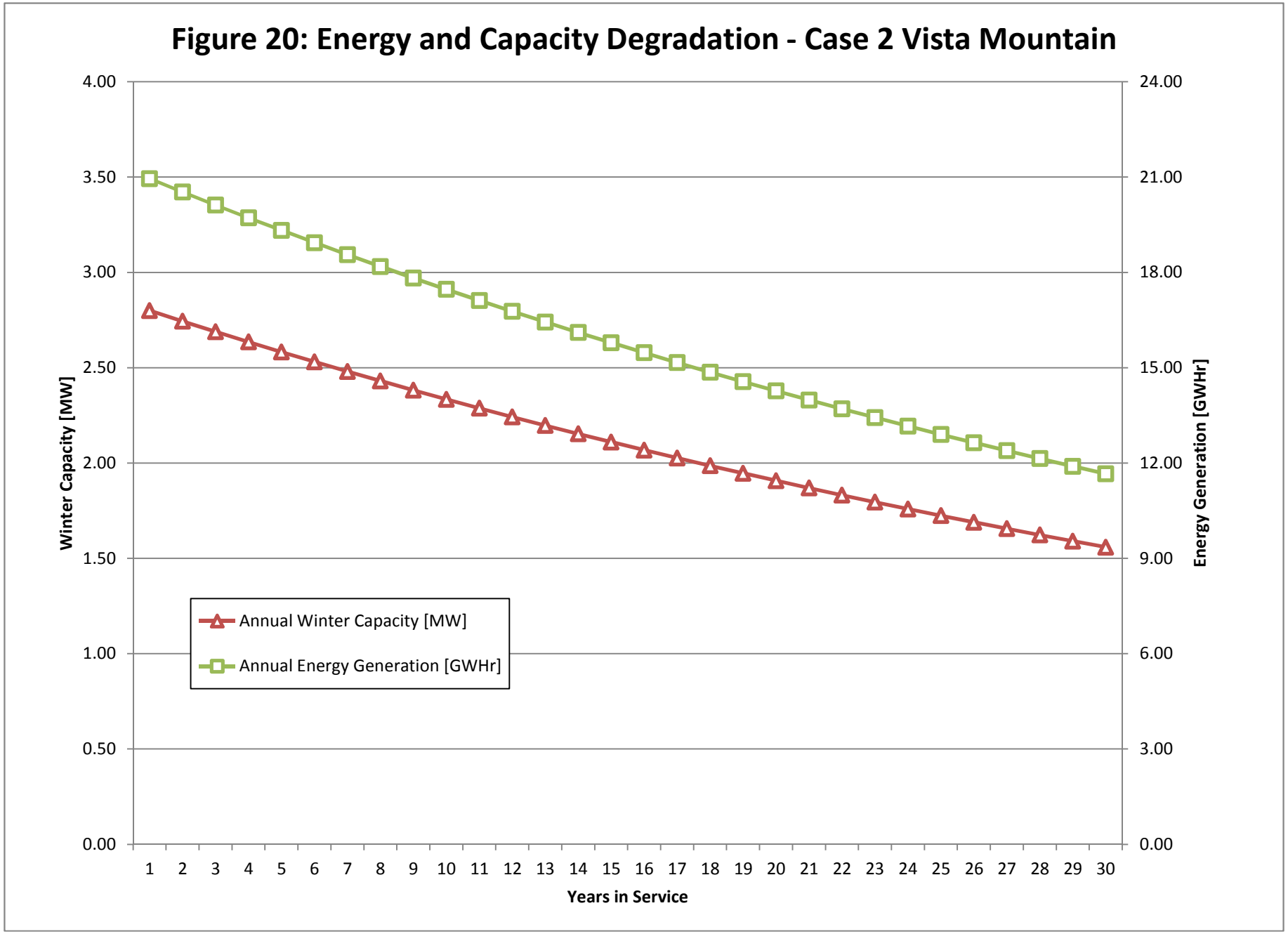


Figure 20: Energy and Capacity Degradation - Case 2 Vista Mountain
Winter Capacity [MW]
Energy Generation [GWHr]
Years in Service
Annual Winter Capacity [MW]
Annual Energy Generation [GWHr]
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
24.00
21.00
18.00
15.00
12.00
9.00
6.00
3.00
0.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30

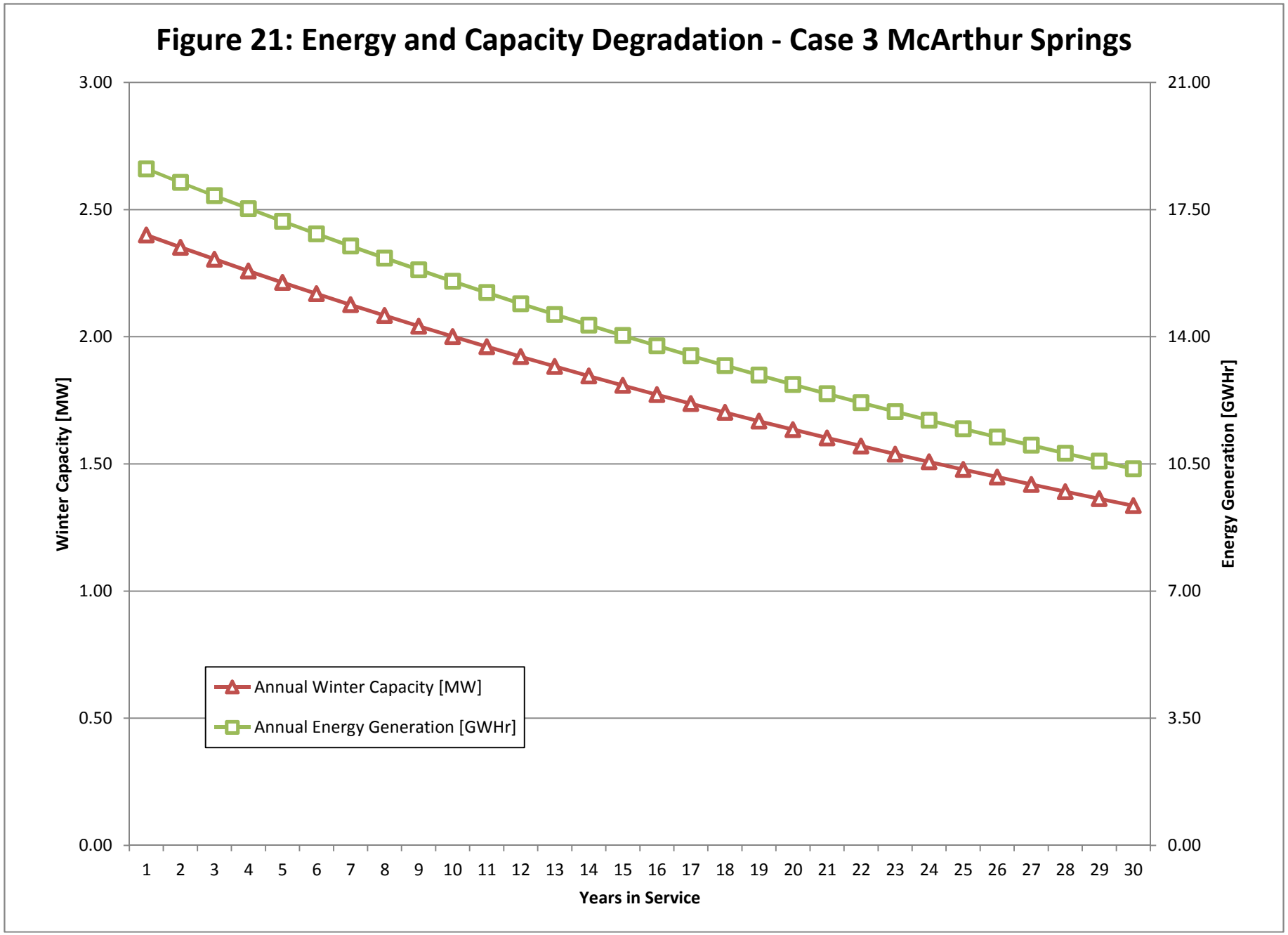


Figure 21: Energy and Capacity Degradation - Case 3 McArthur Springs
Winter Capacity [MW]
Energy Generation [GWHr]
Years in Service
Annual Winter Capacity [MW]
Annual Energy Generation [GWHr]
3.00
2.50
2.00
1.50
1.00
0.50
0.00
21.00
17.50
14.00
10.50
7.00
3.50
0.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30

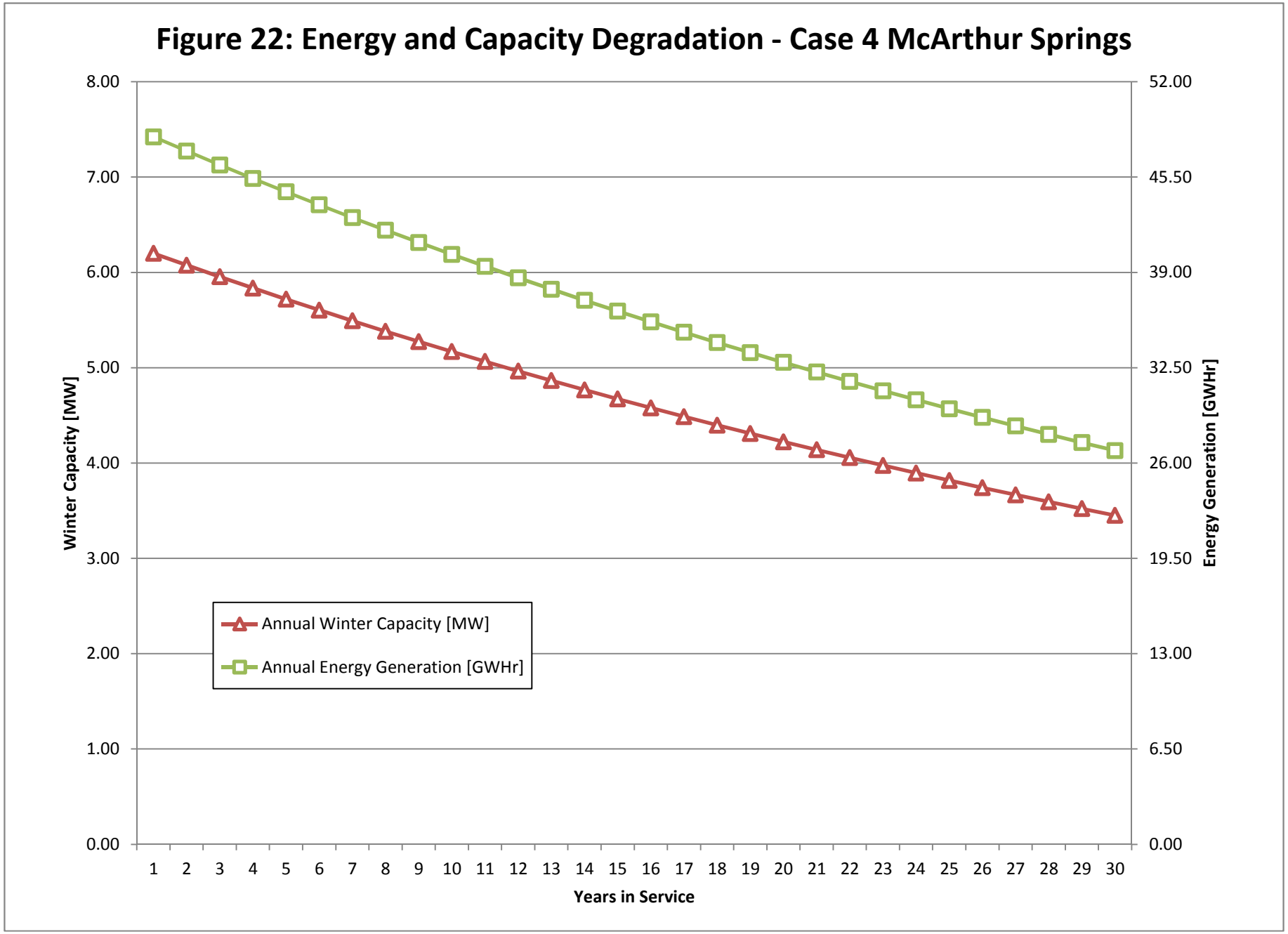


Figure 22: Energy and Capacity Degradation - Case 4 McArthur Springs
Winter Capacity [MW]
Energy Generation [GWHr]
Years in Service
Annual Winter Capacity [MW]
Annual Energy Generation [GWHr]
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
52.00
45.50
39.00
32.50
26.00
19.50
13.00
6.50
0.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30

APPENDIX A

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Klump, Stephan., Brennwald, Matthias S., Morrison, David., Kipfer, Rolf., EBA, A Tetra Tech Company, Whitehorse, Yukon, Canada, sklump@eba.ca (* presenting author) Eawag: Swiss Federal Institute of Aquatic Science and Technology, Duebendorf, Switzerland, matthias.brennwald@eawag.ch Yukon Energy Corp., Whitehorse, Yukon, Canada, david.morrison@yec.yk.ca Swiss Federal Institute of Technology, ETH Zurich, Zurich,

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APPENDIX B

SITE RANKING SUMMARY

APPENDIX B - SITE RANKING SUMMARY

Site Ranking	Spring Name Within 50 km corridor	St. Line Distance to T Line	Approx. Access Road Length, KM	Approx. T Line Length, KM	LOCATION			Site Geology (inferred)	Surface Temp.	Geothermometer Estimated Temp °C	Geochemistry	Spring Flow Rate	Comments	References
					LAT.	LONG	Description							
1	Vista MT Warm Springs	1	1	1			~20 km North of Whitehorse ~1 km west of Klondike Hwy.	-Granite pluton associtated with Whitehorse trough - Thick overburden cover. Assumed deep flow system and major fault system	14	110	$CaCo_3$ + SO_4		-Meteoric water conditions, short residence time	1
2	Takhini	1	1	1	60.867	135.367	~33 km North of Whitehorse ~ 6 km North of Yukon Hwy 1	- Fractured Basalt - Whitehorse trough-fault zones - Thin sedimentary cover	47	96	$CaSo_4$	340 L/min		1,2, 4
3	Stinky Lake Warm Springs	1	1	1			~10 km North of Whitehorse	- Fractured Basalt - Whitehorse trough-fault zones - Thin sedimentary cover	19	85	CaMg HCO_3 H25 odour		-Possible origin of thermal water in sedimentary carbonate rich rocks	1, 2, 14
4	Versluce	1	1	1	60.767	135.15	~16 km North of Whitehorse	- Fractured Basalt - Whitehorse trough-fault zones - Thin sedimentary cover	13	54	CaMg HCO_3	60 L/min	- West of Porter Creek - NE of Whitehorse landfill	1,2, 5
5	Jarvis River / Warm Springs	5	5	5	60.9	137.95	Shakwak Valley ~31 km north west of Haines Junction (5 km south of Yukon Hwy 1)	- Thick overburden deep geothermal vertical faults	≤16	100	$NaHCO_3$		- Most seismicly active area in Yukon - Artesian flow from O/B at 47 m, - Possible meteroic origin difficult to seal drill hole	2, 12
6	Partridge Creek	15	20	20	63.697	137.28	~115 km SE of Dawson	Tintina Trench-Zone of intense fracturing, faulting and shearing	25	95	Na-HCO_3-SO_4		-Terrain/access challenges -Thermal water has long residence time (>>10,000 years); limited young, shallow water.	13
7	McArthur Spring (>50 km corridor)	37	45	45	60.067	135.7	Selkirk First Nation Lands ~32 km West of Yukon Hwy #2 (NW of Pelly Crossing)	- Selwin Fold belt	54	120	$NaHCO_3$		- Springs SW of McArthur Pluton	2, 10
8	Mayo Well	1	1	1	63.6	135.883	~17 km North of Mayo		15		$NaHCO_3$			6
9	Atlin	20	1	22	59.4	133.583	~165 km SE of Whitehorse		29		$Ca(CO_3)_2$			7
10	Morin North	22	33	33	59.983	134.217	~100 Km S of Whitehorse		<29		$Ca(CO_3)_2$			8
	Morin Middle				59.967	134.217								9
	Morin South				59.967	134.217								11
11	Jones Lake	22	22	22			~115 km SE of Whitehorse		<29		$Ca(CO_3)_2$			10
Sites near 50 km Corridor														
1	McPherson	41	50	50	61.867	129.617	~200 km N of Watson Lake ~30 Km NW of Yukon Hwy		N/A					12
2	Volcano Mountain	44	50	50			~40 km NW of Pelly Crossing	Volcano deposits of the Selkirk Volcanics are the youngest (<10,000 yrs)	N/A				- No Surface springs detected - Subsurface drilling required	2

Notes:

1. See YEC Figure 1: Location Plan with Grid Overview and hand marked geothermal sites.
2. Geothermometoe calculated temperatures estimated using the silica based method are considered to be a more plausible lower temperature estimate, versus the higher temperature Na-K-Ca based method.

References:

1. EBA, December 2012; Preliminary Geothermal Assessment Vista Mountain Warm Springs North of Whitehorse, Yukon
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13. EBA, April 2012; Geological Mapping and Geochemistry, Partridge Creek Warm Spring, Yukon
14. EBA, March 2011; Geology and Hydrogeochemistry of the Stinky Lake Warm Springs, Whitehorse, Yukon

APPENDIX C

DETAILED COST ESTIMATES

BASIS OF COST ESTIMATES

KGS Group has completed and is currently involved in several Canadian utility development projects. These projects are located in similarly remote locations, such as northern Manitoba, northeastern Ontario, and in northern Saskatchewan. The building and site costs for this geothermal project our based on KGS Group's recent experience.

Mannvit has been involved with the design and construction of several geothermal projects; throughout the world. The well and power plant costs, including the turbine, generator, heat exchangers, condensers, controls and pipeline costs are based from their database of projects.

Well costs included are "normal" costs for deep well drilling. Some areas in the world are currently seeing a 20% to 30 % reduction in these costs due to the slowdown in oil exploration and development. Depending on the timing of any well drilling, these savings may or may not be realized.

Direct costs include the construction expenses of the proposed geothermal development, including all temporary works such as access roads required during construction as well as all component costs needed during development. These component costs, including the turbine, generator, wells, transmission lines and interconnection have been estimated based on calculated material quantities for the arrangements and unit prices.

At this conceptual level of study the various indirect costs have been estimated as percentages of the direct costs, including the General Contractor's indirect costs, travel and camp costs, contingencies, and contractor markups. Owner's costs have also been estimated as percentages of the project direct costs, and include environmental approval studies and consultations through the approval process with all stakeholders. Owner's costs also include additional feasibility assessment costs, final design, site assistance, quality assurance and interest during construction. The Mayo B contract, as well as other more recent hydro projects, were used to develop a criteria for estimating the indirect and owner costs for the potential geothermal development for this study.

VISTA MOUNTAIN GEOTHERMAL PROJECT **DIRECT COST DETAILS**

ITEMS	Unit	Case 1 0.9 MW Quantity	Case 1 0.9 MW Unit Cost	Case 1 0.9 MW Cost (2015 $)	Case 2 2.3 MW Quantity	Case 2 2.3 MW Unit Cost	Case 2 2.3 MW Cost (2015 $)
SITEWORK				**$100,000**			**$120,000**
Clearing	ha	1	$18,900	$19,000	1	$18,900	$19,000
Foundation Preparation							
- Powerhouse	sq metre	108	$22	$3,000	140	$22	$10,000
- Condenser	sq metre	216	$22	$5,000	756	$22	$20,000
Access road maintenance	months	12	$5,800	$70,000	12	$5,800	$70,000
STRUCTURES & EXCAVATION				**$930,000**			**$1,190,000**
Rock Excavation	cubic metre	90	$100	$9,000	140	$100	$14,000
General Excavation	cubic metre	1,840	$30	$56,000	2,600	$30	$78,000
Granular Fill	cubic metre	0	$50	$0	0	$50	$0
Reinforced Concrete							
- Pump Station	cubic metre	65	$2,200	$143,000	83	$2,200	$182,000
- Ventilator Foundations	per foundation	21	$1,500	$32,000	32	$1,500	$48,000
- Well Pump Buildings and Misc.	cubic metre	40	$2,200	$88,000	51	$2,200	$113,000
Powerhouse/Control Building							
- Superstructure Steel	cubic metre	756	$120	$90,720	1120	$120	$134,400
- Steel Cladding	sq. metre	400	$450	$180,000	500	$450	$225,000
- Architectural/HVAC/Water/Lighting	LS	1	$108,000	$108,000	1	$140,000	$140,000
Powerhouse Crane	EA	1	$150,000	$150,000	1	$150,000	$150,000
Well Pump Buildings	sq. metre	50	$1,500	$75,000	72	$1,500	$108,000
POWER PLANT				**$2,900,000**			**$5,400,000**
Turbines, Generators & All M&E Process	LS	1	$2,900,000	$2,900,000	1	$5,400,000	$5,400,000
WELLS & WATER SUPPLY SYSTEM				**$9,070,000**			**$9,320,000**
Production Wells (2700 m)	EA	2	$2,600,000	$5,200,000	2	$2,600,000	$5,200,000
Injection Well (2700 m)	EA	1	$2,600,000	$2,600,000	1	$2,600,000	$2,600,000
Mobilization of Drilling Rig	LS	1	$380,000	$380,000	1	$380,000	$380,000
Pipelines (Pre-insulated buried pipe)	LS	1	$630,000	$630,000	1	$760,000	$760,000
Well Pumps	EA	2	$130,000	$260,000	2	$190,000	$380,000
TRANSMISSION LINE				**$990,000**			**$990,000**
Transmission Line (34.5 kV)	km	5	$167,000	$835,000	5	$167,000	$835,000
Interconnection	LS	1	$150,000	$150,000	1	$150,000	$150,000
ACCESS				**$640,000**			**$640,000**
Clearing	ha	2.3	$18,900	$43,000	2.3	$18,900	$43,000
Access road	km	1.5	$400,000	$600,000	1.5	$400,000	$600,000
ENVIRONMENTAL & MITIGATION ITEMS	LS	1	$500,000	**$500,000**	1	$500,000	**$500,000**
TOTAL DIRECT COSTS				***$15,130,000***			***$18,160,000***

McARTHUR SPRINGS GEOTHERMAL PROJECT **DIRECT COST DETAILS**

ITEMS	Unit	Case 3 2.1 MW Quantity	Case 3 2.1 MW Unit Cost	Case 3 2.1 MW Cost (2015 $)	Case 4 5.5 MW Quantity	Case 4 5.5 MW Unit Cost	Case 4 5.5 MW Cost (2015 $)
SITEWORK				**$110,000**			**$130,000**
Clearing	ha	1	$18,900	$19,000	1	$18,900	$19,000
Foundation Preparation							
- Powerhouse	sq metre	140	$22	$4,000	204	$22	$10,000
- Condensor	sq metre	756	$22	$17,000	1,620	$22	$40,000
Access road maintenance	months	12	$5,800	$70,000	12	$5,000	$60,000
STRUCTURES & EXCAVATION				**$1,660,000**			**$2,550,000**
Rock Excavation	cubic metre	70	$100	$7,000	102	$100	$11,000
General Excavation	cubic metre	2,740	$30	$83,000	5,204	$30	$157,000
Granular Fill	cubic metre	2,600	$50	$130,000	5,000	$50	$250,000
Reinforced Concrete							
- Pump Station	cubic metre	111	$2,200	$245,000	160	$2,200	$352,000
- Powerhouse Piles	per pile	12	$8,100	$98,000	20	$8,100	$162,000
- Ventilator Foundation Piles	per pile	32	$8,100	$260,000	64	$8,100	$519,000
- Well Pump Buildings and Misc.	cubic metre	65	$2,200	$143,000	87	$2,200	$192,000
Powerhouse/Control Building							
- Superstructure Steel	cubic metre	980	$120	$118,000	1428	$120	$172,000
- Steel Cladding	sq. metre	476	$450	$215,000	610	$450	$275,000
- Architectural/HVAC/Water/Lighting	LS	1	$140,000	$140,000	1	$204,000	$204,000
Powerhouse Crane	EA	1	$150,000	$150,000	1	$150,000	$150,000
Well Pump Buildings	sq metre	50	$1,500	$75,000	72	$1,500	$108,000
POWER PLANT				**$4,400,000**			**$8,400,000**
Turbines, Generators & All M&E Process	LS	1	$4,400,000	$4,400,000	1	$8,400,000	$8,400,000
WELLS & WATER SUPPLY SYSTEM				**$8,800,000**			**$9,050,000**
Production Wells (2700 m)	EA	2	$2,510,000	$5,020,000	2	$2,510,000	$5,020,000
Injection Well (2700 m)	EA	1	$2,510,000	$2,510,000	1	$2,510,000	$2,510,000
Mobilization of Drilling Rig	LS	1	$380,000	$380,000	1	$380,000	$380,000
Pipelines (Pre-insulated buried pipe)	LS	1	$630,000	$630,000	1	$760,000	$760,000
Well Pumps	EA	2	$130,000	$260,000	2	$190,000	$380,000
TRANSMISSION LINE				**$11,120,000**			**$11,120,000**
Transmission Line (138 kV)	km	43	$255,000	$10,965,000	43	$255,000	$10,965,000
Interconnection	LS	1	$150,000	$150,000	1	$150,000	$150,000
ACCESS				**$18,420,000**			**$18,420,000**
Clearing	ha	64.5	$18,900	$1,220,000	64.5	$18,900	$1,220,000
Access road	km	43.0	$400,000	$17,200,000	43.0	$400,000	$17,200,000
ENVIRONMENTAL & MITIGATION ITEMS	LS	1	$500,000	**$500,000**	1	$500,000	**$500,000**
TOTAL DIRECT COSTS				***$45,010,000***			***$50,170,000***

APPENDIX D

FINANCIAL TABLES

Table 1: Summary Yukon Energy Corporation Geothermal Generation Options

Step 1 - Financial analysis

Geothermal Cases	Option Assumptions											Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC)					
	Capital Cost (2015$)			Annual Fixed O&M Costs (2015$)	Annual Variable O&M Costs (2015$)	Annual Average Capacity [net output] - First Year	Reliable Winter Capacity [net output] - First Year	Annual Average Capacity Factor	Annual Average Energy - First Year	Expected Life	Expected In-Service Date (January 1)	3.38% Real WACC		4.61% Real WACC		8.82% Real WACC	
	Plant Capital Cost	Transmission Capital Cost	Total Capital Cost									LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)	LCOE (2015$)	LCOC (2015$)
	$000	$000	$000	$000	$/MW.h	MW	MW	%	GW.h	Years	Year	$/kW.h	$/MW	$/kW.h	$/MW	$/kW.h	$/MW
A	B	C	D=B+C	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Vista Mountain Case 1: 0.9 MW	$35,400	$2,400	$37,800	$350	$0	1.0	1.1	95%	8.2	30	2019	$0.368	$2,330,074	$0.412	$2,658,409	$0.577	$3,901,681
Vista Mountain Case 2: 2.3 MW	$42,800	$2,400	$45,200	$800	$0	2.5	2.8	95%	20.9	30	2019	$0.194	$1,094,589	$0.214	$1,248,829	$0.290	$1,832,876
McArthur Springs Case 3: 2.1 MW	$86,100	$27,900	$114,000	$800	$0	2.2	2.4	95%	18.6	30	2020	$0.469	$3,220,803	$0.527	$3,674,652	$0.746	$5,393,197
McArthur Springs Case 4: 5.5 MW	$99,100	$27,900	$127,000	$1,800	$0	5.8	6.2	95%	48.2	30	2020	$0.225	$1,388,937	$0.250	$1,584,655	$0.343	$2,325,759

Notes:
1. Annual average capacity is based on average available capacity throughout the year - Table 1 shows capacity and energy in year 1 of operation.
2. For each project a 3%/year degradation of annual capacity assumed over the life of project [annual energy also reduced by 3%/year].

Step 2 - Ranking

The review of Geothermal options identified two separate projects, each with 2 different scales of development.

Technical Attributes

1. Each project provides reliable energy and capacity, but is not dispatchable [technically dispatchable, however, it is not economically feasible to dispatch].
2. Each project option degrades each year in capacity and energy.
3. The only differences are:
   - in scale: McArthur Springs option is materially larger than Vista Mountain at each of the two scales examined for each project; and
   - in distance to grid: McArthur Springs requires much longer transmission line to connect to the Yukon electrical grid.

Financial Attributes

1. Vista Mountain Case 2 with 2.3 MW option shows the lowest LCOE and LCOC. This option also has a lower capital cost compared to McArthur Project with a similar scale of development option.
2. McArthur Springs Case 4 with 5.5 MW option shows the second lowest LCOE and LCOC. However, this option requires larger load demand than other cases in order to develop on an economic basis.
3. Both of the smaller scale options, Vista Mountain Case 1 [0.9 MW] and McArthur Springs Case 3 [2.1 MW], show much higher LCOE and LCOC, highlighting that small scale versions of each project are not financially attractive. McArthur Springs Case 3 capital cost is 2.5 times higher compared to Vista Mountain Case 2 [even though Case 3 has a slightly smaller amount of capacity and energy output].

Summary

Considering isolated nature of the Yukon Electrical grid, the best option depends on following:
- Energy demand:
  - If the energy demand requires in the range of 2.5 to 3 MW of reliable winter capacity and about 20 GW.h/year energy in near term (or less), Vista Mountain case is best option
  - If the energy demand requires in the range of 6 MW of reliable winter capacity and about 50 GW.h/year energy in near term, McArthur Springs is a competitive option only if the larger scale development is confirmed.
  - Any materially smaller load requirement than assumed in Case 2 (for Vista Mountain) and Case 4 (for McArthur Springs) will result in much higher cost per unit of energy for either option.
- Potential benefit from new transmission as regards other loads or resource options might add benefit to the McArthur Springs larger scale option that is not considered in this analysis.

Table A-1: Financial Analysis (WACC at 5.45%): **Vista Mountain Case 1: 0.9 MW**

			Average MW	Winter MW
Capital ($000)	2015	$37,800	1.0	1.1
Capital ($000)	2019	$40,916		
Energy		8.2	GWh/yr	
Capacity Factor		95%CF		
Fuel	2015			-2.0%
O&M (Fixed)	2015	350.0	$000/yr	8.2 GW.h
O&M (Variable)	2015	0.0	$/MWh	
Life		30	years	
Salvage cost		0%		

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, Vista Mountain Case 1: 0.9 MW

Life Cycle Cost (2015$000's)	46,085
Depreciation & Return Cost (2015$000's)	39,331
Project LCOE ($/kWh)	$0.368
Project LCOC ($/MW)	$2,330,074

Year	Vista Mountain Case 1: 0.9 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2019	39,552	1,364	2,193	379	3,935	48
2020	38,188	1,364	2,118	386	3,869	48
2021	36,824	1,364	2,044	394	3,802	49
2022	35,460	1,364	1,970	402	3,736	49
2023	34,097	1,364	1,895	410	3,669	49
2024	32,733	1,364	1,821	418	3,603	49
2025	31,369	1,364	1,747	427	3,537	49
2026	30,005	1,364	1,672	435	3,471	49
2027	28,641	1,364	1,598	444	3,406	49
2028	27,277	1,364	1,524	453	3,340	49
2029	25,913	1,364	1,449	462	3,275	49
2030	24,550	1,364	1,375	471	3,210	49
2031	23,186	1,364	1,301	480	3,145	49
2032	21,822	1,364	1,226	490	3,080	49
2033	20,458	1,364	1,152	500	3,016	49
2034	19,094	1,364	1,078	510	2,952	49
2035	17,730	1,364	1,003	520	2,887	49
2036	16,366	1,364	929	530	2,823	49
2037	15,003	1,364	855	541	2,760	49
2038	13,639	1,364	780	552	2,696	49
2039	12,275	1,364	706	563	2,633	48
2040	10,911	1,364	632	574	2,570	48
2041	9,547	1,364	557	586	2,507	48
2042	8,183	1,364	483	597	2,444	48
2043	6,819	1,364	409	609	2,382	47
2044	5,455	1,364	334	622	2,320	47
2045	4,092	1,364	260	634	2,258	47
2046	2,728	1,364	186	647	2,196	46
2047	1,364	1,364	111	660	2,135	46
2048	0	1,364	37	673	2,074	46
2049						
2050						
2051						
2052						
2053						
2054						
2055						
2056						
2057						
2058						
2059						
2060						
2061						
2062						
2063						
PV		21,018	21,555	7,311	49,884	
$2015PV		19,418	19,913	6,754	46,085	
					89,734	

Year from In-service	Annual Energy GW.h, Vista Mountain Case 1: 0.9 MW	Annual Winter Capacity MW, Vista Mountain Case 1: 0.9 MW
1	8.15	1.10
2	7.99	1.08
3	7.83	1.06
4	7.67	1.04
5	7.52	1.01
6	7.37	0.99
7	7.22	0.97
8	7.08	0.95
9	6.94	0.94
10	6.80	0.92
11	6.66	0.90
12	6.53	0.88
13	6.40	0.86
14	6.27	0.85
15	6.14	0.83
16	6.02	0.81
17	5.90	0.80
18	5.78	0.78
19	5.67	0.76
20	5.55	0.75
21	5.44	0.73
22	5.33	0.72
23	5.23	0.71
24	5.12	0.69
25	5.02	0.68
26	4.92	0.66
27	4.82	0.65
28	4.72	0.64
29	4.63	0.62
30	4.54	0.61
31		
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45		
Net Present Value	103	
Total energy	185	
Avg Annual energy	6	

Table A-2: Financial Analysis (WACC at 6.70%): **Vista Mountain Case 1: 0.9 MW**

Weighted Average Cost of Capital	6.70%
Inflation Rate	2%
Real Weighted Average Cost of Capital	4.61%

LCOE and LCOC with 6.7% WACC, Vista Mountain Case 1: 0.9 MW

Life Cycle Cost (2015$000's)	45,645
Depreciation & Return Cost (2015$000's)	39,756
Project LCOE ($/kWh)	$0.412
Project LCOC ($/MW)	$2,658,409

Year	Vista Mountain Case 1: 0.9 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2019	39,552	1,364	2,696	379	4,438	54
2020	38,188	1,364	2,604	386	4,355	55
2021	36,824	1,364	2,513	394	4,271	55
2022	35,460	1,364	2,422	402	4,187	55
2023	34,097	1,364	2,330	410	4,104	55
2024	32,733	1,364	2,239	418	4,021	55
2025	31,369	1,364	2,147	427	3,938	55
2026	30,005	1,364	2,056	435	3,855	54
2027	28,641	1,364	1,965	444	3,772	54
2028	27,277	1,364	1,873	453	3,690	54
2029	25,913	1,364	1,782	462	3,608	54
2030	24,550	1,364	1,691	471	3,525	54
2031	23,186	1,364	1,599	480	3,443	54
2032	21,822	1,364	1,508	490	3,362	54
2033	20,458	1,364	1,416	500	3,280	53
2034	19,094	1,364	1,325	510	3,199	53
2035	17,730	1,364	1,234	520	3,118	53
2036	16,366	1,364	1,142	530	3,037	53
2037	15,003	1,364	1,051	541	2,956	52
2038	13,639	1,364	959	552	2,875	52
2039	12,275	1,364	868	563	2,795	51
2040	10,911	1,364	777	574	2,715	51
2041	9,547	1,364	685	586	2,635	50
2042	8,183	1,364	594	597	2,555	50
2043	6,819	1,364	503	609	2,476	49
2044	5,455	1,364	411	622	2,397	49
2045	4,092	1,364	320	634	2,318	48
2046	2,728	1,364	228	647	2,239	47
2047	1,364	1,364	137	660	2,161	47
2048	0	1,364	46	673	2,082	46
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PV		18,616	24,418	6,374	49,408	
$2015PV		17,198	22,558	5,889	45,645	
					97,406	

Table A-3: Financial Analysis (WACC at 11.00%): **Vista Mountain Case 1: 0.9 MW**

Weighted Average Cost of Capital	11.00%
Inflation Rate	2%
Real Weighted Average Cost of Capital	8.82%

LCOE and LCOC with 11% WACC, Vista Mountain Case 1: 0.9 MW

Life Cycle Cost (2015$000's)	45,264
Depreciation & Return Cost (2015$000's)	41,289
Project LCOE ($/kWh)	$0.577
Project LCOC ($/MW)	$3,901,681

Year	Vista Mountain Case 1: 0.9 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2019	39,552	1,364	4,426	379	6,168	76
2020	38,188	1,364	4,276	386	6,026	75
2021	36,824	1,364	4,126	394	5,884	75
2022	35,460	1,364	3,976	402	5,742	75
2023	34,097	1,364	3,826	410	5,600	74
2024	32,733	1,364	3,676	418	5,458	74
2025	31,369	1,364	3,526	427	5,316	74
2026	30,005	1,364	3,376	435	5,175	73
2027	28,641	1,364	3,226	444	5,033	73
2028	27,277	1,364	3,076	453	4,892	72
2029	25,913	1,364	2,925	462	4,751	71
2030	24,550	1,364	2,775	471	4,610	71
2031	23,186	1,364	2,625	480	4,470	70
2032	21,822	1,364	2,475	490	4,329	69
2033	20,458	1,364	2,325	500	4,189	68
2034	19,094	1,364	2,175	510	4,049	67
2035	17,730	1,364	2,025	520	3,909	66
2036	16,366	1,364	1,875	530	3,770	65
2037	15,003	1,364	1,725	541	3,630	64
2038	13,639	1,364	1,575	552	3,491	63
2039	12,275	1,364	1,425	563	3,352	62
2040	10,911	1,364	1,275	574	3,213	60
2041	9,547	1,364	1,125	586	3,075	59
2042	8,183	1,364	975	597	2,936	57
2043	6,819	1,364	825	609	2,798	56
2044	5,455	1,364	675	622	2,661	54
2045	4,092	1,364	525	634	2,523	52
2046	2,728	1,364	375	647	2,386	50
2047	1,364	1,364	225	660	2,248	49
2048	0	1,364	75	673	2,112	47
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PV		13,161	31,531	4,303	48,996	
$2015PV		12,159	29,130	3,975	45,264	
					123,796	

Table B-1: Financial Analysis (WACC at 5.45%): **Vista Mountain Case 2: 2.3 MW**

			Average MW	Winter MW
Capital ($000)	2015	$45,200	2.5	2.8
Capital ($000)	2019	$48,926		
Energy		20.9	GWh/yr	
Capacity Factor		95%CF		
Fuel	2015			
O&M (Fixed)	2015	800.0	$000/yr	
O&M (Variable)	2015	0.0	$/MWh	
Life		30	years	
Salvage cost		0%		

Load Growth -2.0%

20.9 GW.h

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, Vista Mountain Case 2: 2.3 MW

Life Cycle Cost (2015$000's)	62,469
Depreciation & Return Cost (2015$000's)	47,031
Project LCOE ($/kWh)	$0.194
Project LCOC ($/MW)	$1,094,589

Year	Vista Mountain Case 2: 2.3 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2019	47,295	1,631	2,622	866	5,119	24
2020	45,664	1,631	2,533	883	5,047	25
2021	44,033	1,631	2,444	901	4,976	25
2022	42,402	1,631	2,355	919	4,905	25
2023	40,772	1,631	2,266	937	4,835	25
2024	39,141	1,631	2,178	956	4,765	25
2025	37,510	1,631	2,089	975	4,695	25
2026	35,879	1,631	2,000	995	4,625	25
2027	34,248	1,631	1,911	1,015	4,556	26
2028	32,617	1,631	1,822	1,035	4,488	26
2029	30,986	1,631	1,733	1,056	4,420	26
2030	29,356	1,631	1,644	1,077	4,352	26
2031	27,725	1,631	1,555	1,098	4,285	26
2032	26,094	1,631	1,467	1,120	4,218	26
2033	24,463	1,631	1,378	1,143	4,151	26
2034	22,832	1,631	1,289	1,165	4,085	26
2035	21,201	1,631	1,200	1,189	4,020	27
2036	19,570	1,631	1,111	1,213	3,954	27
2037	17,940	1,631	1,022	1,237	3,890	27
2038	16,309	1,631	933	1,262	3,826	27
2039	14,678	1,631	844	1,287	3,762	27
2040	13,047	1,631	755	1,312	3,699	27
2041	11,416	1,631	667	1,339	3,636	27
2042	9,785	1,631	578	1,366	3,574	27
2043	8,154	1,631	489	1,393	3,513	27
2044	6,523	1,631	400	1,421	3,452	27
2045	4,893	1,631	311	1,449	3,391	27
2046	3,262	1,631	222	1,478	3,331	27
2047	1,631	1,631	133	1,508	3,272	27
2048	0	1,631	44	1,538	3,213	28
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PV		25,133	25,775	16,711	67,618	
$2015PV		23,219	23,812	15,438	62,469	
					124,053	

Year from In-service	Annual Energy GW.h, Vista Mountain Case 2: 2.3 MW	Annual Winter Capacity MW, Vista Mountain Case 2: 2.3 MW
1	20.95	2.80
2	20.53	2.74
3	20.12	2.69
4	19.72	2.64
5	19.32	2.58
6	18.94	2.53
7	18.56	2.48
8	18.19	2.43
9	17.82	2.38
10	17.47	2.33
11	17.12	2.29
12	16.77	2.24
13	16.44	2.20
14	16.11	2.15
15	15.79	2.11
16	15.47	2.07
17	15.16	2.03
18	14.86	1.99
19	14.56	1.95
20	14.27	1.91
21	13.99	1.87
22	13.71	1.83
23	13.43	1.80
24	13.16	1.76
25	12.90	1.72
26	12.64	1.69
27	12.39	1.66
28	12.14	1.62
29	11.90	1.59
30	11.66	1.56
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Net Present Value	264	
Total energy	476	
Avg Annual energy	16	

Table B-2: Financial Analysis (WACC at 6.70%): **Vista Mountain Case 2: 2.3 MW**

Weighted Average Cost of Capital	6.70%
Inflation Rate	2%
Real Weighted Average Cost of Capital	4.61%

LCOE and LCOC with 6.7% WACC, Vista Mountain Case 2: 2.3 MW

Life Cycle Cost (2015$000's)	61,000
Depreciation & Return Cost (2015$000's)	47,539
Project LCOE ($/kWh)	$0.214
Project LCOC ($/MW)	$1,248,829

Year	Vista Mountain Case 2: 2.3 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2019	47,295	1,631	3,223	866	5,720	27
2020	45,664	1,631	3,114	883	5,628	27
2021	44,033	1,631	3,005	901	5,537	28
2022	42,402	1,631	2,896	919	5,445	28
2023	40,772	1,631	2,786	937	5,355	28
2024	39,141	1,631	2,677	956	5,264	28
2025	37,510	1,631	2,568	975	5,174	28
2026	35,879	1,631	2,459	995	5,084	28
2027	34,248	1,631	2,349	1,015	4,995	28
2028	32,617	1,631	2,240	1,035	4,906	28
2029	30,986	1,631	2,131	1,056	4,817	28
2030	29,356	1,631	2,021	1,077	4,729	28
2031	27,725	1,631	1,912	1,098	4,641	28
2032	26,094	1,631	1,803	1,120	4,554	28
2033	24,463	1,631	1,694	1,143	4,467	28
2034	22,832	1,631	1,584	1,165	4,381	28
2035	21,201	1,631	1,475	1,189	4,295	28
2036	19,570	1,631	1,366	1,213	4,209	28
2037	17,940	1,631	1,257	1,237	4,124	28
2038	16,309	1,631	1,147	1,262	4,040	28
2039	14,678	1,631	1,038	1,287	3,956	28
2040	13,047	1,631	929	1,312	3,872	28
2041	11,416	1,631	820	1,339	3,789	28
2042	9,785	1,631	710	1,366	3,707	28
2043	8,154	1,631	601	1,393	3,625	28
2044	6,523	1,631	492	1,421	3,543	28
2045	4,893	1,631	382	1,449	3,462	28
2046	3,262	1,631	273	1,478	3,382	28
2047	1,631	1,631	164	1,508	3,302	28
2048	0	1,631	55	1,538	3,223	28
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PV		22,260	29,198	14,570	66,028	
$2015PV		20,565	26,974	13,460	61,000	
					133,226	

Table B-3: Financial Analysis (WACC at 11.00%): **Vista Mountain Case 2: 2.3 MW**

Weighted Average Cost of Capital	11.00%
Inflation Rate	2%
Real Weighted Average Cost of Capital	8.82%

LCOE and LCOC with 11% WACC, Vista Mountain Case 2: 2.3 MW

Life Cycle Cost (2015$000's)	58,458
Depreciation & Return Cost (2015$000's)	49,372
Project LCOE ($/kWh)	$0.290
Project LCOC ($/MW)	$1,832,876

Year	Vista Mountain Case 2: 2.3 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2019	47,295	1,631	5,292	866	7,789	37
2020	45,664	1,631	5,113	883	7,627	37
2021	44,033	1,631	4,933	901	7,465	37
2022	42,402	1,631	4,754	919	7,304	37
2023	40,772	1,631	4,575	937	7,143	37
2024	39,141	1,631	4,395	956	6,982	37
2025	37,510	1,631	4,216	975	6,822	37
2026	35,879	1,631	4,036	995	6,662	37
2027	34,248	1,631	3,857	1,015	6,502	36
2028	32,617	1,631	3,678	1,035	6,343	36
2029	30,986	1,631	3,498	1,056	6,185	36
2030	29,356	1,631	3,319	1,077	6,026	36
2031	27,725	1,631	3,139	1,098	5,869	36
2032	26,094	1,631	2,960	1,120	5,711	35
2033	24,463	1,631	2,781	1,143	5,554	35
2034	22,832	1,631	2,601	1,165	5,398	35
2035	21,201	1,631	2,422	1,189	5,241	35
2036	19,570	1,631	2,242	1,213	5,086	34
2037	17,940	1,631	2,063	1,237	4,931	34
2038	16,309	1,631	1,884	1,262	4,776	33
2039	14,678	1,631	1,704	1,287	4,622	33
2040	13,047	1,631	1,525	1,312	4,468	33
2041	11,416	1,631	1,345	1,339	4,315	32
2042	9,785	1,631	1,166	1,366	4,162	32
2043	8,154	1,631	987	1,393	4,010	31
2044	6,523	1,631	807	1,421	3,859	31
2045	4,893	1,631	628	1,449	3,708	30
2046	3,262	1,631	448	1,478	3,557	29
2047	1,631	1,631	269	1,508	3,408	29
2048	0	1,631	90	1,538	3,258	28
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PV		15,738	37,704	9,835	63,277	
$2015PV		14,539	34,833	9,086	58,458	
					164,783	

Table C-1: Financial Analysis (WACC at 5.45%): **McArthur Springs Case 3: 2.1 MW**

			Average MW	Winter MW
Capital ($000)	2015	$114,000	2.2	2.4
Capital ($000)	2020	$125,865		
Energy		18.6 GWh/yr		
Capacity Factor		95%CF		
Fuel	2015			
O&M (Fixed)	2015	800.0 $000/yr		
O&M (Variable)	2015	0.0 $/MWh		
Life		30 years		
Salvage cost		0%		

Load Growth -2.0%

18.6 GW.h

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, McArthur Springs Case 3: 2.1 MW

Life Cycle Cost (2015$000's)	134,055
Depreciation & Return Cost (2015$000's)	118,617
Project LCOE ($/kWh)	$0.469
Project LCOC ($/MW)	$3,220,803

Year	McArthur Springs Case 3: 2.1 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	121,670	4,196	6,745	883	11,824	63
2021	117,474	4,196	6,517	901	11,613	64
2022	113,279	4,196	6,288	919	11,402	64
2023	109,083	4,196	6,059	937	11,192	64
2024	104,888	4,196	5,831	956	10,982	64
2025	100,692	4,196	5,602	975	10,773	64
2026	96,497	4,196	5,373	995	10,564	64
2027	92,301	4,196	5,145	1,015	10,355	64
2028	88,106	4,196	4,916	1,035	10,146	64
2029	83,910	4,196	4,687	1,056	9,939	64
2030	79,715	4,196	4,459	1,077	9,731	64
2031	75,519	4,196	4,230	1,098	9,524	64
2032	71,324	4,196	4,001	1,120	9,317	64
2033	67,128	4,196	3,773	1,143	9,111	64
2034	62,933	4,196	3,544	1,165	8,905	63
2035	58,737	4,196	3,315	1,189	8,700	63
2036	54,542	4,196	3,087	1,213	8,495	63
2037	50,346	4,196	2,858	1,237	8,290	63
2038	46,151	4,196	2,630	1,262	8,087	62
2039	41,955	4,196	2,401	1,287	7,883	62
2040	37,760	4,196	2,172	1,312	7,680	62
2041	33,564	4,196	1,944	1,339	7,478	61
2042	29,369	4,196	1,715	1,366	7,276	61
2043	25,173	4,196	1,486	1,393	7,075	60
2044	20,978	4,196	1,258	1,421	6,874	60
2045	16,782	4,196	1,029	1,449	6,674	59
2046	12,587	4,196	800	1,478	6,474	59
2047	8,391	4,196	572	1,508	6,275	58
2048	4,196	4,196	343	1,538	6,076	57
2049	0	4,196	114	1,569	5,878	57
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PV		64,656	66,307	17,045	148,008	
$2015PV		58,561	60,056	15,438	134,055	
					264,592	

Year from In-service	Annual Energy GW.h, McArthur Springs Case 3: 2.1 MW	Annual Winter Capacity MW, McArthur Springs Case 3: 2.1 MW
1	18.62	2.40
2	18.25	2.35
3	17.88	2.30
4	17.53	2.26
5	17.18	2.21
6	16.83	2.17
7	16.50	2.13
8	16.17	2.08
9	15.84	2.04
10	15.53	2.00
11	15.22	1.96
12	14.91	1.92
13	14.61	1.88
14	14.32	1.85
15	14.03	1.81
16	13.75	1.77
17	13.48	1.74
18	13.21	1.70
19	12.95	1.67
20	12.69	1.63
21	12.43	1.60
22	12.18	1.57
23	11.94	1.54
24	11.70	1.51
25	11.47	1.48
26	11.24	1.45
27	11.01	1.42
28	10.79	1.39
29	10.58	1.36
30	10.37	1.34
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Net Present Value	234	
Total energy	423	
Avg Annual energy	14	

Table C-2: Financial Analysis (WACC at 6.70%): McArthur Springs Case 3: 2.1 MW

Weighted Average Cost of Capital	6.70%
Inflation Rate	2%
Real Weighted Average Cost of Capital	4.61%

LCOE and LCOC with 6.7% WACC, McArthur Springs Case 3: 2.1 MW

Life Cycle Cost (2015$000's)	133,361
Depreciation & Return Cost (2015$000's)	119,900
Project LCOE ($/kWh)	$0.527
Project LCOC ($/MW)	$3,674,652

Year	McArthur Springs Case 3: 2.1 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	121,670	4,196	8,292	883	13,371	72
2021	117,474	4,196	8,011	901	13,108	72
2022	113,279	4,196	7,730	919	12,845	72
2023	109,083	4,196	7,449	937	12,582	72
2024	104,888	4,196	7,168	956	12,320	72
2025	100,692	4,196	6,887	975	12,058	72
2026	96,497	4,196	6,606	995	11,796	72
2027	92,301	4,196	6,325	1,015	11,535	71
2028	88,106	4,196	6,044	1,035	11,274	71
2029	83,910	4,196	5,763	1,056	11,014	71
2030	79,715	4,196	5,481	1,077	10,754	71
2031	75,519	4,196	5,200	1,098	10,494	70
2032	71,324	4,196	4,919	1,120	10,235	70
2033	67,128	4,196	4,638	1,143	9,976	70
2034	62,933	4,196	4,357	1,165	9,718	69
2035	58,737	4,196	4,076	1,189	9,460	69
2036	54,542	4,196	3,795	1,213	9,203	68
2037	50,346	4,196	3,514	1,237	8,946	68
2038	46,151	4,196	3,233	1,262	8,690	67
2039	41,955	4,196	2,952	1,287	8,434	66
2040	37,760	4,196	2,670	1,312	8,178	66
2041	33,564	4,196	2,389	1,339	7,924	65
2042	29,369	4,196	2,108	1,366	7,669	64
2043	25,173	4,196	1,827	1,393	7,415	63
2044	20,978	4,196	1,546	1,421	7,162	62
2045	16,782	4,196	1,265	1,449	6,910	61
2046	12,587	4,196	984	1,478	6,657	60
2047	8,391	4,196	703	1,508	6,406	59
2048	4,196	4,196	422	1,538	6,155	58
2049	0	4,196	141	1,569	5,905	57
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PV		57,266	75,113	14,861	147,241	
$2015PV		51,868	68,033	13,460	133,361	
					288,192	

Table C-3: Financial Analysis (WACC at 11.00%): McArthur Springs Case 3: 2.1 MW

Weighted Average Cost of Capital	11.00%
Inflation Rate	2%
Real Weighted Average Cost of Capital	8.82%

LCOE and LCOC with 11% WACC, McArthur Springs Case 3: 2.1 MW

Life Cycle Cost (2015$000's)	133,609
Depreciation & Return Cost (2015$000's)	124,523
Project LCOE ($/kWh)	$0.746
Project LCOC ($/MW)	$5,393,197

Year	McArthur Springs Case 3: 2.1 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	121,670	4,196	13,614	883	18,693	100
2021	117,474	4,196	13,153	901	18,249	100
2022	113,279	4,196	12,691	919	17,806	100
2023	109,083	4,196	12,230	937	17,363	99
2024	104,888	4,196	11,768	956	16,920	99
2025	100,692	4,196	11,307	975	16,478	98
2026	96,497	4,196	10,845	995	16,036	97
2027	92,301	4,196	10,384	1,015	15,594	96
2028	88,106	4,196	9,922	1,035	15,153	96
2029	83,910	4,196	9,461	1,056	14,712	95
2030	79,715	4,196	8,999	1,077	14,272	94
2031	75,519	4,196	8,538	1,098	13,832	93
2032	71,324	4,196	8,076	1,120	13,392	92
2033	67,128	4,196	7,615	1,143	12,953	90
2034	62,933	4,196	7,153	1,165	12,514	89
2035	58,737	4,196	6,692	1,189	12,076	88
2036	54,542	4,196	6,230	1,213	11,638	86
2037	50,346	4,196	5,769	1,237	11,201	85
2038	46,151	4,196	5,307	1,262	10,764	83
2039	41,955	4,196	4,846	1,287	10,328	81
2040	37,760	4,196	4,384	1,312	9,892	80
2041	33,564	4,196	3,923	1,339	9,457	78
2042	29,369	4,196	3,461	1,366	9,022	76
2043	25,173	4,196	3,000	1,393	8,588	73
2044	20,978	4,196	2,538	1,421	8,154	71
2045	16,782	4,196	2,077	1,449	7,721	69
2046	12,587	4,196	1,615	1,478	7,289	66
2047	8,391	4,196	1,154	1,508	6,857	64
2048	4,196	4,196	692	1,538	6,426	61
2049	0	4,196	231	1,569	5,995	58
2050						
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2063						
2064						
PV		40,487	96,996	10,032	147,515	
$2015PV		36,670	87,853	9,086	133,609	
					369,375	

Table D-1: Financial Analysis (WACC at 5.45%): **McArthur Springs Case 4: 5.5 MW**

			Average MW	Winter MW
Capital ($000)	2015	$127,000	5.8	6.2
Capital ($000)	2020	$140,218		
Energy		48.2	GWh/yr	
Capacity Factor		95%CF		
Fuel	2015			
O&M (Fixed)	2015	1800.0	$000/yr	
O&M (Variable)	2015	0.0	$/MWh	
Life		30	years	
Salvage cost		0%		

Load Growth -2.0%

48.2 GW.h

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, McArthur Springs Case 4: 5.5 MW

Life Cycle Cost (2015$000's)	166,879
Depreciation & Return Cost (2015$000's)	132,144
Project LCOE ($/kWh)	$0.225
Project LCOC ($/MW)	$1,388,937

Year	McArthur Springs Case 4: 5.5 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	135,544	4,674	7,515	1,987	14,176	29
2021	130,870	4,674	7,260	2,027	13,961	30
2022	126,196	4,674	7,005	2,068	13,747	30
2023	121,522	4,674	6,750	2,109	13,533	30
2024	116,849	4,674	6,496	2,151	13,321	30
2025	112,175	4,674	6,241	2,194	13,109	30
2026	107,501	4,674	5,986	2,238	12,898	30
2027	102,827	4,674	5,731	2,283	12,688	30
2028	98,153	4,674	5,477	2,328	12,479	30
2029	93,479	4,674	5,222	2,375	12,271	31
2030	88,805	4,674	4,967	2,423	12,064	31
2031	84,131	4,674	4,713	2,471	11,857	31
2032	79,457	4,674	4,458	2,520	11,652	31
2033	74,783	4,674	4,203	2,571	11,448	31
2034	70,109	4,674	3,948	2,622	11,245	31
2035	65,435	4,674	3,694	2,675	11,042	31
2036	60,761	4,674	3,439	2,728	10,841	31
2037	56,087	4,674	3,184	2,783	10,641	31
2038	51,413	4,674	2,929	2,838	10,442	31
2039	46,739	4,674	2,675	2,895	10,244	31
2040	42,065	4,674	2,420	2,953	10,047	31
2041	37,392	4,674	2,165	3,012	9,851	31
2042	32,718	4,674	1,910	3,072	9,657	31
2043	28,044	4,674	1,656	3,134	9,464	31
2044	23,370	4,674	1,401	3,197	9,271	31
2045	18,696	4,674	1,146	3,260	9,081	31
2046	14,022	4,674	892	3,326	8,891	31
2047	9,348	4,674	637	3,392	8,703	31
2048	4,674	4,674	382	3,460	8,516	31
2049	0	4,674	127	3,529	8,331	31
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2064						
PV		72,029	73,868	38,351	184,248	
$2015PV		65,239	66,905	34,736	166,879	
					335,469	

Year from In-service	Annual Energy GW.h, McArthur Springs Case 4: 5.5 MW	Annual Winter Capacity MW, McArthur Springs Case 4: 5.5 MW
1	48.24	6.20
2	47.28	6.08
3	46.33	5.95
4	45.41	5.84
5	44.50	5.72
6	43.61	5.60
7	42.74	5.49
8	41.88	5.38
9	41.04	5.27
10	40.22	5.17
11	39.42	5.07
12	38.63	4.96
13	37.86	4.87
14	37.10	4.77
15	36.36	4.67
16	35.63	4.58
17	34.92	4.49
18	34.22	4.40
19	33.54	4.31
20	32.86	4.22
21	32.21	4.14
22	31.56	4.06
23	30.93	3.98
24	30.31	3.90
25	29.71	3.82
26	29.11	3.74
27	28.53	3.67
28	27.96	3.59
29	27.40	3.52
30	26.85	3.45
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
Net Present Value	607	
Total energy	1,096	
Avg Annual energy	37	

Table D-2: Financial Analysis (WACC at 6.70%): McArthur Springs Case 4: 5.5 MW

Weighted Average Cost of Capital	6.70%
Inflation Rate	2%
Real Weighted Average Cost of Capital	4.61%

LCOE and LCOC with 6.7% WACC, McArthur Springs Case 4: 5.5 MW

Life Cycle Cost (2015$000's)	163,859
Depreciation & Return Cost (2015$000's)	133,573
Project LCOE ($/kWh)	$0.250
Project LCOC ($/MW)	$1,584,655

Year	McArthur Springs Case 4: 5.5 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	135,544	4,674	9,238	1,987	15,899	33
2021	130,870	4,674	8,925	2,027	15,626	33
2022	126,196	4,674	8,612	2,068	15,353	33
2023	121,522	4,674	8,299	2,109	15,082	33
2024	116,849	4,674	7,985	2,151	14,811	33
2025	112,175	4,674	7,672	2,194	14,540	33
2026	107,501	4,674	7,359	2,238	14,271	33
2027	102,827	4,674	7,046	2,283	14,003	33
2028	98,153	4,674	6,733	2,328	13,735	33
2029	93,479	4,674	6,420	2,375	13,469	33
2030	88,805	4,674	6,107	2,423	13,203	33
2031	84,131	4,674	5,793	2,471	12,938	33
2032	79,457	4,674	5,480	2,520	12,675	33
2033	74,783	4,674	5,167	2,571	12,412	33
2034	70,109	4,674	4,854	2,622	12,150	33
2035	65,435	4,674	4,541	2,675	11,889	33
2036	60,761	4,674	4,228	2,728	11,630	33
2037	56,087	4,674	3,914	2,783	11,371	33
2038	51,413	4,674	3,601	2,838	11,114	33
2039	46,739	4,674	3,288	2,895	10,857	33
2040	42,065	4,674	2,975	2,953	10,602	33
2041	37,392	4,674	2,662	3,012	10,348	33
2042	32,718	4,674	2,349	3,072	10,095	33
2043	28,044	4,674	2,036	3,134	9,843	32
2044	23,370	4,674	1,722	3,197	9,593	32
2045	18,696	4,674	1,409	3,260	9,344	32
2046	14,022	4,674	1,096	3,326	9,096	32
2047	9,348	4,674	783	3,392	8,849	32
2048	4,674	4,674	470	3,460	8,604	31
2049	0	4,674	157	3,529	8,360	31
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2064						
PV		63,797	83,679	33,438	180,913	
$2015PV		57,783	75,791	30,286	163,859	
					361,760	

Table D-3: Financial Analysis (WACC at 11.00%): McArthur Springs Case 4: 5.5 MW

Weighted Average Cost of Capital	11.00%
Inflation Rate	2%
Real Weighted Average Cost of Capital	8.82%

LCOE and LCOC with 11% WACC, McArthur Springs Case 4: 5.5 MW

Life Cycle Cost (2015$000's)	159,167
Depreciation & Return Cost (2015$000's)	138,723
Project LCOE ($/kWh)	$0.343
Project LCOC ($/MW)	$2,325,759

Year	McArthur Springs Case 4: 5.5 MW					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	135,544	4,674	15,167	1,987	21,828	45
2021	130,870	4,674	14,653	2,027	21,354	45
2022	126,196	4,674	14,139	2,068	20,880	45
2023	121,522	4,674	13,625	2,109	20,407	45
2024	116,849	4,674	13,110	2,151	19,936	45
2025	112,175	4,674	12,596	2,194	19,464	45
2026	107,501	4,674	12,082	2,238	18,994	44
2027	102,827	4,674	11,568	2,283	18,525	44
2028	98,153	4,674	11,054	2,328	18,056	44
2029	93,479	4,674	10,540	2,375	17,589	44
2030	88,805	4,674	10,026	2,423	17,122	43
2031	84,131	4,674	9,511	2,471	16,656	43
2032	79,457	4,674	8,997	2,520	16,192	43
2033	74,783	4,674	8,483	2,571	15,728	42
2034	70,109	4,674	7,969	2,622	15,265	42
2035	65,435	4,674	7,455	2,675	14,804	42
2036	60,761	4,674	6,941	2,728	14,343	41
2037	56,087	4,674	6,427	2,783	13,883	41
2038	51,413	4,674	5,913	2,838	13,425	40
2039	46,739	4,674	5,398	2,895	12,968	39
2040	42,065	4,674	4,884	2,953	12,511	39
2041	37,392	4,674	4,370	3,012	12,056	38
2042	32,718	4,674	3,856	3,072	11,602	38
2043	28,044	4,674	3,342	3,134	11,150	37
2044	23,370	4,674	2,828	3,197	10,698	36
2045	18,696	4,674	2,314	3,260	10,248	35
2046	14,022	4,674	1,799	3,326	9,799	34
2047	9,348	4,674	1,285	3,392	9,351	33
2048	4,674	4,674	771	3,460	8,905	32
2049	0	4,674	257	3,529	8,460	32
2050						
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2064						
PV		45,104	108,057	22,571	175,733	
$2015PV		40,852	97,871	20,443	159,167	
					452,201	

Appendix 5.11
Solar Site Inventory
(Solvest 2016)

Solar Site Inventory

May 2016

(updated August 2016)

Prepared for:

YUKON ENERGY

Prepared by:

SOLVEST

Contents

Abstract 1
1. Introduction 2
2. Site Selection Process 3
2.1 Selection Criteria 3
2.2 Chosen locations 3
Location #1: Whitehorse Copper 4
Location #2: Haines Junction 5
2.3 Irradiance Data 6
2.3.1 Comparison of Yukon PV Potential Against Global Utility-Scale PV Installation Sites 7
3 Technology Review 9
3.1 Module Technologies 9
3.1.1 P-type vs N-type Silicon 9
3.1.2 Polycrystalline 10
3.1.3 Monocrystalline 11
3.1.4 Bi-Facial 12
3.1.5 Thin Film 12
3.1.6 Developing Module Technologies 13
3.2 Inverter Technologies 14
3.2.1 Central Inverters 14
3.2.2 String Inverters 15
3.2.3 Micro Inverters 16
3.3 Racking Technologies 17
3.3.1 Fixed Racking 17
3.3.2 Single Axis Trackers 18
3.3.3 Dual Axis Trackers 18
3.3.4 Rail Trackers 20
3.4 Energy Storage 21
4 Asset Service Life 22
5 Operations and Maintenance Plan 23

5.1 Maintenance Training 23
5.2 Spare Parts List 23
5.3 1 MW/5MW O&M Plan 23
5.4 10 MW O&M Plan 24
6 Project Schedules 24
6.1 Whitehorse Schedule – 10 MW 25
6.2 Haines Junction Schedule – 5 MW & 1MW 25
7 Energy Modeling Methodology 27
7.1 Systems Component Choices for the PVSyst Simulations 27
7.1.1 Module Selection 27
7.1.2 Inverter Selection 28
7.1.3 Racking Selection 28
7.2 Assumptions Used in the PVSyst Model 28
7.3 A Note on Spacing Requirements and Shading 29
Shading profiles 30
8 Haines Junction Energy Analysis 31
8.1 Racking and Tracking Simulation Results 31
8.1.1 Fixed Tilt Racking 31
8.1.2 Single Axis and Dual Axis Tracking 31
8.2 Effect of inverters 33
8.3 Area Requirements 33
8.3.1 Haines Junction – 1 MW Array Footprints 34
8.3.2 Haines Junction – 5 MW Array Footprints 35
9 Whitehorse Quarry Energy Analysis 36
9.1 Racking and Tracking Simulation Results 36
9.1.1 Fixed Tilt Racking 36
9.1.2 Single Axis and Dual Axis Tracking 36
9.2 Area Requirements 38
9.2.2 Whitehorse – 1 MW Array Footprints 39
9.2.3 Whitehorse – 5 MW Array Footprints 39
9.2.4 Whitehorse – 10 MW Array Footprints 40
10 Financial Analysis Methodology 42

10.1 Engineering Fees Explanation 42
10.2 Capital Expenditures Examples 43
10.3 Operations and Maintenance Examples 44
10.4 Levelized Cost of Electricity (LCOE) 45
11 Financial Analysis – Haines Junction 46
11.1 Capital Expenses at Haines Junction 46
11.2 Financial Trends Due to Module Cost 46
11.3 Fixed Tilt Racking vs. Trackers 47
11.4 Effect of Inverter Choice 47
12 Financial Analysis – Whitehorse 49
12.1 Capital Expenses at Whitehorse 49
12.2 Fixed Tilt Racking vs. Trackers 49
12.3 Comparison Against Haines Junction 50
12.4 Module Comparison 51
13 Summary and Recommendations 52
Site and Panel Recommendations 52
Racking and Inverter Recommendations 52
Financial Summary 52
Potential Show Stoppers 52
Appendix A – Monthly Profile Data 54
1 MW Haines Junction Monthly Generation Data 54
5 MW Haines Junction Monthly Generation Data 60
1 MW Whitehorse Monthly Generation Data 65
5 MW Whitehorse Monthly Generation Data 69
10 MW Whitehorse Monthly Generation Data 74
Appendix B – Additional Energy Simulations Results 78
Haines Junction – 1 MW, Fixed Tilt, Central Inverters 78
Haines Junction – 1 MW, Single Axis, Central Inverters 78
Haines Junction – 1 MW, Dual Axis, Central Inverters 79
Haines Junction – 5 MW, Fixed Tilt, Central Inverters 79
Haines Junction – 5 MW, Single Axis Trackers, Central Inverters 80
Whitehorse – 1 MW, Fixed Tilt Racking, Central Inverters 80

Whitehorse – 1 MW, Single Axis Tracking, Central Inverters 81
Whitehorse – 5 MW, Fixed Tilt Racking, Central Inverters 81
Whitehorse – 5 MW, Single Axis Tracking, Central Inverters 82
Whitehorse – 10 MW, Fixed Tilt Racking, Central Inverters 82
Appendix C – Complete LCOE Tables 83
Haines Junction – 1 MW Fixed Tilt 83
Haines Junction – 1 MW Single Axis Trackers 84
Haines Junction – 1 MW Dual Axis Trackers 85
Haines Junction – 5 MW Fixed Tilt Racking 86
Haines Junction – 5 MW Single Axis Tracking 87
Whitehorse – 1 MW Fixed Tilt Racking 88
Whitehorse – 1 MW Single Axis Tracking 89
Whitehorse – 5 MW Fixed Tilt Racking 90
Whitehorse – 5 MW Single Axis Tracking 91
Whitehorse – 10 MW Fixed Tilt Racking 92
Whitehorse – 10 MW Single Axis Tracking 92

Abstract

The Yukon Energy Corporation (YEC) is entering a new planning cycle for future upgrades and improvements to the Yukon Territory's electricity supply. This report, prepared by Solvest Inc., is intended to assist in the future planning of the Yukon electricity grid by providing information on the viability of utility scale photovoltaic solar energy at several locations across the Yukon. Expected electricity generation capabilities are modelled, and a preliminary financial analysis presented. These numbers can be used to compare against other proposed energy projects in the areas of hydro, wind, geothermal and energy storage that are also currently being completed.

Four locations were initially investigated as potential sites for 1MW, 5MW or 10MW photovoltaic power plants. Of these sites, one at Haines Junction and one near Whitehorse were settled on as being the most appropriate. Both have large, flat, unshaded spaces, and are close to urban locations with high demand for electricity. The Haines Junction site is located close to both the airport and the dump, and is not likely to be ideal for many other uses. The Whitehorse site is already human impacted and clear of trees – an old quarry that is no longer in use.

The energy modeling revealed that the 1MW installations yielded 1050 – 1190 MWh annually for panels installed on fixed tilt racking. There was no significant influence on energy production due to location choice. For 1MW installations using single axis tracking, the annual energy yield jumped to 1290 – 1490 MWh. Moving from single axis tracking to dual axis tracking only improved the energy yield by about 6%, while increasing the cost and complexity of the installation significantly.

For 5MW installations, the annual energy yield for fixed tilt racking systems fell between 5230 and 5460 MWh. For single axis tracking systems, the yield was between 6000 and 6750 MWh depending on the choice of modules. For 10 MW fixed tilt racking systems, the annual energy yield was about 11,000 to 11,500 MWh.

Different inverter choices were also modeled, and the energy yield between the inverter options was similar. The major difference comes from the cost. Two different quotations for central inverters were obtained, which were significantly different. String inverters can be more expensive due to the increased number of inverters and wiring complexity, however the string inverter system costs here fell between the two central inverter costs.

The LCOE for the 1MW systems ranged from $0.17 to $0.20/kWh. The LCOE for the 5MW systems is quite attractive, ranging from $0.14 to $0.18 on average. For the 10MW system, additional battery storage is needing for smoothing in case of power fluctuations, since the 10MW system will have a greater penetration of the electricity grid. For the 10MW system along with battery storage, the LCOE is about $0.21/kWh. Due to the area requirements, it will be difficult to fit 10MW of photovoltaics at the Haines Junction site. There is ample room at the Whitehorse Quarry site, however, so if a PV plant of this size is desired, it should be located at Whitehorse.

1. Introduction

There are three main groupings to this report: 1) All the information that defines the project and informs the site selection; 2) The energy modeling for each site and system option; and 3) The financial analysis of each option.

The site selection is outlined in Section 2: Site Selection Process, and includes the selection criteria and irradiance data. More helpful background information that will be required to complete the energy and financial sections is found in the technology review in Section 3, and the asset service life, operations and maintenance (O&M) plan, and the project schedule in Sections 4 through 6.

Sections 7 through 9 go through the energy modelling for the systems at each of the proposed site under the various technical options. Section 7 explains the loss inputs that were included in the PVSyst simulation. The complete monthly energy profile data can be found in Appendix A. Additional data from the energy simulations can be found in Appendix B.

Sections 10 through 12 walk through the highlights of the financial assessment. Section 10 describes the method by which the Levelized Cost of Electricity (LCOE) is calculated. Full tables of all the LCOE results for all the systems modeled can be found in Appendix C.

Conclusions, recommendations and potential show-stoppers are shared in the final section of the report.

In addition to this report, all the Excel files from the financial analysis, data from the PVSyst simulations, simulation reports, kmz and CAD files showing footprints of the sites, and project schedule Gantt charts are accompanying this report in a shared Dropbox folder. A “hard-copy” of all this data as well as the report will be submitted to YEC on either a CD or flash drive via mail.

2. Site Selection Process

2.1 Selection Criteria

The following criteria were evaluated when selecting the two sites for the proposed utility scale PV power plants:

1. **Solar Irradiance Profiles**. The solar irradiance data for each community on the Yukon Energy transmission grid was evaluated to determine which communities have favorable solar generation profiles. As shown in the chart above the solar irradiance profiles for the communities in the Yukon varies 8% between the lowest community (Keno Hill) and the highest community (Dawson).
2. **Proximity to existing transmission infrastructure**. By selecting sites close to existing substations, grid connection costs for the proposed power plants are minimized allowing lower transmission and distribution costs for Yukon Energy and a lower levelized cost of energy for the PV power plant.
3. **Proximity to communities**. In order to minimize construction costs and provide continued access for on-going maintenance, both sites selected are located close to existing communities. Additionally, given that a significant percentage of the load capacity on the Yukon electrical grid is located in the Whitehorse to Haines Junction corridor both sites selected are located in this area to minimize the distance from generation to the end consumer.
4. **Topographic Profile**. Utility scale solar generation requires a large amount of land (6-10 acres per MW) with minimal elevation changes across the property. Topographic maps of both Whitehorse and Haines Junction were carefully analyzed to determine which areas had enough flat land within close proximity to identified substations.
5. **Land Ownership**. Using the Yukon Lands-viewer tool (http://mapservices.gov.yk.ca/Lands/Load.htm) the identified areas were analyzed to confirm if there are any existing land use restrictions for the proposed sites such as wildlife reserves or residential development hold backs. Additionally, each site was verified against a data base to confirm that no third parties currently own the proposed properties.
6. **Open Land**. In order to minimize site preparation costs, sites with open land or minimal tree cover were selected. Mulching costs were estimated at $3500 an acre, so both chosen sites have minimal tree cover to try and reduce this cost.

2.2 Chosen locations

The solar irradiation map of the Yukon was investigated, and from the initial review four main sites of interest were chosen: Haines Junction, Whitehorse Copper, Takhini, and Canyon. Topographical maps were consulted, as well as site visits to the proposed locations, and from the initial four sites, Whitehorse and Haines Junction best fit the criteria. Takhini, from the topography graphs, had a very uneven site, and a large hill or ridge on the west side that would block the evening sun. Upon inspection, the site was also seen to be very boulder-strewn and construction would have been significantly difficult. Canyon was awkwardly shaped, and there was some question of land ownership. Both the Whitehorse Copper and Haines Junction sites were physically suitable and in close proximity to communities where the energy would be needed, and so they became the sites of choice.

Location #1: Whitehorse Copper

Nearest Community: Whitehorse

GPS Coordinates: 60.643440, -135.058548

Available Space: 120 Acres

Distance to Substation: 2.8 KM

Connection Voltage: 34.5 KV

Soil type: Mine Tailings

Geotechnical Analysis Required: Yes

Site Description: The chosen site is the old tailings pile for the Whitehorse Copper Mine which was operated from 1972 to 1982 near Mount Sima Ski Hill. The tailings pile was chosen as it is an abandoned mine site that cannot be used for traditional development projects without further reclamation work. The pile consists of 120 acres of open land with minimal fluctuations in elevation across the pile, which will reduce development costs for constructing the solar farm by eliminating land clearing costs and reducing the amount of compaction and excavation work required to prepare the site for construction.

Additional benefits of the site include, established road access, close proximity to the mount sima substation (2.8 Km), and a geotechnical profile consisting of fine grain mill material making it easy to drive piles to support the solar array. Finally, by being located within Whitehorse city limits, this site ensures that the distance from generation to the consumer is minimized and reduces construction costs by being located close to the main source of materials and labour within the Yukon.

Figure 2.1: Proposed site of a PV power plant at Whitehorse Copper

Location #2: Haines Junction

Nearest Community: Haines Junction

GPS Coordinates: 60.784897, -137.505541

Available Space: 65 Acres

Distance to Substation: 3.4 KM

Connection Voltage: 25 KV

Soil type: Organics/Clay

Geotechnical Analysis Required: Yes

Site Description: The chosen site is located 1 km north of the Haines Junction dump in a 65 acre, semi-open area with minimal elevation changes across the site. This site was selected due to its close proximity to the highway (500 m) and substation (3.4 km) as well as the site consists of largely open land with thin tree cover reducing land clearing costs significantly.

Additionally, by being located within Haines Junction, this site ensures that construction costs will be reduced by having accommodations for construction crews in close proximity from site.

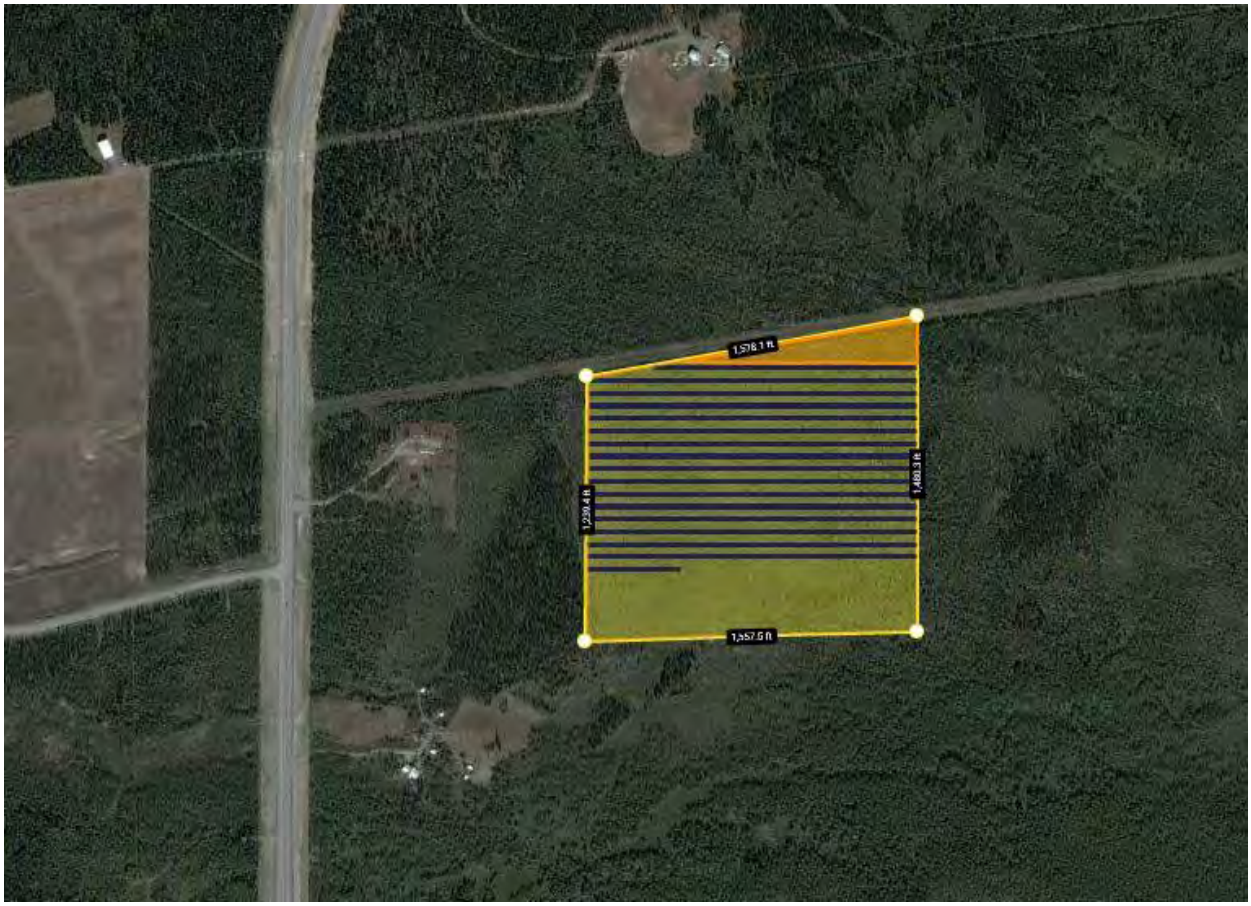


Figure 2.2: Proposed site of a PV power plant at Haines Junction

2.3 Irradiance Data

In order to determine the best locations in terms of solar resource in the Yukon, the solar irradiance data for the territory was analyzed. Table 2.1 shows the irradiance data for all major communities connected to the Yukon Energy transmission grid.

Table 2.1: Solar potential data for communities in the Yukon[1]

Municipality	Solar Potential (kWh/kW)
Whitehorse	985±158.0
Teslin	964±154.0
Tagish	981±157.0
Stewart Crossing	1011±162.0
Ross River	962±154.
Pelly Crossing	1016±163.0
Mayo	991±159.0
Marsh Lake	981±157.0
Keno Hill	961±154.0
Haines Junction	1038±166.0
Faro	966±155.0
Dawson	1043±167.0
Carmacks	1013±162.0
Carcross	978±157.0

Annual Irradiance figures shown were collected at a south facing tilt angle of latitude -15.

The data in Table 2.1 shows a variance of only 9% across all municipalities connected to the Yukon Energy Hydro Grid, and only 6 % variance from Whitehorse. Based on this information the two locations for further investigation will be Whitehorse and Haines Junction. This decision was made based on increased construction costs as one gets further from Whitehorse and will allow Yukon Energy to keep the proposed power plants close to existing electrical infrastructure and points of use.

Tables 2.2 and 2.3 show the solar irradiance data by month at various tilt angles for both Whitehorse and Haines Junction:

Table 2.2: Monthly irradiance data for Whitehorse (kWh/m^2/month)

Month	South-facing vertical (tilt=90°)	South-facing, tilt=latitude	South-facing, tilt=lat+15°	South-facing, tilt=lat-15°
January	31	30	31	26
February	63	63	65	58
March	97	108	105	104
April	97	123	112	127

[1] The data in Table 2.1 was obtained from NRCAN's website data base of solar irradiance data available at: http://pv.nrcan.gc.ca/index.php?m=s&lang=e&lang=e&prov=yk

May	84	119	103	129
June	80	116	99	128
July	77	111	95	122
August	81	110	98	116
September	68	83	78	83
October	49	53	53	51
November	30	30	31	27
December	17	16	17	14
Annual	**774±124.0**	**961±154.0**	**887±142.0**	**985±158.0**

Table 2.3: Monthly irradiance data for Haines Junction (kWh/m^2/month)

Month	**South-facing vertical (tilt=90°)**	**South-facing, tilt=latitude**	**South-facing, tilt=lat+15°**	**South-facing, tilt=lat-15°**
January	38	36	38	32
February	68	68	70	62
March	105	115	113	110
April	102	127	117	129
May	88	124	108	134
June	79	116	98	128
July	78	113	97	124
August	85	113	101	120
September	74	87	82	88
October	60	63	63	60
November	37	36	37	32
December	25	23	24	20
Annual	**838±134.0**	**1021±163.0**	**949±152.0**	**1038±166.0**

2.3.1 Comparison of Yukon PV Potential Against Global Utility-Scale PV Installation Sites

To further illustrate that solar is a good choice of renewable energy on a utility-level scale for the Yukon, Table 2.4 lists the solar potential of the selected Yukon sites (kWh/kW) against a selection of comparable jurisdictions that have implemented grid scale solar around the world (e.g. Germany, Ontario, etc). While the Yukon is on the low side in terms of solar PV potential in Canada, it has higher potential than Berlin, Germany. Germany has a number of utility-scale PV installations, close to 100 MW in size, close to Berlin (the Brandenburg-Briest Solar Park is located less than 100 km from Berlin, and is 91 MW in size). The Yukon also has better solar potential than Japan, which has embraced solar in the

wake of the Fukushima nuclear disaster and now has a number of utility-scale PV plants located across the country (and notably in the Fukushima prefecture).

Table 2.4: Comparison of solar potential for various cities across Canada and around the World

Major Canadian cities and capitals	Yearly PV potential (kWh/kW)	Major cities worldwide	Yearly PV potential (kWh/kW)
Regina (Saskatchewan)	1361	Cairo, Egypt	1635
Calgary (Alberta)	1292	Capetown, South Africa	1538
Winnipeg (Manitoba)	1277	New Delhi, India	1523
Edmonton (Alberta)	1245	Los Angeles, U.S.A.	1485
Ottawa (Ontario)	1198	Mexico City, Mexico	1425
Montréal (Quebec)	1185	**Regina, Canada**	**1361**
Toronto (Ontario)	1161	Sydney, Australia	1343
Fredericton (New Brunswick)	1145	Rome, Italy	1283
Québec (Quebec)	1134	Rio de Janeiro, Brazil	1253
Charlottetown (Prince Edward Island)	1095	Beijing, China	1148
Yellowknife (Northwest Territories)	1094	Washington, D.C., U.S.A.	1133
Victoria (British Columbia)	1091	Paris, France	838
Halifax (Nova Scotia)	1074	**St. John's, Canada**	**933**
Iqaluit (Nunavut)	1059	Tokyo, Japan	885
Vancouver (British Columbia)	1009	Berlin, Germany	848
Whitehorse (Yukon)	960	Moscow, Russia	803
St. John's (Newfoundland and Labrador)	933	London, England	728
Source: Natural Resources Canada. (2007). Photovoltaic potential and solar resources maps of Canada. Retrieved February 1, 2010, from https://qlfc.cfsnet.nfis.org/mapserver/pv/rank.php?NEK=e			

3 Technology Review

In recent years, the price of solar panels and their related systems has dropped significantly. This has been the result of both economies of scale and design improvements. With the design improvements, there are now a wide variety of module technologies, inverter technologies, and racking systems. This section explores the types of modules, inverters, and racking systems that are currently on the market, looks at their performance under conditions in the north as well as their costs, and helps us to arrive at the options that will be best for YEC. There is also a section at the end that comments on the types of energy storage options available for grid applications and the option that we recommend accompanies larger solar utility projects in the Yukon.

3.1 Module Technologies

In this section we'll look at the major cell and module technologies that are on the market today, and then briefly touch a few that are in the pipeline so that in 5 or 10 years, so that if more solar projects are planned in the future, the viability of these new technologies can be looked at as well. An explanation of the following module and cell types is presented here:

- P-type vs N-type silicon for solar cells
- Multicrystalline solar cells
- Monocrystalline solar cells
- Bi-facial cells and panels
- Thin film cells and panels
- Emerging technologies

3.1.1 P-type vs N-type Silicon

While not as widely adopted as p-type silicon technologies, n-type solar cells have been around for a long time, and have held the record for the highest-efficiency commercial solar products for about as long. The two most well-know are Sunpower's IBC (interdigitated back contact) cell, and Sayno's HIT cell (now owned by Panasonic). A number of other companies are now getting on board. Yingli's PANDA cell, Sunpreme's heterojunction bi-facial cell, and Suniva all make use of n-type silicon wafers.

N-type silicon has a number of benefits over p-type silicon, the first of which is that there is no light-induced degradation (LID) with n-type silicon. P-type silicon is typically doped with boron during the crystal growth process. Both Czochralski-grown and cast-multi silicon ingots are exposed to air during the casting process, which results in the presence of oxygen in the melt. When the silicon wafers later undergo high temperature processing during cell manufacturing, this creates boron-oxygen complexes, defects in the silicon, which activate after the cell is used in the light for the first time, and results in up to 2% degradation in module performance after deployment in the field. As n-type silicon is doped with phosphorous during the casting process, rather than boron, there is no chance for the boron-oxygen defects to form, resulting in a high quality material.

Similarly, n-type materials tend to be more resilient against other types of impurity defects as well, the most cited of which being iron. The lifetime of free electrons and holes in an n-type silicon wafer is also 3 times longer than in a p-type wafer due to the capture cross-section of the defects being smaller. For all these reasons, in an n-type wafer, once an electron has been generated by sunlight, the chance of that electron becoming part of the usable current of the solar cell is much, much higher.

While not an inherent material property, higher efficiency solar cells such as n-type solar cells, tend to have better temperature coefficients than p-type cells. When working in cold climates, the voltage change as a function of temperature becomes a critical design component. As temperature drops, the cell voltage increases. At very low temperatures, as can often be had in the Yukon, this voltage drop can risk exceeding the maximum allowable voltage on the inverters. As a result, strings of modules are limited to what the cold-temperature open-circuit voltage can reach. P-type solar modules have temperature coefficients of -0.31 %/°C typically (see Heliene and Canadian Solar data sheets). Sunpower's n-type modules have temperature coefficients in the range of -0.29 %/°C to -0.298 %/°C and Sanyo's HIT cell does even better with a temperature coefficient of -0.239 %/°C. This may be a function of the low-temperature manufacturing process that the HIT cell utilizes. Similar designs, such as Sunpreme's heterojunction bifacial cells, achieve a similar temperature coefficient of -0.23 %/°C. The benefit of having a temperature coefficient closer to zero is that you don't have to over-size your inverters to take into account high voltages in low weather, and you also don't have large voltages drops and resulting power drops in hot weather.

Despite the obvious benefits of using n-type wafers, their use has not become wide-spread yet due to several factors: the higher cost of the material; and difficulties in some of the processing steps. The material cost for n-type silicon is partly due to economies of scale – there is less demand for it, and so it is produced in smaller amounts by fewer manufacturers. The crystallization of n-type silicon also tends to be less uniform than that of p-type silicon, meaning that the phosphorous doping concentration in the silicon changes as the ingot crystallizes. This results in a range of material resistivities being produced during the casting process, and the resulting wafers need to be sorted and binned later to create batches with similar material characteristics. The processing steps become more difficult in two main places: high temperature boron diffusions for forming the p-n junction are difficult, and a good method was not discovered until the late '90s, and the typical surface passivation that is used on p-type solar cells (silicon nitride) does not work on n-type solar cells, and actually makes their performance worse, so alternate passivation methods had to be developed.

In summary, the benefits of modules employing n-type wafers is the absence of light-induced degradation, higher efficiency, better voltage performance in both high and low temperatures, and lower balance-of-system costs due to both the higher efficiency and better voltages. The only draw-back is due to the higher module price, but depending on the project, this may be offset due to the benefit in the aforementioned areas.

3.1.2 Polycrystalline

Polycrystalline, or multicrystalline, solar cells are produced from chunks of purified silicon which are heated in a ceramic crucible to above the melting point of silicon and then cooled in a controlled

manner. This forms blocks of polycrystalline silicon which are then cut and sliced into in wafers to form solar cells. Recognizable by their square cell shape, polycrystalline solar modules are less efficient than monocrystalline modules due to breaks within the crystal structure of the cell. However due to lower manufacturing costs, polycrystalline solar modules account for over 75% of the solar modules manufactured annually as of 2015[2].

Benefits:

- Lower manufacturing costs. (10- 15 cents per watt cheaper than standard monocrystalline, 50% cheaper than high efficiency monocrystalline cells)

Drawbacks:

- Lower efficiency. (Polycrystalline cells range from 14.5% to 17% efficiency, Monocrystalline ranges from 16% to 22%)
- Less efficient in low light conditions[3].

3.1.3 Monocrystalline

Monocrystalline solar cells are made from single crystal silicon ingots formed using the Czochralski method. A single crystal of silicon is used as a seed and dipped into vat of liquid silicon. The seed is lifted and rotated at a controlled speed, growing a single crystal silicon ingot out of the bath as it rises. The tubular crystal is then sawn into wafers, and the edges cut straight, except for their corners. Recognizable by the diamond pattern formed by the gaps between the corners of cells, monocrystalline solar modules are high efficiency solar cells producing more energy per square meter than polycrystalline solar modules[2].

Benefits:

- Higher efficiency. (Polycrystalline cells range from 14.5% to 17% efficiency, Monocrystalline ranges from 16% to 22%)
- Lower temperature coefficient, leading to improved performance in hot climates compared to Polycrystalline. (Monocrystalline averages -0.31% per degree C, Polycrystalline averages -0.40% per degree C)
- Improved low light condition performance (sunrise and sunset, cloudy weather) over polycrystalline solar cells due to higher shunt resistance (i.e. fewer shorts or flaws in the p-n junction)[3].

Drawbacks:

[2] https://www.ihs.com/pdf/Top-Solar-Power-Industry-Trends-for-2015_213963110915583632.pdf
[3] http://www.ecn.nl/docs/library/report/2005/rx05034.pdf

- Higher cost to manufacture due to requirement for single crystal silicon ingots. (Standard monocrystalline cells are 10- 15 cents per watt more than Polycrystalline, high efficiency monocrystalline cells are twice the price per watt)

3.1.4 Bi-Facial

Bi-Facial Solar cells are manufactured to allow the cells to absorb light on both sides. Traditional solar cells join the silicon cell to a solid conductive backing made of aluminum or copper, bi-facial cells bond the silicon to a grid shaped backing allowing light to be absorbed on both sides. Recognizable by their transparent glass frames with visible cells on the back side.

Benefits:

- Very high efficiency. (19% to 28% with backside power production factored in)
- Improved winter performance due to reflected light of snow covered surfaces. (Up to 50% more power per square meter under certain albedo conditions)
- Improved low light performance, due to using an amorphous Si layer, which has higher light absorption, as well as using monocrystalline silicon[4].
- Can be installed at various angles and orientations with limited impact on power production.
- Aesthetically appealing (often used by architects for building integrated solar installations)

Drawbacks:

- Very expensive to manufacture. (30-60% more per watt to manufacturer than polycrystalline modules)
- Require customized racking that does not obstruct the cells on the backside of the module.

3.1.5 Thin Film

Thin Film solar cells are made from depositing very thin layers of photovoltaic materials "film" onto a conductive backing. Each layer of film absorbs a separate spectrum of light and combine to form a solar cell. This manufacturing process makes these solar cells extremely thin and flexible allowing them to be installed in a variety of applications including on curved roof surfaces or in calculators.

Benefits:

- Lower cost to manufacture. (10 to 20 cents per watt cheaper than polycrystalline modules)
- Best low light performance of all the technologies studied in this report[5].

Drawbacks:

- Much lower efficiency. (Thin film modules average 10% to 15% cell efficiency levels)
- Large space requirements for similar power yields to silicon solar technologies.
- High operating voltages prohibit micro inverter use.

[4] http://www.ecn.nl/docs/library/report/2005/rx05034.pdf
[5] http://profs.sci.univr.it/~romeo/Publications/Derk_17Munich-1.pdf

- Reverse bias, as is experienced when portions of a module become shaded, can damage the junction.

Due to the damage that can be done to the module when it becomes shaded, which is highly likely in the event of snowfall, thin film panels are not recommended for use in the Yukon.

3.1.6 Developing Module Technologies

The following technologies are in various stages of development and commercialization. These technologies are being developed to address a variety of deficiencies with photovoltaics including low electrical conversion factors (efficiency), high manufacturing costs, and power density.

- **Organic Semiconductor Solar Cells** were discovered and tested by a team of scientists at Cambridge University in October 2014 studying how plants convert light to energy through the process of photosynthesis[6]. The team observed that plants are able to absorb both spin-triplet light photons and spin-singlet light photons, while current solar technologies can only capture spin-singlet light photons resulting in much of the available solar energy going to waste. This observation led them to create a unique solar cell with an organic semi-conductor layer to capture the spin-triplet light photons and an inorganic semi-conductor layer to capture the spin-singlet light photons leading to a world record cell efficiency of over 75%. While this technology is still in its infancy, if it can be successfully commercialized it has huge potential for the photovoltaics industry as it would drastically increase the power density of PV technology.
- **Perovskite Solar Cells** are solar cells formed with organic/in-organic compounds to mimic the cell structure of Perovskite, which is conducive to photovoltaic conductivity. By mimicking this cell structure scientists have been able to create thin, transparent solar cells with efficiencies ranging from 3.8-9% and semitransparent solar cells with efficiencies as high as 21%[7]. The manufacturing process for perovskite solar cells is much more cost effective than traditional silicon or thin-film solar technologies and could lead to a huge decline in module production prices. Additionally, the advent of transparent solar cells paves the way for use of photovoltaics in glass building construction which represents a huge growth market for photovoltaics. However, perovskites are very unstable and can dissolve in water so finding a cost effective and means of sealing the solar cells is critical in order to allow for commercialization[4].
- **Graphene Solar Cells** consist of using thin layers of graphene to form the conductive layer within the solar cells rather than silver and copper. Graphene's carbon nanostructure makes it an excellent conductor while being extremely strong, virtually transparent and flexible[8]. These traits could allow for high efficiency, transparent, and flexible solar cells that could be used widely in applications such as building integrated photovoltaics, however currently researchers are struggling to successfully integrate graphene with existing silicon photovoltaic technologies[5].
- **Concentrated Photovoltaics (CPV)** involve using lenses to concentrate the sun onto a solar cell, allowing for exponential power production per square meter. This technology has been

[6] http://www.cam.ac.uk/research/news/hybrid-materials-could-smash-the-solar-efficiency-ceiling
[7] http://www.rsc.org/chemistryworld/2015/10/thin-film-perovskite-solar-cell-passes-efficiency-test-0
[8] http://www.graphene-info.com/graphene-solar-panels

developed and successfully commercialized with over 500 MW of installed capacity as of 2014[9]. While CPV does significantly increase power density it does have a number of draw backs that have limited its wide spread implementation including:

- **Cooling problems:** concentrating the sun on a single point leads to increased temperatures which can damage and destroy solar cells if not effectively managed.
- **Requires direct sunlight:** this severely limits the number of locations in which CPV can be implemented[10].
- **Manufacturing costs**: concentrating lenses are made of highly reflective glass which is very costly to manufacture. Additionally, cooling systems for high concertation CPV can be complex and expensive.

3.2 Inverter Technologies

Inverters are critical component to any photovoltaic system from residential installations to large utility scale power plants. Photovoltaic modules produce direct current (DC) which must be converted to alternating current (AC) in order to be used in homes and buildings or transmitted through the electrical grid. Inverters convert DC power to AC power by "switching" the DC current off rapidly inducing an AC current in a secondary conductor. The AC signal is then smoothed out using a sine wave filter to ensure its frequency matches the electrical grid[11]. There are three types of inverters used in photovoltaic applications:

- Central inverters
- String inverters
- Micro inverters

3.2.1 Central Inverters

Central inverters are designed for large scale PV installations and range in size from 100 kW to 3 MW rated capacity. When installing a central inverter, multiple strings of PV modules are combined in parallel in combiner boxes before connecting to the inverter, the high voltage DC power is then inverted to 3 phase AC power before being transmitted to the grid. Additionally, many central inverters come with prewired transformer and switch gear packages allowing high voltage grid connection right at the inverter. Accounting for over 40% of all inverter sales globally, central inverters are the industry standard for large scale PV installations with ever evolving technology[12]. In 2016, central inverter designs are expected to shift from 1000VDC architecture to 1500 VDC designs to allow for longer string sizing and reduced balance of system costs for large installations[13].

[9] https://www.ihs.com/pdf/Top-Solar-Power-Industry-Trends-for-2015_213963110915583632.pdf
[10] http://www.greenrhinoenergy.com/solar/market/micro_market.php
[11] http://www.homepower.com/articles/solar-electricity/equipment-products/how-inverters-work

[12] https://www.ihs.com/pdf/Top-Solar-Power-Industry-Trends-for-2015_213963110915583632.pdf

[13] http://www.greentechmedia.com/articles/read/1500-Volt-Systems-Will-Account-for-4.6-GW-of-Global-Utility-Scale-Solar-In

Benefits:

1. Low manufacturing cost per rated DC watt. (8 to 20 cents USD per watt)
2. Prewired, "plug and play" designs allow for quick installation times.
3. Proven, "bankable" technology. With over 8 GW in annual installations and a 100 GW installed globally, central inverters have a well-established track record for reliable performance for utility scale PV power plants[9].
4. Integrated design. Most major central inverter suppliers offer fully integrated containerized inverter solutions which feature central inverters, a transformer, switch gear, and SCADA platform allowing for easy system design and seamless grid integration.
5. Minimizes electrical architecture complexity, reducing electrical installation labor costs.

Drawbacks:

1. No module level monitoring or string optimization. This means central inverters cannot be used in areas with partial or constant shading concerns as shading one module will impact entire strings. Additionally, module level failures cannot be detected remotely and can only be identified using thermal scans of the power plant adding the to the maintenance costs.
2. Required Annual Maintenance. Due to the size of the inverters central inverters produce a lot of heat and require complex cooling systems in order to ensure they continue to function optimally.
3. Concentrated points of failure. With input capacities typically ranging from 250 KW to 1.5 MW when a central inverter fails a large portion of a PV power plant is down until the inverter is brought online. This can be a concern for remote locations where technicians are not readily available.
4. Lifespan. Central inverters typically require significant upgrades after 12 to 15 years, which must be budgeted for in order to allow for PV power plants to fulfill their 30 year operational lifespans.
5. Temperature sensitive. Central inverters cannot operate in temperatures below -25 C and must be housed in heated containers if installed in locations with winter temperatures below -30.
6. Heavy. Central inverters typically weight 1500 to 3000 KG or more if packaged with transformers and switch gear. This limits where they can be installed and generally require being installed on concrete pads.

3.2.2 String Inverters

String inverters are designed for a wide variety of PV installations and range in size from 2 KW single phase units to 40 KW three phase units. Typically string inverters have built in maximum power point tracking (MPPT) allowing the inverter to optimize the performance of 1-3 strings of modules depending on the inverter size. Single phase string inverters typically have a maximum DC input voltage of 600V while three phase string inverters allow for 1000V and in some cases 1500V DC input voltages[14].

[14] http://www.greentechmedia.com/articles/read/1500-Volt-Systems-Will-Account-for-4.6-GW-of-Global-Utility-Scale-Solar-In

Benefits:

1. No maintenance. String inverters have self-contained cooling systems and are outdoor rated for operating temperatures as low as -40 C.
2. Small compact design allows for deployment on racking, sides of buildings or in containerized solutions, providing system designers flexibility.
3. Decentralized design. With rate capacities ranging from 2KW to 40 KW, if a string inverter fails on a large PV installation a small segment of the power plant is down during the repairs.
4. Allow for power optimizer use. Power optimizers provide module level DC voltage optimization and monitoring minimizing the effects of shading and allowing system operators to monitor the power production of each module.

Drawbacks:

1. Higher cost. String inverters are more expensive than central inverters per installed DC watt of PV capacity. (15 to 30 cents USD per watt)
2. Increased balance of system costs and electrical architecture complexity. Installing string inverters decentralizes the AC system architecture of a PV power plant leading to increased design and installation costs associated with additional AC wiring/infrastructure.
3. Lifespan. String inverters typically need replacing after 12 to 15 years of operating time depending on conditions. Replacement costs must be budgeted for in order for PV power plants to fulfill their 30 year operational lifespans.
4. Complex system integration. While increasingly common, string inverters are typically not designed for utility scale applications leading to potential problems when integrating them with grid connection SCADA platforms and secondary switchgear packages. It is recommended that installers using string inverters for utility scale applications purchase them from vertically integrated suppliers such as Schneider, ABB or SMA to ensure that there is available grid connection equipment that is compatible with the inverters.

3.2.3 Micro Inverters

Micro inverters are connected to each module and invert the DC power supply directly at the module, eliminating the need for DC wiring. While typically used for residential and small commercial applications, micro inverters can be used for utility scale power generation.

Benefits:

1. No high voltage DC wiring. This increases the safety of solar installations and minimizes line loss concerns.
2. Completely decentralized design. Micro inverter designs ensure that module and inverter failures do not have any impact on the rest of the system. Additionally, the “plug and play” nature of micro-inverters means that personnel with minimal training can safely perform repairs.
3. Life span. Micro inverters carry 25 year comprehensive warranties ensuring that they will last the entire service life off the PV power plant.

4. Module level MPPT. Micro Inverters provide module level DC voltage optimization minimizing the effects of shading as well as allow system operators to monitor the power production of each module.
5. Easy to install. Micro inverters are "plug and play" units allowing for low qualified personnel to install a larger percentage of the PV system architecture minimizing installation costs.

Drawbacks:

1. High cost. For utility scale PV installations micro inverters are typically 50% more than string inverters and twice the cost of central inverters per DC watt[15]. (30 to 50 cents per watt USD)
2. Increased balance of system costs and electrical architecture complexity. Micro inverters completely decentralize the electrical system architecture of a PV power plant leading to increased design and installation costs associated with adding combiner boxes, medium voltage transformers, and large amounts of high amperage AC wiring.
3. Complex system integration. Micro inverters were not designed for utility scale applications and are typically manufactured by companies that are not vertically integrated, making communicating with SCADA platforms and secondary switchgear packages more complex and expensive.

3.3 Racking Technologies

There are a number of options available for mounting solar panels depending on the situation and environment in which they're being used. The most common for utility scale applications are fixed tile racking, single axis tracking, and dual axis tracking. More recently, rail trackers are also beginning to be used.

3.3.1 Fixed Racking

Over 90% of all utility scale PV power generation (systems >500KW) is installed as ground mount installations and of those 70% of the installations are fixed racking[16]. Ranging from concrete ballasted designs, to pile drive foundations, fixed racking provides PV power plant designers reliability and flexibility at an extremely low cost.

Benefits:

1. Very low cost. With an average price of $0.20 per watt USD fully installed for system over 1 MW, fixed ground mount racking is the lowest cost racking solution on the market[13].
2. Flexible. Ground mount racking can easily be customized to handle a variety of terrain and geotechnical conditions with varied foundation options including, driven piles, helical screws, concrete ballast, or rock bolts. This allows system designers to customize their racking to handle almost any terrain type allowing for solar installations in a wide variety of locations.

[15] https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf
[16] https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf

3. Robust and reliable. Comprised of galvanized steel or anodized aluminum with no moving parts, fixed ground mount racking ensures system operators that there will be no maintenance concerns and that the racking will outlast the life span of the project.
4. Ease of installation. Fixed racking designs are quite simple and can easily be assembled quickly by low qualified personnel lowering installation costs. Additionally, low continuous spans of racking make wire management easy to manage limiting the amount of work required by more expensive electrical personnel.

Drawbacks:

1. Lower power production as modules are fixed in place.

3.3.2 Single Axis Trackers

Single Axis trackers follow the sun as it moves east to west throughout each day leading to increased power production. With movement on only one axis, single axis tracker designs are relatively simple and light weight allowing for deployment in a variety of locations with only small amounts of maintenance required.

Benefits:

1. Increased power production. Single axis trackers allow for increased power production of 20 to 30% annually depending on the installation location.
2. Simple designs. By moving on a single axis these trackers have simple designs that require minimal annual maintenance.
3. Light weight/lower wind resistance. Typical single axis trackers are made of lightweight materials allowing for them to be installed using a ballasted design or helical screws making installations less complex than dual axis trackers.

Drawbacks:

1. Higher cost than racking. With an average price of $0.30 per watt USD fully installed for system over 1 MW.
2. Less power production that dual axis trackers.
3. Greater land use requirements due to inter-row shading as the trackers follow the sun throughout the day.
4. Annual maintenance is often required.
5. Less flexible foundation design than fixed racking.

3.3.3 Dual Axis Trackers

Dual Axis trackers follow track the sun both east-west as well as vertically across the sky throughout the day. This allows for maximum power yields per module as the modules will always be directly pointing at the sun.

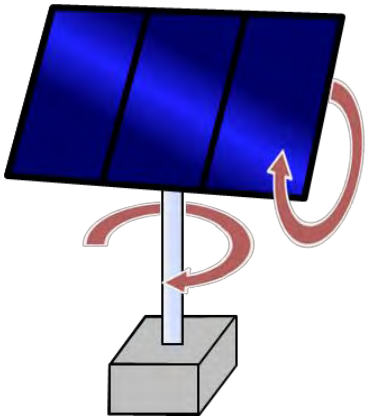


Photo Credit: Sedona Solar Technology

Benefits:

1. Maximum power generation per module producing up to 45% more power per module compared with fixed installations[17].

Drawbacks:

1. High Cost. With an average price of $0.70 per watt USD fully installed for system over 1 MW.
2. Single point of failure. Traditional dual axis trackers rotate around a complex single bearing that allows the tracker to move both directions and is required to support the weight of up to 40 solar modules. This design often leads to the bearing failure, causing the tracker to jam ad can lead to long down times and high maintenance costs.
3. High Wind Problems. Due to having 40 modules mounted side by side, traditional dual axis trackers are not designed to handle high winds and can experience structural failure in winds of 150 kph or more.
4. Large Foundation Requirements. The weight of traditional dual axis tracking systems requires large concrete foundations adding considerable costs to installing them.
5. Heavy Components. Due to the stresses being concentrated on a single point, dual axis trackers are constructed on heavily reinforced materials that weigh a considerable amount. This adds significant extra costs when transporting the trackers to remote locations.
6. Non Scalable. Each tracker is an isolated unit leading to limited cost savings when installing larger system.
7. Large land use requirements. Inter-tracker shading can be a significant problem if trackers are located too closely together leading to large land use requirements.

[17] https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf

3.3.4 Rail Trackers

Rail trackers are a unique dual axis tracker that is designed to address many of shortfalls of dual axis trackers. While it is a new product on the market is has shown excellent potential to become a key player in the tracking market in the years to come.

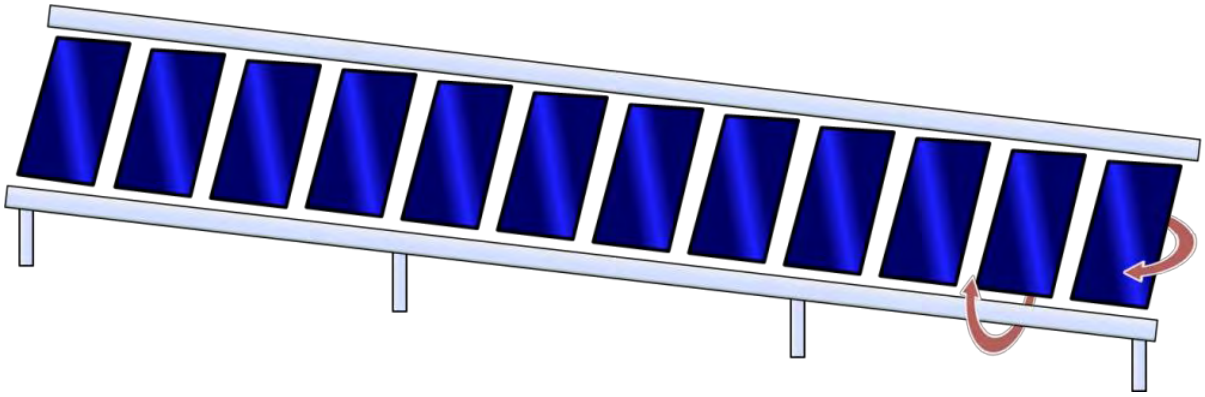


Photo Credit: Sedona Solar Technology

Benefits:

1. Maximizes power production per module by allowing for flexible frame sizes, allowing for designers to use large high wattage modules with minimal extra cost.
2. Low levelized cost of energy. Rail tracking prices are slightly lower than single axis trackers ($.25 USD per watt) while providing power production yields 5% lower than dual axis trackers.
3. Weight is spread out over the entire array significantly reducing the stress on the actuators.
4. Simple design. Rail trackers have just 2 moving parts that operate in a single axis, reducing complexity and making the system less prone to failure.
5. Does not require concrete foundations. This leads to significant savings in installation costs as well as decreased installation time.
6. Space between modules significantly decreases the wind resistance of the dual axis tracker enabling it to safely handle wind speeds of up to 240kph[18].
7. Scalable design allows for frames to share actuators, producing significant cost savings for utility scale projects.
8. Reduced land use requirements compared with standard dual axis trackers as trackers are long single rows with no inter-row shading concerns.

Drawbacks:

1. Limited track record. As this is a new technology there are a limited number of installations globally at this time providing a small data set from which to draw modeling and design conclusions. This is expected to change as more installations come online in 2016-2017 using rail trackers.

[18] http://sedonasolartechnology.com/technology/

2. Inter-module shading at higher latitude locations. Due to the frame design, when the sun is located at either true-east or true west, the modules will partially shade one another down the row limiting power production at those times. This has a small impact on annual power production compared with dual axis trackers in northern locations.

3.4 Energy Storage

For the Yukon, it's expected that battery storage for energy back-up will only be required for the 10MW installation scenario. It's been seen in Germany and other locations that the grid can handle solar PV penetration well above 10% before stability becomes an issue. It should be noted that the location of PV in relation to the loads should also be taken into account. Two locations are studied in this report – Whitehorse, and Haines Junction. As Whitehorse is the major centre of population and industry for the territory, and has a high demand for electricity, adding 5 to 10 MW of solar PV may only account for about 10 to 20% of the local energy use. For Whitehorse, storage may not be necessary. For Haines Junction, a 5 MW PV plant may make up a much larger chunk of the local electricity supply. For Haines Junction then, to ensure a stable grid locally, it may be desirable to include some energy storage. Figure 3.1 shows the type of storage options for grid scale applications that are good for various timescales. For maintaining grid stability, only 5 to 15 min of energy storage capacity is needed to bridge the gap until a back-up generation source, such as stored hydro, can be brought online, and so batteries would be a suitable option for the projects being looked at by YEC (if it's deemed they're needed – we would need a bit more data about the local energy demand to full answer that question).

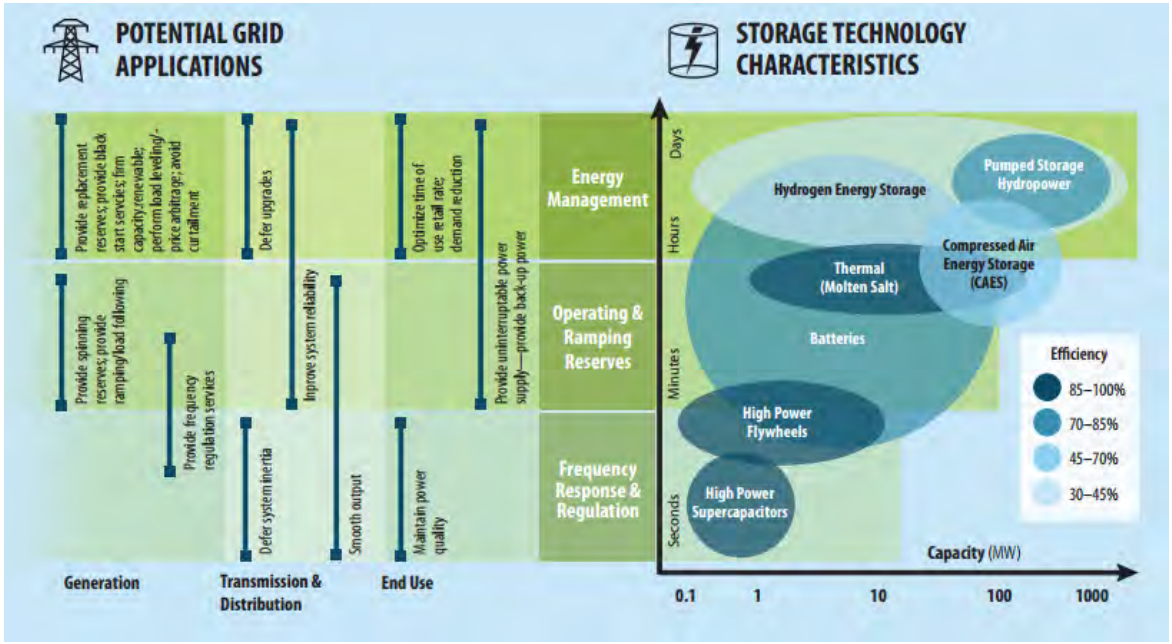


Figure 3.1: Energy storage options for grid applications[19]

[19] http://www.nrel.gov/docs/fy16osti/64764.pdf

For this reports, originally an 8 MW, 15 min battery storage option was included for the 10 MW power plant. This energy storage component was a Younicos system. The energy storage is no longer part of the financial analysis, but should you wish to include it, this was the system we were working with.

4 Asset Service Life

Typical asset service lifetimes are detailed in Table 4.1. As can be seen, the majority of the components of a PV system are expected to be good for at least 25 to 30 years. The only component that has a shorter lifetime that the system lifetime of 30 years is the inverters. As a result, a large investment in maintenance in Year 20 of the financial model reflects the expected replacing of the inverters at this point in the lifetime of the system.

Table 4.1: Asset service lifetimes

Component	Service Life	Warranty	Maintenance Costs (Annually)	Replacement Cost
Modules	30 + years	25 year power warranty 10 – 25 year product warranty	Cleaning = $1000 per MW	N/A
Inverters	20 years	10 years	$2000 per MW	$0.10 USD per W
Energy Storage Inverters	25 Years	10 years	$2000 per MW	
Battery	25 years	25 years	$65,000 per year	
SCADA/Plant Controller	25 years	5 years	$250 annual software update	
Racking	30 + years	5 years	None	N/A
Single Axis Trackers	25 + years	5 years basic + 5 year extended	$800 USD per MW	N/A
Medium Voltage Substations	30 years	2 years	None	N/A
DC Wiring	30 + Years	N/A	$2000 USD per MW	$0.90 CAD per M as needed
DC Combiner Boxes	30 + Years	2 Years	$3000 USD per MW	N/A
AC Wiring	30 + Years	N/A	None. Wire is buried in conduit/sheathed in armored cable.	
Chain Link Fence	30 + years	1 Year	None	N/A

5 Operations and Maintenance Plan

The operations and maintenance plan for the 1 MW and 5 MW power plants will be identical with the costs scaling proportionally. The O&M plan for a 10 MW facility will be more complex due to the overall size of the power plant and incorporation of batteries into the design.

5.1 Maintenance Training

Local workers would be trained in the following areas:

1. Module replacement.
2. DC Wiring/Combiner box repairs.
3. Tracker bearing/motor repairs.
4. String Inverter replacement.
5. Component communication system repairs.
6. General grounds keeping/fencing repairs.

5.2 Spare Parts List

As part of the construction costs a certain number of spare components will be purchased. These will include:

- Modules: 8 pallets – 200 modules
- Inverters: This only applies to string inverters, and 1 unit per MW would be kept on-hand.
- Tracker bearings: 25 bearing per MW or as manufacturer advises
- PV wire: 1 KM of positive and negative wire
- MC4 connectors: 100 connectors with a crimping kit
- Combiner boxes: 2 combiner boxes per MW

5.3 1 MW/5MW O&M Plan

Service	Frequency	Cost per MW	Description
Module Cleaning	Bi-Annually	$1000	Using a squeegee to clean modules and remove dust/animal droppings
DC Wiring Inspections	Annually	$1000	Inspect all above surface DC wiring for damage caused by animals or wires that have come loose from their clips.
Thermal Scans for the Modules	Annually	$2000	Using an infrared camera to can modules for faulty modules. Malfunctioning modules will have increased resistance leading to increased levels of heat.
Thermal Scans of Combiner Boxes	Annually	$1000	Using an infrared camera to scan combiner boxes. Boxes with loose connections will produce more heat due to higher resistance between connections.
Tracker Inspections	Annually	$1500	Inspecting motors and bearing ensuring they are operating as expected and not wearing unevenly.
Thermal Scans of Inverters	Annually	$1000	Scan the DC disconnects and combiner boxes connected to the inverter for loose connections.

HVAC Unit Inspection	Annually	$500	Inspecting the HVAC unit that heats the insulated containers housing the inverters and transformers.
General grounds Keeping	Spring/Fall	$2000	Trimming any weeds that are growing under the trackers/racking, repairing any damage to the fencing, and removing garbage.
24/7 System Monitoring	Always	$10,000	Third party monitoring usually provided by the inverter manufacture using a software platform that communicates with the telemetry of the inverters and trackers. This system is accessible by the monitoring company, the local utility and the plant owner.
Total Annual Cost:		$20,000/ $100,000	1 MW = $20,000 per year, 5 MW = $100,000 per year

5.4 10 MW O&M Plan

Service	**Frequency**	**Cost**	**Description**
Module Cleaning	Bi-Annually	$10,000	Using a squeegee to clean modules and remove dust/animal droppings
DC Wiring Inspections	Annually	$10,000	Inspect all above surface DC wiring for damage caused by animals or wires that have come loose from their clips.
Thermal Scans for the Modules	Annually	$20,000	Using an infrared camera to can modules for faulty modules. Malfunctioning modules will have increased resistance leading to increased levels of heat.
Thermal Scans of Combiner Boxes	Annually	$10,000	Using an infrared camera to scan combiner boxes. Boxes with loose connections will produce more heat due to higher resistance between connections.
Tracker Inspections	Annually	$15,000	Inspecting motors and bearing ensuring they are operating as expected and not wearing unevenly.
Thermal Scans of Inverters	Annually	$20,000	Scan the DC disconnects and combiner boxes connected to the inverter for loose connections.
HVAC Unit Inspection	Annually	$5,000	Inspecting the HVAC unit that heats the insulated containers housing the inverters and transformers.
General grounds Keeping	Spring/Fall	$20,000	Trimming any weeds that are growing under the trackers/racking, repairing any damage to the fencing, and removing garbage.
24/7 System Monitoring	Always	$130,000	Third party monitoring would be provided by the energy storage system supplier as the energy storage inverter system will have a built in SCADA controller that will integrate the PV and batteries into once control unit.
Total Annual Cost:		**$240,000**	

6 Project Schedules

The project schedules for the 1 MW, 5 MW and 10 MW plants are shown in this section. Copies of the Gantt charts can be found in the Excel files accompanying this report.

6.1 Whitehorse Schedule – 10 MW

Task	Require Time (Weeks)
Environmental Assessment	52
Geo-technical Assessment	4
Finalize System Layout	4
Structural Engineering Review	4
Finalize Electrical Schematics	4
Electrical Engineering Review	4
Materials Ordered	2
Finalize Construction Plan	4
Survey and Mark-out all racking, trenching and pad locations	2
Power Line construction from substation to site	4
Dig cable trenches and level pads	2
Chain link fence construction	2
Position Inverter Centers	1
Racking Construction	4
DC Electrical Work and Inverter Connections	2
Module Installation	4
AC wiring and MV Substation Connections	2
Grid Connection	1
SCADA Installation	1
System Testing	1

6.2 Haines Junction Schedule – 5 MW & 1MW

Task	Require Time (Weeks)
Environmental Assessment	52
Clear and Mulch Property	4
Geo-technical Assessment	4
Finalize System Layout	4
Structural Engineering Review	4
Finalize Electrical Schematics	4
Electrical Engineering Review	4
Finalize Construction Plan	4
Materials Ordered	2
Survey and Mark-out all racking, trenching and pad locations	2
Access Road Construction	6

Power Line construction from substation to site	4
Dig cable trenches and level pads	2
Chain link fence construction	2
Position Inverter Centers	1
Racking Construction	4
DC Electrical Work and Inverter Connections	2
Module Installation	4
AC wiring and MV Substation Connections	2
Grid Connection	1
SCADA Installation	1
System Testing	1
Power Plant Commissioned	1

7 Energy Modeling Methodology

There are a number of things that can affect the energy performance of a PV power plant. The efficiency of the panels chosen, the panel's response to temperature changes, the racking and tracking systems, the inverters, and the distance to the nearest substation all have an effect. To better understand how much energy can be generated at each site using different systems designs, simulations were run using PVSyst. The following system design components were evaluated in the simulations:

- Module type
- Inverter type
- Racking type
- Plant size

PVSyst is a powerful modeling program that's also capable of modeling a number of loss mechanisms in the plant. In this section we explain the rationale behind the modules, inverters, and racking systems that were modeled, as well as the various losses that were included in the simulations.

7.1 Systems Component Choices for the PVSyst Simulations

7.1.1 Module Selection

The following modules were analysed for their performance at Haines Junction using PVSyst:

- Heliene polycrystalline (320W)
- Canadian Solar monocrystalline (290W)
- Canadian Solar polycrystalline (320W)
- Sunpower n-type monocrystalline (445W)
- Panasonic Heterojunction with Intrinsic Thin layer (HIT) (330W), n-type
- Prism Solar bi-facial, n-type (343W)

Heliene – Based in Canada, so prices are more stable (priced in $CDN). Shipped from Ontario. Comparable to Canadian Solar modules, as they supply fairly standard p-type mono and p-type multi panels.

Canadian Solar – Headquartered in Canada, with manufacturing in both Canada and China. Again, more stable prices in Canadian dollars. They can ship from Canada or Asia, and costs on shipping by sea from Asia may actually be cheaper. Heliene and Canadian Solar mono- and multi-crystalline panels are both fairly standard panels with nothing special or surprising. Both manufacturers use p-type silicon, and hence are subject to 2% light-induced degradation (LID) once they go into use in the field.

Sunpower – US company, with manufacturing in Asia, mainly the Philippines. Prices are in USD, so subject to some fluctuation, shipping by boat from Asia should be a reasonable cost. These are n-type silicon solar cells, so not subject to the 2% LID experienced by the p-type cells. This is the only supplier studied that has a 25 year warranty on both the product and power production. The typical

warranty terms for all the other panels are a 10 year product warranty, with a 20 to 25 year guarantee on power production (80% production guaranteed after 25 years in service, typically).

Panasonic – Originally the HIT was developed by Sanyo, and then this portion of the company was purchase by Panasonic. Based in Japan, however there is a presence in Canada as well (Panasonic Eco Solution, in Mississauga, does a lot of work with smart grids, green energy, and energy storage). The n-type heterojunction cell offered by Panasonic has the best temperature stability, meaning that the voltage does not fluctuate with temperature nearly as much as the other panels studied.

Prism Solar – Bi-facial cells. US company, Prism Solar has manufacturing in Arizona and New York for the modules. Quotes in USD, so price fluctuations based on currency exchange rates to be expected. Bi-facial cells are able to take advantage of light reflecting onto the back of the cell, boosting the current and hence the power output of the panels by up to 2%.

7.1.2 Inverter Selection

The following inverters were analysed for their performance using PVSyst:

- Schneider Electric central inverter – Conext Core XC-540
- SMA string inverter – Sunny Tripower 60-US-10
- ABB central inverter – PVS800

Micro inverters were not modeled, as there is some question as to whether or not they will be able to hold up to the harsh weather conditions experienced in the Yukon.

Also, it should be noted that after running a few simulations with the Schneider inverter and comparing them to the ABB inverter results, the difference in energy yield was negligible. The energy models were run using just one type of central inverter (the Schneider ones) after that. When doing the financial analysis, the central inverter energy results are used for both the Schneider and ABB analyses – the only differences come from the price difference between the two system.

7.1.3 Racking Selection

The following racking systems were analysed for their performance using PVSyst:

- Fixed tilt racking – (manufacturer not important for the energy analysis)
- Single axis trackers – Deger TOPTracker 40NT and 8.5
- Dual axis trackers – Deger D60H

For the most part, the supplier of the racking systems is not important in terms of energy production. The critical criteria, particularly for the trackers, is whether or not they can achieve the optimal angles for the Yukon. Panels should be at an angle of 45° in the Yukon for maximum energy yield, however the Deger TOPTrackers are limited to 30° according to the data sheets (see accompanying documentation). Other suppliers, or even Deger, should be able to provide a solution that meets YEC's needs, however there may be an extra engineering cost associated with this type of design change.

7.2 Assumptions Used in the PVSyst Model

The following assumptions were included in the PVSyst simulation:

Albedo:

- Snow albedo (0.8) November thru February
- March is half-way at 0.6, April and October at 0.4
- The rest of the year – 0.2 for grass

Fixed Rack Tilt:

- Fixed tilt angle is 45° - optimal tilt angle for the locations chosen

Soiling:

- Soiling in the winter is 20% (mostly due to snow). As the tilt angle is fairly high, snow is not expected to accumulate too much

Temperature:

- Maximum voltage was calculated at -40°C. PVSyst will not allow a lower temperature to be input, but some voltage space to allow for temperatures to drop to -45°C is recommended.

Maintenance:

- Down-time for maintenance 3 times per year, randomly distributed, total time down is 7.3 days for the year

Shading:

- Spacing between racking/modules was chosen to maintain less than 5% near shading as much as possible.

Electrical:

- Wiring loss was limited to 1.5% - default, and what the electrical design should aim for to avoid too much voltage loss during transmission

7.3 A Note on Spacing Requirements and Shading

A short test was done to illustrate the effect that shading has on the power generation of a PV installation. Here, 1 MW of Heliene monocrystalline modules are arranged in an array with the following dimensions:

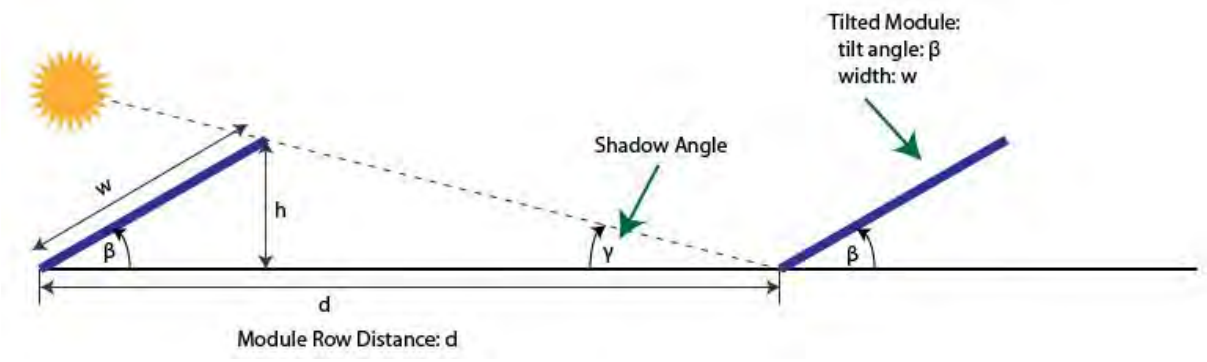
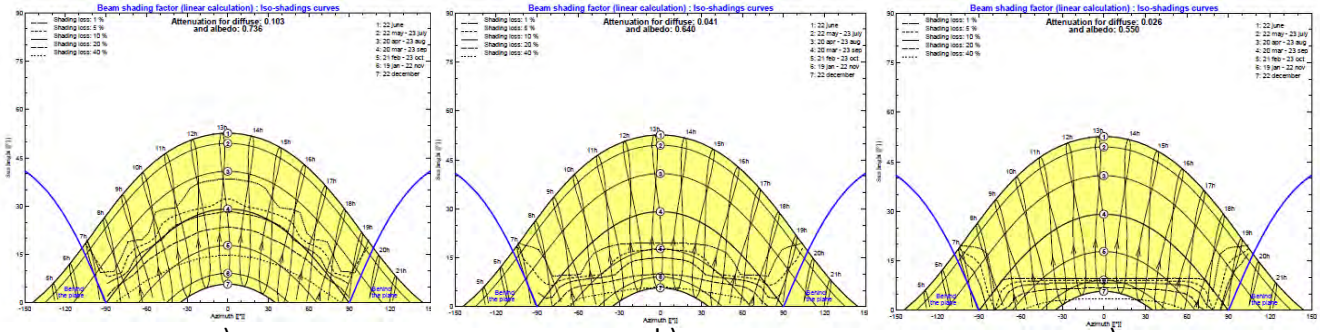


Figure 7.1: Row spacing, d, for an array using fixed tilt racking [http://www.greenrhinoenergy.com/].

The row-to-row distance, *x*, was varied to show the effect of increased shading on power production. Spacings of 5m, 10m, and 15m were used here. The row-to-row distance to ensure no shading at noon on 21 December was calculated to be 17.4m, for comparison.

Shading profiles

The shading profiles over the course of the year for the three different row spacings, as calculated by PVSyst, are shown in Figure 7.2.



a) b) c)

Figure 7.2: Shading profile for a) 5m row separation; b) 10m row separation, and c) 15m row separation

As expected, the less shaded the panels produce more energy. However, the extent to which this is a benefit is a trade-off with the increased area required for the array. A larger area requirement means more area needs to be cleared of brush, and longer wire lengths are needed to connect up the array, as well as larger wire diameters. This can add to the over-all up front costs of the project, and looking into how the finances are affected by the increases in energy yield are important in making a decision on the best array design.

Table 7.1 shows some key parameters for the 3 different row spacing designs: near shading %, energy yield, installation area, and estimated LCOE. LCOE calculations were based on a 30 year project lifetime.

Table 7.1: Effect of row spacing on energy yield and LCOE

Row Spacing	Near Shading (%)	Annual Energy Yield (MWh)	Installation Area (acres)	LCOE ($/kWh)
5 m	12.0	918.6	3.1	0.2680
10 m	5.2	1013	6.2	0.2442
15 m	3.3	1040	9.3	0.2398

While the benefit from moving from a 5m spacing to a 10m spacing is clear, there begins to be diminishing returns beyond that point. For the purpose of the simulations throughout this report, the near shadings value was attempted to be kept below 5% to provide a balance between maximizing energy and reducing area requirements, while maintaining a decent LCOE

8 Haines Junction Energy Analysis

In this section we look at the various options for a power plant at Haines Junction, and recommend what, for this location, makes the most sense. The following options have been modeled: different panel technologies, racking systems, tracking systems, and inverter setups.

8.1 Racking and Tracking Simulation Results

8.1.1 Fixed Tilt Racking

Simulations with the various panel types were run in PVSyst using fixed racking tilted at 45°. The results can be seen in Table 8.1.

Table 8.1: Annual energy production of PV power plants at Haines Junction using fixed racking and central inverters vs. string inverters

	Central	String	Central
Haines Junction	**1 MW (MWh/yr)**	**1 MW (MWh/yr)**	**5 MW (MWh/yr)**
Heliene 72P-320W	1168	1168	5603
CDN Solar CS6K-290MS	1103		5385
CDN Solar CS6X-320P	1163		5475
Sunpower SPR-440NE-WHT-D	1125	1106	5389
Panasonic VBHN330SJ47	1110		5319
Prism Bi60-343BSTC	1143	1124	5560

The installed capacity varied slightly depending on the string arrangements. As expected, the more efficient the solar panel, the fewer panels will be needed in order to get to the desired installed capacity. At the 1 MW size, area is not a critical characteristic yet, however, so lower efficiency modules, well spaced out may come in with the best price per watt.

8.1.2 Single Axis and Dual Axis Tracking

The energy modeling results from PVSyst for a PV plant using single axis and dual axis tracking, as well as central vs. string inverters, are detailed in Table 8.2.

Table 8.2: Annual energy production of PV power plants at Haines Junction using single axis and dual axis tracking, and central inverters vs. string inverters

	Single Axis	Single Axis	Dual Axis	Single Axis
	Central	String	Central	Central
Haines Junction	1MW (MWh/yr)	1MW (MWh/yr)	1MW (MWh/yr)	5MW (MWh/yr)
Heliene 72P-320W	1437	1360	1439	5751
CDN Solar CS6K-290MS	1461		1433	6750
CDN Solar CS6X-320P	1389		1356	6425
Sunpower SPR-440NE-WHT-D	1352	1294	1425	6723
Panasonic VBHN330SJ47	1435		1383	6526
Prism Bi60-343BSTC	1480		1423	6695

The increase in energy generated when going from fixed tilt racking to single axis tracking is significant – a nearly 30% increase (see Table 8.3). However, when moving from single axis to dual axis, the energy yield effects are not as impressive – only 5.6% for the Sunpower cells, and a negative impact on the Canadian Solar poly cells, possibly due to the increased shading from the way in which the panels orient themselves. The percent increase in energy production production between each type of module and tracking system is detailed in Table 8.3.

Table 8.3: Relative increase in annual energy production with each type of tracking system, for each module type, for a 1MW plant

Haines Junction	Fixed	Single	Increase from Fixed	Dual	Increase from Single
Heliene 72P-320W	1119	1403	25.4%	1405	0.1%
CDN Solar CS6K-290MS	1056	1399	32.5%	1373	-1.9%
CDN Solar CS6X-320P	1113	1413	27.0%	1379	-2.4%
Sunpower SPR-440NE-WHT-D	1109	1334	20.3%	1405	5.3%
Panasonic VBHN330SJ47	1112	1438	29.3%	1386	-3.6%
Prism Bi60-343BSTC	1111	1438	29.4%	1383	-3.8%

The increase in energy production from fixed tilt racking to single axis tracking is significant; once the financial analysis is taken into account, this may be the ideal system for Haines. However, the relative increase in production from single axis to dual axis tracking is much less pronounced, while the increase in complexity of the system is quite significant.

As the impact of having dual axis tracking is not necessarily beneficial, dual axis tracking was not simulated for the larger systems. Table 8.4 shows the increase in energy production when going from

fixed tilt to single axis tracking for a 5 MW system at Haines Junction – about a 25% increase in annual energy yield.

Table 8.4: Increase in specific energy production for single axis trackers over fixed tilt for a 5MW system

Haines Junction - 5MW	Fixed	Single	Increase
Heliene 72P-320W	1029	1248	21.3%
CDN Solar CS6K-290MS	986	1238	25.6%
CDN Solar CS6X-320P	1002	1253	25.0%
Sunpower SPR-440NE-WHT-D	988	1240	25.5%
Panasonic VBHN330SJ47	1021	1272	24.6%
Prism Bi60-343BSTC	1036	1301	25.6%

8.2 Effect of inverters

Only a selection of the original eight panel types was modeled with string inverters, to show the trends and save on simulation time. A comparison of power production of central vs. string inverters can be seen in Table 8.5.

Table 8.5: Effect of string inverters on fixed and single-axis mounted 1MW arrays (specific energy production)

	Fixed			Single Axis		
	Central	String		Central	String	
Modules	Specific Production (kWh/kWp)	Specific Production (kWh/kWp)	% increase	Specific Production (kWh/kWp)	Specific Production (kWh/kWp)	% increase
Heliene 72P-320W	1110	1119	0.81%	1385	1402	1.23%
Sunpower SPR-440NE-WHT-D	1102	1084	-1.63%	1330	1296	-2.56%
Prism Bi60-343BSTC	1083	1090	0.65%	1405		-

In the case of the fixed tilt arrays, the string inverters can provide a modest energy benefit of 0.6% to 0.8%. For the single axis arrays, the string inverters can give a benefit up to 1.6%. A final assessment of whether the string inverters as worth it will come from the financial analysis.

8.3 Area Requirements

The types of panels used, and the type of racking or tracking, will determine the footprint required for the installation. Table 8.6 shows the area requirements for each module type studied, with each choice of racking.

Table 8.6: Area requirements for 1, 5 and 10 MW PV installations

	Area (acres) - Fixed Tilt			Area (acres) - Trackers		
Modules	1 MW	5 MW	10 MW	1 MW	5 MW	10 MW
Heliene Poly	13.6	45.7	91.4	39.5	74	148
CDN Solar Mono	9.9	49.9	99.8	35.6	66.7	133.4
CDN Solar Poly	10.9	53.6	107.2	38	71.2	142.4
Sunpower	8.5	40	80	28.4	53.4	106.8
Panasonic HIT	8.9	40.4	80.8	24.9	46.7	93.4
Prism Bi-facial	8.9	43.5	87	30	54	108

8.3.1 Haines Junction – 1 MW Array Footprints

Figures 8.1 and 8.2 illustrate the smallest and largest potential plant footprints for 1 MW arrays at Haines Junction.

Figure 8.1: 1 MW fixed tilt area requirements at Haines Junction. Left: Smallest (8.5 acres); Right: Largest (13.6 acres)

Figure 8.2: 1 MW single axis tracker area requirements at Haines Junction. Left: Smallest (25 acres); Right: Largest (40 acres)

8.3.2 Haines Junction – 5 MW Array Footprints

Figures 8.3 and 8.4 illustrate the smallest and largest potential plant footprints for 5 MW arrays at Haines Junction.

Figure 8.3: 5 MW fixed tilt area requirements at Haines Junction. Left: Smallest (40 acres); Right: Largest (53.6 acres)

Figure 8.4: 5 MW single axis tracker area requirements at Haines Junction. Smallest option only (40 acres). The installation options over 55 acres do not fit at this location.

From the footprints, it can be seen that as the array size increases at this location, space becomes much more of a premium. If a 5 MW installation is desired at Haines Junction, some of the less efficient panels may not be suitable. A 10 MW installation already cannot be accommodated at this location.

9 Whitehorse Quarry Energy Analysis

In this section we look at the various options for a power plant at the Copper Quarry site in Whitehorse, and recommend what, for this location, makes the most sense. The following options have been modeled: different panel technologies, racking systems, tracking systems, and inverter setups.

9.1 Racking and Tracking Simulation Results

9.1.1 Fixed Tilt Racking

Simulations with the various panel types were run in PVSyst using fixed racking tilted at 45°. The results can be seen in Table 9.1.

Table 9.1: Annual energy production of PV power plants at Haines Junction using fixed racking and central inverters

Whitehorse Quarry	Central 1 MW (MWh/yr)	Central 5 MW (MWh/yr)	Central 10 MW (MWh/yr)
Heliene 72P-320W	1123	5647	11471
CDN Solar CS6K-290MS	1059	5435	*11067**
CDN Solar CS6X-320P	1107	5555	*11311**
Sunpower SPR-440NE-WHT-D	1189	5456	11136
Panasonic VBHN330SJ47	1151	5391	*10977**
Prism Bi6-343BSTC	1152	5634	*11472**

** Values in italics were calculated based on trends, not run through the simulation program, due to the long duration these large simulations take.*

String inverters were not modeled at the Whitehorse location, as it's expected that the trends will be similar to those seen at the Haines Junction location (Section 8.1.1). It was seen in that section that there is not a large difference in the energy harvested using either inverter set-up. Cost and maintenance concerns will play a larger role in inverter choice than energy expectations.

Monthly energy expectations for each design choice can be found in Appendix B.

9.1.2 Single Axis and Dual Axis Tracking

As dual axis tracking was seen to not be effective in the Haines Junction simulations, it was left out of the analysis at Whitehorse. The energy modeling results from PVSyst for a PV plant using single tracking and central inverters are detailed in Table 9.2.

Table 9.2: Annual energy production of PV power plants at Whitehorse Quarry using single axis tracking, and central inverters

	Central	Central	Central
Whitehorse	**1 MW (MWh/yr)**	**5 MW (MWh/yr)**	**10 MW (MWh/yr)**
Heliene 72P-320W	1344	6041	*13960**
CDN Solar CS6K-290MS	1366	6786	*13468**
CDN Solar CS6X-320P	1290	6447	*13765**
Sunpower SPR-440NE-WHT-D	1330	6757	13558
Panasonic VBHN330SJ47	1326	6555	*13359**
Prism Bi6-343BSTC	1483	6934	*13961**

** Values in italics were calculated based on trends, not run through the simulation program, due to the long duration these large simulations take.*

The increase in energy generated when going from fixed tilt racking to single axis tracking is significant – on average over 25% (see Table 9.3).

Table 9.3: Relative increase in annual energy production with each type of tracking system, for each module type, for a 1 MW plant

Whitehorse - 1MW	Fixed	Single	Increase
Heliene 72P-320W	1075	1313	22.1%
CDN Solar CS6K-290MS	1056	1309	24.0%
CDN Solar CS6X-320P	1059	1312	23.9%
Sunpower SPR-440NE-WHT-D	1074	1312	22.2%
Panasonic VBHN330SJ47	1101	1329	20.7%
Prism Bi60-343BSTC	1119	1441	28.8%

The increase in energy production from fixed tilt racking to single axis tracking is significant; once the financial analysis is taken into account, this may be the ideal system. Table 9.4 shows the increase in energy production when going from fixed tilt to single axis tracking for a 5 MW system at Whitehorse – an average 22.6% increase in annual energy yield.

Table 9.4: Increase in specific energy production when moving from fixed tilt tacking to single axis trackers for a 5 MW installation at Whitehorse Quarry

Whitehorse - 5MW	Fixed	Single	Increase
Heliene 72P-320W	1081	1311	21.3%
CDN Solar CS6K-290MS	1041	1300	24.9%
CDN Solar CS6X-320P	1064	1312	23.3%
Sunpower SPR-440NE-WHT-D	1076	1333	23.9%
Panasonic VBHN330SJ47	1080	1314	21.7%
Prism Bi60-343BSTC	1117	1348	20.7%

Table 9.5 shows the increase in energy production when going from fixed tilt to single axis tracking for a 10 MW system at Whitehorse. Only one data point is shown, due to the size of the simulations – Sunpower, requiring the least number of modules due to their high efficiency – was able to be modeled in a reasonable time frame. It's expected that the other types of modules would also experience about a 20% increase in energy yield by moving to single axis tracking.

Table 9.5: Increase in specific energy production when moving from fixed tilt tacking to single axis trackers for a 10 MW installation at Whitehorse Quarry

Whitehorse – 10 MW	Fixed	Single	Increase
Sunpower SPR-440NE-WHT-D	11,136	13,558	21.7%*

**This value was used to extrapolate the energy production of all the module types.*

9.2 Area Requirements

The types of panels used, and the type of racking or tracking, will determine the footprint required for the installation. Table 8.6, re-shown from the Haines Junction analysis, contains the area requirements for each module type studied with each choice of racking.

Table 8.6: Area requirements for 1, 5 and 10 MW PV installations

	Area (acres) - Fixed Tilt			Area (acres) - Trackers		
Modules	1 MW	5 MW	10 MW	1 MW	5 MW	10 MW
Heliene Poly	13.6	45.7	91.4	39.5	74	148
CDN Solar Mono	9.9	49.9	99.8	35.6	66.7	133.4
CDN Solar Poly	10.9	53.6	107.2	38	71.2	142.4
Sunpower	8.5	40	80	28.4	53.4	106.8
Panasonic HIT	8.9	40.4	80.8	24.9	46.7	93.4
Prism Bi-facial	8.9	43.5	87	30	54	108

9.2.2 Whitehorse – 1 MW Array Footprints

Figures 9.1 and 9.2 illustrate the smallest and largest potential plant footprints for 1 MW arrays at the Whitehorse Quarry.

Figure 9.1: 1 MW fixed tilt area requirements at Whitehorse. Left: Smallest (8.5 acres); Right: Largest (13.6 acres)

Figure 9.2: 1 MW single axis tracker area requirements at Whitehorse. Left: Smallest (25 acres); Right: Largest (40 acres)

9.2.3 Whitehorse – 5 MW Array Footprints

Figures 9.3 and 9.4 illustrate the smallest and largest potential plant footprints for 5 MW arrays at the Whitehorse Quarry.

Figure 9.3: 5 MW fixed tilt area requirements at Whitehorse. Left: Smallest (40 acres); Right: Largest (53.6 acres)

Figure 9.4: 5 MW single axis tracker area requirements at Whitehorse. Left: Smallest (46 acres); Right: Largest (74 acres)

From the footprints, it can be seen that there is ample space at the quarry for 5 MW arrays using any of the module or racking types available.

9.2.4 Whitehorse – 10 MW Array Footprints

Figures 9.5 and 9.6 illustrate the smallest and largest potential plant footprints for 10 MW arrays at the Whitehorse Quarry.

Figure 9.5: 10 MW fixed tilt area requirements at Whitehorse. Left: Smallest (80 acres); Right: Largest (107 acres)

Figure 9.6: 10 MW single axis trackers area requirements at Whitehorse. Only the smallest array options (less than 110 acres – 93 acres shown) will fit.

For the 10 MW array, any module option will work with fixed racking. However, when moving to single axis tracking, more space is required to ensure the modules don't become too shaded, and **only the three highest efficiency modules – Sunpower, Panasonic, and Prism Solar – will meet the area restrictions.**

10 Financial Analysis Methodology

The financial analyses for each size and location of power plant were approached in the same manner. Before getting into the details of the analyses, a few notes on the engineering expenses are explained.

10.1 Engineering Fees Explanation

At first glance the estimated engineering costs for the construction of the proposed solar arrays might seem quite low. This is due to the fact that much of the engineering costs associated with constructing a solar array are represented in the costs of various materials for the project.

Structural/Civil Engineering:

When constructing a utility scale solar power plant, developers will typically work with integrated racking companies such a Schletter or Sunlink. These companies have in-house structural, civil and geotechnical engineering teams that will fully engineer and stamp the racking design before manufacturing the racking according the specifications.

This approach ensures that clients receive racking that is designed for the geotechnical and climatic conditions on location, giving solar project developers peace of mind that their racking will last the entire operating life of the power plant.

Geotechnical Engineering:

When designing solar farms with ground mount racking/trackers, a geotechnical analysis of the site must be performed in order to determine the racking substructure design and piling layout/depths. While the racking supplier will typically analyze the geotechnical samples collected they do not provide the onsite engineering teams to collect the samples for analysis. The added cost of collecting the samples is represented in each budget with the analysis of the samples incorporated into the racking costs.

Electrical Engineering:

Typically, utility scale solar power plants use Central Inverter or String Inverter electrical architecture with all DC/AC electrical equipment provided by an integrated electrical supplier such a Schneider, ABB, or SMA.

In the case of central inverters this typically means central inverters are housed in pre-wired skids or containers along with step-up transformers and switch gear. These containers or skids are fully engineered by the supplier to the plant specifications, allow for direct grid connection to the primary bushings of the transformer in each container. As with the racking this engineering work is performed/stamped by the suppliers in house engineering team with the cost included in the materials cost.

When constructing solar power plants with string inverters, developers typically look to the inverter supplier to provide pre-wire substations containing step-up transformers and switch gear allowing for multiple string inverters to connect to the grid at one central location. These substations are pre-engineered to work with the specific string inverter used on location by the inverter supplier's in-house engineering team with the engineering costs absorbed in the cost of the materials.

Environmental Engineering:

Typically, environmental engineering is not required for most utility scale solar projects unless constructed on previously contaminated sites or old landfills. However, it is advised that solar project developers pay for a basic third party baseline environmental assessment of any property being considered for a solar power plant to ensure that there are no pre-existing contaminants on location that could be disturbed as part of construction or lead to misplaced liability for the costs of cleaning the contamination at a later date. The cost of a baseline environmental assessment is represented in the budget for each proposed project in this report.

10.2 Capital Expenditures Examples

An example of the detailed capital expenditures is shown in Table 10.1. The breakdown for each individual technology choice can be found in the Excel spreadsheets accompanying this report. Table 10.1 shows a 1 MW installation at Haines Junction using central inverters.

Table 10.1: CapEx breakdown example – Heliene 72P modules using ABB central inverters and fixed tilt racking

	Price
Component	**$1,520,799.97**
Modules	**$844,168.77**
Heliene 72P	$844,168.77
Racking	**$354,631.20**
Schletter	$354,631.20
Inverter Centers (ABB Central Inverters)	**$225,000.00**
SCADA (included with inverters)	**$0.00**
Electrical Components	**$85,000.00**
Fencing	**$12,000.00**
Service	**$483,000.00**
Shipping	**$105,000.00**
Driving Piles	**$20,000.00**
Surveying	**$8,000.00**
Geo-Technical Assessment	**$15,000.00**
Environmental Quality Assessment	**$5,000.00**
Road Construction and Excavation	**$40,000.00**
Crane Services	**$4,000.00**
Tree/Brush Removal	**$60,000.00**
Fencing Installation	**$16,000.00**
System Design & Engineering	**$45,000.00**
Civil Engineering	**$25,000.00**
Electrical Engineering Review	**$35,000.00**
Electrical Installation	**$25,000.00**
Solar Installation	**$70,000.00**

Commissioning	**$10,000.00**
Project Management Costs	**$65,000.00**
OHS Management	**$5,000.00**
Project Management	**$50,000.00**
Logistics Management	**$10,000.00**
Other Costs	**$390,320.00**
Taxes	**$103,440.00**
Duty	
Permitting	**$80,000.00**
Land Purchase	
10% Contingency	**$206,880.00**
TOTAL:	**$2,459,119.97**

10.3 Operations and Maintenance Examples

Operations and maintenance costs were broken down in a similar manner. Full details can be found in the accompanying financial spreadsheets and two examples are shown in Tables 10.2 and 10.3 for reference. In addition to the annual maintenance costs, some increased expenses are included for once the product warranties on some of the components begin to expire. There is also a large inverter replacement cost at Year 20.

Table 10.2: Example of annual operations and maintenance costs for 1MW fixed tilt PV installation at Haines Junction

Repair	Year 1
Module cleaning	$1,000.00
Brushing and grounds upkeep	$2,000.00
Module hot spot monitoring	$2,000.00
DC wiring inspections	$1,000.00
Land use payments	$4,000.00
Inverter repairs after warranty expires	($2,000.00) Y6+
Inverter & combiner box inspections	$2,000.00
Possible inverter replacement - Y20	($147,945.00) Y20
HVAC maintenance	$500.00
24/7 monitoring	$10,000.00
Insurance	$7,000.00
Total Annual Costs:	**$29,500.00**

Table 10.3: Example of annual operations and maintenance costs for 10MW fixed tilt PV installation at Whitehorse Quarry

Maintenance/Repair	Year 1
HVAC maintenance	$5,000.00
Module cleaning	$10,000.00
Module hot spot monitoring	$20,000.00
DC wiring, combiner and inverter thermal inspections	$40,000.00
Energy storage maintenance	$20,000.00
Inverter repairs after warranty expires	($10,000.00) Y6+
Inverter consumables	$2,500.00
Possible inverter replacement	($1,125,000.00) Y20
Reserve Fund	$76,400.70
24/7 monitoring	$130,000.00
Total Annual Costs:	**$303,900.70**

10.4 Levelized Cost of Electricity (LCOE)

The Levelized Cost of Electricity (LCOE) was calculated for each generation option at Haines. These were calculated over 30 years, using the real Weighted Average Cost of Capital of 3.38% provided by YEC for YEC resource options. LCOE was calculated using the following equation:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where

- I = capital expenditures in year t
- M = operations and maintenance costs in year t
- F = fuel costs in year t
- E = energy generated in year t
- r = discount rate

For our purposes, the fuel costs of this project are zero.

11 Financial Analysis – Haines Junction

11.1 Capital Expenses at Haines Junction

The over-all capital expenses are summarized for the various Haines Junction projects. Here we will show average results to give a sense of the magnitude of the project expenses. Full details for each project can be found in the accompanying financial analysis spreadsheets.

Table 11.1: Average capital and operating expenses for PV power plant at Haines Junction using various racking options

	Capital Cost (2015$)			Annual Fixed O&M Costs (2015$)
	Plant Capital Cost	Transmission Capital Cost	Total Capital Cost	
	$000	$000	$000	$000
Fixed Tilt: 1 MW	$2,876,350	$0*	$2,876,350	$31,500
Fixed Tilt: 5 MW	$12,359,119	$460,000	$12,819,119	$142,600
Single Axis: 1 MW	$3,434,393	$0*	$3,434,393	$36,926
Single Axis: 5 MW	$12,994,800	$460,000	$13,454,800	$169,252

**For a 1 MW project at Haines, the existing power lines running nearby should be able to accommodate this amount of additional current generation*

This gives a sense of the expected over-all project costs. The value of each project in terms of levelized costs of electricity (LCOE) is better for comparing projects of different sizes, and are presented in the following sections.

11.2 Financial Trends Due to Module Cost

Full tables of LCOE data can be found in Appendix C. A subset of the data, as well as average results, is presented here for simplicity.

Table 11.2 shows the calculated LCOE results for a 1MW array using SMA inverters and fixed tilt racking at Haines Junction. In general, all the LCOE results for all simulations in all locations follow the general trend seen here. Heliene Poly, Prism, and Canadian Solar Mono fluctuate between providing the lowest LCOE, mostly due to differences in system sizing and the amount of racking required. Sunpower is always the most expensive option. At the 1MW level, there is ample area for the arrays using any technology, and a decision can be made entirely on price and the ease of maintenance.

Table 11.2: LCOE values for 1 MW fixed tilt PV installations at Haines Junction using SMA string inverters.

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 2: Heliene Poly	$0.166	$0.186	$0.262
Inverter Option 2: CDN Solar Mono	$0.198	$0.222	$0.315
Inverter Option 2: CDN Solar Poly	$0.200	$0.224	$0.318
Inverter Option 2: Sunpower	$0.238	$0.268	$0.384
Inverter Option 2: Panasonic HIT	$0.204	$0.229	$0.325
Inverter Option 2: Prism Bi-Facial	$0.184	$0.207	$0.292

11.3 Fixed Tilt Racking vs. Trackers

The average LCOE values for each type of installation was calculated for the Haines Junction location and can be seen in Table 11.3.

Table 11.3: Comparison of average LCOE values for different racking options at Haines Junction.

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Fixed Tilt: 1 MW	$0.189	$0.213	$0.302
Fixed Tilt: 5 MW	$0.173	$0.193	$0.272
Single Axis: 1 MW	$0.178	$0.200	$0.281
Single Axis: 5 MW	$0.165	$0.185	$0.261
Dual Axis: 1 MW	$0.192	$0.215	$0.304

Despite the fact that the capital and maintenance expenses are higher for single axis tracking projects, since the trackers allow for 22% to 25% more energy to be collected, the cost of the energy is much lower. As expected, dual axis tracking comes in as the most expensive option due to the limited energy benefit and increased cost and complexity.

11.4 Effect of Inverter Choice

The average LCOE values for each inverter option was calculated for the 5 MW, fixed tilt racking Haines Junction installation. The results can be seen in Figure 11.1. This graph is typical of what is seen in all the installations looked at in this report. Both Schneider and ABB have central inverter options, however one is the most expensive choice, and one is the least. The difference in energy collected between central and string inverters is only slight, not enough to have an impact one way or the other on the LCOE. As such, inverter choice should be made based on maintenance concerns and weather-resistance rather than on cost or energy.

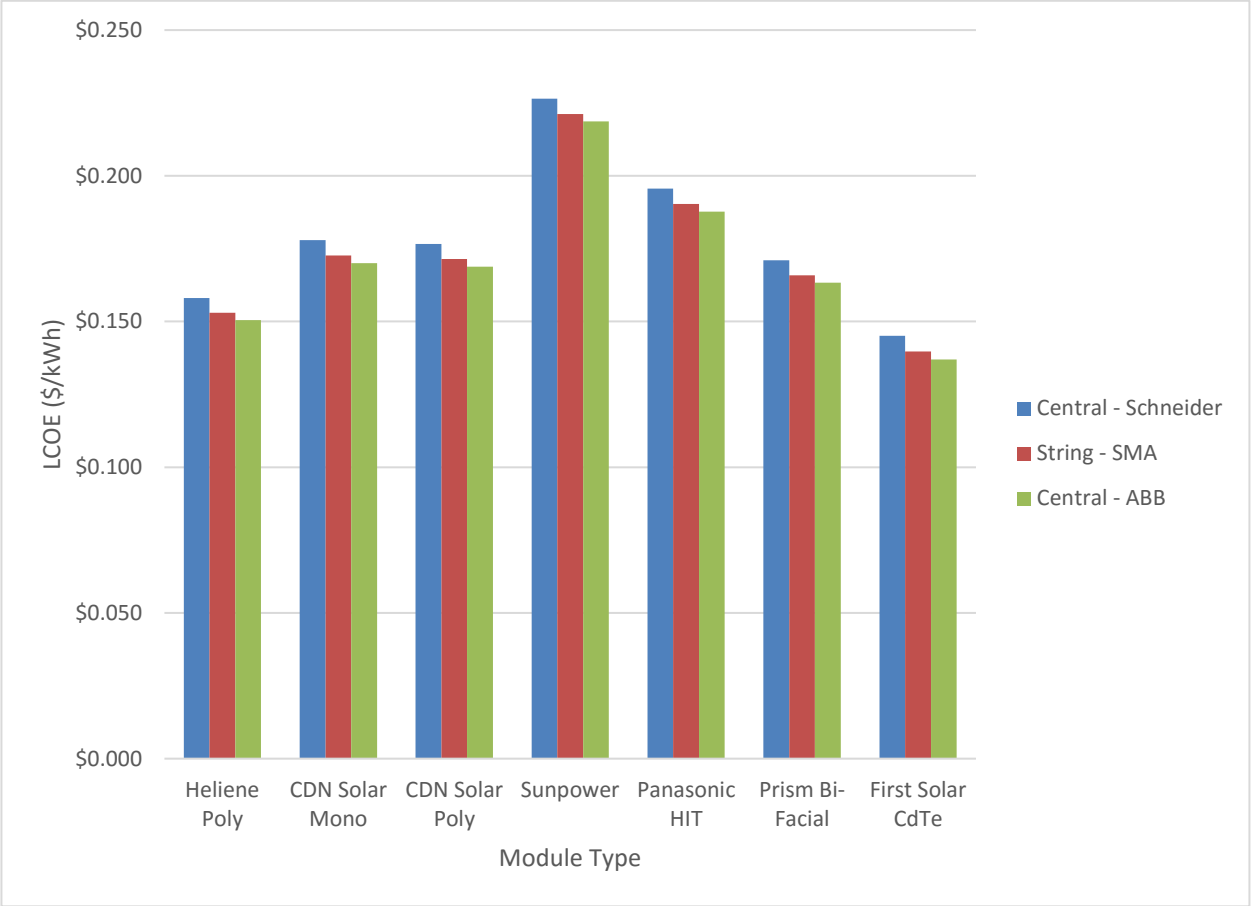


Figure 11.1: Comparison of average LCOE values for different inverter options at Haines Junction.

12 Financial Analysis – Whitehorse

12.1 Capital Expenses at Whitehorse

The over-all capital expenses are summarized for the various Whitehorse projects. Here we will show average results to give a sense of the magnitude of the project expenses. Full details for each project can be found in the accompanying financial analysis spreadsheets.

Table 12.1: Average capital and operating expenses for PV power plant at Whitehorse using various racking options

	Capital Cost (2015$)			Annual Fixed O&M Costs (2015$)
	Plant Capital Cost	Transmission Capital Cost	Total Capital Cost	
Fixed Tilt: 1 MW	$2,855,817	$460,000	$3,315,817	$31,500
Fixed Tilt: 5 MW	$12,225,363	$460,000	$12,685,363	$142,600
Fixed Tilt: 10 MW	$25,041,563	$460,000	$25,501,563	$307,384
Single Axis: 1 MW	$3,244,377	$460,000	$3,704,377	$36,926
Single Axis: 5 MW	$12,998,387	$460,000	$13,458,387	$167,346
Single Axis: 10 MW	$28,130,039	$460,000	$28,590,069	$352,346

This gives a sense of the expected over-all project costs. The value of each project in terms of levelized costs of electricity (LCOE) is better for comparing projects of different sizes, and are presented in the following sections.

12.2 Fixed Tilt Racking vs. Trackers

The average LCOE value for each type of installation was calculated for the Whitehorse location and can be seen in Table 12.2.

Table 12.2: Average LCOE comparison of the various installation types and sizes at Whitehorse

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Fixed Tilt: 1 MW	$0.200	$0.227	$0.333
Fixed Tilt: 5 MW	$0.157	$0.178	$0.259
Fixed Tilt: 10 MW	$0.172	$0.193	$0.272
Single Axis: 1 MW	$0.193	$0.219	$0.321
Single Axis: 5 MW	$0.140	$0.159	$0.233
Single Axis: 10 MW*	$0.163	$0.183	$0.258

***Sunpower, Prism Solar and Panasonic options only*

The same trends are seen here that were seen at Haines Junction – as you increase from 1 to 5 MW in size, the price drops due to economies of scale. There are also benefits in going from fixed racking to

single axis tracking. While the trackers are more expensive to install and maintain, the added energy benefit out-weights the costs and the LCOE drops.

12.3 Comparison Against Haines Junction

To better see how the two sites stack up against each other, we compare their LCOE values. Tables 12.3 and 12.4 compare the fixed tilt installation costs and single axis tracker installation costs at the two sites.

Table 12.3: LCOE comparison of fixed tilt installations at Haines Junction and Whitehorse

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Haines: 1 MW	$0.178	$0.201	$0.293
Haines: 5 MW	$0.159	$0.180	$0.262
Whitehorse: 1 MW	$0.200	$0.227	$0.333
Whitehorse: 5 MW	$0.157	$0.178	$0.259
Whitehorse: 10 MW	$0.172	$0.193	$0.272

Table 12.4: LCOE comparison of single axis tracker installations at Haines Junction and Whitehorse

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Haines: 1 MW	$0.178	$0.200	$0.281
Haines: 5 MW	$0.165	$0.185	$0.261
Whitehorse: 1 MW	$0.193	$0.219	$0.321
Whitehorse: 5 MW	$0.140	$0.159	$0.233
Whitehorse: 10 MW*	$0.163	$0.183	$0.258

**Sunpower, Prism and Panasonic options only*

Interestingly, a 1 MW installation is more cost effective at Haines Junction than it is at Whitehorse. This is because, even though the land needs to be cleared at Haines, the site can make use of nearby low voltage lines as a connection point. As the size of the installation increases to 5 MW, better transmission lines are required to be installed to handle the current, and the cost increases. At Whitehorse, a transmission line will need to be built regardless of the size of the install, and so that cost is included in the price for the 1 MW option as well as the others.

At the 5 MW level, with the increased land clearing requirements at Haines as well as the transmission line installation, Whitehorse becomes the best option for the PV plant.

Only the Whitehorse location can accommodate a 10 MW PV plant. And it should be noted again that with trackers, only the three highest efficiency panels – Sunpower, Panasonic, and Prism Solar – will be able to be used.

12.4 Module Comparison

Once more, we quickly look at how the module performance stacks up in terms of cost. Table 12.5 shows the detailed LCOE breakdown for a 5 MW single axis tracker installation at Whitehorse using Schneider central inverters. Jumping to 10 MW, there would likely be an LCOE increase of about $0.015/kWh for the 3.38% real WACC case.

Table 12.5: Comparison of LCOE for various module options in a 5 MW single axis tracker installation at Whitehorse making use of Schneider central inverters

Photovoltaic Options	**3.38% Real WACC**	**4.61% Real WACC**	**8.82% Real WACC**
	LCOE (2015$)	**LCOE (2015$)**	**LCOE (2015$)**
	$/kW.h	**$/kW.h**	**$/kW.h**
Heliene Poly	$0.153	$0.170	$0.238
CDN Solar Mono	$0.151	$0.169	$0.239
CDN Solar Poly	$0.152	$0.170	$0.239
Sunpower	$0.190	$0.214	$0.305
Panasonic HIT	$0.168	$0.189	$0.267
Prism Bi-Facial	$0.165	$0.185	$0.263

While Sunpower modules certainly are more expensive, the Prism Solar and Panasonic options are reasonable. Of these, Prism bi-facial modules are the least expensive, and the Panasonic modules have the best weather characteristics and come from a highly bankable company. Either are a good option.

13 Summary and Recommendations

Site and Panel Recommendations

Two excellent sites were found as potential locations for future photovoltaic power plants: Haines Junction, near the airport and dump, and the old Copper Quarry site in Whitehorse.

For 1 MW installations, Haines Junction is the most cost effective site, with either Heliene Poly or Prism Bi-Facial modules and single axis trackers being recommended.

For 5 MW installations and larger, the Whitehorse site becomes the most cost effective option. Lower prices for electricity and capacity are achieved at the 5 MW level. For fixed tilt installations at both sites, any module can be used. For single axis trackers at Haines Junction, only the three highest efficiency panels – Sunpower, Panasonic, and Prism – will fit in the available space. Heliene and Prism solar panels again have the lowest LCOE.

For 10 MW installations, only the Whitehorse site has adequate space available. For fixed tilt racking installations, any modules can be used. For single axis tracking, only the three most efficient panels (Sunpower, Panasonic, and Prism Solar) will fit.

Racking and Inverter Recommendations

In general, we recommend the use of single axis trackers due to the large increase in energy collected (22% to 25%), even through they cost more to install and maintain. The gains out-weigh the costs.

The difference between central inverters and string inverters was found to have no significant effect on the energy generation. The cost between the two options is also very comparable. String inverters are recommended as maintenance and replacement could be done by local workers as opposed to waiting for servicing of central inverters by the manufacturer, however this should be weighed against the weather-resistance of the inverter choice, and the price and service contracts that can be negotiated with the suppliers.

Financial Summary

The LCOE for the 1MW systems ranged from $0.16 to $0.20/kWh.

The LCOE for the 5MW systems is quite attractive, ranging from $0.14 to $0.18 on average.

For the 10MW system, additional battery storage is needing for smoothing in case of power fluctuations, since the 10MW system will have a greater penetration of the electricity grid. For the 10MW system along with battery storage, the LCOE is about $0.21/kWh. When the energy storage is taken out of the equation, the LCOE for a 10 MW solar plant becomes on average $0.16/kWh to $0.17/kWh.

Potential Show Stoppers

There are a several things to keep in mind when planning this project that could be potential show-stoppers:

1. YESAB assessment has an issue with the perceived environmental impact (mostly pertains to Haines Junction).
2. Archeological site is discovered during pre-construction (Only applies to Haines junction as the quarry is all old mine tailings that have been processed).
3. General Public does not want development at either location.
4. Mineral rights dispute (Whitehorse location only)
5. Rare/Endangered species discovered living on location (Haines Junction only).
6. Sudden collapse in the Canadian Dollar as all major components are provided by US based suppliers.
7. Aboriginal groups objecting/opposing the project.

Appendix A – Monthly Profile Data

Tables of monthly energy generation data for the PV array configurations looked at in this report.

1 MW Haines Junction Monthly Generation Data

January						
Module	**Racking**	**Inverter**	**Array Energy (kWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	23600	21800	12.21	11.29
Canadian Solar - Mono	Single Axis	Schneider - Central	29165	27295	13.72	12.84
Canadian Solar - Poly	Single Axis	Schneider - Central	28505	26728	13.41	12.57
Canadian Solar - Poly	Fixed	Schneider - Central	24400	21000	11.92	10.26
Canadian Solar - Mono	Dual Axis	Schneider - Central	33180	31270	13.08	12.33
Heliene - Poly	Fixed	Schneider - Central	30079	28219	13.43	12.6
Heliene - Poly	Single Axis	Schneider - Central	30100	28200	13.43	12.6
Heliene - Poly	Single Axis	SMA - String	20395	19153	8.93	8.38
Prism - Bi-facial	Fixed	Schneider - Central	24467	22638	14.94	13.82
Prism - Bi-facial	Single Axis	Schneider - Central	29522	27632	16.36	15.31
Prism - Bi-facial	Fixed	SMA - String	24035	22721	14.97	14.15
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	22925	19225	13.83	11.6
Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	27186	25269	14.89	13.84
SunPower - Mono	Fixed	Schneider - Central	24125	22458	14.79	13.77
SunPower - Mono	Fixed	SMA - String	23595	22321	14.7	13.9
SunPower - Mono	Single Axis	Schneider - Central	21390	19807	11.9	11.02

February						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	67300	64600	13.57	13.03
Canadian Solar - Mono	Single Axis	Schneider - Central	81173	78182	13.96	13.44
Canadian Solar - Poly	Single Axis	Schneider - Central	78778	75983	13.54	13.06
Canadian Solar - Poly	Fixed	Schneider - Central	69500	66700	13.18	12.65
Canadian Solar - Mono	Dual Axis	Schneider - Central	90944	87664	13.85	13.35
Heliene - Poly	Fixed	Schneider - Central	83302	80311	13.59	13.11
Heliene - Poly	Single Axis	Schneider - Central	83300	80300	13.59	13.11
Heliene - Poly	Single Axis	SMA - String	76838	74475	12.39	12.01
Prism - Bi-facial	Fixed	Schneider - Central	69407	66614	16.47	15.81
Prism - Bi-facial	Single Axis	Schneider - Central	83067	79957	16.82	16.19
Prism - Bi-facial	Fixed	SMA - String	68070	65800	16.49	15.94
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	66239	63377	15.54	14.87
Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	79246	76083	15.86	15.23

SunPower - Mono	Fixed	Schneider - Central	68418	65952	16.31	15.72
SunPower - Mono	Fixed	SMA - String	67391	65212	16.32	15.79
SunPower - Mono	Single Axis	Schneider - Central	74086	71520	15.24	14.71

March

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	111882	107818	13.21	12.73
Canadian Solar - Mono	Single Axis	Schneider - Central	144018	139140	13.65	13.19
Canadian Solar - Poly	Single Axis	Schneider - Central	137853	133351	13.17	12.74
Canadian Solar - Poly	Fixed	Schneider - Central	115100	110900	12.79	12.32
Canadian Solar - Mono	Dual Axis	Schneider - Central	147889	142846	13.65	13.19
Heliene - Poly	Fixed	Schneider - Central	146490	141603	13.28	12.84
Heliene - Poly	Single Axis	Schneider - Central	146500	141600	13.28	12.84
Heliene - Poly	Single Axis	SMA - String	141234	137197	12.84	12.47
Prism - Bi-facial	Fixed	Schneider - Central	115703	97565	16.09	13.57
Prism - Bi-facial	Single Axis	Schneider - Central	147102	141997	16.44	15.87
Prism - Bi-facial	Fixed	SMA - String	113476	96283	16.1	13.66
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	110857	106453	15.23	14.63
Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	140499	135322	15.64	15.06
SunPower - Mono	Fixed	Schneider - Central	113528	109760	15.86	15.33
SunPower - Mono	Fixed	SMA - String	111831	108453	15.87	15.39
SunPower - Mono	Single Axis	Schneider - Central	135291	131006	15.76	15.26

April

Module	Racking	Inverter	Array Energy (kWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	175200	134500	15.87	12.89
Canadian Solar - Mono	Single Axis	Schneider - Central	233011	224995	16.36	15.8
Canadian Solar - Poly	Single Axis	Schneider - Central	218385	211394	15.49	14.99
Canadian Solar - Poly	Fixed	Schneider - Central	177700	171500	15.15	14.62
Canadian Solar - Mono	Dual Axis	Schneider - Central	214853	207195	16.4	15.82
Heliene - Poly	Fixed	Schneider - Central	232784	225047	15.67	15.15
Heliene - Poly	Single Axis	Schneider - Central	232800	225000	15.67	15.15
Heliene - Poly	Single Axis	SMA - String	221060	214698	15.16	14.72
Prism - Bi-facial	Fixed	Schneider - Central	178514	172208	19.05	18.37
Prism - Bi-facial	Single Axis	Schneider - Central	233367	225319	19.33	18.66
Prism - Bi-facial	Fixed	SMA - String	171739	166418	18.7	18.12
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	175148	154632	18.47	16.3

Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	228804	220329	18.92	18.22
SunPower - Mono	Fixed	Schneider - Central	176929	171293	18.96	18.36
SunPower - Mono	Fixed	SMA - String	170288	165207	18.54	17.99
SunPower - Mono	Single Axis	Schneider - Central	214139	207359	18.82	18.22

May						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	165900	159900	15.63	15.06
Canadian Solar - Mono	Single Axis	Schneider - Central	212334	204892	16	15.44
Canadian Solar - Poly	Single Axis	Schneider - Central	199706	193116	15.21	14.71
Canadian Solar - Poly	Fixed	Schneider - Central	169400	163300	15.01	14.47
Canadian Solar - Mono	Dual Axis	Schneider - Central	197190	190295	15.96	15.41
Heliene - Poly	Fixed	Schneider - Central	212689	205505	15.38	14.86
Heliene - Poly	Single Axis	Schneider - Central	212700	205500	15.38	14.86
Heliene - Poly	Single Axis	SMA - String	205663	199992	15.07	14.65
Prism - Bi-facial	Fixed	Schneider - Central	170480	164234	18.91	18.22
Prism - Bi-facial	Single Axis	Schneider - Central	214570	207016	19.08	18.41
Prism - Bi-facial	Fixed	SMA - String	165946	160970	18.78	18.22
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	167637	160947	18.38	17.64
Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	210529	202442	18.69	17.97
SunPower - Mono	Fixed	Schneider - Central	168735	145745	18.8	16.24
SunPower - Mono	Fixed	SMA - String	164491	142893	18.62	16.17
SunPower - Mono	Single Axis	Schneider - Central	199136	192684	18.71	18.1

June						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	147300	141700	15.17	14.59
Canadian Solar - Mono	Single Axis	Schneider - Central	186042	179288	15.54	14.98
Canadian Solar - Poly	Single Axis	Schneider - Central	175519	169475	14.83	14.32
Canadian Solar - Poly	Fixed	Schneider - Central	151000	145300	14.63	14.08
Canadian Solar - Mono	Dual Axis	Schneider - Central	181718	175540	15.58	15.05
Heliene - Poly	Fixed	Schneider - Central	186890	164880	14.99	13.23
Heliene - Poly	Single Axis	Schneider - Central	186900	164900	14.99	13.23
Heliene - Poly	Single Axis	SMA - String	180720	160718	14.63	13.01
Prism - Bi-facial	Fixed	Schneider - Central	152270	146422	18.47	17.76
Prism - Bi-facial	Single Axis	Schneider - Central	188933	182052	18.62	17.95
Prism - Bi-facial	Fixed	SMA - String	148644	144250	18.4	17.86
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	150090	143779	17.99	17.24

Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	185813	178368	18.3	17.57
SunPower - Mono	Fixed	Schneider - Central	150548	145300	18.34	17.7
SunPower - Mono	Fixed	SMA - String	147321	143145	18.24	17.72
SunPower - Mono	Single Axis	Schneider - Central	175468	169531	18.21	17.6

July						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	142400	137000	15.06	14.48
Canadian Solar - Mono	Single Axis	Schneider - Central	181194	174621	15.44	14.88
Canadian Solar - Poly	Single Axis	Schneider - Central	170977	165099	14.74	14.23
Canadian Solar - Poly	Fixed	Schneider - Central	146100	140600	14.53	13.98
Canadian Solar - Mono	Dual Axis	Schneider - Central	175960	169907	15.45	14.91
Heliene - Poly	Fixed	Schneider - Central	182004	153223	14.9	12.54
Heliene - Poly	Single Axis	Schneider - Central	182000	153200	14.9	12.54
Heliene - Poly	Single Axis	SMA - String	175395	148739	14.52	12.32
Prism - Bi-facial	Fixed	Schneider - Central	147426	141738	18.35	17.65
Prism - Bi-facial	Single Axis	Schneider - Central	184185	177480	18.52	17.84
Prism - Bi-facial	Fixed	SMA - String	144407	140129	18.35	17.8
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	145489	139343	17.9	17.14
Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	181302	174051	18.22	17.49
SunPower - Mono	Fixed	Schneider - Central	145727	140608	18.22	17.58
SunPower - Mono	Fixed	SMA - String	143224	139152	18.19	17.68
SunPower - Mono	Single Axis	Schneider - Central	170471	164704	18.1	17.49

August						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	137500	132500	15.3	14.73
Canadian Solar - Mono	Single Axis	Schneider - Central	175196	169052	15.66	15.11
Canadian Solar - Poly	Single Axis	Schneider - Central	165627	160121	14.94	14.45
Canadian Solar - Poly	Fixed	Schneider - Central	140800	135700	14.74	14.2
Canadian Solar - Mono	Dual Axis	Schneider - Central	163044	157098	15.64	15.07
Heliene - Poly	Fixed	Schneider - Central	176259	170298	15.1	14.59
Heliene - Poly	Single Axis	Schneider - Central	176300	170300	15.1	14.59
Heliene - Poly	Single Axis	SMA - String	170277	165629	14.78	14.38
Prism - Bi-facial	Fixed	Schneider - Central	141946	123129	18.59	16.13
Prism - Bi-facial	Single Axis	Schneider - Central	177988	171705	18.77	18.1
Prism - Bi-facial	Fixed	SMA - String	138556	121075	18.52	16.18
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	140103	134418	18.14	17.4

Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	175317	168548	18.45	17.74
SunPower - Mono	Fixed	Schneider - Central	140407	118766	18.47	15.63
SunPower - Mono	Fixed	SMA - String	137371	116957	18.36	15.63
SunPower - Mono	Single Axis	Schneider - Central	165309	159892	18.38	17.78

September						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	98300	89400	15.68	14.26
Canadian Solar - Mono	Single Axis	Schneider - Central	124704	120138	16.06	15.47
Canadian Solar - Poly	Single Axis	Schneider - Central	118838	114694	15.4	14.86
Canadian Solar - Poly	Fixed	Schneider - Central	101100	97200	15.17	14.58
Canadian Solar - Mono	Dual Axis	Schneider - Central	122471	117940	16.01	15.42
Heliene - Poly	Fixed	Schneider - Central	126454	121960	15.55	15
Heliene - Poly	Single Axis	Schneider - Central	126500	122000	15.55	15
Heliene - Poly	Single Axis	SMA - String	122390	118839	15.25	14.81
Prism - Bi-facial	Fixed	Schneider - Central	101924	97899	19.14	18.38
Prism - Bi-facial	Single Axis	Schneider - Central	127391	122665	19.34	18.62
Prism - Bi-facial	Fixed	SMA - String	99596	96429	19.08	18.47
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	99476	75501	18.46	14.01
Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	124355	119345	18.79	18.03
SunPower - Mono	Fixed	Schneider - Central	100442	88791	18.94	16.74
SunPower - Mono	Fixed	SMA - String	98448	87420	18.86	16.75
SunPower - Mono	Single Axis	Schneider - Central	118410	114338	18.88	18.23

October						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	76200	73000	16.04	15.37
Canadian Solar - Mono	Single Axis	Schneider - Central	92411	88800	16.46	15.82
Canadian Solar - Poly	Single Axis	Schneider - Central	89004	85650	15.88	15.28
Canadian Solar - Poly	Fixed	Schneider - Central	78500	68300	15.54	13.53
Canadian Solar - Mono	Dual Axis	Schneider - Central	97781	93964	16.43	15.79
Heliene - Poly	Fixed	Schneider - Central	94662	91049	16.03	15.42
Heliene - Poly	Single Axis	Schneider - Central	94700	91000	16.03	15.42
Heliene - Poly	Single Axis	SMA - String	88364	85551	14.79	14.32
Prism - Bi-facial	Fixed	Schneider - Central	79071	67920	19.61	16.84
Prism - Bi-facial	Single Axis	Schneider - Central	94568	90817	19.84	19.05
Prism - Bi-facial	Fixed	SMA - String	77520	67197	19.61	17
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	76358	72863	18.71	17.86

Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	91250	87368	18.96	18.16
SunPower - Mono	Fixed	Schneider - Central	77652	74662	19.34	18.6
SunPower - Mono	Fixed	SMA - String	76451	73913	19.34	18.7
SunPower - Mono	Single Axis	Schneider - Central	86052	82855	18.38	17.7

November						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	29800	27700	12.73	11.87
Canadian Solar - Mono	Single Axis	Schneider - Central	36055	33896	13.81	12.99
Canadian Solar - Poly	Single Axis	Schneider - Central	35182	33128	13.48	12.69
Canadian Solar - Poly	Fixed	Schneider - Central	31000	28900	12.47	11.64
Canadian Solar - Mono	Dual Axis	Schneider - Central	39559	37389	12.86	12.16
Heliene - Poly	Fixed	Schneider - Central	37294	35128	13.56	12.77
Heliene - Poly	Single Axis	Schneider - Central	37300	35100	13.56	12.77
Heliene - Poly	Single Axis	SMA - String	26952	25586	9.61	9.12
Prism - Bi-facial	Fixed	Schneider - Central	31142	29059	15.69	14.64
Prism - Bi-facial	Single Axis	Schneider - Central	34754	32594	15.68	14.71
Prism - Bi-facial	Fixed	SMA - String	30479	29005	15.67	14.91
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	29153	27063	14.51	13.47
Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	32613	30448	14.54	13.58
SunPower - Mono	Fixed	Schneider - Central	30382	28491	15.37	14.42
SunPower - Mono	Fixed	SMA - String	14008	12960	10.94	10.12
SunPower - Mono	Single Axis	Schneider - Central	27533	25746	12.49	11.68

December						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	14100	12700	9.19	8.28
Canadian Solar - Mono	Single Axis	Schneider - Central	22130	20564	13.68	12.71
Canadian Solar - Poly	Single Axis	Schneider - Central	21644	20162	13.37	12.46
Canadian Solar - Poly	Fixed	Schneider - Central	14700	13200	8.96	8.09
Canadian Solar - Mono	Dual Axis	Schneider - Central	23584	22082	11.6	10.86
Heliene - Poly	Fixed	Schneider - Central	22826	19525	13.39	11.45
Heliene - Poly	Single Axis	Schneider - Central	22800	19500	13.39	11.45
Heliene - Poly	Single Axis	SMA - String	10929	8986	6.29	5.17
Prism - Bi-facial	Fixed	Schneider - Central	14733	13314	11.27	10.19
Prism - Bi-facial	Single Axis	Schneider - Central	22057	20499	16.06	14.92
Prism - Bi-facial	Fixed	SMA - String	14490	13411	11.32	10.47
Panasonic HIT - Bi-facial	Fixed	Schneider - Central	13902	12479	10.51	9.44

Panasonic HIT - Bi-facial	Single Axis	Schneider - Central	19369	17870	13.93	12.86
SunPower - Mono	Fixed	Schneider - Central	14135	12809	10.87	9.85
SunPower - Mono	Fixed	SMA - String	27533	25746	12.49	11.68
SunPower - Mono	Single Axis	Schneider - Central	14054	12745	10.28	9.32

5 MW Haines Junction Monthly Generation Data

January						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (KWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	78667	60715	8.16	6.29
Canadian Solar - Mono	Single Axis	Schneider - Central	95462	87211	8.98	8.21
Canadian Solar - Poly	Single Axis	Schneider - Central	82894	74380	8.09	7.26
Canadian Solar - Poly	Fixed	Schneider - Central	82900	74400	8.09	7.26
Heliene - Poly	Fixed	Schneider - Central	82454	73837	7.95	7.12
Heliene - Poly	Single Axis	Schneider - Central	94189	86871	9.34	8.62
Prism - Bi-facial	Fixed	Schneider - Central	119504	110128	14.89	13.72
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	73104	59159	8.82	7.14
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	107563	98871	9.59	8.81
SunPower - Mono	Fixed	Schneider - Central	77872	70037	9.55	8.59
SunPower - Mono	Single Axis	Schneider - Central	99912	92039	11.12	10.24

February						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	320528	278942	12.92	11.24
Canadian Solar - Mono	Single Axis	Schneider - Central	357325	343884	12.29	11.83
Canadian Solar - Poly	Single Axis	Schneider - Central	331112	317573	12.56	12.04
Canadian Solar - Poly	Fixed	Schneider - Central	331100	317600	12.56	12.04
Heliene - Poly	Fixed	Schneider - Central	335589	321656	12.59	12.06
Heliene - Poly	Single Axis	Schneider - Central	340566	328157	12.45	12
Prism - Bi-facial	Fixed	Schneider - Central	338818	324454	16.41	15.72
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	308831	295125	14.49	13.85
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	367892	353805	12.03	11.56
SunPower - Mono	Fixed	Schneider - Central	319225	307419	15.22	14.66
SunPower - Mono	Single Axis	Schneider - Central	364921	352216	15.01	14.49

March						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	547974	527963	12.94	12.47
Canadian Solar - Mono	Single Axis	Schneider - Central	681631	658272	13.1	12.65
Canadian Solar - Poly	Single Axis	Schneider - Central	564217	475495	12.54	10.56
Canadian Solar - Poly	Fixed	Schneider - Central	564200	475500	12.54	10.56
Heliene - Poly	Fixed	Schneider - Central	575339	553590	12.64	12.16
Heliene - Poly	Single Axis	Schneider - Central	623005	601944	12.84	12.4
Prism - Bi-facial	Fixed	Schneider - Central	563384	473974	15.99	13.45
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	541965	520272	14.9	14.3
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	672452	649111	12.35	11.92
SunPower - Mono	Fixed	Schneider - Central	556174	537629	15.54	15.02
SunPower - Mono	Single Axis	Schneider - Central	675673	654262	15.75	15.25

April						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	858399	828458	15.55	15.01
Canadian Solar - Mono	Single Axis	Schneider - Central	1096843	1059085	15.76	15.22
Canadian Solar - Poly	Single Axis	Schneider - Central	871671	841355	14.86	14.34
Canadian Solar - Poly	Fixed	Schneider - Central	871700	841400	14.86	14.34
Heliene - Poly	Fixed	Schneider - Central	890822	787160	15.02	13.27
Heliene - Poly	Single Axis	Schneider - Central	977209	944542	15.19	14.68
Prism - Bi-facial	Fixed	Schneider - Central	869528	837386	18.93	18.23
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	856889	756385	18.07	15.95
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	1062821	1026356	14.66	14.16
SunPower - Mono	Fixed	Schneider - Central	867310	839658	18.59	18
SunPower - Mono	Single Axis	Schneider - Central	1069584	1035721	18.8	18.2

May						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	818051	788170	15.41	14.85
Canadian Solar - Mono	Single Axis	Schneider - Central	1013639	977691	15.59	15.03
Canadian Solar - Poly	Single Axis	Schneider - Central	835479	805176	14.81	14.27

Canadian Solar - Poly	Fixed	Schneider - Central	835500	805200	14.81	14.27
Heliene - Poly	Fixed	Schneider - Central	853367	747844	14.96	13.11
Heliene - Poly	Single Axis	Schneider - Central	907500	876479	15.07	14.55
Prism - Bi-facial	Fixed	Schneider - Central	832360	800264	18.84	18.12
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	825032	791915	18.09	17.36
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	990553	955319	14.59	14.08
SunPower - Mono	Fixed	Schneider - Central	831739	717949	18.54	16
SunPower - Mono	Single Axis	Schneider - Central	995067	962819	18.7	18.09

June

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	724882	617534	14.93	12.72
Canadian Solar - Mono	Single Axis	Schneider - Central	885184	852451	15.09	14.53
Canadian Solar - Poly	Single Axis	Schneider - Central	743364	714982	14.41	13.86
Canadian Solar - Poly	Fixed	Schneider - Central	743400	715000	14.41	13.86
Heliene - Poly	Fixed	Schneider - Central	759115	729636	14.55	13.99
Heliene - Poly	Single Axis	Schneider - Central	798152	703676	14.65	12.91
Prism - Bi-facial	Fixed	Schneider - Central	743116	712968	18.4	17.65
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	737138	705877	17.67	16.92
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	872809	840305	14.24	13.71
SunPower - Mono	Fixed	Schneider - Central	740732	714668	18.05	17.42
SunPower - Mono	Single Axis	Schneider - Central	876725	847050	18.2	17.58

July

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	701017	673750	14.82	14.25
Canadian Solar - Mono	Single Axis	Schneider - Central	858930	827221	14.99	14.44
Canadian Solar - Poly	Single Axis	Schneider - Central	719546	691919	14.31	13.76
Canadian Solar - Poly	Fixed	Schneider - Central	719500	691900	14.31	13.76
Heliene - Poly	Fixed	Schneider - Central	734623	705921	14.45	13.89
Heliene - Poly	Single Axis	Schneider - Central	775440	651972	14.55	12.24
Prism - Bi-facial	Fixed	Schneider - Central	719494	690175	18.28	17.54
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	714574	684077	17.58	16.83
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	848615	817057	14.18	13.65
SunPower - Mono	Fixed	Schneider - Central	717062	691579	17.93	17.3
SunPower - Mono	Single Axis	Schneider - Central	851740	822915	18.09	17.48

August						
Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	678321	653086	15.09	14.53
Canadian Solar - Mono	Single Axis	Schneider - Central	835005	805212	15.27	14.72
Canadian Solar - Poly	Single Axis	Schneider - Central	694927	602926	14.54	12.62
Canadian Solar - Poly	Fixed	Schneider - Central	694900	602900	14.54	12.62
Heliene - Poly	Fixed	Schneider - Central	709415	682725	14.68	14.13
Heliene - Poly	Single Axis	Schneider - Central	751802	725936	14.79	14.28
Prism - Bi-facial	Fixed	Schneider - Central	693133	599974	18.53	16.04
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	689777	661570	17.86	17.13
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	822709	793132	14.39	13.87
SunPower - Mono	Fixed	Schneider - Central	692371	585114	18.22	15.4
SunPower - Mono	Single Axis	Schneider - Central	826022	798950	18.37	17.77

September						
Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	485385	466290	15.48	14.87
Canadian Solar - Mono	Single Axis	Schneider - Central	597402	575109	15.68	15.1
Canadian Solar - Poly	Single Axis	Schneider - Central	499326	479724	14.98	14.39
Canadian Solar - Poly	Fixed	Schneider - Central	499300	479700	14.98	14.39
Heliene - Poly	Fixed	Schneider - Central	509792	489391	15.12	14.52
Heliene - Poly	Single Axis	Schneider - Central	539938	520335	15.25	14.7
Prism - Bi-facial	Fixed	Schneider - Central	497835	477051	19.07	18.28
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	490198	371152	18.19	13.77
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	586853	564743	14.76	14.2
SunPower - Mono	Fixed	Schneider - Central	495700	438036	18.7	16.52
SunPower - Mono	Single Axis	Schneider - Central	591681	571329	18.86	18.22

October						
Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)

Canadian Solar - Mono	Fixed	Schneider - Central	368027	352228	15.5	14.83
Canadian Solar - Mono	Single Axis	Schneider - Central	421575	404552	15.11	14.5
Canadian Solar - Poly	Single Axis	Schneider - Central	379287	324994	15.03	12.88
Canadian Solar - Poly	Fixed	Schneider - Central	379300	325000	15.03	12.88
Heliene - Poly	Fixed	Schneider - Central	387048	370131	15.16	14.5
Heliene - Poly	Single Axis	Schneider - Central	394107	378715	14.96	14.37
Prism - Bi-facial	Fixed	Schneider - Central	385853	330565	19.53	16.73
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	366671	349523	17.97	17.13
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	427828	410487	14.56	13.97
SunPower - Mono	Fixed	Schneider - Central	373600	358875	18.61	17.88
SunPower - Mono	Single Axis	Schneider - Central	428255	412314	18.29	17.61

November						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	105488	96297	9.03	8.24
Canadian Solar - Mono	Single Axis	Schneider - Central	121945	112891	9.34	8.65
Canadian Solar - Poly	Single Axis	Schneider - Central	111118	101713	8.94	8.19
Canadian Solar - Poly	Fixed	Schneider - Central	111100	101700	8.94	8.19
Heliene - Poly	Fixed	Schneider - Central	111315	97272	8.86	7.74
Heliene - Poly	Single Axis	Schneider - Central	121470	113125	9.82	9.14
Prism - Bi-facial	Fixed	Schneider - Central	152432	141832	15.67	14.58
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	98294	88786	9.79	8.84
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	139866	130196	10.15	9.45
SunPower - Mono	Fixed	Schneider - Central	103318	94638	10.46	9.58
SunPower - Mono	Single Axis	Schneider - Central	128733	119935	11.68	10.88

December						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	48005	41444	6.24	5.39
Canadian Solar - Mono	Single Axis	Schneider - Central	52858	46058	6.53	5.69
Canadian Solar - Poly	Single Axis	Schneider - Central	51889	45246	6.35	5.53
Canadian Solar - Poly	Fixed	Schneider - Central	51900	45200	6.35	5.53
Heliene - Poly	Fixed	Schneider - Central	50961	44206	6.16	5.35
Heliene - Poly	Single Axis	Schneider - Central	48787	39375	6.36	5.13
Prism - Bi-facial	Fixed	Schneider - Central	68379	61369	10.68	9.58
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	41167	34915	6.23	5.28

Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	63529	56680	7.44	6.64
SunPower - Mono	Fixed	Schneider - Central	39586	33362	6.09	5.13
SunPower - Mono	Single Axis	Schneider - Central	60305	53891	8.82	7.88

1 MW Whitehorse Monthly Generation Data

January						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (KWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	21113	16286	10.15	7.83
Canadian Solar - Mono	Single Axis	Schneider - Central	22097	20373	9.32	8.59
Canadian Solar - Poly	Single Axis	Schneider - Central	18624	16881	8.09	7.33
Canadian Solar - Poly	Fixed	Schneider - Central	22946	21278	9.67	8.97
Heliene - Poly	Fixed	Schneider - Central	18528	16758	7.95	7.2
Heliene - Poly	Single Axis	Schneider - Central	23753	22034	9.5	8.82
Prism - Bi-facial	Fixed	Schneider - Central	27955	26026	15.19	14.14
Prism - Bi-facial	Single Axis	Schneider - Central	32438	30426	16.11	15.11
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	21563	18312	11.05	9.39
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	20492	18727	10.06	9.19
SunPower - Mono	Fixed	Schneider - Central	21663	19992	11.83	10.91
SunPower - Mono	Single Axis	Schneider - Central	24927	23233	12.43	11.59

February						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	65365	58048	13.28	11.8
Canadian Solar - Mono	Single Axis	Schneider - Central	75513	72685	12.6	12.13
Canadian Solar - Poly	Single Axis	Schneider - Central	68277	65491	12.53	12.02
Canadian Solar - Poly	Fixed	Schneider - Central	73887	71189	12.37	11.92
Heliene - Poly	Fixed	Schneider - Central	68974	66117	12.52	12
Heliene - Poly	Single Axis	Schneider - Central	77869	75001	12.38	11.92
Prism - Bi-facial	Fixed	Schneider - Central	71998	69104	16.54	15.88
Prism - Bi-facial	Single Axis	Schneider - Central	86161	82917	16.91	16.28
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	69752	66754	15.12	14.47
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	70954	68015	13.85	13.27
SunPower - Mono	Fixed	Schneider - Central	67673	65196	15.62	15.04
SunPower - Mono	Single Axis	Schneider - Central	76627	73952	15.23	14.69

March						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**

Canadian Solar - Mono	Fixed	Schneider - Central	107786	104114	13.18	12.73
Canadian Solar - Mono	Single Axis	Schneider - Central	138963	134127	13.33	12.87
Canadian Solar - Poly	Single Axis	Schneider - Central	114999	100425	12.7	11.09
Canadian Solar - Poly	Fixed	Schneider - Central	132124	127676	12.87	12.43
Heliene - Poly	Fixed	Schneider - Central	117553	113071	12.84	12.35
Heliene - Poly	Single Axis	Schneider - Central	140360	135547	12.98	12.53
Prism - Bi-facial	Fixed	Schneider - Central	117117	102253	16.19	14.13
Prism - Bi-facial	Single Axis	Schneider - Central	148610	143394	16.54	15.96
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	116607	111965	15.2	14.6
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	134318	129231	15.25	14.68
SunPower - Mono	Fixed	Schneider - Central	111880	108090	15.53	15.01
SunPower - Mono	Single Axis	Schneider - Central	137531	133109	15.94	15.42

April						
Module	**Racking**	**Inverter**	**Array Energy (kWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	166971	161639	15.86	15.35
Canadian Solar - Mono	Single Axis	Schneider - Central	222253	214571	16.09	15.53
Canadian Solar - Poly	Single Axis	Schneider - Central	175955	169835	15.1	14.57
Canadian Solar - Poly	Fixed	Schneider - Central	204867	198248	15.23	14.74
Heliene - Poly	Fixed	Schneider - Central	180470	157991	15.31	13.41
Heliene - Poly	Single Axis	Schneider - Central	218338	211027	15.41	14.9
Prism - Bi-facial	Fixed	Schneider - Central	178906	172579	19.21	18.53
Prism - Bi-facial	Single Axis	Schneider - Central	233270	225200	19.51	18.84
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	182427	164462	18.48	16.66
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	214328	206315	18.61	17.91
SunPower - Mono	Fixed	Schneider - Central	172545	167055	18.61	18.02
SunPower - Mono	Single Axis	Schneider - Central	215233	208408	19.09	18.49

May						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	159212	153866	15.48	14.96
Canadian Solar - Mono	Single Axis	Schneider - Central	207284	199952	15.67	15.12
Canadian Solar - Poly	Single Axis	Schneider - Central	168722	162652	14.81	14.28
Canadian Solar - Poly	Fixed	Schneider - Central	192595	186170	14.93	14.43
Heliene - Poly	Fixed	Schneider - Central	172885	154315	15.01	13.4
Heliene - Poly	Single Axis	Schneider - Central	205098	198115	15.09	14.58
Prism - Bi-facial	Fixed	Schneider - Central	171820	165568	18.88	18.19
Prism - Bi-facial	Single Axis	Schneider - Central	218429	210754	19.12	18.45

Panisonic HIT - Bi-facial	Fixed	Schneider - Central	175781	168874	18.22	17.51
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	202315	194464	18.31	17.6
SunPower - Mono	Fixed	Schneider - Central	165550	145793	18.27	16.09
SunPower - Mono	Single Axis	Schneider - Central	202283	195749	18.72	18.12

June						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	140998	124771	15.01	13.28
Canadian Solar - Mono	Single Axis	Schneider - Central	178886	172174	15.17	14.6
Canadian Solar - Poly	Single Axis	Schneider - Central	149683	143936	14.39	13.84
Canadian Solar - Poly	Fixed	Schneider - Central	167483	161531	14.49	13.97
Heliene - Poly	Fixed	Schneider - Central	153379	147385	14.58	14.01
Heliene - Poly	Single Axis	Schneider - Central	178370	158772	14.65	13.04
Prism - Bi-facial	Fixed	Schneider - Central	152942	147030	18.41	17.69
Prism - Bi-facial	Single Axis	Schneider - Central	189689	182685	18.63	17.94
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	157036	150450	17.83	17.08
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	176966	169650	17.88	17.14
SunPower - Mono	Fixed	Schneider - Central	147296	142058	17.8	17.17
SunPower - Mono	Single Axis	Schneider - Central	176441	170394	18.21	17.59

July						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	137128	132299	14.91	14.38
Canadian Solar - Mono	Single Axis	Schneider - Central	175383	169123	15.07	14.53
Canadian Solar - Poly	Single Axis	Schneider - Central	146323	140891	14.37	13.83
Canadian Solar - Poly	Fixed	Schneider - Central	164940	159321	14.49	13.99
Heliene - Poly	Fixed	Schneider - Central	149710	144054	14.54	13.99
Heliene - Poly	Single Axis	Schneider - Central	175406	157067	14.63	13.1
Prism - Bi-facial	Fixed	Schneider - Central	149686	144086	18.4	17.71
Prism - Bi-facial	Single Axis	Schneider - Central	187452	180832	18.65	17.99
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	153269	147066	17.77	17.05
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	173675	166816	17.81	17.11
SunPower - Mono	Fixed	Schneider - Central	143690	138743	17.74	17.13
SunPower - Mono	Single Axis	Schneider - Central	173159	167477	18.15	17.55

August						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**

Canadian Solar - Mono	Fixed	Schneider - Central	126702	122374	15.09	14.58
Canadian Solar - Mono	Single Axis	Schneider - Central	163584	157819	15.28	14.74
Canadian Solar - Poly	Single Axis	Schneider - Central	134955	118615	14.52	12.76
Canadian Solar - Poly	Fixed	Schneider - Central	152900	147791	14.64	14.15
Heliene - Poly	Fixed	Schneider - Central	138152	133012	14.7	14.15
Heliene - Poly	Single Axis	Schneider - Central	162677	157146	14.79	14.28
Prism - Bi-facial	Fixed	Schneider - Central	137776	120993	18.55	16.29
Prism - Bi-facial	Single Axis	Schneider - Central	174014	167923	18.81	18.15
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	141162	135525	17.93	17.22
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	161024	154734	18	17.3
SunPower - Mono	Fixed	Schneider - Central	132468	114336	17.92	15.47
SunPower - Mono	Single Axis	Schneider - Central	160605	155409	18.35	17.75

September

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	92266	88844	15.56	14.99
Canadian Solar - Mono	Single Axis	Schneider - Central	116560	112156	15.73	15.13
Canadian Solar - Poly	Single Axis	Schneider - Central	98517	94612	15.01	14.41
Canadian Solar - Poly	Fixed	Schneider - Central	110171	106172	15.13	14.58
Heliene - Poly	Fixed	Schneider - Central	100839	96767	15.19	14.58
Heliene - Poly	Single Axis	Schneider - Central	117206	112882	15.28	14.72
Prism - Bi-facial	Fixed	Schneider - Central	100493	96475	19.16	18.4
Prism - Bi-facial	Single Axis	Schneider - Central	124140	119453	19.42	18.68
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	101876	83977	18.33	15.11
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	114677	109916	18.37	17.61
SunPower - Mono	Fixed	Schneider - Central	96368	87097	18.46	16.68
SunPower - Mono	Single Axis	Schneider - Central	115552	111507	18.88	18.22

October

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	68030	65304	15.87	15.24
Canadian Solar - Mono	Single Axis	Schneider - Central	82959	79668	15.59	14.97
Canadian Solar - Poly	Single Axis	Schneider - Central	72305	63913	15.24	13.47
Canadian Solar - Poly	Fixed	Schneider - Central	79882	76809	15.16	14.58
Heliene - Poly	Fixed	Schneider - Central	73916	70672	15.41	14.73
Heliene - Poly	Single Axis	Schneider - Central	84777	81490	15.27	14.68
Prism - Bi-facial	Fixed	Schneider - Central	74643	65987	19.69	17.41
Prism - Bi-facial	Single Axis	Schneider - Central	91454	87855	20.05	19.26

Panisonic HIT - Bi-facial	Fixed	Schneider - Central	74342	70924	18.5	17.65
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	80579	77039	17.83	17.05
SunPower - Mono	Fixed	Schneider - Central	71021	68218	18.82	18.08
SunPower - Mono	Single Axis	Schneider - Central	83344	80272	18.82	18.13

November						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	24196	22446	10.51	9.75
Canadian Solar - Mono	Single Axis	Schneider - Central	26271	24476	9.93	9.25
Canadian Solar - Poly	Single Axis	Schneider - Central	22409	20571	8.79	8.07
Canadian Solar - Poly	Fixed	Schneider - Central	26559	24800	10.03	9.37
Heliene - Poly	Fixed	Schneider - Central	22634	19675	8.78	7.63
Heliene - Poly	Single Axis	Schneider - Central	27947	26113	10.02	9.36
Prism - Bi-facial	Fixed	Schneider - Central	31752	29696	15.59	14.58
Prism - Bi-facial	Single Axis	Schneider - Central	36446	34296	16.22	15.26
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	25308	23320	11.72	10.8
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	23469	21638	10.32	9.52
SunPower - Mono	Fixed	Schneider - Central	24902	23141	12.28	11.41
SunPower - Mono	Single Axis	Schneider - Central	28389	26612	12.69	11.9

December						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	9857	8514	7.72	6.67
Canadian Solar - Mono	Single Axis	Schneider - Central	10592	9176	7.57	6.56
Canadian Solar - Poly	Single Axis	Schneider - Central	10169	8744	7.2	6.19
Canadian Solar - Poly	Fixed	Schneider - Central	10274	8951	7.34	6.4
Heliene - Poly	Fixed	Schneider - Central	10213	8769	7.15	6.14
Heliene - Poly	Single Axis	Schneider - Central	10549	9128	7.16	6.19
Prism - Bi-facial	Fixed	Schneider - Central	13617	12137	12.06	10.75
Prism - Bi-facial	Single Axis	Schneider - Central	19143	17533	16.11	14.76
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	10380	8891	8.67	7.43
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	10792	9393	8.98	7.81
SunPower - Mono	Fixed	Schneider - Central	10493	9137	9.34	8.13
SunPower - Mono	Single Axis	Schneider - Central	12664	11316	10.71	9.57

5 MW Whitehorse Monthly Generation Data

January

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (KWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	89326	67291	8.24	6.21
Canadian Solar - Mono	Single Axis	Schneider - Central	108042	99359	9.11	8.38
Canadian Solar - Poly	Single Axis	Schneider - Central	95276	86385	8.27	7.5
Canadian Solar - Poly	Fixed	Schneider - Central	115658	107180	9.75	9.04
Heliene - Poly	Fixed	Schneider - Central	94033	85026	8.07	7.3
Heliene - Poly	Single Axis	Schneider - Central	105356	97603	9.37	8.68
Prism - Bi-facial	Fixed	Schneider - Central	136945	127044	15.19	14.09
Prism - Bi-facial	Single Axis	Schneider - Central	109685	100971	10.89	10.03
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	81737	66960	8.78	7.19
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	105356	97603	9.37	8.68
SunPower - Mono	Fixed	Schneider - Central	86933	78767	9.49	8.6
SunPower - Mono	Single Axis	Schneider - Central	116012	107651	11.57	10.74

February						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	329963	291256	12.87	11.36
Canadian Solar - Mono	Single Axis	Schneider - Central	371568	357550	12.4	11.94
Canadian Solar - Poly	Single Axis	Schneider - Central	342759	328701	12.58	12.07
Canadian Solar - Poly	Fixed	Schneider - Central	369163	355682	12.36	11.91
Heliene - Poly	Fixed	Schneider - Central	346700	332242	12.59	12.06
Heliene - Poly	Single Axis	Schneider - Central	348888	336017	12.32	11.87
Prism - Bi-facial	Fixed	Schneider - Central	351993	337050	16.5	15.8
Prism - Bi-facial	Single Axis	Schneider - Central	385860	371137	15.17	14.6
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	316544	302492	14.37	13.74
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	348888	336017	12.32	11.87
SunPower - Mono	Fixed	Schneider - Central	328224	315961	15.15	14.58
SunPower - Mono	Single Axis	Schneider - Central	377705	364458	15.01	14.48

March						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	561225	540483	12.97	12.49
Canadian Solar - Mono	Single Axis	Schneider - Central	690969	666944	13.26	12.8
Canadian Solar - Poly	Single Axis	Schneider - Central	578127	504890	12.57	10.98
Canadian Solar - Poly	Fixed	Schneider - Central	660565	638322	12.86	12.43
Heliene - Poly	Fixed	Schneider - Central	589189	566739	12.67	12.18
Heliene - Poly	Single Axis	Schneider - Central	631592	609931	12.98	12.53
Prism - Bi-facial	Fixed	Schneider - Central	575894	501821	15.99	13.93

Prism - Bi-facial	Single Axis	Schneider - Central	710086	684891	16.09	15.52
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	554799	532445	14.92	14.32
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	631592	609931	12.98	12.53
SunPower - Mono	Fixed	Schneider - Central	569239	550001	15.56	15.03
SunPower - Mono	Single Axis	Schneider - Central	687558	665449	15.93	15.42

April

Module	Racking	Inverter	Array Energy (kWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	872644	842172	15.59	15.04
Canadian Solar - Mono	Single Axis	Schneider - Central	1106558	1068307	16.02	15.47
Canadian Solar - Poly	Single Axis	Schneider - Central	886797	855947	14.9	14.38
Canadian Solar - Poly	Fixed	Schneider - Central	1024351	991254	15.23	14.74
Heliene - Poly	Fixed	Schneider - Central	905846	793043	15.05	13.18
Heliene - Poly	Single Axis	Schneider - Central	982447	949551	15.41	14.89
Prism - Bi-facial	Fixed	Schneider - Central	882613	849999	18.94	18.24
Prism - Bi-facial	Single Axis	Schneider - Central	1112688	1074009	19.06	18.39
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	870516	784779	18.1	16.31
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	982447	949551	15.41	14.89
SunPower - Mono	Fixed	Schneider - Central	881244	853111	18.62	18.03
SunPower - Mono	Single Axis	Schneider - Central	1076530	1042390	19.1	18.49

May

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	826980	796994	15.43	14.87
Canadian Solar - Mono	Single Axis	Schneider - Central	1032096	995547	15.61	15.05
Canadian Solar - Poly	Single Axis	Schneider - Central	845783	815343	14.85	14.32
Canadian Solar - Poly	Fixed	Schneider - Central	962932	930806	14.93	14.43
Heliene - Poly	Fixed	Schneider - Central	863407	770661	14.99	13.38
Heliene - Poly	Single Axis	Schneider - Central	922940	891510	15.09	14.58
Prism - Bi-facial	Fixed	Schneider - Central	841052	808866	18.86	18.14
Prism - Bi-facial	Single Axis	Schneider - Central	1047852	1010658	18.71	18.04
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	833675	800439	18.11	17.39
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	922940	891510	15.09	14.58
SunPower - Mono	Fixed	Schneider - Central	840691	740282	18.56	16.34
SunPower - Mono	Single Axis	Schneider - Central	1011878	979184	18.73	18.12

June

Module	Racking	Inverter	Array Energy (KWh)	Energy to Grid (kWh)	Array Efficiency (%)	System Efficiency (%)
Canadian Solar - Mono	Fixed	Schneider - Central	731655	645949	14.95	13.2
Canadian Solar - Mono	Single Axis	Schneider - Central	890359	856872	15.1	14.53
Canadian Solar - Poly	Single Axis	Schneider - Central	750294	721482	14.43	13.87
Canadian Solar - Poly	Fixed	Schneider - Central	837411	807648	14.49	13.97
Heliene - Poly	Fixed	Schneider - Central	765898	735949	14.56	13.99
Heliene - Poly	Single Axis	Schneider - Central	802607	714415	14.65	13.04
Prism - Bi-facial	Fixed	Schneider - Central	748357	717837	18.38	17.63
Prism - Bi-facial	Single Axis	Schneider - Central	909054	874960	18.18	17.5
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	743949	712127	17.7	16.94
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	802607	714415	14.65	13.04
SunPower - Mono	Fixed	Schneider - Central	747124	720557	18.06	17.42
SunPower - Mono	Single Axis	Schneider - Central	882505	852251	18.22	17.59

July						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	710842	684167	14.84	14.28
Canadian Solar - Mono	Single Axis	Schneider - Central	872673	841459	15	14.46
Canadian Solar - Poly	Single Axis	Schneider - Central	733223	706001	14.4	13.87
Canadian Solar - Poly	Fixed	Schneider - Central	824680	796577	14.49	13.99
Heliene - Poly	Fixed	Schneider - Central	747564	719304	14.52	13.97
Heliene - Poly	Single Axis	Schneider - Central	789280	706753	14.62	13.1
Prism - Bi-facial	Fixed	Schneider - Central	732155	703226	18.37	17.64
Prism - Bi-facial	Single Axis	Schneider - Central	896841	864657	18.19	17.54
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	725479	695547	17.62	16.9
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	789280	706753	14.62	13.1
SunPower - Mono	Fixed	Schneider - Central	728081	703042	17.98	17.36
SunPower - Mono	Single Axis	Schneider - Central	865987	837568	18.15	17.56

August						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	657497	633397	15.04	14.49
Canadian Solar - Mono	Single Axis	Schneider - Central	814538	785784	15.22	14.68
Canadian Solar - Poly	Single Axis	Schneider - Central	676394	594521	14.55	12.79
Canadian Solar - Poly	Fixed	Schneider - Central	764493	738944	14.64	14.15
Heliene - Poly	Fixed	Schneider - Central	689950	664262	14.68	14.13

Heliene - Poly	Single Axis	Schneider - Central	732001	707107	14.79	14.28
Prism - Bi-facial	Fixed	Schneider - Central	674239	590891	18.53	16.24
Prism - Bi-facial	Single Axis	Schneider - Central	833008	803433	18.39	17.73
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	668901	641779	17.8	17.08
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	732001	707107	14.79	14.28
SunPower - Mono	Fixed	Schneider - Central	671979	580028	18.18	15.69
SunPower - Mono	Single Axis	Schneider - Central	803263	777269	18.35	17.76

September						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	478683	459673	15.5	14.89
Canadian Solar - Mono	Single Axis	Schneider - Central	580447	558489	15.66	15.07
Canadian Solar - Poly	Single Axis	Schneider - Central	493676	474107	15.04	14.45
Canadian Solar - Poly	Fixed	Schneider - Central	550874	530874	15.13	14.58
Heliene - Poly	Fixed	Schneider - Central	503663	483312	15.18	14.56
Heliene - Poly	Single Axis	Schneider - Central	527361	507900	15.28	14.71
Prism - Bi-facial	Fixed	Schneider - Central	491787	471034	19.14	18.33
Prism - Bi-facial	Single Axis	Schneider - Central	596125	573262	19	18.27
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	482706	397439	18.19	14.98
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	527361	507900	15.28	14.71
SunPower - Mono	Fixed	Schneider - Central	488817	441921	18.73	16.93
SunPower - Mono	Single Axis	Schneider - Central	577864	557635	18.89	18.22

October						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	351217	336112	15.5	14.84
Canadian Solar - Mono	Single Axis	Schneider - Central	411697	395271	15.47	14.86
Canadian Solar - Poly	Single Axis	Schneider - Central	363848	321664	15.11	13.36
Canadian Solar - Poly	Fixed	Schneider - Central	399393	384017	15.16	14.58
Heliene - Poly	Fixed	Schneider - Central	370991	354712	15.24	14.57
Heliene - Poly	Single Axis	Schneider - Central	380883	366099	15.25	14.66
Prism - Bi-facial	Fixed	Schneider - Central	367441	324029	19.49	17.19
Prism - Bi-facial	Single Axis	Schneider - Central	427181	410004	18.94	18.18
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	349699	333226	17.97	17.12
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	380883	366099	15.25	14.66
SunPower - Mono	Fixed	Schneider - Central	357044	342905	18.64	17.9
SunPower - Mono	Single Axis	Schneider - Central	414550	399250	18.72	18.03

November						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	107993	98861	9.01	8.25
Canadian Solar - Mono	Single Axis	Schneider - Central	126745	117762	9.58	8.9
Canadian Solar - Poly	Single Axis	Schneider - Central	113479	104104	8.9	8.17
Canadian Solar - Poly	Fixed	Schneider - Central	132078	123169	9.98	9.31
Heliene - Poly	Fixed	Schneider - Central	114502	99821	8.88	7.75
Heliene - Poly	Single Axis	Schneider - Central	123922	115699	9.88	9.22
Prism - Bi-facial	Fixed	Schneider - Central	156071	145490	15.64	14.58
Prism - Bi-facial	Single Axis	Schneider - Central	132103	122993	11.76	10.95
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	99213	89904	9.63	8.73
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	123922	115699	9.88	9.22
SunPower - Mono	Fixed	Schneider - Central	103641	95163	10.22	9.39
SunPower - Mono	Single Axis	Schneider - Central	133730	124987	11.96	11.17

December						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Canadian Solar - Mono	Fixed	Schneider - Central	45785	38798	6.89	5.84
Canadian Solar - Mono	Single Axis	Schneider - Central	49541	42483	7.08	6.07
Canadian Solar - Poly	Single Axis	Schneider - Central	49204	42079	6.97	5.96
Canadian Solar - Poly	Fixed	Schneider - Central	49175	42508	7.03	6.07
Heliene - Poly	Fixed	Schneider - Central	48979	41811	6.86	5.85
Heliene - Poly	Single Axis	Schneider - Central	44857	38494	6.76	5.8
Prism - Bi-facial	Fixed	Schneider - Central	63923	56534	11.56	10.22
Prism - Bi-facial	Single Axis	Schneider - Central	49854	42787	8.39	7.2
Panisonic HIT - Bi-facial	Fixed	Schneider - Central	40218	33422	7.04	5.85
Panisonic HIT - Bi-facial	Single Axis	Schneider - Central	44857	38494	6.76	5.8
SunPower - Mono	Fixed	Schneider - Central	41041	34535	7.3	6.15
SunPower - Mono	Single Axis	Schneider - Central	55932	49298	9.46	8.34

10 MW Whitehorse Monthly Generation Data

January						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (KWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	234898	215872	10.09	9.27

SunPower - Mono	Fixed	Schneider - Central	220385	203572	12.03	11.11
SunPower - Mono	Single Axis	Schneider - Central	230669	213976	11.51	10.67

February						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	716940	687452	13.01	12.48
SunPower - Mono	Fixed	Schneider - Central	690657	665488	15.94	15.36
SunPower - Mono	Single Axis	Schneider - Central	756936	730430	15.04	14.51

March						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	1184201	1139160	12.73	12.25
SunPower - Mono	Fixed	Schneider - Central	1146526	1107888	15.67	15.14
SunPower - Mono	Single Axis	Schneider - Central	1381590	1337027	16.01	15.49

April						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	1820400	1593869	15.13	13.24
SunPower - Mono	Fixed	Schneider - Central	1774482	1717921	18.75	18.15
SunPower - Mono	Single Axis	Schneider - Central	2161262	2092710	19.17	18.56

May						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	1734685	1548335	15.06	13.44
SunPower - Mono	Fixed	Schneider - Central	1692234	1490330	18.68	16.45
SunPower - Mono	Single Axis	Schneider - Central	2030504	1964927	18.79	18.19

June						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	1539655	1479652	14.64	14.07
SunPower - Mono	Fixed	Schneider - Central	1505078	1451847	18.19	17.55
SunPower - Mono	Single Axis	Schneider - Central	1771384	1710724	18.28	17.66

July						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	1503266	1446631	14.6	14.05
SunPower - Mono	Fixed	Schneider - Central	1467386	1417187	18.12	17.5
SunPower - Mono	Single Axis	Schneider - Central	1738614	1681618	18.22	17.62

August						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	1386726	1335237	14.75	14.21
SunPower - Mono	Fixed	Schneider - Central	1353442	1168416	18.31	15.8
SunPower - Mono	Single Axis	Schneider - Central	1612174	1560058	18.42	17.82

September						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	1012318	971534	15.25	14.64
SunPower - Mono	Fixed	Schneider - Central	984466	890052	18.86	17.05
SunPower - Mono	Single Axis	Schneider - Central	1159755	1119224	18.95	18.29

October						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	752653	719879	15.46	14.78
SunPower - Mono	Fixed	Schneider - Central	728460	699990	19.02	18.27
SunPower - Mono	Single Axis	Schneider - Central	831688	801086	18.78	18.09

November						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	274255	243669	10.64	9.45
SunPower - Mono	Fixed	Schneider - Central	254571	236819	12.56	11.68
SunPower - Mono	Single Axis	Schneider - Central	266650	249187	11.92	11.14

December						
Module	**Racking**	**Inverter**	**Array Energy (KWh)**	**Energy to Grid (kWh)**	**Array Efficiency (%)**	**System Efficiency (%)**
Heliene - Poly	Fixed	Schneider - Central	104768	90153	7.33	6.31

SunPower - Mono	Fixed	Schneider - Central	100047	86552	8.9	7.7
SunPower - Mono	Single Axis	Schneider - Central	110267	97045	9.32	8.2

Appendix B – Additional Energy Simulations Results

Haines Junction – 1 MW, Fixed Tilt, Central Inverters

Table B.1: Properties and performance of 1MW nominal power installations at Haines Junction using fixed racking and central inverters

Modules	Number of Modules	Installed Capacity (MW)	Annual Production (MWh)	Specific Production (kWh/kWp)	Performance Ratio (%)	Near Shading (%)
Heliene 72P-320W	3264	1.044	1168	1119	82.3	-3
CDN Solar CS6K-290MS	3600	1.044	1103	1056	77.7	-3.1
CDN Solar CS6X-320P	3264	1.044	1163	1113	81.9	-3.1
Sunpower SPR-440NE-WHT-D	2304	1.014	1125	1109	81.6	-3.1
Panasonic VBHN330SJ47	3024	0.998	1110	1112	81.9	-3.2
Prism Bi60-343BSTC	3000	1.029	1143	1111	81.7	-3

Haines Junction – 1 MW, Single Axis, Central Inverters

Table 8.2: Properties and performance of 1MW power installations at Haines Junction using single-axis trackers

Modules	Number of Modules	Installed Capacity (MW)	Annual Production (MWh)	Specific Production (kWh/kWp)	Performance Ratio (%)	Near Shading (%)
Heliene 72P-320W	3200	1.024	1437	1403	84.6	-1.1
CDN Solar CS6K-290MS	3600	1.044	1461	1399	83.7	-1.7
CDN Solar CS6X-320P	3264	0.938	1389	1413	85.2	-1.1
Sunpower SPR-440NE-WHT-D	2304	1.014	1352	1334	83.2	-4.7
Panasonic VBHN330SJ47	3024	0.998	1435	1438	86.9	-1.8
Prism Bi6-343BSTC	3000	1.029	1480	1438	86.1	-1.6

Haines Junction – 1 MW, Dual Axis, Central Inverters

Table 8.3: Properties and performance of 1MW power installations at Haines Junction using dual-axis trackers

Modules	Number of Modules	Installed Capacity (MW)	Annual Production (MWh)	Specific Production (kWh/kWp)	Performance Ratio (%)	Near Shading (%)
Heliene 72P-320W	3200	1.024	1439	1405	86.3	-1.7
CDN Solar CS6K-290MS	3600	1.044	1433	1373	82.9	-2.1
CDN Solar CS6X-320P	3072	0.983	1356	1379	84.7	-1.7
Sunpower SPR-440NE-WHT-D	2304	1.014	1425	1405	86.7	-1.9
Panasonic VBHN330SJ47	3024	0.998	1383	1386	85.8	-2.5
Prism Bi6-343BSTC	3000	1.029	1423	1383	83.9	-2.1

Haines Junction – 5 MW, Fixed Tilt, Central Inverters

Table 9.1: Properties and performance of 5MW nominal power installations at Haines Junction

Modules	# modules	Installed Capacity (MW)	Annual Production (MWh)	Spec. Production (kWh/kWp)	Performance Ratio (%)	Near Shading (%)
Heliene 72P-320W	16320	5.222	5372	1029	76.1	-5.6
CDN Solar CS6K-290MS	18000	5.22	5145	986	72.9	-5.6
CDN Solar CS6X-320P	16320	5.222	5230	1002	74.1	-5.6
Sunpower SPR-440NE-WHT-D	11520	5.069	5006	988	73.1	-5.8
Panasonic VBHN330SJ47	15120	4.99	5096	1021	75.6	-6.2
Prism Bi60-343BSTC	14700	5.042	5226	1036	76.7	-3.2

Haines Junction – 5 MW, Single Axis Trackers, Central Inverters

Table 9.2: Properties and performance of 5MW power installations at Haines Junction using single-axis trackers

Modules	# modules	Installed Capacity (MW)	Annual Production (MWh)	Spec. Production (kWh/kWp)	Performance Ratio (%)	Near Shading (%)
Heliene 72P-320W	14400	4.608	5751	1248	77.8	-4.3
CDN Solar CS6K-290MS	18000	5.22	6462	1238	75.8	-5.4
CDN Solar CS6X-320P	15360	4.915	6157	1253	78.1	-4.3
Sunpower SPR-440NE-WHT-D	11520	5.069	6287	1240	77.8	-4.7
Panasonic VBHN330SJ47	15120	4.99	6348	1272	79.5	-6.1
Prism Bi6-343BSTC	15000	5.145	6695	1301	79.5	-4.9

Whitehorse – 1 MW, Fixed Tilt Racking, Central Inverters

Table 12.1: Properties and performance of 1MW nominal power installations at the Whitehorse Quarry. Central inverters and fixed tilt racking used.

Modules	# modules	Installed Capacity (MW)	Annual Production	Spec. Production	Performance Ratio	Near Shading
Heliene 72P-320W	3264	1.044	1123	1075	79.2	-5.5
CDN Solar CS6K-290MS	3456	1.002	1059	1056	77.8	-4.1
CDN Solar CS6X-320P	3264	1.044	1107	1059	78.1	-5.3
Sunpower SPR-440NE-WHT-D	2304	1.014	1189	1074	79.1	-4.1
Panasonic VBHN330SJ47	3168	1.045	1151	1101	81.1	-4.3
Prism Bi6-343BSTC	3000	1.029	1152	1119	82.5	-2.8

Whitehorse – 1 MW, Single Axis Tracking, Central Inverters

Table 12.2: Properties and performance of 1MW power installations at the Whitehorse Quarry site using single-axis trackers

Modules	# modules	Installed Capacity (MW)	Annual Production	Spec. Production	Performance Ratio	Near Shading
Heliene 72P-320W	3200	1.024	1344	1313	81.5	-4.3
CDN Solar CS6K-290MS	3600	1.044	1366	1309	79.7	-4.6
CDN Solar CS6X-320P	3072	0.983	1290	1312	81.5	-4.2
Sunpower SPR-440NE-WHT-D	2304	1.014	1330	1312	82	-4.5
Panasonic VBHN330SJ47	3024	0.998	1326	1329	82.7	-5.5
Prism Bi6-343BSTC	3000	1.029	1483	1441	86.5	-1.6

Whitehorse – 5 MW, Fixed Tilt Racking, Central Inverters

Table 13.1: Performance of 5MW PV plant at Whitehorse Quarry using fixed tilt racking and central inverters

Modules	# modules	Installed Capacity (MW)	Annual Production	Spec. Production	Performance Ratio	Near Shading
Heliene 72P-320W	16320	5.222	5396	1033	76.1	-5.6
CDN Solar CS6K-290MS	18000	5.22	5170	990	73	-5.7
CDN Solar CS6X-320P	16320	5.222	5286	1012	74.6	-5.5
Sunpower SPR-440NE-WHT-D	11520	5.069	5047	996	73.4	-6
Panasonic VBHN330SJ47	15120	4.99	5153	1033	76.7	-6.1
Prism Bi6-343BSTC	14700	5.042	5406	1072	79	-3.2

Whitehorse – 5 MW, Single Axis Tracking, Central Inverters

Table 13.2: Annual energy production and other characteristics of 5MW single axis tracker PV plants at Whitehorse

Modules	# modules	Installed Capacity (MW)	Annual Production	Spec. Production	Performance Ratio	Near Shading
Heliene 72P-320W	14400	4.608	5832	1266	78.6	-4.4
CDN Solar CS6K-290MS	18000	5.22	6509	1247	76	-5.3
CDN Solar CS6X-320P	15360	4.915	6193	1260	78.2	-4.3
Sunpower SPR-440NE-WHT-D	11520	5.069	6333	1249	78.1	-4.8
Panasonic VBHN330SJ47	15120	4.99	6386	1280	79.6	-6.2
Prism Bi6-343BSTC	15000	5.145	6695	1301	79.5	-4.9

Whitehorse – 10 MW, Fixed Tilt Racking, Central Inverters

Table 14.1: Energy production characteristics of 10MW PV arrays with fixed tilt racking and central inverters at Whitehorse

Modules	# modules	Installed Capacity (MW)	Annual Production (MWh)	Spec. Prod. (kWh/kWp)	Performance Ratio (%)	Near Shading (%)
Heliene 72P-320W	32640	10.445	10372	993	73.2	-4.4
Sunpower SPR-440NE-WHT-D	23040	10.138	9614	948	69.9	-4.6

Appendix C – Complete LCOE Tables

Haines Junction – 1 MW Fixed Tilt

Table C.1: LCOE for 1 MW installations at Haines Junction (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.179	$0.201	$0.285
Inverter Option 1: CDN Solar Mono	$0.203	$0.228	$0.324
Inverter Option 1: CDN Solar Poly	$0.194	$0.218	$0.310
Inverter Option 1: Sunpower	$0.247	$0.279	$0.401
Inverter Option 1: Panasonic HIT	$0.216	$0.243	$0.347
Inverter Option 1: Prism Bi-Facial	$0.196	$0.220	$0.313
Inverter Option 2: Heliene Poly	$0.166	$0.186	$0.262
Inverter Option 2: CDN Solar Mono	$0.198	$0.222	$0.315
Inverter Option 2: CDN Solar Poly	$0.200	$0.224	$0.318
Inverter Option 2: Sunpower	$0.238	$0.268	$0.384
Inverter Option 2: Panasonic HIT	$0.204	$0.229	$0.325
Inverter Option 2: Prism Bi-Facial	$0.184	$0.207	$0.292
Inverter Option 3: Heliene Poly	$0.161	$0.181	$0.254
Inverter Option 3: CDN Solar Mono	$0.184	$0.206	$0.292
Inverter Option 3: CDN Solar Poly	$0.176	$0.197	$0.279
Inverter Option 3: Sunpower	$0.229	$0.258	$0.369
Inverter Option 3: Panasonic HIT	$0.198	$0.222	$0.315
Inverter Option 3: Prism Bi-Facial	$0.178	$0.199	$0.282

Haines Junction – 1 MW Single Axis Trackers

Table C.1: LCOE for 1 MW installations at Haines Junction (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.171	$0.191	$0.268
Inverter Option 1: CDN Solar Mono	$0.177	$0.199	$0.280
Inverter Option 1: CDN Solar Poly	$0.188	$0.211	$0.297
Inverter Option 1: Sunpower	$0.231	$0.260	$0.370
Inverter Option 1: Panasonic HIT	$0.191	$0.214	$0.303
Inverter Option 1: Prism Bi-Facial	$0.172	$0.192	$0.271
Inverter Option 2: Heliene Poly	$0.170	$0.189	$0.265
Inverter Option 2: CDN Solar Mono	$0.169	$0.189	$0.266
Inverter Option 2: CDN Solar Poly	$0.171	$0.191	$0.269
Inverter Option 2: Sunpower	$0.229	$0.257	$0.365
Inverter Option 2: Panasonic HIT	$0.179	$0.200	$0.281
Inverter Option 2: Prism Bi-Facial	$0.166	$0.186	$0.260
Inverter Option 3: Heliene Poly	$0.156	$0.174	$0.243
Inverter Option 3: CDN Solar Mono	$0.163	$0.182	$0.256
Inverter Option 3: CDN Solar Poly	$0.173	$0.194	$0.272
Inverter Option 3: Sunpower	$0.216	$0.242	$0.344
Inverter Option 3: Panasonic HIT	$0.175	$0.196	$0.276
Inverter Option 3: Prism Bi-Facial	$0.158	$0.176	$0.247

Haines Junction – 1 MW Dual Axis Trackers

Table C.1: LCOE for 1 MW installations at Haines Junction (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaics Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.191	$0.214	$0.302
Inverter Option 1: CDN Solar Mono	$0.199	$0.223	$0.316
Inverter Option 1: CDN Solar Poly	$0.213	$0.239	$0.339
Inverter Option 1: Sunpower	$0.234	$0.263	$0.376
Inverter Option 1: Panasonic HIT	$0.209	$0.234	$0.333
Inverter Option 1: Prism Bi-Facial	$0.183	$0.205	$0.289
Inverter Option 2: Heliene Poly	$0.180	$0.202	$0.284
Inverter Option 2: CDN Solar Mono	$0.188	$0.211	$0.298
Inverter Option 2: CDN Solar Poly	$0.202	$0.226	$0.319
Inverter Option 2: Sunpower	$0.223	$0.251	$0.357
Inverter Option 2: Panasonic HIT	$0.196	$0.220	$0.311
Inverter Option 2: Prism Bi-Facial	$0.172	$0.193	$0.271
Inverter Option 3: Heliene Poly	$0.176	$0.197	$0.278
Inverter Option 3: CDN Solar Mono	$0.184	$0.206	$0.291
Inverter Option 3: CDN Solar Poly	$0.197	$0.221	$0.312
Inverter Option 3: Sunpower	$0.219	$0.246	$0.351
Inverter Option 3: Panasonic HIT	$0.192	$0.215	$0.304
Inverter Option 3: Prism Bi-Facial	$0.169	$0.188	$0.264

Haines Junction – 5 MW Fixed Tilt Racking

Table C.1: LCOE for 5 MW installations at Haines Junction (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.162	$0.182	$0.255
Inverter Option 1: CDN Solar Mono	$0.182	$0.204	$0.289
Inverter Option 1: CDN Solar Poly	$0.181	$0.203	$0.287
Inverter Option 1: Sunpower	$0.231	$0.260	$0.372
Inverter Option 1: Panasonic HIT	$0.200	$0.225	$0.319
Inverter Option 1: Prism Bi-Facial	$0.175	$0.196	$0.278
Inverter Option 2: Heliene Poly	$0.157	$0.176	$0.246
Inverter Option 2: CDN Solar Mono	$0.177	$0.198	$0.280
Inverter Option 2: CDN Solar Poly	$0.176	$0.197	$0.278
Inverter Option 2: Sunpower	$0.226	$0.254	$0.363
Inverter Option 2: Panasonic HIT	$0.195	$0.218	$0.310
Inverter Option 2: Prism Bi-Facial	$0.170	$0.190	$0.269
Inverter Option 3: Heliene Poly	$0.155	$0.173	$0.243
Inverter Option 3: CDN Solar Mono	$0.175	$0.196	$0.276
Inverter Option 3: CDN Solar Poly	$0.174	$0.194	$0.274
Inverter Option 3: Sunpower	$0.223	$0.251	$0.359
Inverter Option 3: Panasonic HIT	$0.192	$0.216	$0.306
Inverter Option 3: Prism Bi-Facial	$0.168	$0.188	$0.265

Haines Junction – 5 MW Single Axis Tracking

Table C.1: LCOE for 5 MW installations at Haines Junction (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.167	$0.186	$0.261
Inverter Option 1: CDN Solar Mono	$0.158	$0.177	$0.250
Inverter Option 1: CDN Solar Poly	$0.159	$0.178	$0.251
Inverter Option 1: Sunpower	$0.192	$0.216	$0.308
Inverter Option 1: Panasonic HIT	$0.173	$0.194	$0.275
Inverter Option 1: Prism Bi-Facial	$0.175	$0.196	$0.278
Inverter Option 2: Heliene Poly	$0.168	$0.188	$0.264
Inverter Option 2: CDN Solar Mono	$0.154	$0.173	$0.244
Inverter Option 2: CDN Solar Poly	$0.159	$0.178	$0.250
Inverter Option 2: Sunpower	$0.188	$0.212	$0.302
Inverter Option 2: Panasonic HIT	$0.169	$0.190	$0.268
Inverter Option 2: Prism Bi-Facial	$0.171	$0.192	$0.272
Inverter Option 3: Heliene Poly	$0.166	$0.186	$0.260
Inverter Option 3: CDN Solar Mono	$0.153	$0.171	$0.241
Inverter Option 3: CDN Solar Poly	$0.157	$0.176	$0.247
Inverter Option 3: Sunpower	$0.187	$0.210	$0.299
Inverter Option 3: Panasonic HIT	$0.167	$0.188	$0.265
Inverter Option 3: Prism Bi-Facial	$0.169	$0.190	$0.269

Whitehorse – 1 MW Fixed Tilt Racking

Table C.1: LCOE for 1 MW installations at Whitehorse (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.208	$0.234	$0.333
Inverter Option 1: CDN Solar Mono	$0.234	$0.264	$0.377
Inverter Option 1: CDN Solar Poly	$0.226	$0.254	$0.363
Inverter Option 1: Sunpower	$0.255	$0.287	$0.414
Inverter Option 1: Panasonic HIT	$0.230	$0.259	$0.371
Inverter Option 1: Prism Bi-Facial	$0.234	$0.263	$0.378
Inverter Option 2: Heliene Poly	$0.194	$0.218	$0.310
Inverter Option 2: CDN Solar Mono	$0.220	$0.247	$0.352
Inverter Option 2: CDN Solar Poly	$0.212	$0.238	$0.339
Inverter Option 2: Sunpower	$0.242	$0.273	$0.392
Inverter Option 2: Panasonic HIT	$0.217	$0.244	$0.348
Inverter Option 2: Prism Bi-Facial	$0.219	$0.246	$0.352
Inverter Option 3: Heliene Poly	$0.190	$0.213	$0.301
Inverter Option 3: CDN Solar Mono	$0.215	$0.241	$0.343
Inverter Option 3: CDN Solar Poly	$0.207	$0.233	$0.331
Inverter Option 3: Sunpower	$0.237	$0.268	$0.384
Inverter Option 3: Panasonic HIT	$0.212	$0.238	$0.340
Inverter Option 3: Prism Bi-Facial	$0.216	$0.243	$0.347

Whitehorse – 1 MW Single Axis Tracking

Table C.1: LCOE for 1 MW installations at Whitehorse (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.191	$0.214	$0.301
Inverter Option 1: CDN Solar Mono	$0.198	$0.222	$0.314
Inverter Option 1: CDN Solar Poly	$0.212	$0.237	$0.335
Inverter Option 1: Sunpower	$0.244	$0.274	$0.391
Inverter Option 1: Panasonic HIT	$0.209	$0.234	$0.331
Inverter Option 1: Prism Bi-Facial	$0.190	$0.213	$0.301
Inverter Option 2: Heliene Poly	$0.226	$0.254	$0.361
Inverter Option 2: CDN Solar Mono	$0.187	$0.209	$0.295
Inverter Option 2: CDN Solar Poly	$0.200	$0.224	$0.315
Inverter Option 2: Sunpower	$0.232	$0.261	$0.371
Inverter Option 2: Panasonic HIT	$0.197	$0.221	$0.311
Inverter Option 2: Prism Bi-Facial	$0.178	$0.199	$0.282
Inverter Option 3: Heliene Poly	$0.176	$0.196	$0.274
Inverter Option 3: CDN Solar Mono	$0.183	$0.205	$0.288
Inverter Option 3: CDN Solar Poly	$0.195	$0.219	$0.308
Inverter Option 3: Sunpower	$0.228	$0.256	$0.364
Inverter Option 3: Panasonic HIT	$0.193	$0.216	$0.304
Inverter Option 3: Prism Bi-Facial	$0.176	$0.197	$0.277

Whitehorse – 5 MW Fixed Tilt Racking

Table C.1: LCOE for 5 MW installations at Whitehorse (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.160	$0.179	$0.252
Inverter Option 1: CDN Solar Mono	$0.180	$0.201	$0.285
Inverter Option 1: CDN Solar Poly	$0.178	$0.199	$0.281
Inverter Option 1: Sunpower	$0.227	$0.256	$0.366
Inverter Option 1: Panasonic HIT	$0.197	$0.221	$0.313
Inverter Option 1: Prism Bi-Facial	$0.172	$0.193	$0.272
Inverter Option 2: Heliene Poly	$0.155	$0.173	$0.242
Inverter Option 2: CDN Solar Mono	$0.174	$0.195	$0.275
Inverter Option 2: CDN Solar Poly	$0.172	$0.192	$0.272
Inverter Option 2: Sunpower	$0.216	$0.242	$0.346
Inverter Option 2: Panasonic HIT	$0.191	$0.214	$0.303
Inverter Option 2: Prism Bi-Facial	$0.167	$0.186	$0.263
Inverter Option 3: Heliene Poly	$0.153	$0.171	$0.240
Inverter Option 3: CDN Solar Mono	$0.173	$0.193	$0.272
Inverter Option 3: CDN Solar Poly	$0.170	$0.191	$0.269
Inverter Option 3: Sunpower	$0.214	$0.241	$0.344
Inverter Option 3: Panasonic HIT	$0.189	$0.212	$0.301
Inverter Option 3: Prism Bi-Facial	$0.165	$0.185	$0.260

Whitehorse – 5 MW Single Axis Tracking

Table C.1: LCOE for 5 MW installations at Whitehorse (Option 1: Schneider; Option 2: SMA; Option 3: ABB)

Photovoltaic Options	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.153	$0.170	$0.238
Inverter Option 1: CDN Solar Mono	$0.151	$0.169	$0.239
Inverter Option 1: CDN Solar Poly	$0.152	$0.170	$0.239
Inverter Option 1: Sunpower	$0.190	$0.214	$0.305
Inverter Option 1: Panasonic HIT	$0.168	$0.189	$0.267
Inverter Option 1: Prism Bi-Facial	$0.165	$0.185	$0.263
Inverter Option 2: Heliene Poly	$0.154	$0.172	$0.241
Inverter Option 2: CDN Solar Mono	$0.148	$0.165	$0.232
Inverter Option 2: CDN Solar Poly	$0.152	$0.169	$0.238
Inverter Option 2: Sunpower	$0.186	$0.209	$0.298
Inverter Option 2: Panasonic HIT	$0.165	$0.184	$0.260
Inverter Option 2: Prism Bi-Facial	$0.162	$0.181	$0.257
Inverter Option 3: Heliene Poly	$0.152	$0.169	$0.237
Inverter Option 3: CDN Solar Mono	$0.146	$0.163	$0.229
Inverter Option 3: CDN Solar Poly	$0.149	$0.167	$0.234
Inverter Option 3: Sunpower	$0.184	$0.207	$0.295
Inverter Option 3: Panasonic HIT	$0.162	$0.182	$0.257
Inverter Option 3: Prism Bi-Facial	$0.159	$0.179	$0.253

Whitehorse – 10 MW Fixed Tilt Racking

Table C.1: LCOE for 10 MW installations at Whitehorse (Option 1: Schneider; Option 2: SMA; Option 3: ABB). NOTE: the cost of energy storage is NOT included in these cost estimates!

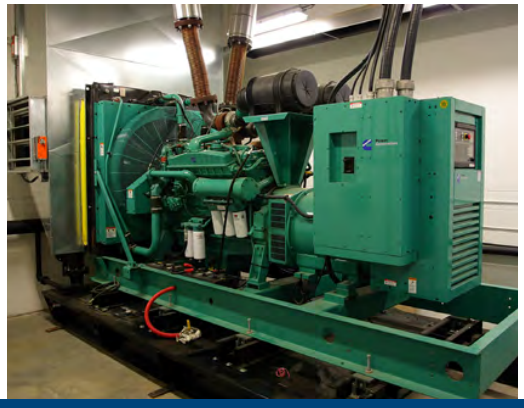
	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.153	$0.171	$0.239
Inverter Option 1: CDN Solar Mono	$0.171	$0.191	$0.270
Inverter Option 1: CDN Solar Poly	$0.170	$0.190	$0.268
Inverter Option 1: Sunpower	$0.203	$0.228	$0.325
Inverter Option 1: Panasonic HIT	$0.188	$0.210	$0.298
Inverter Option 1: Prism Bi-Facial	$0.164	$0.183	$0.258
Inverter Option 2: Heliene Poly	$0.150	$0.167	$0.234
Inverter Option 2: CDN Solar Mono	$0.168	$0.188	$0.265
Inverter Option 2: CDN Solar Poly	$0.167	$0.186	$0.263
Inverter Option 2: Sunpower	$0.200	$0.224	$0.319
Inverter Option 2: Panasonic HIT	$0.185	$0.207	$0.293
Inverter Option 2: Prism Bi-Facial	$0.161	$0.180	$0.253
Inverter Option 3: Heliene Poly	$0.148	$0.165	$0.231
Inverter Option 3: CDN Solar Mono	$0.166	$0.186	$0.262
Inverter Option 3: CDN Solar Poly	$0.165	$0.184	$0.260
Inverter Option 3: Sunpower	$0.198	$0.223	$0.316
Inverter Option 3: Panasonic HIT	$0.183	$0.205	$0.290
Inverter Option 3: Prism Bi-Facial	$0.159	$0.178	$0.250

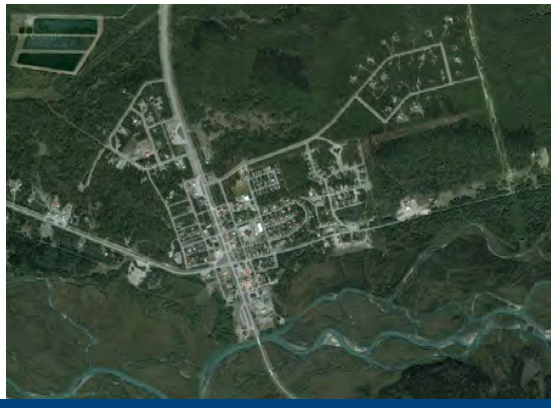
Whitehorse – 10 MW Single Axis Tracking

Table C.1: LCOE for 10 MW installations at Whitehorse (Option 1: Schneider; Option 2: SMA; Option 3: ABB). NOTE: the cost of energy storage is NOT included in these cost estimates!

	3.38% Real WACC	4.61% Real WACC	8.82% Real WACC
	LCOE (2015$)	LCOE (2015$)	LCOE (2015$)
	$/kW.h	$/kW.h	$/kW.h
Inverter Option 1: Heliene Poly	$0.147	$0.164	$0.231
Inverter Option 1: CDN Solar Mono	$0.162	$0.181	$0.256
Inverter Option 1: CDN Solar Poly	$0.162	$0.181	$0.256
Inverter Option 1: Sunpower	$0.170	$0.190	$0.270
Inverter Option 1: Panasonic HIT	$0.172	$0.193	$0.273
Inverter Option 1: Prism Bi-Facial	$0.154	$0.172	$0.242
Inverter Option 2: Heliene Poly	$0.145	$0.161	$0.227
Inverter Option 2: CDN Solar Mono	$0.159	$0.178	$0.251
Inverter Option 2: CDN Solar Poly	$0.160	$0.179	$0.252
Inverter Option 2: Sunpower	$0.167	$0.188	$0.265
Inverter Option 2: Panasonic HIT	$0.170	$0.190	$0.268

Inverter Option 2: Prism Bi-Facial	$0.151	$0.169	$0.238
Inverter Option 3: Heliene Poly	$0.143	$0.160	$0.224
Inverter Option 3: CDN Solar Mono	$0.158	$0.177	$0.249
Inverter Option 3: CDN Solar Poly	$0.158	$0.177	$0.249
Inverter Option 3: Sunpower	$0.166	$0.186	$0.263
Inverter Option 3: Panasonic HIT	$0.168	$0.188	$0.266
Inverter Option 3: Prism Bi-Facial	$0.150	$0.168	$0.236





REPORT

Final FEED Report

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

October 18, 2013

Stantec

This document has been prepared exclusively for the client and the project identified herein.
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.

Disclaimer

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This document entitled Final Report - Front End Engineering Design (FEED) Study, Yukon Bioenergy Demonstration Project in Haines Junction, Yukon was prepared by Stantec Consulting Ltd. for the account of Yukon Energy. The material in it reflects Stantec's best judgment in light of the information available to it at the time of preparation. Any use which a third party makes of this report, or any reliance on or decisions made based on it, are the responsibilities of such third parties. Stantec Consulting Ltd. accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this report.

This version of the report is to support Yukon Energy's public release of the document. Due to the sensitive nature of the feedstock costing information and proprietary and confidential information provided by the equipment vendors, some information has been omitted. Omitted information was deemed to represent breaches of trust related to information transfer during the course of the study, and would impact the competitive advantage of the new company's operations, equipment vendors, and feedstock suppliers.

Executive Summary

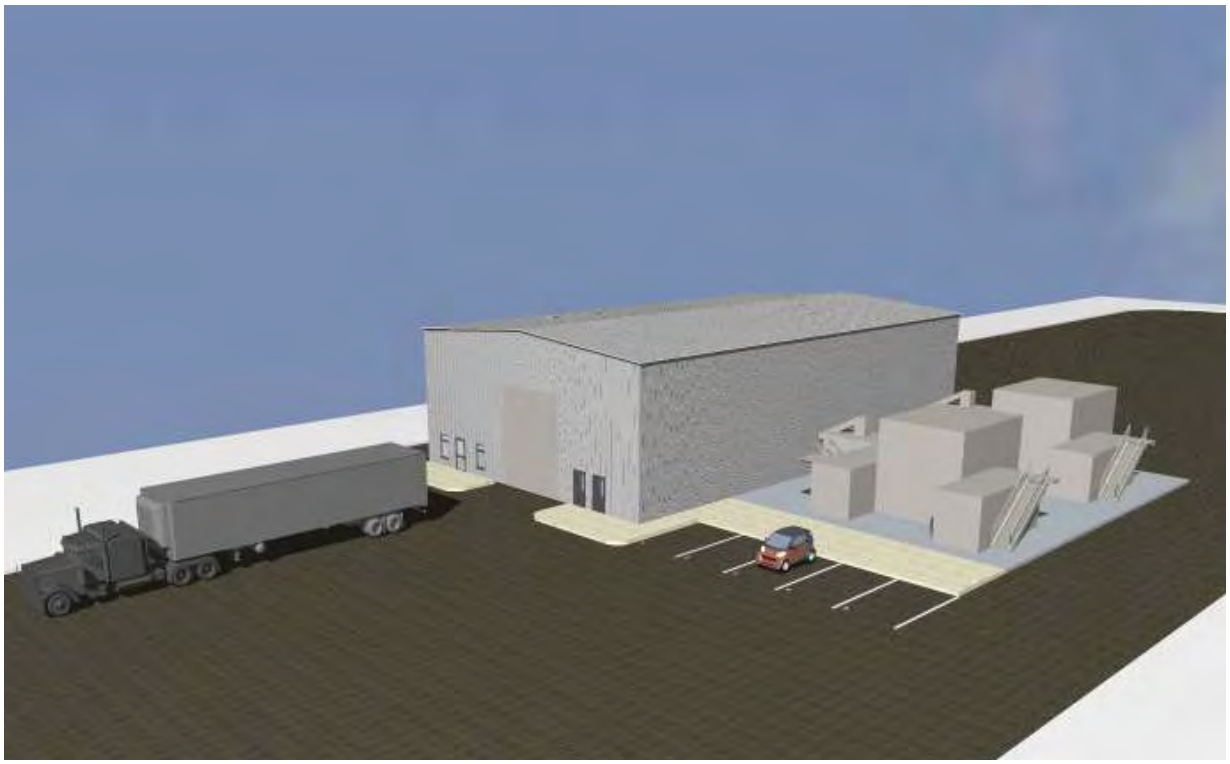
Stantec Consulting Ltd. (Stantec) has been contracted by a Steering Committee led by Yukon Energy Corporation (YEC) and the Champagne and Aishihik First Nations (CAFN) to complete a Front End Engineering Design (FEED) Study for the Yukon Bioenergy Demonstration Project in Haines Junction, Yukon. The focus of the study was to evaluate available biomass gasification technologies for application in the North in the range of 2 MW_e – 4 MW_e and determine its potential viability. The primary objectives were to complete a preliminary design of the facility, define its business case, draft baseline conditions and an impact assessment to form part of a submission to the Yukon Environmental and Socio-Economic Assessment Board (YESAB), and develop and support the engagement of CAFN members and members of the public.

The first steps in the study were to review the available gasification technologies and conduct site visits with members of the Steering Committee. The cursory technology review revealed that although available around the world, gasification technology using a reciprocating engine (as required for the project) is not developed to a high level of commercialization seen with conventional technologies. Any installation made for this project would be one of only a few in Canada, and one of only a handful in comparable cold climates. Furthermore, for most of the vendors contacted for quotations, this installation would represent one of only a few supplying their technology in conjunction with a reciprocating engine.

After narrowing the technology search by those applicable to the study's requirements, three vendors were approached to conduct site visits. Stantec and members of the Steering Committee visited Nexterra, Entropic, and Community Power Corporation (CPC) installations in Canada. Following the site visits, giving consideration to the technology review and waste heat usage, the facility's preliminary design would focus on a smaller generation capacity (0.5 MW_e to 2.0 MW_e) to better align with heating requirements of the village (for combined heat and power production) and to facilitate consideration of smaller gasification technology vendors.

Using the CPC units as a basis, Stantec prepared a preliminary design for a 500 kW_e gasification plant to be located near the centre of Haines Junction to facilitate heating local buildings. Given the smaller installation capacity, the focus of the design was to allow for future expansion for the facility once it is proven at the 500 kW_e scale as a demonstration project. Therefore, the preliminary design incorporated the ability to expand by an addition 500 kW_e, and increase in size to 2.0 MW_e to meet the study objectives. Opinions of probable capital cost and a rendering of the potential facility are presented below:

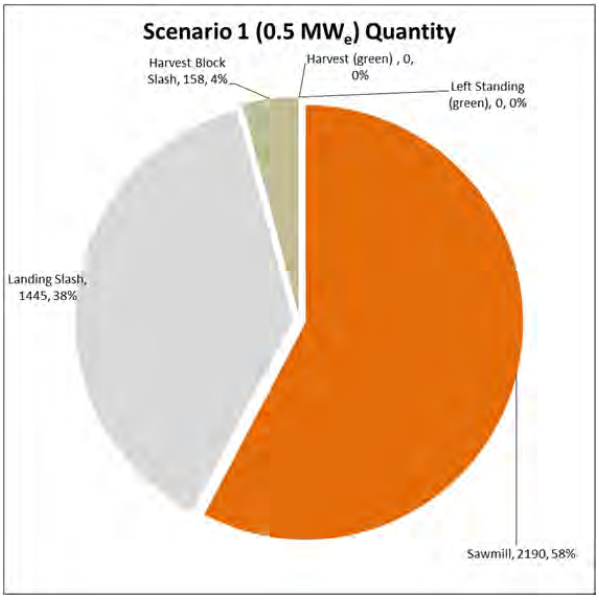
Option	Description	Opinion of Probable Capital Cost
1	500 kWe – Full Building Enclosure	$ 12.7 M
2	500 kWe – Architectural Building Enclosure	$ 13.5 M
3	500 kWe – Fuel Handling Enclosed	$ 11.4 M
4a	1,000 kWe – 500 kWe Expansion	(Exp = $ 9.8 M) $ 22.5 M
4b	2,000 kWe – 1,500 kWe Expansion	$ 45.0 M

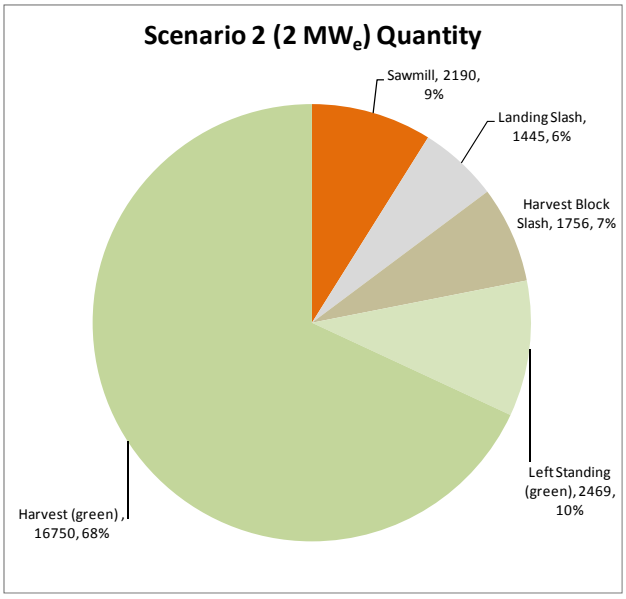


500 kW_e – Fuel Handling Enclosed – Artistic Concept

With any biomass installation, the two greatest ongoing costs are those to fuel the plant, and those for operation and maintenance (O&M). Stantec developed an opinion of operating costs, using the minimum number of operators requested for CPC's equipment, while AGFOR conducted a feedstock assessment to support determining the plant fuel costs as well as the development of the impact assessment. AGFOR's assessment determined that based on existing harvesting operations, a plant capacity of 500 kW_e could likely be supplied with minimal impact to existing operators/policies. This supply would be primarily sawmill residues and forest harvesting residues at the landing and in the harvest block; mostly dead trees from the spruce beetle infestation until that supply runs out. The larger plant capacities would require additional biomass supplied from new harvesting operations/policies and would extend into harvesting green trees sooner. Based on meeting with local regulators and harvesting operators, an opinion of probable supply costs below were determined, including sourcing breakdown.

Option	Description	Opinion of Probable Cost ($/GMT)
500 kWe	Roadside Chipping and Supplied Directly to Plant	Omitted
	Secondary Storage and Chipping	Omitted
2,000 kWe	Roadside Chipping and Supplied Directly to Plant	Omitted
	Secondary Storage and Chipping	Omitted



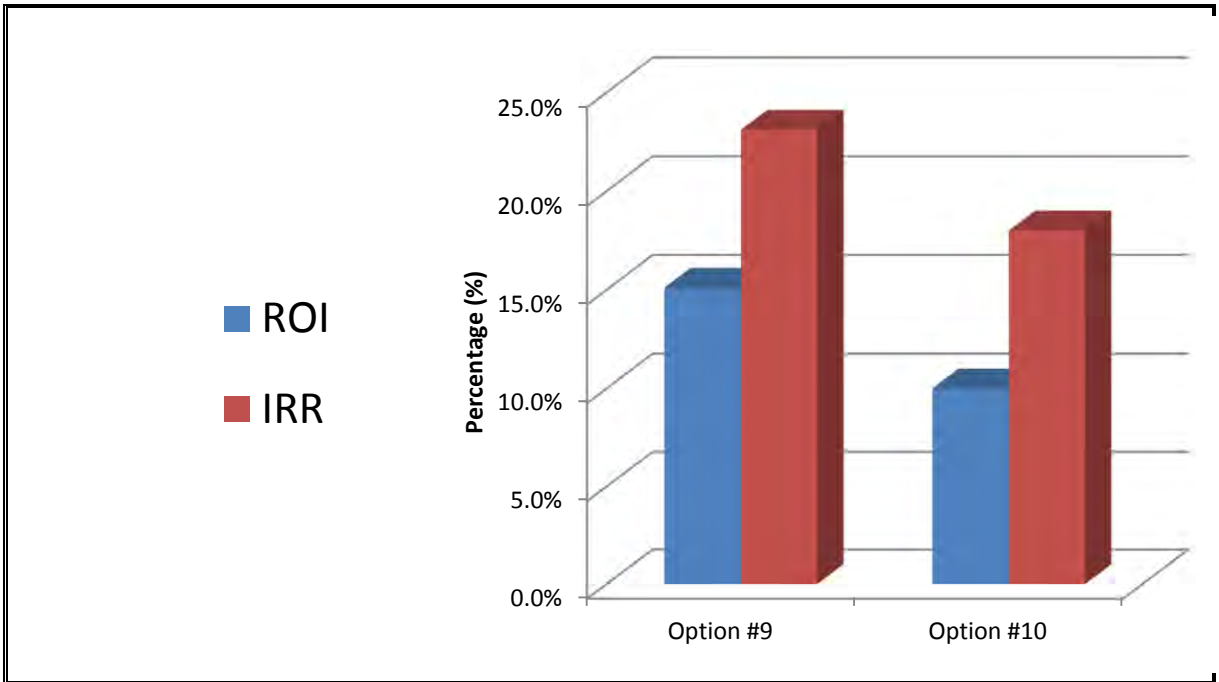


With a preliminary plant and feedstock supply concept established, a draft Environmental and Socio-economic Impact Assessment (IA) was prepared based on information currently available on the project and existing conditions in the area. The report includes an overview of the effects assessment and regulatory regimes associated with permitting the project, scoping of the assessment to include relevant Valued Components (VC), summaries of baseline conditions for each VC and expected effects and proposed mitigation. Determination of significance was based on residual effects after implementation of mitigation. Adaptive management and monitoring activities are also outlined where deemed applicable. The environmental and socio-economic impact assessment report draft is included in an appendix and is drafted to support a complete project submission to YESAB at a later date. The public and First Nation consultation activities are covered in the IA, with the draft engagement plan presented in a separate appendix.

The final aspect of the study was a review of the business model, funding opportunities and assessment of financial viability. Options for owning and operating different aspects of the plant are presented and weighed. The most suitable approach will be dependent on the technology and vendor selected, and the level of involvement in fuel supply the New Company (NEWCO) wishes to assume. A number of avenues for project funding are available, but will again depend on the technology and approach taken on the project; more risky, new technologies that do not have a commercial offering would likely qualify for additional funding, but more commercial technologies likely will not qualify. Continued funding through NRCan, which has funded this study in part, is a top candidate.

The financial analysis focused on ten (10) different plant options that varied with respect to generation capacity, building enclosure design, and vendor selection. To determine the potential viability of these options, financial cases were prepared for each installation taking into account the plant life span, capital and operation costs, and feedstock costing among other key

parameters. Without any initial capital subsidization, none of the options were viable. Project viability was achieved for a select number of options assuming the project partners could successful receive capital subsidies from one or more sources. Impacts of electricity pricing in conjunction with capital subsidy were also explored to assess viability. The highest returns came from switching technology vendors to Proton Power from CPC with the financial results shown in the table below due to their lower quoted price.



	Item	Option #9 – 500 kW_e Fuel Enclosed $50/GMT, $200/MWh, 67% Capital Subsidy
500 kW_e	Return on Investment (ROI)	15.1%
	Internal Rate of Return (IRR)	23.1%
2.0 MW_e	**Item**	**Option #10 – 2000 kW_e Fuel Enclosed $50/GMT, $200/MWh, 67% Capital Subsidy**
	Return on Investment (ROI)	10.0%
	Internal Rate of Return (IRR)	18.0%

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FEED REPORT
FRONT END ENGINEERING DESIGN (FEED) STUDY

Table of Contents

1.0 PROJECT DEFINITION 1.1
1.1 CATALOGUE OF TECHNOLOGIES 1.1
1.1.1 Conversion Options 1.1
1.2 TECHNOLOGY REVIEW AND RANKING 1.3
1.2.1 Catalog of Technologies 1.4
1.3 TECHNOLOGY SELECTION 1.6
1.3.1 Interim Report #1 Technology Recommendation 1.6
1.4 FACILITY VISIT OF SELECT TECHNOLOGIES 1.8
1.4.1 Nexterra Visit 1.8
1.4.2 Entropic Visit 1.9
1.4.3 CPC Visit 1.10

2.0 PRELIMINARY DESIGN 2.1
2.1 VENDOR RESPONSE TO RFQ 2.1
2.1.1 B&W Volund 2.1
2.1.2 Nexterra 2.1
2.1.3 Community Power Corporation 2.3
2.1.4 WEISS 2.5
2.1.5 Proton Power 2.7
2.1.6 Biomass Engineering Ltd. 2.9
2.1.7 Borealis Wood Power Corporation (Spanner Re2 GmbH) 2.11
2.1.8 E-Rational (ORC –Technology) 2.12
2.2 VENDOR COMPARISON 2.13
2.3 FACILITY SITING ASSESSMENT 2.15
2.4 PRELIMINARY DESIGN AND CAPITAL COST 2.18
2.4.1 Option #1 – Full Building Enclosure – 500 kW_e 2.18
2.4.2 Option #2 – Full Architectural Enclosure – 500 kW_e 2.32
2.4.3 Option #3 – Fuel Handling Enclosed – 500 kW_e 2.35
2.4.4 Option #4 – Options for Expansion – 500 kW_e, 1000 kW_e, & 2000 kW_e 2.36
2.5 OPERATING COST 2.38
2.5.1 Opinion of Probable O&M Costs 2.40
2.6 FEEDSTOCK CHARACTERIZATION (AGFOR) 2.40
2.6.1 Harvesting and Existing Industries 2.40
2.6.2 From the Forest 2.44
2.6.3 Moisture Content 2.45
2.6.4 Feedstock Cost 2.46
2.6.5 Pre-Processing Implications of Biomass Properties 2.49

3.0 ENVIRONMENTAL ASSESSMENT AND PERMITTING 3.1
3.1 REGULATORY APPROVALS STRATEGY 3.1
3.2 DESKTOP FEEDSTOCK HARVESTING ANALYSIS 3.2
3.3 RISK MANAGEMENT STRATEGY FOR ENVIRONMENTAL/SOCIO-ECONOMIC AND REGULATORY APPROVALS 3.5

Stantec

FEED REPORT
FRONT END ENGINEERING DESIGN (FEED) STUDY

TABLE OF CONTENTS

3.3.1 Gaps and Uncertainties 3.5
3.3.2 Feedstock Harvesting 3.6
3.3.3 Next Steps 3.7
3.3.4 Preliminary Field Study and Permitting Schedule 3.9

4.0 RISK, FINANCIAL & OPERATIONS ANALYSIS 4.1
4.1 SOURCES OF PROJECT FINANCING 4.1
4.1.1 Sustainable Development Technology Canada 4.1
4.1.2 The ecoENERGY Innovation Initiative 4.1
4.1.3 Potential Funding Sources 4.2
4.2 NEWCO BUSINESS MODELS 4.3
4.2.1 Risk Analysis 4.5
4.2.2 Risk Analysis Summary 4.11
4.2.3 Financial and Operational Analysis 4.12
4.2.4 Biomass Plant Analysis 4.14
4.2.5 Summary of Analyses 4.17
4.2.6 Conclusion 4.18
4.3 FINANCIAL ANALYSIS 4.18
4.3.1 Sensitivity Analyses 4.25

5.0 NEXT STEPS 5.1
5.1 NEXT LEVEL OF DEVELOPMENT 5.1
5.2 IMPLIMENTATION SCHEDULE 5.4

6.0 WORKS CITED 6.1

7.0 APPENDICES 7.1

APPENDIX A INTERIM REPORT # 1
APPENDIX B INTERIM REPORT # 2
APPENDIX C VENDOR PACKAGES
APPENDIX D BASIS OF ESTIMATE – OPTION # 1
APPENDIX E ARCHITECTURAL UPGRADE - OPTION # 2
APPENDIX F BASIS OF ESTIMATE – OPTION # 3
APPENDIX G 500 kWe EXPANSION – OPTION # 4
APPENDIX H IMPACT ASSESSMENT
APPENDIX I ENGAGEMENT PLAN
APPENDIX J FINANCIALS
APPENDIX K IMPLEMENTATION SCHEDULE

Stantec

FEED REPORT
FRONT END ENGINEERING DESIGN (FEED) STUDY

TABLE OF CONTENTS

TABLES

Table 1.1 Properties of Gasification Reactor Types (McKendry, 2001) 1.2
Table 1.2 Advantages and Disadvantages of Biomass Pyrolysis Systems (Vamvuka, 2011) 1.3
Table 1.3 Interim Report Screening Criterion 1.4
Table 1.4 Sample Technology Screening Scorecard 1.5
Table 1.5 Summary of Vendor Scorecards 1.7
Table 2.1 Nexterra Summary 2.2
Table 2.2 Community Power Corporation Summary 2.4
Table 2.3 Weiss (Scan America) Summary 2.6
Table 2.4 Proton Power Summary 2.8
Table 2.5 Biomass Engineering (UK) Summary 2.10
Table 2.6 Borealis Wood Power Corporation (Spanner) Summary 2.12
Table 2.7 Vendor Comparison 2.14
Table 2.8 Option #1 Opinion of Probble Capital Cost 2.31
Table 2.9 Option #2 Opinion of Probble Capital Cost 2.34
Table 2.10 Option #3 Opinion of Probble Capital Cost 2.36
Table 2.11 Option #4 Opinion of Probble Capital Cost 2.38
Table 2.12 Opinion of Probable Conventional Biomass O&M Costs 2.40
Table 2.13 Opinion of Probable Harvest and Sawmill Residues (GMT) 2.44
Table 2.14 Feedstock Moisture Content 2.45
Table 2.15 Summary of Feedstock Requirement 2.46
Table 2.16 Employment Impacts from Biomass Plant 2.51
Table 4.1 Business Model Options Analysis 4.4
Table 4.2 Scoring Structure 4.5
Table 4.3 Risk Score Summary – Feedstock Yard/Logging 4.5
Table 4.4 Risk Assessment – Feedstock Yard/Logging 4.6
Table 4.5 Risk Summary – Biomass Plant 4.8
Table 4.6 Risk Assessment – Biomass Plant 4.9
Table 4.7 Risk Summary 4.11
Table 4.8 Financial and Operations Analysis – Feedstock Yard/Logging 4.13
Table 4.9 Financial and Operations Analysis– Biomass Plant 4.15
Table 4.10 Financial and Operations Summary 4.17
Table 4.11 Recommended Owner/Operator Model 4.18
Table 4.12 Financial Inputs: Options #1 - #6 ..... 4.20
Table 4.13 Financial Inputs: Options #7 - #10 ..... 4.20
Table 4.14 Financial Assumptions 4.21
Table 4.15 Biomass Plant Return on Investment Performance: CPC 4.22
Table 4.16 Biomass Plant Return on Investment Performance: Proton Power 4.23
Table 4.17 Tornado Diagram Results 4.29
Table 5.1 Implementation Schedule 5.5

Stantec

FEED REPORT
FRONT END ENGINEERING DESIGN (FEED) STUDY

TABLE OF CONTENTS

FIGURES

Figure 2.1 Building Heating Locations with 400 m Buffers 2.16
Figure 2.2 Biomass Potential Plant Location 2.17
Figure 2.3 Expansion Incremental Costing 2.37
Figure 2.4 Harvesting Tiers 2.42
Figure 3.1 YESAA Simplified Process Flow Diagram for 2.0 MW Capacity 3.11
Figure 4.1 Potential Proton Power Containerized 500 kW_e Units 4.19
Figure 4.2 ROE Capital Subsidy Sensitivity 4.24
Figure 4.3 ROE Electricity Price Sensitivity 4.24
Figure 4.4 ROE/NPV Feedstock Price Sensitivity 4.26
Figure 4.5 ROE/NPV Annual Plant O&M Price Sensitivity 4.27
Figure 4.6 ROE/NPV District Heating Sales Sensitivity 4.27
Figure 4.7 ROE/NPV District Heating Sale Price Sensitivity 4.28
Figure 4.8 ROE/NPV District Heating Sale Price Sensitivity 4.29

1.0 Project Definition

At the project's onset, it was necessary to define the technology base that would be applicable to the project and the community that would house it. To this end an initial catalogue of technologies was prepared, reviewed and ranked, and ultimately used to determine the project's path forward. This section covers an overview of the findings of this effort as was presented in the project's Interim Report #1. The interim report is attached in Appendix A for further information and reference.

1.1 CATALOGUE OF TECHNOLOGIES

The production of electricity through the conversion of biomass can be accomplished using a variety of different processes and a multitude of feedstocks. The production of bioenergy not only employs a previously underutilized fuel source, but also mitigates the effects of energy production on the environment. When selecting the appropriate technology, it is important to keep in mind the available feedstocks, required amount of generated electricity, environmental standards, capital cost, and process efficiency (McKendry, 2001). Accordingly, with timber being the sole feedstock at the present time, and the target energy production range at the time of the interim report being 2 - 4 MW_e, three different types of biomass conversion options will be investigated: gasification, pyrolysis and an externally fired gas turbine.

1.1.1 Conversion Options

Each of the conversion options, along with their different reactor types and/or arrangements are described in detail in the report presented in Appendix A. Summary tables for the main advantages and disadvantages for the host of technologies are presented in Table 1.1 and 1.2. Of all the technologies, the updraft and downdraft gasifiers were the most applicable to the requirements of the project from the standpoint of complexity, power generation capacity, feedstock acceptance, and level of development.

Table 1.1 Properties of Gasification Reactor Types (McKendry, 2001)

Reactor Type	Advantages	Disadvantages
Fixed bed, updraft	Simple, inexpensive process Exit gas temperature about 250°C Operates satisfactorily under pressure High carbon conversion efficiency Low dust levels in gas High thermal efficiency	Large tar production Potential channeling Potential bridging Small feed size Potential clinkering
Fixed bed, down draft	Simple process Only traces of tar in product gas	Minimum feed size Limited ash content allowable Limits to scale up capacity Potential for bridging and clinkering
Fluidized bed, circulating	Flexible process Up to 850°C operating temperature	Corrosion and attrition problems Poor operational control using biomass
Fluidized Bed, bubbling	Flexible feed rate and composition High ash fuels acceptable Able to pressurize High CH_4 in product gas High volumetric capacity Easy temperature control	Operating temperature limited by ash clinkering High product gas temperature High tar and fines content in gas Possibility of high C content in fly ash

Table 1.2 Advantages and Disadvantages of Biomass Pyrolysis Systems (Vamvuka, 2011)

Reactor Type	Advantages	Disadvantages
Fluid type	Good solids mixing High heat transfer rates Good temperature control Ease of scaling	Heat transfer to bed must be proven at large scale Max particle sizes up to 6 mm If circulating, increased complexity of system, char attrition and reactor wear
Entrained flow	None	Low heat transfer rates Limited gas/solid mixing Small particle sizes required
Rotating cone	Good solids mixing No carrier gas required Ease of scaling Small investment cost	Heat transfer to bed must be proven at large scale Small particle sizes required
Vacuum reactor	No carrier gas required Lower temperature required Can process larger particles	Low heat transfer rates Solids residence time high Liquid yield rather low
Ablative reactor	Heat transfer gas not required Lower temperature required Can process larger particles Compact design and intensive system	Reaction rates limited by heat transfer to the reactor Char abrasion Scaling is costly

1.2 TECHNOLOGY REVIEW AND RANKING

Throughout the world one can find biomass gasification taking place from a scale suitable to heat a home, to that to capable of generating electricity to supply the grid. The focus of this study was to concentrate on a gasification technology capable of producing a syngas for cleanup that could then be introduced to a reciprocating engine in the initial capacity range of 2 – 4 MW_e. Although the technology could be innovative, it must be at or near commercialization to facilitate its installation in a northern community (i.e., not for research but practical/reliable use). Several technologies also require the use of steam, which is not available through co-locating near an existing facility, nor considered for self-generation. Two other biomass technologies were showcased for comparison (external fired gas turbine and pyrolysis-oil/ethanol/bio-oil).

To facilitate screening of the technologies, a ranking or scoring system was established to support the technology recommendation. The criterion used for the ranking system as well as the points awarded by criterion are outlined in Table 1.3. The ranking system does not include items affecting all the biomass systems, such as feedstock availability, socio-economic viability,

job creation, or permitting requirements as these are common to all the systems at this level of evaluation.

Table 1.3 Interim Report Screening Criterion

Level of Development	R&D / Pilot – 0 Pts.	Demonstration – 3 Pts.	Commercial – 5 Pts.
Capacity Range	Outside 2-4 MW_e – 0 Pts.	Within 2-4 MW_e* - 5 Pts.	
Use of Engine for Power	No – 0 Pts.	Yes – 5 Pts.	
Gasification Complexity**	Advanced – 0 Pts.	Standard – 3 Pts.	Direct Comb. – 5 Pts.
Installation Base	1 Installation – 0 Pts.	2 Installations – 3 Pts.	More than two – 5 Pts.
Steam Required	Yes – 0 Pts.	No – 5 Pts.	
Achievable Score	**Minimum – 0 Pts.**	**Maximum – 30 Pts. (100%)**	

* Includes modular units capable of entering range (i.e. if maximum size is 1 MW_e, two units could be installed to enter desired range). Units significantly larger than the range would be excluded due to uncertainties regarding scale-down.

** Complexity is based on system design. Advanced is representative of dual bed or pressurized gasifiers, BFBs, and CFBs; Standard represents draft gasifiers (low to medium Btu syngas) to clean-up and the engine; and Direct Combustion is for the externally fired gas turbine.

1.2.1 Catalog of Technologies

In the interim report, each technology was ranked according to the screening criterion presented in Table 1.3. A sample of the scorecard developed for each technology considered is presented on the following page in Table 1.4. Please refer to Appendix A for the scorecards prepared for the other technology vendors.

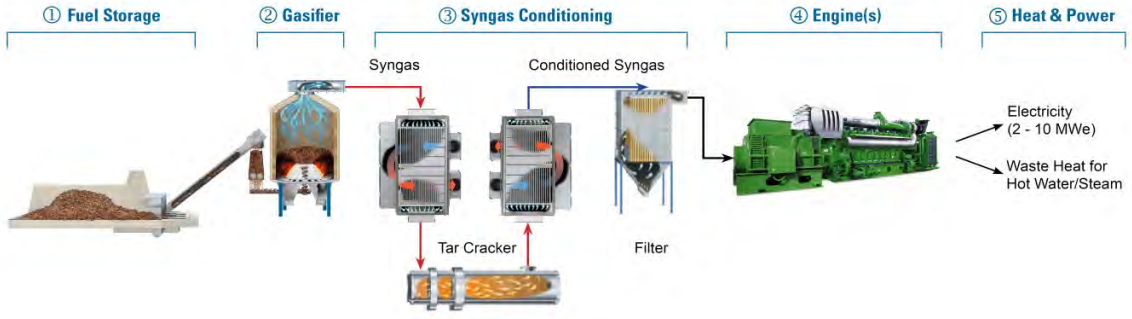
Table 1.4 Sample Technology Screening Scorecard

Developer / Company:	Nexterra Systems Corp.	**Location:**	Multiple – Oak Ridge, Vancouver, Victoria, North Carolina, New Westminster, UBC
Owner:	Various	**Status:**	Operational
Technology:	Dual Bed (BFB & CFB)	**Tech Status:**	Demonstration CHP
Capacity:	UBC: 2 MW_e, 3 MW_{th}	**Application:**	CHP w/ District Heating

Nexterra is the most recognizable Canadian gasification vendor. With installations of their gasifier throughout Canada and the USA, they have developed a solid platform for biomass gasification (low-medium calorific value syngas). Their most recent installation on the University of British Columbia campus is their first CHP using a reciprocating engine. The complexity of the system is Standard with an updraft gasifier and syngas clean-up. Nexterra's gasifier is a proven technology (for heating and steam turbine applications, but not in conjunction with an engine) and does not require steam.

Level of Development	Demonstration – 3 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Standard – 3 Pts.
Installation Base	1 Installations – 0 Pts.
Steam Required	No – 5 Pt.
Score	**21 Pts. (70%)**

Nexterra Advanced Biomass Heat and Power System



SIMPLIFIED ILLUSTRATION

① Fuel Storage - wood residue delivered to storage facility and conveyed to gasifier.
② Gasification Technology - gasification process converts wood residue into clean, renewable synthetic gas or "syngas."
③ Syngas Conditioning Technology - syngas is conditioned and upgraded to meet fuel specification for engine.
④ Engine(s) - high-efficiency internal combustion engine(s) operates on syngas instead of natural gas to generate electricity & heat.
⑤ Heat & Power - systems will generate heat & electricity at small-scale (2 - 10 MWe) economically with efficiencies of up to 65%.

1.3 TECHNOLOGY SELECTION

A summary of the technology scorecards determined in the interim report is presented in Table 1.5 on the following page. In reviewing each vendor's score, the top scores, greater than 20 pts., were ranked from one (1) to six (6). Given the criteria considered, the smaller, modular systems in the smaller capacity ranges took the top two rankings: (1) Community Power Corp., and (2) Biomass Engineering Ltd. The other downdraft unit, Pyroforce ranked third (3) followed by the alternative external fired gas turbine unit (4) Talbott's/Entropic. The final two rankings represent the larger updraft systems: (5) Nexterra, and (6) B&W Vølund. As a select number of vendors were used to represent each category, the groupings in the table highlight which has the best potential to be applicable to this project. This approach was selected with the understanding that bids from additional vendors would be considered later in the project.

1.3.1 Interim Report #1 Technology Recommendation

The technology summary in the previous subsection ranked three (3) technologies as front-runners based on their current installation base and applicability to general project requirements. In order to make a meaningful recommendation at the time the interim report was completed, it was also important to assess as many known considerations as possible. Additional consideration was given to feedstock supply (or lack of secure supply), the availability of trained operators, and plant efficiencies (or production of waste heat). These additional considerations lead to the recommendation to consider a smaller sized plant (or small capacity units) as they require less fuel (easier to secure feedstock), typically required a lower skillset operator (ex-electricians/mechanics compared to stationary engineers), and scored higher on the screening assessment. Part of this recommendation also served to match the plant capacity to the building heating load available in the village.

Table 1.5 Summary of Vendor Scorecards

Technology	Developer/ Owner	Level of Develop.	Capacity Range	Engine	Complexity	Installation Base	Steam Req.	Score	Rank	Elec. Eff.*	Enivron
'Large Scale" Gasification											
Bubbling Fluidized Bed (5,500 kW_e)	Andritz-Carbona (EU – Denmark)	5	0	5	0	0	0	10 (33%)			
2 – 4 MW_e Gasification											
Updraft Gasifier (2,000 kW_e)	Nexterra (CAN – BC)	3	5	5	3	0	5	21 (70%)	5	26%	
Updraft Gasifier (2,000 kW_e)	B&W Vølund (EU – Denmark)	5	5	5	0	5	0	20 (67%)	6		
Dual Bed (2,700 kW_e)	FICFB (Repotec) (EU – Austria)	3	5	5	0	3	0	16 (53%)			
Small Scale / Modular Gasification											
Downdraft Gasifier (100 kW_e)	Community Power Corp. (NA – USA)	5	5	5	3	5	5	28 (93%)	1	20%	California Certified
Downdraft Gasifier (300 kW_e)	Biomass Engineering (EU – UK)	5	5	5	3	3	5	26 (87%)	2		
2-Zone Downdraft (150 kW_e)	Pyroforce (EU – Swiss)	3	5	5	3	3	5	24 (80%)	3		

* Approximate based on published information

1.4 FACILITY VISIT OF SELECT TECHNOLOGIES

Based on the results of technology assessment it was desired to see a number of units in operation. Interim Report #2, available in Appendix B, covers the results of the vendor visits in detail. The next two sub-sections present the overall results of the Nexterra and CPC site visit.

1.4.1 Nexterra Visit

The site visit for Nexterra took place at 10:00 am on Monday, November 5, 2012 on the UBC campus. Phil Beaty, Vice President, Strategic Relationships, for Nexterra, and Brent Sauder, Director, Strategic Initiatives for UBC facilitated the visit. Initially the group met in a conference room on campus to discuss the university's experience during the project's development and execution. This was followed by a guided tour of the facility with the Nexterra representative and operating staff only. During the visit, the plant was operational.

1.4.1.1 Project Overview

This project was kick-started by John Grace of UBC based on his academic research into gasification and more specifically gas conditioning/clean-up. UBC and Nexterra wanted a demonstration-sized plant to prove the concept and facilitate R&D at the university. Based on the UBC concept, GE came in as a partner and supported the development.

UBC is unique in that it is its own municipality with its own substation. The challenge in BC is the low power rates brought on by their hydro resources. That said, UBC still had the desire to demonstrate a BC technology in BC. On the waste heat side, they are also in the process of converting their existing steam district heating system over to hot water.

For UBC the social license was the first step, with five (5) sites initially under consideration. Faculty members were quick to get onboard for the research ability, and the community soon adopted a "yes, in my backyard" mentality. In the end, the unit was located on the edge of the campus in order to reduce truck traffic for fuel deliveries. During full operation, UBC receives three (3) trucks a day, with enough storage for a three (3) day weekend.

On the permitting side, UBC requested the strictest emission regulations be met. To that end, UBC requested that the system be designed and will be tested to meet Metro Vancouver requirements, as well as those in the USA jurisdictions of San Joaquin Valley and the state of Massachusetts. The facility is further equipped with a local and external air shed monitoring system.

Building construction was initially completed using standard steel building formats. During the project's development UBC worked with FP Innovations and selected a new construction method – cross-linked timber or CLT. The current facility uses CLT for the roof and walls of the building.

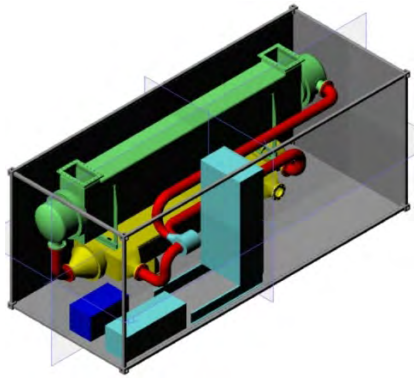
The Nexterra system does require trained operators to run the facility. Operators would require similar skills to that of boiler operators, and if a hot water system was installed, they would not require steam tickets. That said, a 4th to 3rd class ticket would be a starting point for skilled operator requirements. Although the system is automated, skilled operators are required to react quickly in an upset condition. As a minimum, the system requires two (2) full-time staff on-site 24 hours a day / 7 days a week. Currently the UBC plant operates in eight (8) hours shifts, requiring a minimum of eight (8) trained operators to support the plant.

1.4.1.2 Overall Impression

General impression of the group following the visit was that the installation was very large and more complex than expected. The size of the facility, number of operators, and perceived complexity of operation did not seem appropriate for a unit to be located in Haines Junction. The capital cost, maintenance requirements, parts availability, and service technician/operator skill set were also of concern. Mr. Beaty re-iterated that the UBC unit was the first of its kind for Nexterra and they are not actively marketing it. It will be more than a year before annual performance numbers are available, and only then would Nexterra begin to entertain installing their second unit. Further discussion revealed that Nexterra is not interested in a northern site for their second installation.

1.4.2 Entropic Visit

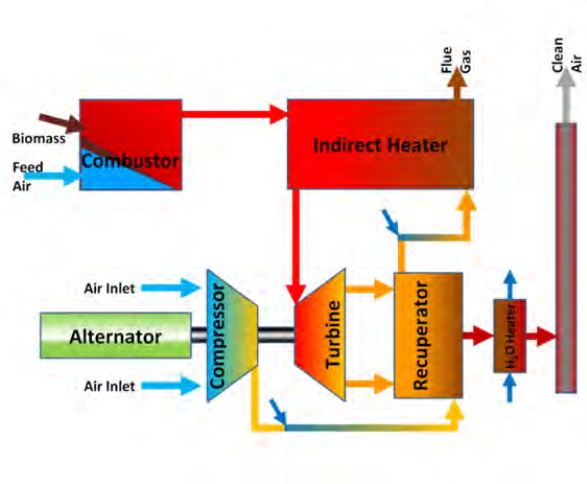
The site visit for Entropic took place at 9:00 am on Tuesday, November 6, 2012 on the University of Manitoba (U of M) campus. Dr. Eric Bibeau, NSERC/Manitoba Hydro Industrial Research Chair in Alternative Energy and co-founder of Entropic, facilitated the visit. Initially the group met in Dr. Bibeau's office on campus to discuss Entropic's technology and product development. This was followed by a guided tour of the installation with Dr. Bibeau. During the visit, the plant was not operational and it was unclear when it would achieve demonstration status.



1.4.2.1 Project Overview

Entropic is in the R&D stages of their technology. The concept is to design a biomass system with a small footprint that can compete on a conventional technology's price point of $4M/MW$_e$.

Using the price point as a basis Dr. Bibeau and this team are trying to apply a hybrid Brayton Cycle to achieve high efficiency power generation in a modular package of 250 kW_e.



The Entropic design builds upon that of the indirect fired Brayton Cycle. The principle difference is in the thermodynamics in that they inject water at critical points in the process to increase unit efficiency. Although only currently theoretical in models, the team at U of M are trying to get their unit up and running. Should they be successful, the hybrid design touts the benefits of maximized energy transfer through increase mass through the turbine, decreased turbine inlet temperature (therefore reduced stress on the unit), maximize equipment capacities, and overall increase in efficiency – to double that of a standard externally fired unit.

1.4.2.2 Overall Impression

General impression of the group following the visit was that this technology/vendor was not appropriate for future consideration. The technology is not near a viable status for consideration on this project, though appears promising.

1.4.3 CPC Visit

The site visit for Community Power Corporation (CPC) took place at 1:00 pm on Tuesday, November 6, 2012 at Pineland Forest Nursery in Hadashville, Manitoba. Carl Peterson, Field Engineer, facilitated the visit for CPC. This unit is located on, and integrated to Pineland's operations, but is owned by Manitoba Hydro. Jeremy Langner is the Project Manager for Manitoba Hydro (MH), but was unavailable at the time of the site visit. Mr. Langner did provide Stantec with some information on the project as a follow-up to the visit. The General Manager of Pineland, Trevor Stanley, was also unable to attend the site visit, but joined the group later in the evening to answer questions and discuss the project. The tour of the unit took place immediately upon arrival, with questions & answers carrying the group through until departure. During the visit the plant was operational.

1.4.3.1 Project Overview

The following overview was developed from follow-up information provided by Mr. Langner.

The CPC system is manufactured in a series of five (5) 20 ft. shipping containers. Shipping the unit in this containerized form allows the majority of the work to be performed at the manufacturer's facility. The Pineland system was installed in June and July 2012, and Manitoba Hydro/CPC/Pineland have been testing it ever since. The unit has been run to peak capacity and has been able to generate a maximum of approximately 120 kW_e of electricity gross, with about 20 kW_e of parasitic loss. Pineland is also recovering heat off of the engine's cooling jackets and exhausts, and sending this to a thermal loop to heat greenhouses. The heat supplements Pineland's existing 2 MW_{th} biomass boiler, located in an adjacent building.

The CPC system uses a stainless steel downdraft gasifier with air injection points throughout the fixed bed. A vibrating grate can dump material if required. The temperature profile is precisely controlled throughout the bed to insure good gas quality. This allows the filtration system to be very simple – filter bags with backup carbon safety filters. This filters out a very fine carbon dust from the gas. The gas is then sent to two (2) 8.1 L V8 spark-ignition engines, each connected to a 65 kW_e alternator. Another feature of the system is the biomass dryer that uses heat from the gas cooling heat exchanger to dry the feedstock. This allows MH/Pineland to accept up to 45% moisture content, and dry down to approximately 15% moisture.

With regards to fuel rates and flows, MH currently pays in the range of $55 to $65 per tonne as delivered for their biomass supply. The wood chips come from several sources within 2 hours or less of the project site. The fuel consumption is stated by CPC as 90 kg of dry biomass per hour, however, MH have not been running consistently enough to determine a more accurate figure. The CPC system can accept ¼" x ¼" through 2" x 2" chips.

As far as maintenance costs are concerned, MH does not have enough data to provide concrete figures. It will highly depend on the number of oil changes per month. CPC has specified an oil change every 10 days. MH are also budgeting the equivalent of 1 hour per day of daily checks, and two (2 to 3 man-days per month spent on gasifier maintenance. During this initial start-up phase, these numbers are expected to be higher.

Operating efficiency is also difficult to determine giving the limited operating hours. Assuming MH/Pineland are burning 90 kg/hr for 100 kW of output (net), and the biomass has a higher heating value of 20 MJ/kg (dry), MH would have a net electrical efficiency of approximately 20%. MH believes that the total efficiency will be at least double when they include the heat.

In a discussion with the Mr. Peterson, CPC typically provides four weeks of commissioning and start-up services. This includes two (2) weeks on-site to commission the unit and systems, one (1) week of full-time training for site personnel, and one (1) week of field supervision following the training. Beyond the four (4) weeks, Mr. Peterson indicated that CPC monitor the unit

remotely for any system warnings or errors. As for the level of skill required to operate the units, Mr. Peterson indicated that the majority of operators are ex-electricians or ex-mechanics. Ex-electricians are preferred give the system electronics and potential advantage when troubleshooting problems, but both have been successful at operating the units.

1.4.3.2 Overall Impression

General impression of the group following the visit was that this technology/vendor was the most appropriate of those visited for Haines Junction. Apart for the small capacity (100 kW_e) the plant's simplicity of operation, level of operator skill required, and proven heat recovery potential make it a strong candidate for installation in the Yukon.

2.0 Preliminary Design

The following subsections outline the preliminary engineering for the FEED study. The first subsection reviews information on the vendors contacted as part of the RFQ process. Vendor information packages are presented in Appendix C for the Steering Committee's review and reference. Not all information requested is available and follow-up requests and questions have been made to the vendors.

The final two subsections outline the facility siting exercise as well as aspects of the preliminary design and opinions of probable cost. The costing presented covers the preliminary options to utilize the CPC 500 kW_e (2 x 250 kW_e) units both inside a building (Option #1) and outside a building (Option #3). An option to have the building exterior completed with an architectural design is also provided (Option #2). As the intent would be to expand the demonstration project in the near future, a fourth option is presented to expand the initial 500 kW_e plant by an additional 500 kW_e in Option #4.

Each option is reviewed briefly in this report with additional information available in Appendix D (Option #1), Appendix E (Option #2), Appendix F (Option #3), and Appendix G (Option #4). Appendices contain the engineering drawings created to support the costing effort as well as the more detailed line item opinions of probable capital cost.

2.1 VENDOR RESPONSE TO RFQ

Each of the vendors contacted as part of the RFQ process are reviewed in the following subsections with their detailed packages contained in Appendix C. Information contained here and in the appendix represents vendor proprietary information and costing. This should not be considered for distribution outside the project team.

2.1.1 B&W Volund

Despite initially being a promising technology source, discussions with B&W Volund revealed otherwise. Upon conversing about the project details, particularly the feedstock characterization, it was determined that the moisture content present in the feedstock was too low for use in B&W Volund's technology. They therefore declined to provide a quotation/information package.

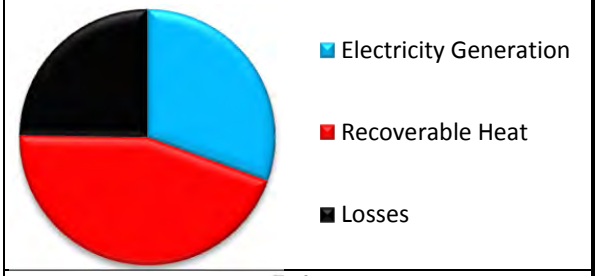
2.1.2 Nexterra

As mentioned previously during the site visit of their facility at UBC, while being an appropriate technology it is not being actively marketed. Nexterra wishes to operate the UBC unit for at least a year before pursuing a second installation. Even after a year, the general impression provided by Nexterra was that the next installation is not likely to be in the North.

2.1.2.1 Vendor Summary

To quickly highlight key aspects of the vendor's response, Table 2.1 has been prepared to summarize data provided. A comparison table of all vendors is available in the next sub-section.

Table 2.1 Nexterra Summary

nexterra		**Headquarters:**	Vancouver, British Columbia	
Developer / Company:	Nexterra	**Vendor Rep:**	None	
System Information	**Quoted Capacity:**	2.0 MW_e		
	Model Number:	Standard CHP System		
	System Configuration:	1-Stage Updraft Gasifier, 1x IC Engine		
	**denotes scaled values*	**As Quoted**	**500 kW_e**	**2.0 MW_e**
Fuel Requirements	**Moisture Content as Fired:**	20%		
	Feedstock Consumption (dry basis):	1,474 kg/hr 3,250 lb/hr	N/A	1,474 kg/hr 3,250 lb/hr
	Feedstock Size:	N/A		
Unit Performance	**Net Electric Generating Capacity:**	2.0 MW_e	N/A	2.0 MW_e
	Operating Parasitic Load:	N/A	N/A	N/A
	Availability:	91%		
	Recoverable Heat:	2.93 MW_{th}	N/A	2.93 MW_{th}
				
	Cogeneration Efficiency:	75%		
	Electrical Efficiency:	31%		
Commercial	**Delivery Lead Time:**	N/A		
	Published Equipment Price:	$18M - $20M	N/A	$18M - $20M

2.1.3 Community Power Corporation

In response to our RFP, Community Power Corporation responded with a budgetary proposal for the design, supply, transportation to site, and supervision of erection and startup, of a demonstration bioenergy system. The proposal outlined several risks that CPC was concerned with that may have a significant impact on the project. These included:

- Long-term bioenergy system reliability and availability (downtime) have not yet been confirmed in a remote, cold climate community.
- Impact of cold climate is not yet known on system performance.
- Operation and maintenance costs need to be verified.
- Sustainable biomass harvesting plan needs to be confirmed.
- Impact of biomass variability on system performance needs to be confirmed (biomass type, heating value, cleanliness, moisture content, etc.).
- Requirements for and impact of permitting and environmental performance requirements are not fully understood.
- Availability of local operators with appropriate maintenance skills.

Given the number and importance of these risk areas, CPC strongly recommends consideration of an initial, single BioMax 100 (kW_e) demonstration system that can address the risk areas at lower cost while still providing all of the insight needed to design and implement the larger follow on 500 kW_e to 2 MW_e deployment. Therefore, based on CPC's experience in bioenergy and renewable energy demonstration projects in remote communities throughout the world, they propose consideration of one, 100 kW_e BioMax bioenergy as described in their proposal.

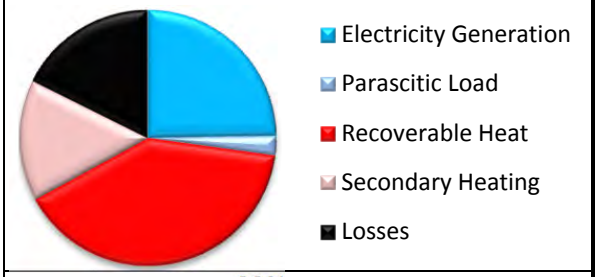
2.1.3.1 Vendor Summary

To quickly highlight key aspects of the vendor's response, Table 2.2 has been prepared to summarize data provided. A comparison table of all vendors is available in the next sub-section.

2.1.3.2 Vendor Response

A copy of CPC's response to the RFQ is included in Appendix C for reference as received.

Table 2.2 Community Power Corporation Summary

Community Power Corporation *A Wholly Owned Subsidiary of Afognak Native Corporation*		**Headquarters:**	Littleton, Colorado	
Developer / Company:	Community Power Corporation	**Vendor Rep:**	None	
System Information	**Quoted Capacity:**	100 kW_e		
	Model Number:	BioMax 100 CHP System		
	System Configuration:	1-Stage Downdraft Gasifier, 2x IC Engines		
	**denotes scaled values*	**As Quoted**	**500 kW_e**	**2.0 MW_e**
Fuel Requirements	**Moisture Content as Fired:**	15%		
	Feedstock Consumption (dry basis):	91 kg/hr 200 lb/hr	363 kg/hr* 800 lb/hr*	1,452 kg/hr* 3,200 lb/hr*
	Feedstock Size:	Chip size: <51 mm		
Unit Performance	**Net Electric Generating Capacity:**	100 kW_e	2x 250 kW_e	8x 250 kW_e
	Operating Parasitic Load:	10 kW_e	40 kW_e*	160 kW_e*
	Availability:	80%		
	Recoverable Heat:	161 kW_{th}	644 kW_{th}*	2,576 kW_{th}*
	Secondary Heat for Drying:	62 kW_{th}	248 kW_{th}*	992 kW_{th}*
	Cogeneration Efficiency (with / without Secondary Heat Recovery):			
		80% / 65%		
	Electrical Efficiency:	25%		
Commercial	**Delivery Lead Time:**	7-8 months		
	Quoted Equipment Only Price:	$ Omitted	$ Omitted	$ Omitted

BioMax100 in Manitoba

BioMax250 from Quotation

2.1.4 WEISS

To achieve the targeted 2 MW_e production capacity, WEISS and Scan American presented their standard 500 kW_e unit modular form. This size supported the RFQ requirements and aligned with the concept design change to only 500 kWe capacity.

2.1.4.1 Vendor Summary

To quickly highlight key aspects of the vendor's response, Table 2.3 has been prepared to summarize data provided. A comparison table of all vendors is available in the next sub-section.

2.1.4.2 Vendor Response

A copy of Weiss' response to the RFQ is included in Appendix C for reference as received.

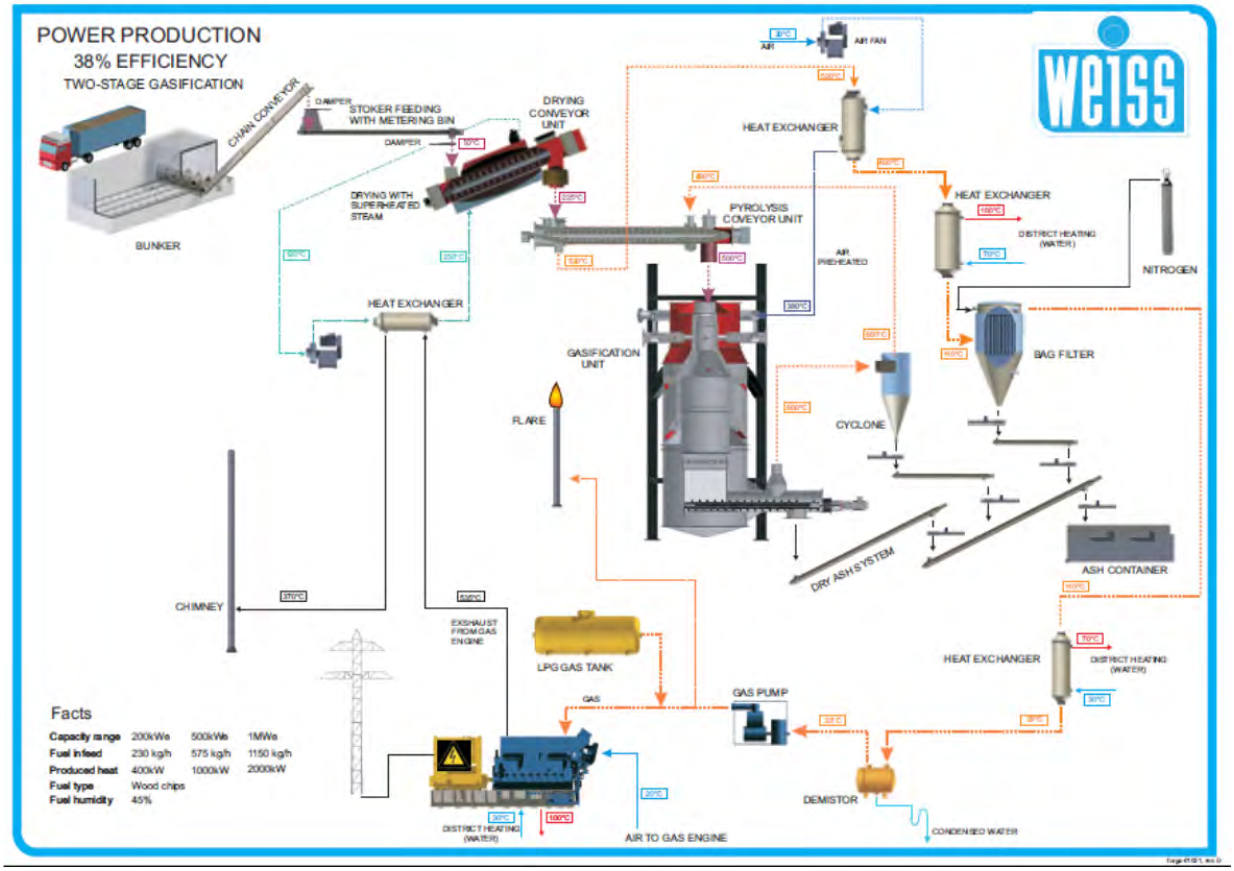
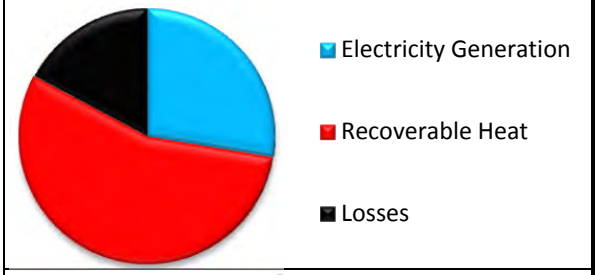
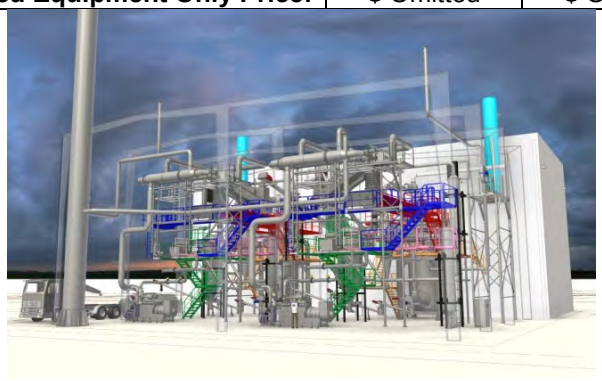


Table 2.3 Weiss (Scan America) Summary

		Headquarters:	Copenhagen, Denmark	
Developer / Company:	Weiss Envikraft A/s	**Vendor Rep:**	Barry Griffith, Kansas City, MO	
System Information	**Quoted Capacity:**	1000 kW_e (1000kW_e, 2000kW_t)		
	Model Number:	Not specified		
	System Configuration:	1xGasification Unit, 1x 800 amp Genset		
		As Quoted	**500 kW_e**	**2 MW_e**
Fuel Requirements	**Moisture Content as Fired:**	35-55%		
	Feedstock Consumption (dry basis):	1150 kg/hr 2535 lb/hr	575 kg/hr 1268 lb/hr	2300 kg/hr 5071 lb/hr
	Feedstock Size:	Chip size: G100		
Unit Performance	**Net Electric Generating Capacity:**	2x500 kW_e	500 kW_e	4x500 kW_e
	Operating Parasitic Load:	N/A	N/A	N/A
	Availability:	Not specified		
	Recoverable Heat:	2000 kW_{th}	1000 kW_{th}	4000 kW_{th}
				
	Cogeneration Efficiency:	83%		
	Electrical Efficiency:	28%		
Commercial	**Delivery Lead Time:**	9-12 months		
	Quoted Equipment Only Price:	$ Omitted	$ Omitted	$ Omitted



2x 500 kW_e Plant Model

2.1.5 Proton Power

The system provided by Proton Power, in response to the RFQ, utilizes the CHyP (Cellulose to Hydrogen Power) product built by Proton Power Inc. to produce up to 2.0 MW_e of electricity using woody biomass as the fuel source. Each CHyP unit that makes up the system is an electrical resistance, multi-zone reactor system specifically designed for the continuous reaction of cellulosic feed materials to a maximum operation temperature of 1200 °C in a non-oxidizing atmosphere. The quotation includes preassembly, mounting, test operation and customer operational witness inspection of all supplied system components and controls prior to shipment to the installation site.

The 250 kW_e system will consist of the following unit operations:

- Automatic biomass processing and feed hoppers.
- CHyP reactor to produce high content hydrogen syngas.
- Automatic solids removal station to collect biochar for packaging, burial or resale.
- Gas cooling and gas cleanup stages.
- Gas composition monitoring for process control.

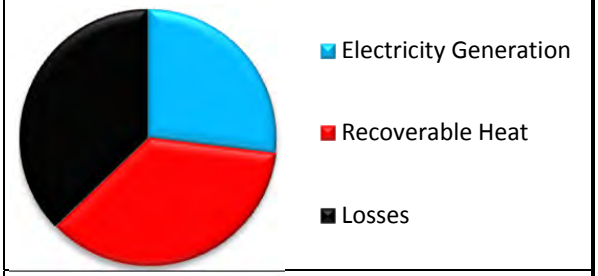
2.1.5.1 Vendor Summary

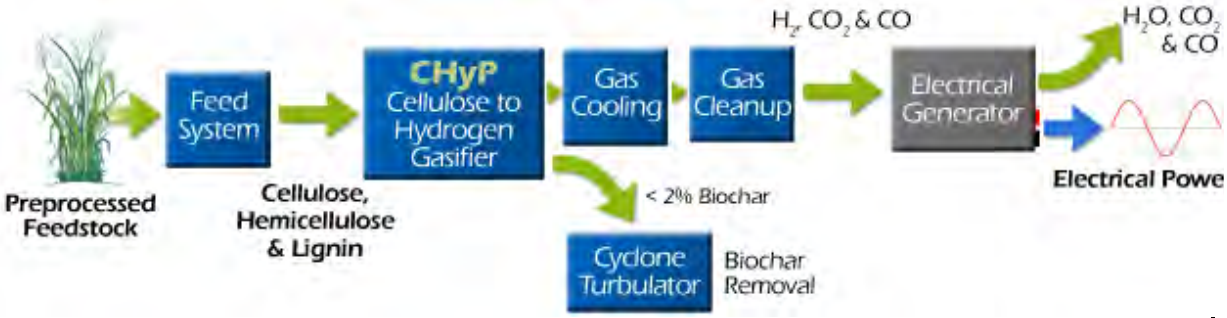
To quickly highlight key aspects of the vendor's response, Table 2.4 has been prepared to summarize data provided. A comparison table of all vendors is available in the next sub-section.

2.1.5.2 Vendor Response

A copy of Proton Power's response to the RFQ is included in Appendix C for reference as received.

Table 2.4 Proton Power Summary

Proton Power (Renewable. Clean. Energy.)		**Headquarters:**	Lenoir, TN	
Developer / Company:	Proton Power, Inc.	**Vendor Rep:**	K. Burnham, Kelowna, BC	
System Information	**Quoted Capacity:**	2.0 MW_e (8x 250 kW_e)		
	Model Number:	250 kW_e CHyP (Cellulose to Hydrogen Power)		
	System Configuration:	1x Multi-zone Reactor, 1x IC Engines		
		As Quoted	**500 kW_e**	**2.0 MW_e**
Fuel Requirements	**Moisture Content as Fired:**	15%		
	Feedstock Consumption (dry basis):	1,670 kg/hr 3,673 lb/hr	417 kg/hr 919 lb/hr	1,670 kg/hr 3,673 lb/hr
	Feedstock Size:	Chip size: <6 mm		
Unit Performance	**Net Electric Generating Capacity:**	8x 250 kW_e	2x 250 kW_e	8x 250 kW_e
	Operating Parasitic Load:	N/A	N/A	N/A
	Availability:	92.5%		
	Recoverable Heat:	2,664 kW_{th}	666 kW_{th}	2,664 kW_{th}
				
	Cogeneration Efficiency:	63%		
	Electrical Efficiency:	27%		
Commercial	**Delivery Lead Time:**	12-18 months		
	Quoted Equipment Only Price:	$ Omitted	$ Omitted	$ Omitted

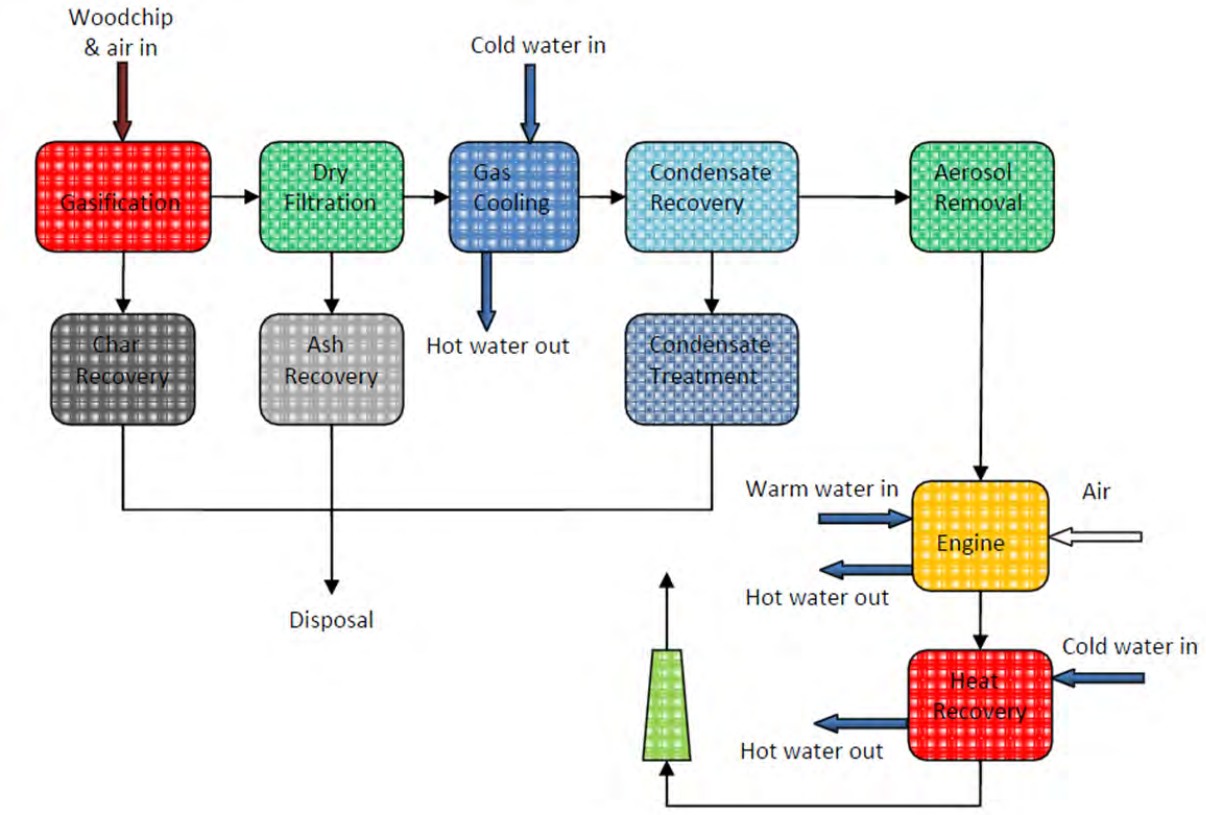


CHyP Process from Quotation

2.1.6 Biomass Engineering Ltd.

In response to our RFQ, Biomass UK responded with a proposal comprising the technical specifications and a budgetary estimate of the design, supply, delivery, installation, testing and commissioning of a 500 kW gasification plant.

Biomass Engineering Ltd. was established over 10 years ago and since that time has specialized in the design, development and supply of advanced gasification systems and the necessary ancillary equipment. Biomass Engineering specializes in the design, manufacture, installation and commissioning of compact gasification plants and equipment for converting the energy stored in wood into electricity and heat. The Biomass Engineering gasifier is designed to convert wood fuel into a steady stream of syngas, seen below:

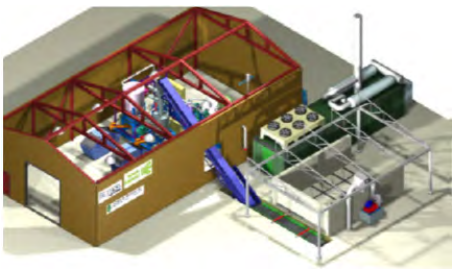


2.1.6.1 Vendor Summary

To quickly highlight key aspects of the vendor's response, Table 2.5 has been prepared to summarize data provided. A comparison table of all vendors is available in the next sub-section. Beyond the system price, many detailed on the system operation were omitted.

Table 2.5 Biomass Engineering (UK) Summary

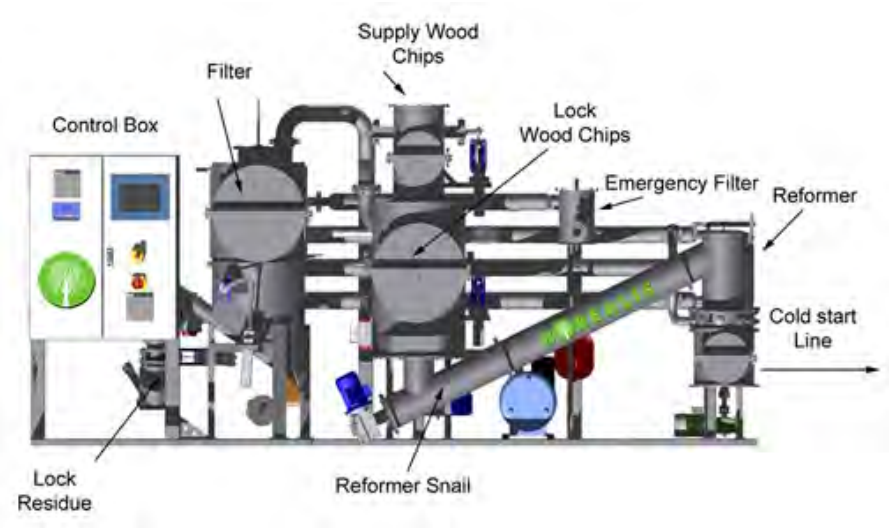
Biomass engineering		**Headquarters:**	Newton-le-Willows, England	
Developer / Company:	Biomass Engineering UK	**Vendor Rep:**	Dave Clitheroe	
System Information	**Quoted Capacity:**	500 kW_e (500kW_e, 2000kW_t)		
	Model Number:	Not specified		
	System Configuration:	1x Gasification Unit, 1x 500kW Gas Engine		
		As Quoted	**1 MW_e**	**2 MW_e**
Fuel Requirements	**Moisture Content as Fired:**	<20%		
	Feedstock Consumption (dry basis):	N/A	N/A	N/A
	Feedstock Size:	Chip size: < 100x100x30 mm		
Unit Performance	**Net Electric Generating Capacity:**	2x250 kW_e	4x250 kW_e	8x250 kW_e
	Operating Parasitic Load:	N/A	N/A	N/A
	Availability:	Not specified		
	Recoverable Heat:	N/A	N/A	N/A
		Electricity Generation Recoverable Heat Losses		
	Cogeneration Efficiency:	Not specified		
	Electrical Efficiency:	24%		
Commercial	**Delivery Lead Time:**	Not specified		
	Quoted Price:	$ Omitted	$ Omitted	$ Omitted



2.1.7 Borealis Wood Power Corporation (Spanner Re2 GmbH)

Technology Background

Borealis Wood Power Corporation is a Canadian company established in 2012, dedicated to marketing the Borealis CHP wood-plant system in Canada. Its focus is on both the market development and technical support for this system developed by Spanner Re2 GmbH of Germany and licensed to Borealis Wood Power Corporation. The system is marketed under the Borealis name and customized to the needs of the Canadian marketplace.

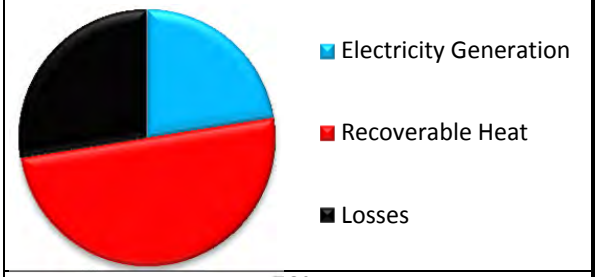


The reactor supports changing the wood chip fuel into wood gas. At the pyrolysis zone, the wood decomposes and begins reducing from its visible wood state. The fuel is then converted to a coal-like hydrocarbon and transported to the oxidation zone where part of the carbon is burned with injected air at approximately 800°C. As the gases move over the hot ember bed (oxidation zone) the tar and hydrocarbons are separated from the gas, resulting in a gas with very low tar.

2.1.7.1 Vendor Summary

To quickly highlight key aspects of the vendor's response, Table 2.6 has been prepared to summarize data provided. A comparison table of all vendors is available in the next sub-section.

Table 2.6 Borealis Wood Power Corporation (Spanner) Summary

BOREALIS Wood Power Corp.™		**Headquarters:**	Burlington, Ontario	
Developer / Company:	Borealis Wood Power Corp.	**Vendor Rep:**	Kevork Sevadjian	
System Information	**Quoted Capacity:**	45 kW_e (45kW_e, 100kW_t)		
	Model Number:	SPANNER 45 kW Wood Power Plant CHP Model 50GH-8 AP		
	System Configuration:	1xGasification Unit, 1xPSI 5.7 Vortec Engine		
		As Quoted	**495 kW_e**	**2.03 MW_e**
Fuel Requirements	**Moisture Content as Fired:**	15%		
	Feedstock Consumption (dry basis):	45 kg/hr 99 lb/hr	495 kg/hr 1091 lb/hr	2025 kg/hr 4464 lb/hr
	Feedstock Size:	Chip size: G30-G40		
Unit Performance	**Net Electric Generating Capacity:**	45 kW_e	11x 45 kW_e	45x 45 kW_e
	Operating Parasitic Load:	N/A	N/A	N/A
	Availability:	Not specified		
	Recoverable Heat:	100 kW_{th}	1100 kW_{th}	4500 kW_{th}
				
	Thermal (CHP) Efficiency:	73%		
	Electrical Efficiency:	23%		
Commercial	**Delivery Lead Time:**	Not specified		
	Quoted Price:	$ Omitted	$ Omitted	$ Omitted

2.1.8 E-Rational (ORC –Technology)

After re-assessing the amount of heat that can be utilized, it was found that a very high percentage would go unused during the summer months. It was therefore determined that the implementation of an Organic Rankine Cycle (ORC) might be beneficial by converting the remaining heat into electricity. E-Rational was selected as the most appropriate technology provider as it has the ability to utilize hot water, although only at 8-10% efficiency.

2.2 VENDOR COMPARISON

The Table 2.7 summarizes various parameters as they relate to each of the selected vendors (with little information available from Nexterra, it was excluded from this comparison). An initial assessment of the table information reveals several obvious omissions, denoted as “N/A”. In many circumstances, this lack of data can be accredited to the specific vendor, whereby much of this information could only be provided following a definitive order or down payment, or with vendors stating that more investigation would be required on their part into many project aspects before more accurate information could be provided. Therefore, vendor comparisons could not be adequately made across all fields, however much of the information provided gives a good general impression of the technology capabilities as a whole.

Table 2.7 Vendor Comparison

		nexterra		Community Power Corporation (A Wholly Owned Subsidiary of Afognak Native Corporation)			Weiss			Proton Power		Biomass engineering			BOREALIS Wood Power Corp.™		
System Information	**Quoted Capacity:**	2.0 MW_e		100 kW_e			1000 kW_e			2.0 MW_e (8x 250 kW_e)		500 kW_e			45 kW_e		
	Model Type/Number:	Standard CHP System		BioMax 100 CHP System			N/A			250 kW_e CHyP (Cellulose to Hydrogen Power)		N/A			SPANNER 45 kW_e Wood Power Plant CHP Model 50GH-8 AP		
	System Configuration:	1-Stage Updraft Gasifier		1-Stage Downdraft Gasifier, 2x IC Engines			1xGasification Unit, 1x 800 amp Genset			1x Multi-zone Reactor, 1x IC Engines		1x Gasification Unit, 1x 500kW Gas Engine			1xGasification Unit, 1xPSI 5.7 Vortec Engine		
**denotes scaled values*		**500 kW_e**	**2.0 MW_e**	**As Quoted**	**500 kW_e**	**2.0 MW_e**	**As Quoted**	**500 kW_e**	**2 MW_e**	**500 kW_e**	**2.0 MW_e**	**As Quoted**	**1 MW_e**	**2 MW_e**	**As Quoted**	**495 kW_e**	**2.03 MW_e**
Fuel Requirements	**Moisture Content as Fired:**	20%		15%			35-55%			15%		<20%			15%		
	Feedstock Consumption (dry basis):	N/A	1,474 kg/hr 3,250 lb/hr	91 kg/hr 200 lb/hr	363 kg/hr* 800 lb/hr*	1,452 kg/hr* 3,200 lb/hr*	1150 kg/hr 2535 lb/hr	575 kg/hr* 1268 lb/hr*	2300 kg/hr* 5071 lb/hr*	417 kg/hr* 919 lb/hr*	1,670 kg/hr 3,673 lb/hr	N/A	N/A	N/A	45 kg/hr 99 lb/hr	495 kg/hr* 1091 lb/hr*	2025 kg/hr* 4464 lb/hr*
	Feedstock Size:	N/A		Chip size: <51 mm			Chip size: G100			Chip size: <6 mm		Chip size: < 100x100x30 mm			Chip size: G30-G40		
Unit Performance	**Net Electric Generating Capacity:**	N/A	2.0 MW_e	100 kW_e	2x 250 kW_e	8x 250 kW_e	2x500 kW_e	500 kW_e	4x500 kW_e	2x 250 kW_e	8x 250 kW_e	2x250 kW_e	4x250 kW_e	8x250 kW_e	45 kW_e	11x 45 kW_e	11x 45 kW_e
	Operating Parasitic Load:	N/A	N/A	10 kW_e	40 kW_e*	160 kW_e*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Availability:	91%		80%			N/A			92.5%		N/A			N/A		
	Recoverable Heat:	N/A	2.93 MW_{th}	161 kW_{th}	644 kW_{th}*	2,576 kW_{th}*	2000 kW_{th}	1000 kW_{th}*	4000 kW_{th}*	666 kW_{th}*	2,664 kW_{th}	N/A	N/A	N/A	100 kW_{th}	1100 kW_{th}*	4500 kW_{th}*
	CHP Efficiency:	75%		80% (w/secondary heat recovery) 65% (w/o secondary heat recovery)			83%			63%		N/A			73%		
	Electrical Efficiency:	31%		25%			28%			27%		24%			23%		
Commercial	**Delivery Lead Time:**	N/A		7-8 months			9-12 months			12-18 months		N/A			N/A		
	Quoted Equipment Only Price:	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted	Omitted

2.3 FACILITY SITING ASSESSMENT

In order to progress preliminary engineering it was necessary to select a site for the biomass plant. In parallel to the Stantec FEED study, Clean Technology Community Gateway (CTCG) was conducting an Evaluation of Waste Heat Potential study (CTCG, 2013). The results of the study were provided in mid-December and indicated that of all the potential waste heat uses, building heat would be the recommend usage (in particular heating only the school if a 500 kW_{th} plant was used). Further to their recommendation, CTCG referred Stantec to a previous Morrison-Hershfield (MH) district heating study for the village as a basis for potential building connection.

Using the results of the CTCG and MH study, Stantec developed a map using our in-house GIS capabilities to outline potential areas to locate the biomass plant. The map excerpt presented in Figure 2.4 shows 400 m buffer zones around buildings that could use the biomass plants waste heat. The buffer zone was established based on viable distance from heat loads determined by CTCG.

Based on the results of the waste heat study and the map areas indicated in Figure 2.4, Stantec recommended proceeding with a location near the school (see Figure 2.5) to capture the school heating load. This location had several advantages associated with it, including

- Being located near the existing diesel generator site.
- Close to the school but off school property – there is a tree line and road between the school and the plant.
- The district heating pipeline from the plant can run down the existing road to the school.
- Future expansion of the line further south would allow the plant to pick up the other buildings identified by CTCG/MH.
- If a greenhouse was of interest now (or becomes of interest in the future), it can be located on school property and fed from the network.
- Truck traffic would be kept to main traffic arteries (out of residential neighborhoods) – potential to receive fuel from the Alaska Highway entrance to the existing diesel site or new entrance.
- Tie in to the grid would be less complicated as the unit would be right next to the switchyard.
- Allows for the possibility of supplying syngas to the existing diesel generators – something CPC has indicated is a possibility.
- Potential exists to tie into the cultural centre to the North.

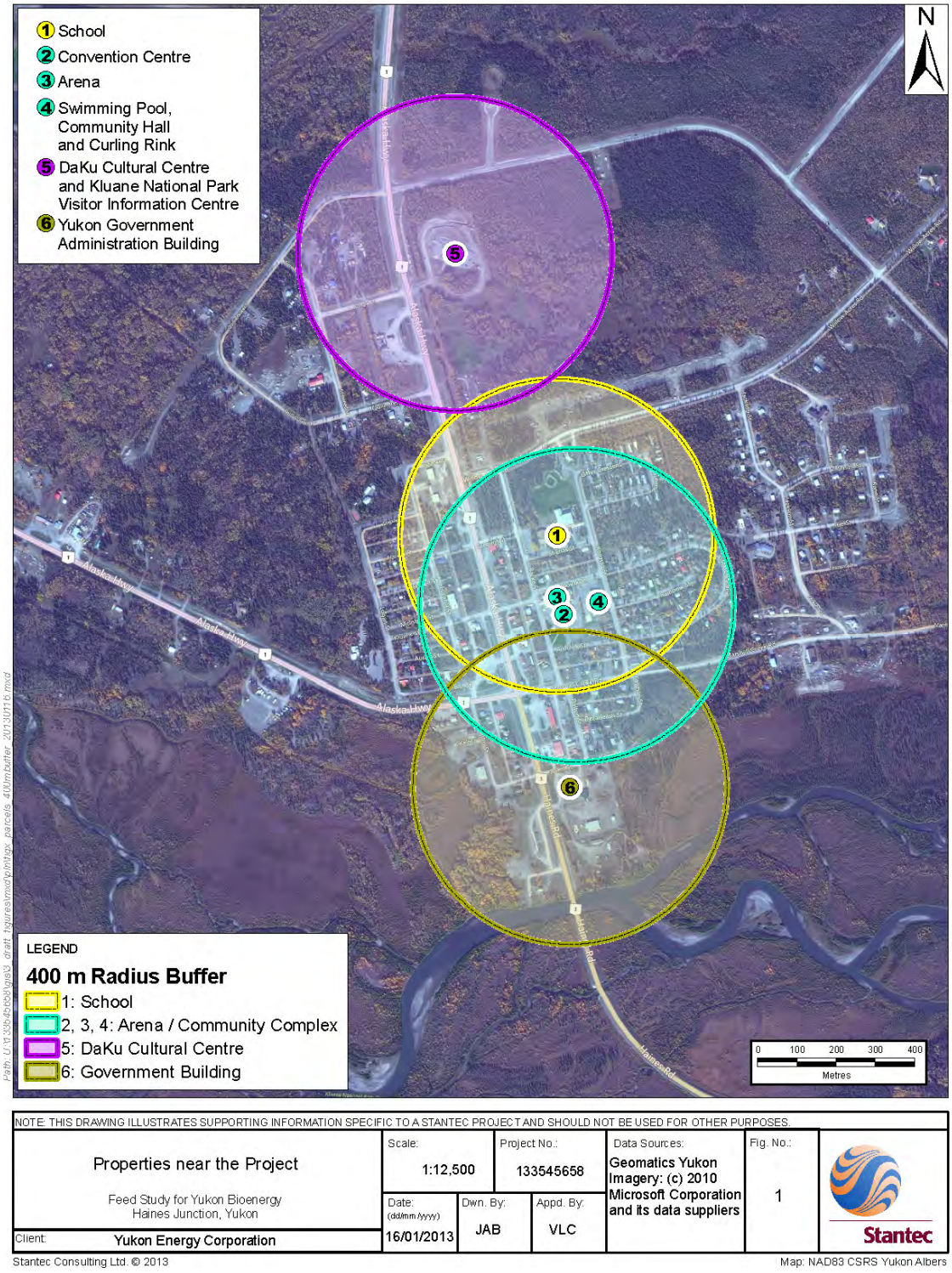


Figure 2.1 Building Heating Locations with 400 m Buffers

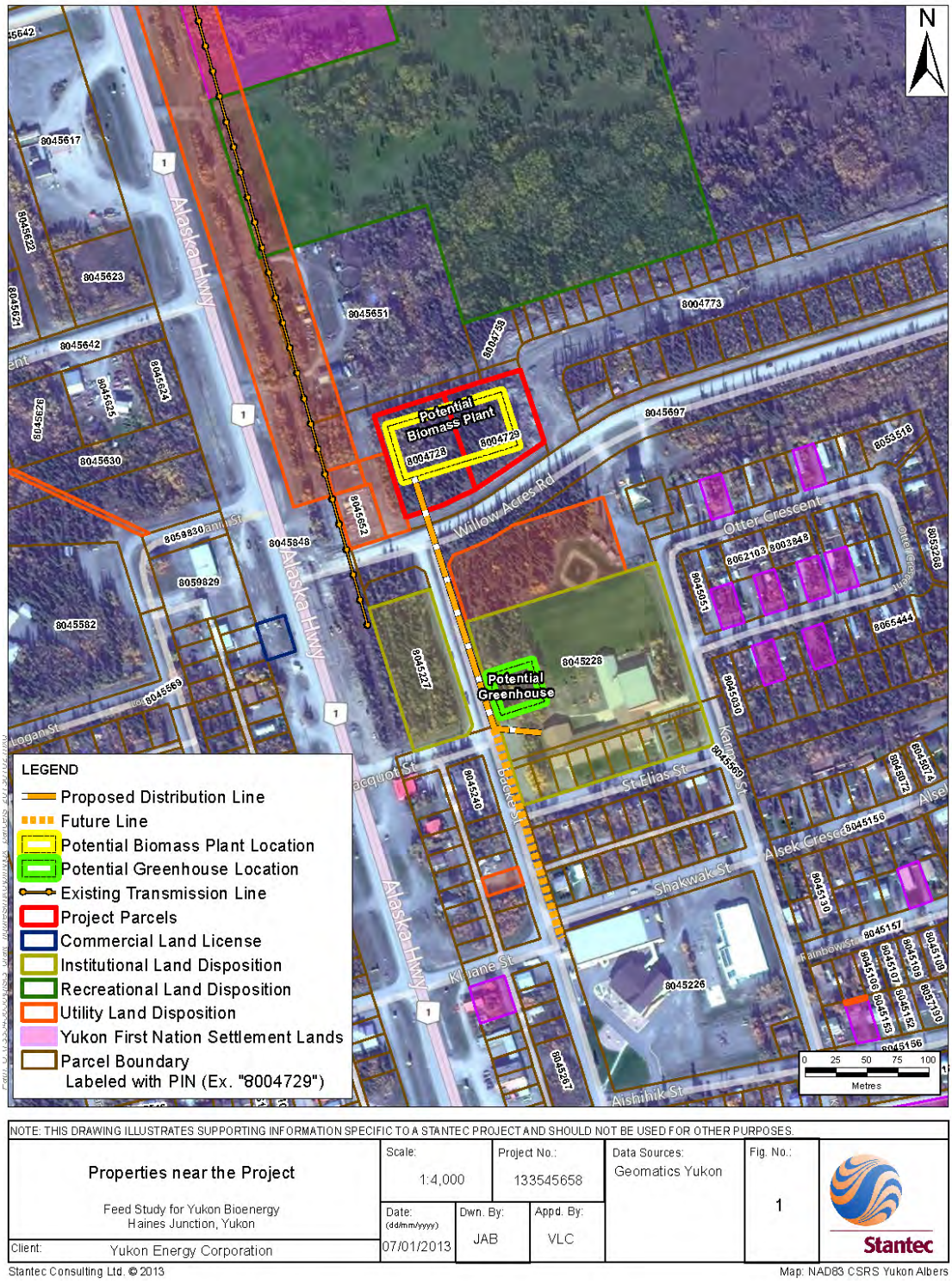


Figure 2.2 Biomass Potential Plant Location

2.4 PRELIMINARY DESIGN AND CAPITAL COST

As mentioned previously, the overall intent of the project is to demonstrate the viability of biomass power generation in the Yukon. For the purposes of the FEED design, it was assumed that the demonstration plant would start as a 500 kW_e power plant, and expand in the future once its operation and financial viability are confirmed. Using this approach, three (3) options to initiate the project were considered: Option #1 includes enclosing the entire plant in the power plant building, Option #2 provides a more aesthetically pleasing building enclosure (architecturally designed), and Option #3 reduces the enclosure to only include the fuel storage facility, locating the gasification plant outside in shipping containers.

Option #4 is presented to highlight the ability of the design to facilitate future expansion to 1.0 MW_e (500 kW_e addition) and 2.0 MW_e. This approach can also be used when the project starts off, if a larger capacity plant is desired. Please refer to Appendix D, E, F, & G for information regarding the design and opinion of capital cost for the biomass plant options described in the following sub-sections.

2.4.1 Option #1 – Full Building Enclosure – 500 kW_e

To support the development of the business case, and based on the preliminary design described herein, Stantec has prepared a Class IV Opinion of Probable Construction Cost (OoPCC) to install 2 x 250 kW_e wood gasification units supplied by Community Power Corporation (CPC) in Haines Junction. Option 1 OoPCC is based on preliminary planning in a new building in Haines Junction near the existing stand-by diesel substation

2.4.1.1 Scope Summary

The scope of work would include:

- Construction of new 37.4 m x 36.4 m pre-engineered building.
- Construction of new service roads.
- Installation of 2 X 250 kVA wood gasification generators.
- Installation of electrical power equipment, including step-up transformer and switchgear, to connect generator output to the existing 25 kV distribution system.

2.4.1.2 Detailed Project Scope Definition

CIVIL / STRUCTURAL

The civil/structural scope includes:

- Site Work. Clearing and grubbing, site grading, road and parking, building foundation preparation, buried water and sewer services.
- Concrete Work. Building foundations, building slab, door aprons, transformer pad, and elevated slab.
- Pre-Engineered Building (37.4 m x 36.4 m = 1360 m^2). Building steel, insulated walls, insulated roof, doors, openings for louvers and vents.
- Building Internals. Interior rooms (with storage above), chip bin areas, divider wall between chip handling and gasification/generation.

MECHANICAL

The mechanical scope includes:

- A 500 kW_e modular wood biomass CHP system.
- Radiant in-floor heating for entire building using boiler thermal energy as heat source with electric circulation heater backup.
- Combination of wall fans and roof gravity ventilators to provide necessary building minimum ventilation airflow as required by applicable standards for occupancy, oxygen levels, and airborne contaminants such as CO and combustion gases.
- Pressurization air units for the electrical and mechanical rooms.

- Split heat pump system covering the office / meeting room and the lunchroom.
- Small humidifier.
- Plumbing of one washroom and one kitchen sink.
- Fire protection provisions including dry sprinkler, standpipe, fire extinguishers, and pull stations for the entire building. Provision for a manual deluge fire suppression line is also included for each biomass conveyor.

ELECTRICAL

The electrical scope includes:

- Utility power for the building services loads and backup power source for the generator auxiliaries. This includes transformer, fused disconnect, and customer metering. Connections and material up to the meter assumed to be supplied by the utility but an allowance has been made in the estimate to cover the costs associated with this work.
- A 480 V / 400 A power distribution panel (complete with main breaker) feeding utility power to building services loads and aux power to the generators when required.
- Transfer switches at each generator allowing choice of auxiliary power source from either the online generators or the utility feed.
- 480 V switchgear to parallel the outputs of the generators.
- An oil filled 600 kVA step up transformer 480 V / 25 kV to connect generator outputs to the utility line. An oil containment system allowance has been carried.
- Allowance for the utility to connect the generator output from the step-up transformer to the line including fused disconnect.
- Allowance for utility to install revenue metering on the secondary of the step-up transformer.
- Allowance for grounding the building and equipment.
- Building services including low voltage distribution panels, lighting, fire alarms, receptacles, communications, etc.
- Allowance for a contractor to make electrical connection between the shipping splits of Vendor supplied equipment.

- A PLC based control system for miscellaneous building services and heating loop indicators and alarms.
- Communication connections between the Vendor's supplied equipment, the PLC controller, and a main network switch. This will allow remote monitoring of building and equipment alarms and allow remote configuration and monitoring of the CPC supplied units.
- All power, control, and communications wiring and raceway required to service the units and the surrounding infrastructure.

2.4.1.3 Detailed Basis of Estimate

ENGINEERING

The preliminary engineering allowance is 3.0% of capital, which would include a Class III estimate for project appropriations.

The detailed engineering allowance is 10% of capital for the purposes of this capital estimate. Should the project move forward and Yukon Energy solicit a proposal for further engineering by Stantec, an Opinion of Probable Engineering Costs (OoPEC) would be prepared and included in that proposal. This allows for typical engineering costs for the purposes of budget appropriations.

PROCUREMENT

Major equipment is assumed to be purchased by Yukon Energy and supplied to the installation contractor on site. In this particular study, that would include the switchgear, the step-up transformer, transfer switches, and Vendor supplied generators. This approach is advantageous in that:

- It ensures adherence to the utility standards for equipment where many options and additions are commonly available.
- It does not delegate away the responsibility of expediting these items to site. By maintaining responsibility, the Owner can exercise greater control of delivery on these critical items.
- It avoids the standard contractor markup of ~10% being added to large value line items.

All other items, including cable, cable tray, and all other commodity items required for the installation shall be supplied by the contractor as part of their lump sum installation pricing. This eliminates the need for utility engineers, managers, or consultants to be responsible or concerned with inventory levels of items that are extremely hard to track on a busy construction site.

PRODUCTIVITY FACTORS

Labour factor adjustments have been applied to this estimate based on the following:

- Distance from Whitehorse as it applies to accessing supplies.
- Distance from Whitehorse as it applies to accessing skilled labour.
- Estimated inventory levels at local supply houses.
- Working outdoors or in non-serviced building.

CONSTRUCTION

This OoPCC is based on the following sources of data for labour and materials:

- In-house databases built from historical or manufacturer’s listed prices.
- Direct contact with vendor for switchgear.
- NECA (National Electrical Contractor’s Association) Manual of Labour Units 2011-2012 for specific items covered by that publication.

- Historical labour costs for other items not specifically listed or requiring special consideration.

DIRECT CONSTRUCTION AND INSTALLATION COSTS

Civil / Structural

Site Work

Site work includes clearing and grubbing, site grading for the initial two unit arrangement, preparation of roadway and parking areas by replacement of 1 m of material with compacted pit run gravel, building foundation excavation and backfill, underground water and sewer services, and a fire water loop with two hydrants. For the purpose of this estimate, it has been assumed that water and sewer services exist under the adjacent streets with sufficient supply pressure for building fire protection.

Quantities were calculated and cost opinions were developed using costs from other jobs, with reference to the RS Means cost database, and with partial input from Jon Schmidt of JTS Cost Consulting, Whitehorse.

Concrete Work

Concrete work includes reinforced cast-in-place concrete for building foundations, grade and elevated slabs, door aprons, and transformer pad. Preliminary design has the building on spread footings founded below frost, with a full perimeter wall that extends 2500 mm above grade in the chip handling area to act as chip bins. Grade slab is 200 mm thick both for truck traffic and to support the gasification/generation equipment.

Stantec provided partial quantities and preliminary building layouts to JTS Cost Consulting who developed the cost opinion raw data.

Pre-Engineered Building

The 1360 m^2 building includes a structural steel frame with girts and purlins, wall panels insulated to R30, roof panels insulated to R50, man doors, overhead doors, and openings for louvers and vents. The roof is symmetrically peaked with a 1:12 slope. The east gable end structure has been designed to allow future expansion of the building in this direction.

Quantities and cost opinion for the building was provided by a pre-engineered building supplier (Varco Pruden Buildings).

Building Internals

Building internals include interior rooms for electrical, mechanical, storage, lunchroom, washroom, and administration. As presently proposed, the rooms would be masonry with a concrete roof slab on metal deck to create a storage area above. A wall aligned with the building peak would provide working separation between the chip storage area and the gasification/generation equipment.

Stantec provided partial quantities and preliminary building layouts to JTS Cost Consulting who developed the cost opinion raw data.

General Conditions

JTS Cost Consulting has provided a cost opinion for General Condition items, including:

- Bond, insurance, and permits.
- Temporary office, power, heat, phone, data, fencing, and toilets.
- Safety.
- Layout.
- Clean-up, snow clearing, and waste management.
- Freight and deliveries, materials handling and protection.
- Vehicles and fuel (vehicle and equipment).
- Hoisting, zoom boom, sky reach, and scaffolding.
- Tools.
- Supervision, project management, and foreman surcharge.
- Room and board, including travel.
- Mobilization, and demobilization.
- Close out, as-builts, and manuals.
- Winter works premium.

These items have been included in the civil-structural estimate although they apply to the entire construction activity and sequence.

Mechanical

The mechanical scope for Option 1 includes:

Wood Biomass CHP System

The assumed CHP system size is 500 kW_e nominal electrical and 644 kW_{th} thermal generation capacity.

Equipment cost based on scaling up base budget proposal from CPC for a 100 kW_e system by a factor of four. Efficiencies of scale are gained to achieve the additional output adding up to 500 kW_e total electrical generation capacity.

This system is installed by assembling 14 container type modules which include feedstock handling end, dryer module, gasifier module, genset module, filter module, and controls module.

HVAC

Radiant In-Floor Heating

Allowances cover the entire building concrete floor slab, including ancillary rooms. The primary source of heat for the in-floor heating will be provided by tapping into some of the thermal energy available from the boiler flow supplying the district heating system output from the plant. The fluid will be circulated to the various areas of the building by two circulation pumps (one backup). Control valves will distribute the flow as necessary to maintain the demand requirements of each temperature zone. The design intent is currently to maintain a floor temperature of 1 °C for the fuel delivery and storage building section, 10 °C for the generator house building section, electrical room, mechanical room, and storage room, and 21 °C for the lunchroom, office/meeting room, and washroom.

An allowance for a pair of electric circulation heaters was provided as a source of backup building heat when the boilers are not in operation.

Welded wire mesh for attaching tubing, vapour barrier, and insulation costs carried under civil estimate.

Radiant concrete slab heating cost estimate includes (2) slab temperature sensors for each temperature zone.

Ventilation

The design approach for ventilation of the areas of the building other than the ancillary rooms is to utilize wall mounted ventilation fans with insulated motorized dampers in conjunction with roof mounted low profile gravity ridge natural ventilators with manual chain operators. Those systems would provide necessary building minimum ventilation airflow as required by applicable standards for occupancy, oxygen levels, and airborne contaminants such as CO and combustion gases.

Roof curbs and flashing for the roof gravity ventilators included as part of the civil estimate.

An allowance has been made for the mechanical room and electrical room to have their own pressurization ventilation unit.

An allowance has been made for a small humidifier.

An allowance was made for rental of equipment required to install the HVAC components.

An allowance was made for HVAC related floor / piping penetrations.

An allowance has been made for a ductless split heat pump system covering the office / meeting room and the lunchroom.

Plumbing

A plumbing allowance has been made for a washroom sink, water closet, kitchen sink, water heater, heating system fill line, floor drain in mechanical room, and sewer line inside building.

Potable water supply assumed to be coming from the street.

Sewer piping from building to street covered in the civil estimate.

Fire Protection

For the purposes of determining fire protection requirements for the building, a cursory review of applicable 2010 NBC (National Building Code of Canada) requirements was conducted:

Preliminary building classification per 2010 NBC is high hazard industrial occupancy F-1 for the fuel delivery and storage building section and generator house building sections.

The generator house section is classified as high hazard F-1, as opposed to F-3 normally allowed by code, to avoid the need for a 2 hour rated fire separation, which would normally be required between the fuel delivery and storage section and generator house section as per NBC Section 3.1.3.1.

The reason to classify the entire building as a Type F-1 occupancy is that it is not practical to maintain a 2 hour fire separation at the biomass conveyor penetrations at the wall. The F-1 building falls under Group F Division 1 up to two storeys, under NBC Section 3.2.2.70 which requires sprinklers throughout.

A standpipe system is also required for the F-1 building since its classification does not fall under the exceptions listed under NBC Section 3.2.5.8.

The building requires stations and fire extinguishers.

Fire detection and alarm covered under electrical section.

In addition to specific NBC requirements, conveyors systems handling this amount of combustible material normally require a few manual deluge connections to provide local suppression from a risk mitigation standpoint. The insurer for the plant typically drives this requirement.

Electrical

General Methodology

The power distribution transformer and associated power system components and cabling have been sized for 250 kW_e output from each unit with a worst-case power factor of 0.85. The CPC supplied equipment is shipped to site in several shipping splits. Although the units are prewired by CPC, the installation contractor will make final connection between shipping splits as per CPC instructions.

General Description of Major Products

All new cable tray installed will be aluminum, B-Line series 25, and industrial cable tray. Typical tray grounding and supports are included.

All new power cables up to the low voltage side of the power distribution step-up transformer are 1 kV rated, Teck cable. Allowances have been made to allow the utility to make the 25 kV connections.

Transfer switches are manual type switches with make before break contacts when moving from utility to generator power after the generator has synchronized to the line.

Switchgear is based on GE LV switchgear with one main breaker and two unit breakers. Allocation has been made for two prepared spaces for future expansion.

The power distribution transformer used to connect the generator output to the grid is a liquid filled type installed outside with a containment system.

Electrical Installation Costs

Service Entrance

Allowances have been made for the utility to supply and install a pole mounted transformer and fused disconnect. Allowances have been made for a metered entrance and it is assumed that the utility preforms all work up to the line side of the meter.

A 400 A, 480 V, 3 phase power distribution panel complete with a main breaker will be installed inside the electrical room to supply building services and unit startup power.

Transfer Switches

Transfer switches will be installed to transfer generator auxiliary loads to the utility power feed for start-up. When the generators are online, the auxiliary loads would be switched back to the unit internal power.

Grounding

Allowance has been made to allow typical grounding of the service entrance, the generators, and the building itself.

Building Services

Power Distribution

Allowances have been made for lighting and miscellaneous power requirements for the building. This includes transformers, panels, and wiring for all building services loads.

Heating and Ventilation

Allowances have been made to connect heating and ventilation equipment.

Lighting

Allowances have been made for lighting in all areas of the building. Allowance has been made for the installation of roadway lighting along the service road.

Communications Including Remote Monitoring and Configuration Links

Combination data and telephone outlets are to be in the office area and several telephone outlets throughout the rest of the facility. Everything will be wired back to an incoming line within the electrical room. The CPC system will also be connected to allow remote monitoring, alarming, and configuration from CPC facilities.

Equipment will be installed to allow remote monitoring of indicators and alarms for major equipment in the building. This includes allowance for a small programmable logic controller and network switch. In addition, this connectivity will serve the CPC supplied equipment to allow for monitoring and configuration from their headquarters.

Fire Alarm

A fire alarm system has been included with smoke detectors, thermal detectors, heat detectors and manual pull stations to provide initiating protection. Horn strobes provide audio and visual

signaling. There is an allowance for several flow and tamper switches for a sprinkler system. Control relays were also considered with the fire alarm system for equipment shut downs.

Generator Output

The owner-supplied switchgear will be installed by the electrical contractor. Switchgear pricing is based on information received from GE for budgeting purposes. The switchgear includes a main breaker, two unit breakers and two prepared spaces in the pricing. All cabling, including raceway, required from the units to the switchgear have been included.

The electrical contractor will install the step-up transformer on a concrete pad outside the building. Pad to be provided by the civil contractor. Transformer pricing is based on review of pricing of similar transformers normalized to a value per kVA and scaled to 600 kVA.

Allowance has been made for the utility to make all connections beyond the secondary of the step-up transformer including a pole mounted fused disconnect and revenue-metering unit.

Instrumentation and Control

Allowances have been made for several poisonous gas detectors to be installed. Alarms will be relayed through the fire alarm panel.

Connections of the Vendor Supplied Equipment

There is an allowance of two men for one week for each unit intended to cover the interconnection of vendor supplied shipping splits. All material for this work is assumed to be supplied by the vendor.

MISCELLANEOUS CONSTRUCTION DIRECTS

Most construction directs have been accounted for in a blended labour rate. This would include small tools and consumables.

Allowances for required equipment rentals used as part of a normal installation are included in the blended labour rate.

Supervision, crew trailer, and personal PPE are also included.

Freight is included in the material / equipment pricing.

INDIRECT CONSTRUCTION COSTS

Construction Staff & Consultants

An allowance of 2.5% of capital has been carried for an onsite construction manager. An allowance of 1% of capital has been carried for site engineering services to support construction.

Owner's Staff Costs

No allowance has been made for Owner's personnel to support this work.

Commissioning Costs

Commissioning costs are carried as 1.5% of capital. This includes allowances to bring vendor representatives to site.

Escalation Costs

An escalation allowance of 5% has been allowed based on lead-time required before construction begins.

Capital Spares

A capital spares allowance of 5% of the equipment cost has been included.

Indirects Specifically Not Included

The indirect costs associated with the following have not been considered and are assumed to be supplied by Owner. No costs have been assigned to these services that will be associated with this project unless specifically noted in the OoPCC.

- Security.
- Lock-out tag-out (LOTO) coordination.
- Waste removal.
- Snow removal.
- Warehousing and utilities including temporary power supply.
- Temporary lighting.
- Taxes.

- Interest charges during construction.
- Owner's administration costs, including:
  - Legal fees.
  - Insurance.
  - Salaries of Owner's project staff.
  - Allowance for operators hours during training, commissioning, and start up.

Special costs to dispose from site construction waste.

2.4.1.4 Opinion of Probable Capital Cost

The Opinion of Probable Capital Cost for this option is $12.7 M. Table 2.7 provides a breakdown of the probable cost with a detailed line item list included in Appendix C.

Table 2.8 Option #1 Opinion of Probble Capital Cost

Line	Description	Labour Cost	Material Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
1	**PROJECT TOTAL, BASE SCOPE**					**$12,727,154**
2	Civil - Structural	$562,428	$1,001,238	$195,250	$1,235,200	$3,528,066
3	Mechanical & HVAC	$168,520	$199,500	$5,205,000	$192,476	$5,816,052
4	Electrical	$371,089	$172,531	$238,465	$74,197	$948,827
5	**Sub Total**	**$1,102,037**	**$1,373,269**	**$5,638,715**	**$1,501,873**	**$10,292,945**
6	Preliminary Engineering @ 3% (Class III Estimate)					$152,647
7	Detail Engineering @ 10% Direct Construction Cost					$508,824
8	Construction Management @ 2.5% Direct Construction Cost					$127,206
9	Site Construction Support by Engineering @ 1% Direct Construction Cost					$50,882
10	Commissioning Costs @ 1.5%					$76,324
11	Escalation Allowance @ 5%					$254,412
12	Capital Spares - 5% of CPC equipment cost					$250,000
13	**Sub Total**					**$11,570,140**
14	Contingency @ 10%					$1,157,014

Capital Cost Risk Analysis

No detailed risk analysis has been made on this Class IV OoPCC. A contingency of 10% has been allocated. As per AACE guidelines, a Class IV OoPCC is accurate to a range between -20% and +40%.

2.4.2 Option #2 – Full Architectural Enclosure – 500 kW_e

Option #2 retains the technical and operational characteristics of Option #1, while providing a superior aesthetic presence to the biomass facility to be located in the village.

2.4.2.1 Architectural Details

Accessed from the Alaska Highway the proposed biomass facility forms bold and angular shapes, establishing a powerful icon against the distant mountains. Elevated roof segments and strong, vertical glazing will serve to provide natural daylight and become a 'beacon' at night for travellers along the highway.

Backing on to boreal forest the building is designed to work with the natural surroundings and take advantage of the environmental conditions.

Sustainability and energy efficiency is modeled within LEED criteria and include:

- Use of natural and recyclable materials.

- Energy efficient building systems.
- Abundance of natural day lighting to reduce energy consumption and provision of a pleasant work environment.
- Use of low VOC materials and adhesives.
- Occupancy sensors to control electrical light fixtures operation.
- Rainwater will be diverted back into the soils.
- Combination wood and steel structure for recycling purposes.

Working within close proximity to the Alaska Highway the roadway entry leads into the clearly defined Main Entry for office personnel. As one approaches the building the single sloped roof, in concert with the 'V'-shaped structure, provides an intriguing form juxtaposed against the dominant, large biomass structure behind. Cladding materials will be a combination of smooth, cementitious, panels and corrugated metal cladding.

The facility is designed to support both the biomass plant function and administrative / office staff in one modern facility that is energy efficient and pleasant to work in. Programmatically the two-storey turbine plant is tucked in behind the one-storey offices and administration spaces. The soaring ceiling, in concert with natural materials, select bright colours and abundance of day lighting provides staff with a strong connection to the natural surroundings. Additionally, the project is designed to allow for future expansion of both specific programs.

Technically the spaces are supported by a thermally superior building envelope complete with coincident air/vapour barrier and polyisocyanurate insulation in the construction assemblies that exceed minimum thermal insulation code requirements.

2.4.2.2 Opinion of Probable Capital Cost

The Opinion of Probable Capital Cost for this option is $13.5 M. Table 2.8 provides a breakdown of the probable cost with a detailed line item list included in Appendix D.

Table 2.9 Option #2 Opinion of Probble Capital Cost

Line	Description	Labour Cost	Material Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
1	**PROJECT TOTAL, BASE SCOPE**					**$13,494,160**
2	Civil - Structural	$617,073	$1,094,838	$203,150	$1,631,800	$3,528,066
3	Mechanical & HVAC	$168,520	$199,500	$5,205,000	$192,476	$5,816,052
4	Electrical	$371,089	$172,531	$238,465	$74,197	$948,827
5	**Sub Total**	**$1,156,682**	**$1,466,869**	**$5,646,615**	**$1,898,473**	**$10,292,945**
6	Preliminary Engineering @ 3% (Class III Estimate)					$169,654
7	Detail Engineering @ 10% Direct Construction Cost					$565,514
8	Construction Management @ 2.5% Direct Construction Cost					$141,378
9	Site Construction Support by Engineering @ 1% Direct Construction Cost					$56,551
10	Commissioning Costs @ 1.5%					$84,827
11	Escalation Allowance @ 5%					$282,757
12	Capital Spares - 5% of CPC equipment cost					$250,000
13	**Sub Total**					**$12,267,418**
14	Contingency @ 10%					$1,226,742

Capital Cost Risk Analysis

No detailed risk analysis has been made on this Class IV OoPCC. A contingency of 10% has been allocated. As per AACE guidelines, a Class IV OoPCC is accurate to a range between -20% and +40%.

2.4.3 Option #3 – Fuel Handling Enclosed – 500 kW_e

Option #3 retains the technical and operational characteristics of Option #1, but attempts to reduce costs by only enclosing the fuel handling area. This option would only be available for the CPC and Proton Power units as they are self-contained in standard shipping containers (CPC units depicted in the rendering).

2.4.3.1 Opinion of Probable Capital Cost

The Opinion of Probable Capital Cost for this option is $11.4 M. Table 2.9 provides a breakdown of the probable cost with a detailed line item list included in Appendix E.

Table 2.10 Option #3 Opinion of Probble Capital Cost

Line	Description	Labour Cost	Material Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
1	**PROJECT TOTAL, BASE SCOPE**					**$11,402,782**
2	Civil - Structural	$399,213	$714,346	$167,750	$846,626	$3,528,066
3	Mechanical & HVAC	$205,634	$117,600	$5,204,000	$84,301	$5,816,052
4	Electrical	$463,036	$151,271	$238,235	$85,447	$948,827
5	**Sub Total**	**$1,067,883**	**$983,217**	**$5,609,985**	**$1,016,374**	**$10,292,945**
6	Preliminary Engineering @ 3% (Class III Estimate)					$122,831
7	Detail Engineering @ 10% Direct Construction Cost					$409,438
8	Construction Management @ 2.5% Direct Construction Cost					$102,359
9	Site Construction Support by Engineering @ 1% Direct Construction Cost					$40,944
10	Commissioning Costs @ 1.5%					$61,416
11	Escalation Allowance @ 5%					$204,719
12	Capital Spares - 5% of CPC equipment cost					$250,000
13	**Sub Total**					**$10,366,165**
14	Contingency @ 10%					$1,036,617

Capital Cost Risk Analysis

No detailed risk analysis has been made on this Class IV OoPCC. A contingency of 10% has been allocated. As per AACE guidelines, a Class IV OoPCC is accurate to a range between -20% and +40%.

2.4.4 Option #4 – Options for Expansion – 500 kW_e, 1000 kW_e, & 2000 kW_e

A potential path forward for the project is to first install a 500 kW_e plant as a proof-of-concept demonstration for the North, and then expand the facility in the near future. The design described for Option #1 facilitates the expansion of the power plant by an additional 500 kW_e without the need for added auxiliary services (i.e., sufficient space mechanically and electrically have been left to support the expansion). Beyond the 1.0 MW_e capacity, additional building services will be required. From a cost perspective, the first incremental 500 kW_e expansion will see cost savings compared to the initial installation, whereas achieving a 2.0 MWe would be equivalent to double the cost of the 1.0 MW_e plant. This is depicted in Figure 2.3.

To expand the plant in 500 kW_e blocks without incurring increased costs (i.e., each expansion costs the same) is possible, but would require a higher upfront capital cost to ensure the auxiliary services could support three future expansions. The owner needs to weigh the benefit of having the added infrastructure installed upfront for an expansion that may not take place.

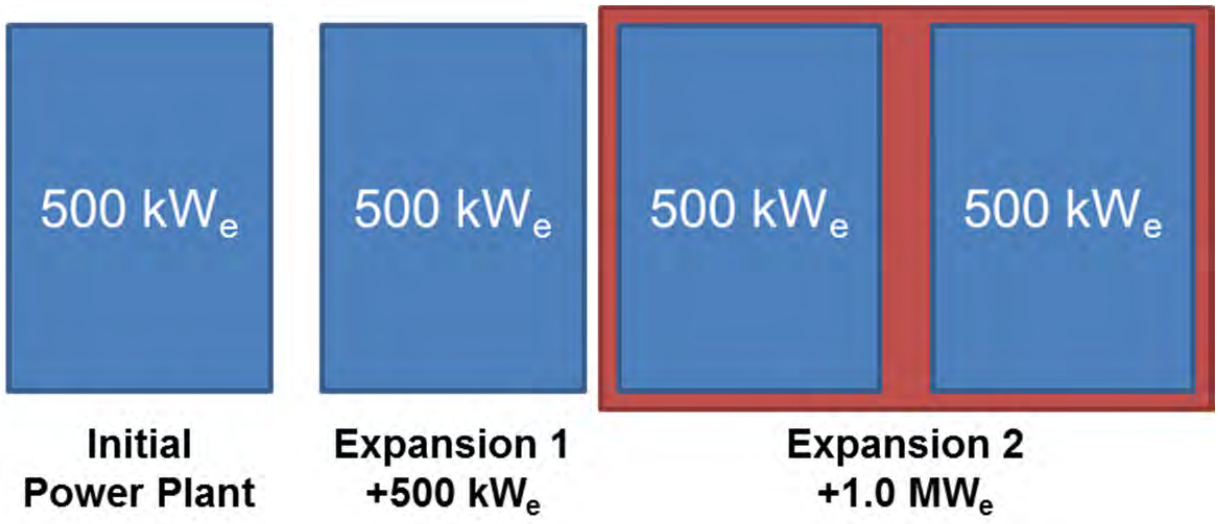


Figure 2.3 Expansion Incremental Costing

2.4.4.1 Opinion of Probable Capital Cost

The Opinion of Probable Capital Cost for this option is an additional $9.8 M on top of the base plant cost to achieve a total 1.0 MW_e capacity, or $22.5 M if 1.0 MW_e is installed initially. To achieve a 2.0 MW_e capacity, the combined figure would double to $45.0 M. Based on equipment costing for the gasification systems, to start the plant with a 2.0 MW_e capacity would be approximately the same budget, $45.0 M.

Table 2.10 provides a breakdown of the probable cost with a detailed line item list included in Appendix G.

Table 2.11 Option #4 Opinion of Probble Capital Cost

Line	Description	Labour Cost	Material Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
1	**PROJECT TOTAL, BASE SCOPE**					**$22,484,173**
2	Civil - Structural	$648,841	$1,226,438	$229,250	$1,390,000	$3,528,066
3	Mechanical & HVAC	$408,694	$376,500	$10,210,000	$302,428	$5,816,052
4	Electrical	$658,369	$283,829	$320,748	$101,033	$948,827
5	**Sub Total**	**$1,715,905**	**$1,886,767**	**$10,759,998**	**$1,793,461**	**$10,292,945**
6	Preliminary Engineering @ 3% (Class III Estimate)					$368,538.46
7	Detail Engineering @ 10% Direct Construction Cost					$1,228,461.54
8	Construction Management @ 2.5% Direct Construction Cost					$307,115.39
9	Site Construction Support by Engineering @ 1% Direct Construction Cost					$122,846.15
10	Commissioning Costs @ 1.5%					$184,269.23
11	Escalation Allowance @ 5%					$614,230.77
12	Capital Spares - 5% of CPC equipment cost					$250,000
13	**Sub Total**					**$20,440,157**
14	Contingency @ 10%					$2,044,016

Capital Cost Risk Analysis

No detailed risk analysis has been made on this Class IV OoPCC. A contingency of 10% has been allocated. As per AACE guidelines, a Class IV OoPCC is accurate in a range between -20% and +40%.

2.5 OPERATING COST

The operation and maintenance estimated cost is based on the use of an outside Operation & Maintenance (O&M) contractor. Operations and maintenance costs for the biomass plant consists of several components:

- Labor.
- Maintenance and materials.
- Major Equipment Repair reserve fund.
- Annual Environmental Testing.
- Consumables and chemicals.

- Miscellaneous supplies.

The items included in each category are explained below:

- **Labor** - The labor component, excluding fuel cost and renewal fund, is the largest cost in an O&M budget. It consists of the salaries and benefits for the operators and admin staff. The size of the staff can vary significantly depending on the size and complexity of the plant. For a 0.5 MW_e biomass plant, the operation will consist of five (5) full-time operators. Staff will have one plant manager and four (4) operators. The staffing compliment could be lower if based on CPC's operator requirements of two (2) trained operators.

- **Maintenance and Materials** - The cost for maintenance and materials reflects normal daily, weekly, monthly costs for regular plant maintenance.

- **Major Equipment Repair Reserve Fund** - The major equipment in a biomass power plant needs to be overhauled and repaired on a regular basis in accordance with the vendor's recommended procedures. This fund is primarily associated with the gasifier and engine but also includes other major pieces of equipment, particularly rotating equipment and heat exchangers. A reserve fund is established so that money is available to cover the significant costs of the equipment overhaul several years in the future. This cost is carried separately in the business case as the Capital Renewal Annual Rate, see Table 4.14.

  In lieu of planning and reserving for major equipment overhauls and inspections, owners sometimes establish a Long Term Service Agreement (LTSA) with the vendor. The LTSA provides annual performance guarantees from the suppliers as well as responsibility for all repairs and overhauls for a fee. The term of the LTSA can vary from 10 to 15 years. Note this approach was not taken for this O&M estimate.

- **Environmental Testing** - Most environmental operating permits require annual testing for any air, water or wastewater discharges from a plant to verify compliance with the permit conditions.

- **Consumables and Chemicals** - The cost of lubricants, oils, chemicals and misc. consumables used during normal plant operation is included in this line item.

- **Misc. Supplies** - This item covers the general administrative cost of running the power plant. It includes phones, office supplies, computers, etc.

2.5.1 Opinion of Probable O&M Costs

The following table, Table 2.11, is a summary of estimated O&M costs for the two biomass plants:

Table 2.12 Opinion of Probable Conventional Biomass O&M Costs

Description	0.5 MW	2 MW
Labor	$200,000	$350,000
Maintenance & Materials	$50,000	$200,000
Environmental Testing	$15,000	$25,000
Consumables & Chemicals	$15,000	$45,000
Misc. Supplies	$5,000	$10,000
Total O&M Estimated Cost	**$285,000**	**$630,000**

The estimate cost for O&M reflects the estimated average annual cost. It does not include cost normally incurred by the owner. These costs include fuel; insurance; property taxes or asset management fees.

2.6 FEEDSTOCK CHARACTERIZATION (AGFOR)

In order to develop an understanding of the potential for local feedstock for the plant at any capacity, several aspects need to be considered. Of primary interest is the current level of harvesting around Haines Junction, Yukon. Second is the industry the current harvest is serving, and potential synergies with the proposed biomass facility. Finally an assessment of the available fuel characteristics (moisture content, heating value), quantities available/required by the plant, and preliminary costing are provided.

2.6.1 Harvesting and Existing Industries

Overall harvest activity is low with little economy of scale; most equipment is bought used to keep costs down. Harvesting is regulated by permit based on experience and capacity.

New personal use entrants with no harvesting track record are issued permit volumes up to 25 m^3 within specified location in a common area; successive permits can be issued upon successful

completion of a permit. Harvesting is by chainsaw and a variety of small scale forwarding equipment from manual, ATV, and snowmobile to pick-up truck.

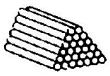
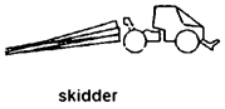
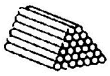
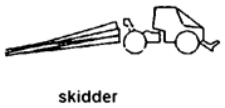
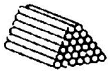
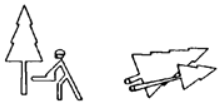
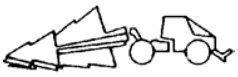
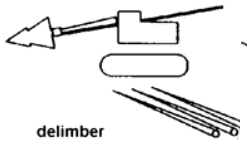
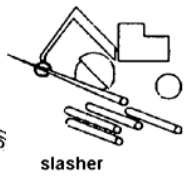
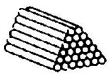
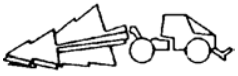
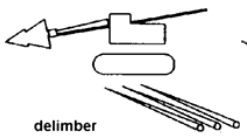
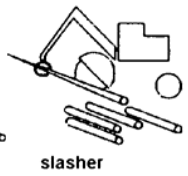
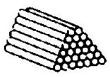
Commercial harvesting activities listed in the Wood Allocation Strategy for Haines Junction are presented in four (4) tiers as follows and depicted in Figure 2.6 on the following page.

Tier 1 – New entrants with no recent Yukon harvest experience (in the past three years) are issued permit volumes from 25 m^3 to 200 m^3. This Tier is for operators who aspire to a Tier 2 permit. Successive permits can be issued. Ten Tier 1 opportunities are made available for a given time period. Harvesting is by chainsaw and a variety of small scale forwarding equipment such as ATVs, snowmobiles, farm tractors and skidders.

Tier 2 – Operators with recent Yukon harvest experience are provided with two years wood supply permits up to 999 m^3 per year within a three-year license period; successive permits can be issued upon successful completion of the current permit. Operators are encouraged to participate in the license design and YESAB screenings. Harvesting is mainly is by chainsaw and a variety of small scale forwarding equipment such as farm equipment and skidders.

Tier 3 – Existing operators with recent Yukon harvesting history (in the past three years) are provided with 1,000 m^3 to 10,000 m^3 per year permits for a maximum of a four-year supply within a five-year period. Operators are required to complete the license design and YESAB screenings. Harvesting is by mechanical felling and bunching, forwarding is by grapple skidder, delimbing ranges from operational limbing (breakage and chainsaw) to cut-to-length processor to produce delimbed logs at the landing ready for loading; alternatively, this is done with chainsaws and or a firewood processor.

Tier 4 – Initiatives requiring significant investment are usually issued a harvest volume greater than 10,000 m^3 per year linked to a capital investment. A five to 10-year term may be considered, depending on availability and the annual allowable cut (AAC). The operator would be responsible to prepare the Timber Harvest Plans (THPs), license area design assessment and YESAB screening and follow the entire process to completion of harvest. Harvesting is by mechanical felling and bunching, forwarding is by grapple skidder, delimbing ranges from operational limbing (breakage and chainsaw) to cut-to-length processor to produce delimbed logs at the landing ready for loading; alternatively, this is done with chainsaws.

New Entrants	**<25 m^3**			
		ATV, snowmobile	**Logs, firewood**	
Tier 1 Entrants	**25 m^3 to 200 m^3**			
			**Chainsaw at landing**	
Tier 2 Existing	**< 999 m^3**	**Tree-length**		
			**Chainsaw at landing**	
Tier 2 Existing	**< 999 m^3**	**Whole-tree**		
				
Tier 3 Existing 1,000–10,000 m^3	**Tier 4 New > 10,000 m^3**			
				

Source: AGFOR Inc.

Figure 2.4 Harvesting Tiers

During the course of the FEED, in addition to desktop level assessments, AGFOR spent eleven (11) days (during two separate trips) in the Yukon meeting with key individuals in the Yukon forestry sector including harvesters, sawmill operator, other forest professionals, and Forestry Management Branch staff.

Initially AGFOR met with the three principal harvesting operators in the region. For each operation, AGFOR sought to gain an appreciation of the following:

- Harvest volume of shipped product (firewood, sawlogs) in the recent year – all tenures considered.
- The quantity of wood left standing after harvest excluding regulatory requirements, expressed as percentage of volume of product shipped - as a precautionary measure, AGFOR reduced the volume left standing by 50% to ensure that the requirement to leave 25% of the original standing volume is not compromised.
- The quantity of wood left lying in the harvest block – all species, expressed as percentage of volume of product shipped.
- The quantity of wood left at the landing after product has been shipped – all species expressed as percentage of volume of product shipped.

The same questions were asked of the forestry professionals familiar with the harvesting practices in the Haines Junction area; responses were consistent with those of the operators. For the most part, their answers were comparable with responses in other jurisdictions (AGFOR in-house).

In the Yukon, there are two principle uses of biomass feedstock: firewood and two small sawmills (one in Dawson and one near Haines Junction). The Haines Junction firewood and sawmill industries are serviced by three principal harvesters who collectively harvest and deliver approximately 25,000 m^3 per year, all tenures considered (>90% of the Haines Junction harvest).

For the sawmill, it was important to estimate bark, sawdust, and shavings left after sawing merchantable lumber, and the mill's current recovery factor (m^3 of logs per thousand board feet – MFBM). Subtracting the sawn lumber volume from the gross log volume delivered to the sawmill allowed for an approximation of the sawmill recovery and residuals

Estimated residues, in green metric tonnes (GMT), for each of the above assessment (i.e., sawmill residues, biomass left standing, left lying in block, and left lying at the landing) are summarized in Table 2.12; these are the forest harvesting residuals after product is shipped and the sawmill residuals from producing lumber – they reflect local practices and conditions.

Table 2.13 Opinion of Probable Harvest and Sawmill Residues (GMT)

Known Sources :	Tonnes/year
Sawmill residues	2,000
Left at landing (slash)	1,450
Left in block (slash)	1,750
Left Standing (- Reduced by 50%)	2,400
Total	**7,600**

2.6.2 From the Forest

With estimates of the potential residues and standing residuals from the three larger forest harvesters in the region and the sawmill totaling approximately 7,600 tonnes/year, it should be possible to supply the biomass to a generating facility capacity of approximately 1 MW_e. The business case for the three larger harvesters should be explored to ensure the validity and longevity of any commitment. The business case for other smaller harvesters and possible new entrants should also be explored to provide forest residuals adding a layer of security of capacity and of supply.

As the biomass plant capacity begins to exceed this level of existing supply (>1 MW_e), it becomes important to appreciate the availability of the required feedstock in relation to the forest resource. A plant capacity larger than 1 MW_e will require green stands to be harvested.

Some of the forest characteristics provide a first indication of the resource:

- Age class distribution and stage of development: Age class distribution is the area of the forest for each age class (10, 20, 30 age classes). This is a gross portrait of the forest landscape and its age. Approximately 40% of the Forest Resource Management Zone (Green Zone) is between 100 and 200 years of age (source: Forest Management Branch data).
- The gross volume (cubic meters of wood per hectare) of timber typically available at each age class is found on a yield curve.
- A significant portion of the forest is mature. Forest stand maturity shifts to over-maturity at just over 200 years when the stand volume begins to decrease. The January 17, 2013 flight over the Haines Junction area suggested that there are no great areas of significant stand volume decrease. The preliminary conclusion is there is mature standing timber.

- A focus on forest stands in the Forest Management Zone (Green Zone) that have more than 75 m^3 per hectare (the lower end of economic operability for many operators) provide the known operable standing volume. This where the requirement should be met. A new forest inventory will provide a better idea of the harvest potential and its geographical distribution.

The first three bullets provide an indication that the overall forest should support the harvest of a small volume of forest biomass. While the final bullet provides an idea of the operable inventory and its location, it should be noted that the current harvest levels with the additional biomass would be below the 2006 temporary salvage harvest. The salvage annual allowable cut ends in 2016. The new Timber Supply Review should identify new areas of potential supply

2.6.3 Moisture Content

Moisture content is a weight-based value; wood from operations is typically quantified on the volume basis, usually by the cord. That means that costs are constant for a given volume regardless of the moisture content. The lower the moisture content, the less wood needs to be harvested. This is operationally significant and contributes to maintaining the overall landscape.

AGFOR heard anecdotal comments of low moisture contents, especially in standing dead trees; a moisture meter reading at the sawmill in October 2012 seemed to confirm that. Reports from other jurisdictions also suggested low moisture contents.

AGFOR undertook to have the moisture contents of wood samples from both freshly harvested live and dead trees. The samples were taken on January 17, 2013. The Yukon Research Centre did the moisture content determinations in their laboratories. The results, shown in Table 2.13 for the dead trees were consistent with expectations, although the results for the live trees were higher than expected.

Table 2.14 Feedstock Moisture Content

Attribute	Moisture Content
Dead spruce	14.8%
Live spruce	47.0%

Chipping to size and moisture content are two key components. The challenge will be the green moisture content and the availability of standing dead (dry) trees. There are indications that the inventory and salvage of standing dead trees will begin to drop with time - when the supply of dead standing spruce becomes unattractive to the firewood business, a move to standing green trees with higher average moisture content is necessary. Moisture content (MC) of 35% is used for standing green trees. When this change occurs during the life of the plant more green wood will enter the feedstock and other pre-processing techniques and measures should be considered. Calculations are based on AGFOR's original assumptions, which are 15% for residues and 35% for standing green wood.

Several factors could affect moisture content at the time of harvest and sampling. Regular moisture content sampling of harvested dead and green trees over a year on different site conditions could provide a better appreciation of the variability.

Measures to reduce moisture content should be explored during the detailed feedstock study following the FEED study; as such, measures could offset the apparent higher than expected moisture content of a limited sample from a few sites. Based on the unit performance outlined previously and 15% moisture content of the immediate feedstock, the feedstock requirements at the bookend capacities are presented in Table 2.14

Table 2.15 Summary of Feedstock Requirement

Scenarios:	0.5 MW_e	2 MW_e
Oven dry tonnes	3,000	15,900
With15% moisture	3,789	20,081
Cubic meters (m^3)	7,293	38,652
Cords	3,241	17,178
Cords per week	62	330
Truck loads/week	2-3 /week	11-15/week

The cubic meter is a solid measure that excludes air spaces and is equivalent to a solid volume of wood one meter wide, one meter high and one meter long

The cord is an apparent volume of stacked bolts of wood including the air spaces between bolts, hence apparent volume. A cord is 128 cubic feet, often described as a pile of wood measuring four feet wide, four feet high and eight feet long or some variation that equals 128 cubic feet.

2.6.4 Feedstock Cost

Feedstock costs are based on the local operating conditions and products that form the operator's business case.

Harvesting Cost

From each operator, AGFOR obtained an indication of their charge-out rate for each function/piece of equipment. This is the cost of harvesting equipment including labour, profit and overhead. In the absence of a charge out rate, AGFOR obtained the roadside selling price of firewood at the forest-roadside landing. From that, the current applicable stumpage and fees are deducted to arrive at a value that approximates their equipment costs with labour, profit and

overhead. These are values used on local operations. They were compared to earlier reference studies and to AGFOR in-house studies and cost models.

Transportation and Handling

Where possible AGFOR obtained local rates and found that they were similar to other sources. They were compared to earlier reference studies and to AGFOR in-house studies. Distances where adjusted to reflect average haul distances over time at 50 km for the sawmill residues and 70 km for the forest harvesting residues and dedicated feedstock harvest. The new forest inventory will provide a better idea of the harvest potential and geographical distribution.

Loading and handling costs rely on in-house data with some adjustment to reflect the small scale of the project. These would need to be validated once the siting and feedstock delivery logistics begin to firm-up during the detailed feedstock analysis.

Chipping costs need to be confirmed. There are approaches, such as roadside (landing) storage and chipping, which could provide value to the plant. These would need to be validated once the amount of feedstock, siting and delivery logistics are finalized.

The costs are competitive by many standards. The extent to which these might be considered will occur in a detailed feedstock procurement exercise.

It is anticipated for either scenario (0.5 MW_e or 2 MW_e), that 50% of the winter harvest would be put into inventory for approximately six months at a storage yard eight kilometers away and then reclaimed for consumption. Interest charges would have to be added to that half of the feedstock. Alternatively, the feedstock could be chipped at roadside and delivered directly to the plant.

Several measures should be explored during the final site selection and feedstock procurement to mitigate the extra handling and inventory costs of an off-site intermediate off-site log yard:

- Explore the possibility of a summer harvest to reduce inventory, and provide work for the harvest crew during the summer – this would need the CAFN/Forest Management Branch's approval and any roads would trigger a review process.
- Store wood at the harvest landing and only reclaim it during the summer for immediate processing and consumption – this would need CAFN/Forest Management Branch's approval and any roads would trigger a review process. We would expect the wood to dry while in storage.
- Using a mobile chipper at the harvest landing and chipping whole trees has significant advantages:
    - Logging cost will be reduced because no limbing or limited limbing would be involved; if chainsaws and skidders are used there is a significant reduction in the risk of injury.

- While the trees are in storage, the moisture content should reduce, and possibly offset the extra handling and storage costs.
- There is a gain in volume/weight by not topping the tree.

Both chipping and whole tree chipping (or with intermediate limbing) at the landing would require the CAFN/Forest Management Branch's approval and likely require regulatory approval.

SCENARIO 1 - 0.5 MW_e

Scenario 1 produces 0.5 MW_e and requires approximately 3,789 GMT at 15% moisture content (green basis). The sources are sawmill residues, logging debris at the landing (slash) and debris left in the harvest block. Little or no standing live trees are anticipated in this scenario. Should dead standing spruce no longer be available at a future date, a shift to standing live trees would occur. Note that residues make up the majority of the Scenario 1 feedstock which are at 15% MC, which aligned with the assumed moisture content required for use of the CPC system (denoted as 'as fired').

Scenario 1 - 0.5 MW_e	
GMT 'as fired'	**GMT @ 15% MC**
3,000	3,789

The following are the combined delivered and chipped costs of sawmill residues, harvest residues at the landing, and in the harvest block.

Scenario 1 costs as fired (bin)		
	$ GMT as fired	**GMT @ 15%**
(a) Direct to plant	Omitted	Omitted
(b) With secondary yard	Omitted	Omitted

Scenario 1(a), 0.5 MW_e, has an expected direct delivery wood cost of ($ Omitted) per GMT at 15% MC as fired (in the bin) without transitioning through an off-site log yard.

Scenario 1(b), 0.5 MW_e has an expected wood cost via an off-site storage yard eight kilometers away of ($ Omitted) per GMT at 15% MC as fired (in the bin).

SCENARIO 2 – 2.0 MW_e

Scenario 2 produces 2 MW_e and requires approximately 20,081 GMT at 15% MC (green basis). The sources are sawmill residues, logging debris at the landing (slash) and debris left in the harvest block and the harvest of standing live trees in this scenario. Should dead standing spruce no longer be available, the harvest of standing live trees would increase to possibly 78%

of the feedstock; this percentage is used in the Scenario 2 cost estimate with wood at 35% MC. This level of harvest would likely require regulatory approval.

Scenario 1 – 2.0 MW_e	
GMT 'as fired' @ 35% MC	**GMT @ 15% MC**
24,610	20,081

The following are the combined delivered and chipped costs of sawmill residues, harvest residues at the landing and in the harvest block, the harvest of standing residuals and the harvest of live trees for feedstock.

Scenario 2 costs as fired (bin)		
	$ GMT as fired	**GMT @ 15%**
(a) Direct to plant	Omitted	Omitted
(b) With secondary yard	Omitted	Omitted

Scenario 2(a), 2 MW_e, has an expected direct delivery wood cost of ($ Omitted) per GMT at 15% MC and ($ Omitted) per GMT as fired (in the bin) without transitioning through a log yard eight kilometers away.

Scenario 2(b), 2 MW_e, has an expected delivered wood cost via a storage yard of ($ Omitted) per GMT at 15% MC and ($ Omitted) per GMT as fired (in the bin).

2.6.5 Pre-Processing Implications of Biomass Properties

Costs (harvesting, handling, transport and chipping) are essentially constant regardless of moisture content as harvesters are paid on a volume basis. The facility operates in green metric tonnes (GMT) and benefits from any reduction in moisture content. The use of sawmill and harvest residues of dead wood is currently an advantage for all of Scenario 1 feedstock requirements and a portion of the Scenario 2 feedstock requirement. The remainder of the Scenario 2 feedstock will rely mostly on live trees (green). Opportunities to reduce the moisture content of live trees needs to be explored and integrated into the procurement practices.

It is anticipated that 50% of the winter harvest would be put into inventory for approximately six months at a storage yard eight kilometers away (assuming the experimental farm is used) and then reclaimed for consumption. Yard inventories of drier dead spruce and the green live spruce should be kept apart and dated for inventory control. The green live spruce should be reclaimed on a first in first out basis to capitalize on any moisture content reduction. Interest charges would have to be added.

Two off-site storage (inventory) opportunities should be explored:

- Leave the wood decked at the roadside landing in the woods that is accessible to a truck year-round, especially in the summer months, and remove for consumption as needed. This would need to be developed in the next phase (during the detailed feedstock analysis) and would likely require regulatory approval.
- Transport wood to an intermediate off-site yard and then reclaim for processing and consumption. This is the current Scenario 1b and 2b.

The first opportunity involves less handling and is less costly than the second.

A minimum operating feedstock inventory equivalent to two or three weeks supply should be sought. Off-site storage is needed for weekly deliveries of wood during the regular season and in the off-season months. The storage area needs to accommodate basic site access infrastructure and right-of way access for trucks and equipment to and from the piles all year including during the spring break-up. The site should have good drainage to support the traffic all year.

The approximate area required is presented below:

Scenario	Storage Capacity (m^3 - cords)	Area (hectares - acres)
1b	3,122 m^3 (1,388 cords)	0.9 hectares (2.1 acres)
2b	18,302 m^3 (13,700 cords)	5.2 hectares (13 acres)

Harvest of Green Trees (Scenario 2)

Harvest and delivery costs (as-fired) of green trees currently left standing and as a dedicated harvest including harvest, transport to plant and chipping are presented below (rounding differences occur).

In Scenario 2(a) direct delivery (no intermediate storage yard) to the plant for Live Trees - are as follows:

$ / m^3 @ 35% MC	GMT @ 35%	$/GMT @ 35%	Factor to 0%	$ /ODT
Omitted	0.639	Omitted	1.76	Omitted

In Scenario 2(b) indirect delivery via an off-site yard for Live Trees - are as follows:

$ / m^3 @ 35% MC	GMT @ 35%	$/GMT @ 35%	Factor to 0%	$ /ODT
Omitted	0.639	Omitted	1.76	Omitted

Potential Employment

Looking at the potential impact to existing employment, either scenario will require an increase both harvesting by local contractors and new employment to support the plant. Based on the fuel quantities expected, the breakdown for added employment is outlined in Table 2.15. This high-level assessment shows the need for increased activity by the local harvesters (Contractor) and the biomass facility (New Corporation (NEWCO)).

Table 2.16 Employment Impacts from Biomass Plant

Employment / Scenario	Scenario 1a	Scenario 1b	Scenario 2a	Scenario 2b
Person Days	265	343	1464	1612
Person Years Total	1.20	1.56	6.65	7.33
Contractor* Person Yrs	0.70	0.70	4.57	4.57
NEWCO Person Yrs + yard-site maintenance	0.50	0.86	2.08	2.76

*Scenario 2 includes part-time conventional chainsaw and skidder volume

3.0 Environmental Assessment and Permitting

3.1 REGULATORY APPROVALS STRATEGY

A draft Environmental and Socio-economic Impact Assessment (IA) has been prepared based on information currently available on the Project and existing conditions in the area. This report includes an overview of the effects assessment and regulatory regimes associated with permitting the Project, scoping of the assessment to include relevant Valued Components (VC), summaries of baseline conditions for each VC and expected effects and proposed mitigation. Determination of significance has been based on residual effects after implementation of mitigation. Adaptive management and monitoring activities are also outlined where deemed applicable. The environmental and socio-economic impact assessment report draft completed to date is attached as Appendix F.

As the plant site has not yet been confirmed, collection of data to provide an understanding of baseline conditions associated with the plant site has been done at a high level for Haines Junction and the surrounding area. Data available at a desktop level indicate that there are no major environmental constraints on the preliminary site (used in the FEED study). Field studies are required to confirm findings once the site has been selected and are suggested to include (but may not be limited to) heritage resource assessment, vegetation and wildlife surveys and an existing sound pressure level survey. Targeted meetings or interviews with CAFN members and the public should also be held to confirm the plant site should not cause any significant effects on traditional and current land use and culture.

The Project team has drafted the effects assessment thus far with the intent to meet the requirements of an Executive Committee level screening. This route was chosen as the full scope of the Project is not yet confirmed, and thus the volumes of harvesting required are not known. These depend on the plant size and the outcome of the preliminary feedstock harvesting study (now complete). The client has also indicated it is likely that an Executive Committee submission is required based on initial consultation with YESAB. At this time, it is important to note that the level of submission required under Yukon Environmental and Socio-economic Assessment Act (YESAA) has not been confirmed with YESAB. The YESAA trigger for Executive Committee assessment of this Project is based on harvesting of 20,000 m^3 or more of standing or fallen trees. If a plant size of 500 kW_e is chosen it is estimated to consume 10,500 m^3 per year with existing harvesting areas having the potential to supply all of this volume (6,000 m^3 in logging residues from current harvesting operations and 4,500 m^3 (2,200 GMT) of sawmill residues not currently being used). Therefore, this size of plant could potentially be permitted through a Designated Office (DO) level submission (assuming DO level proposals are submitted separately by existing operators for ongoing harvesting). This would reduce the level of detail required in the assessment and importantly the potential timelines for approval. These potential timelines for approval (to receive a Decision Document) of an

Executive Committee proposal are 1 to 2.5 years, whereas the DO process timeline is less than 1 year. Note that on occasion, regulators may require an assessment for a project that is otherwise exempted (although this mechanism has never been applied). There is also a possibility that a Project requiring a DO level submission (as per the requirements of YESAA) could be referred to the Executive Committee at either the onset or following initial review of the DO submission. This referral would primarily be based on the potential for adverse effects even with proposed mitigation as well as stakeholder concerns or use of unknown technologies. Therefore, consultation with YESAB is required to confirm the Project's stream and scope of assessment. This strategy is further discussed in Section 4.3.

3.2 DESKTOP FEEDSTOCK HARVESTING ANALYSIS

Key potential environmental and socio-economic issues associated with using beetle kill and potentially green feedstock in the Yukon have been described in the draft IA (Appendix F). Mitigation options have been identified based on the preliminary information available. The feedstock harvesting environmental analysis included consideration of:

- Long-term sustainability of supply (discussion of the overall sustainability of supply for expansion of biomass use).
- Responsible treatment of ecosystem and environment.
- Legislative and regulatory requirements for the timber resources.
- Fire Management.
- Respect of other uses and users of forests.

Some consideration for Traditional Activities and Culture as well as social, recreational, and commercial use has been included however, this is recommended as an area for further study, now that volumes of required harvest are better understood. For the smaller plant, these are not critical considerations in the event that existing harvesting activities are contracted to supply the Project. Very limited documentation exists to support this type of socio-economic assessment at a desktop level and the social aspect requires consultation to ensure current values and uses are considered.

Supply for a 500 kW_e plant has been determined to be sustainable with no change over existing harvest areas expected. The additional requirement for a 2 MW_e plant is also a low percentage of the overall resource; in consideration of the Green zones as denoted in the Integrated Landscape Plan, the current use and the Timber Harvest Level for the Champagne and Aishihik Traditional Territory (2006). Both the availability of supply and the harvest level are subjects for review as part of the new forest inventory of dead and live forests.

Key guiding documents and plans are highlighted as follows:

2004 – Strategic Forest Management Plan for the Champagne and Aishihik Traditional Territory (CATT) provides direction to the planning process presenting the values and objectives for the CATT necessary to ensure sustainability in the broadest terms and reflecting the traditional and non-traditional values and objectives of the community. It provides the indicators and the processes for involvement of the community in the planning process. It addresses the entire land base in the study area.

2006 - The Timber Harvest Level for the Champagne and Aishihik Traditional Territory spells out the harvest level determination of spruce bark beetle affected forest stands and timber harvesting opportunities. This agreement set a harvest ceiling of 1,000,000 m^3 annually for the spruce beetle affected forest over a ten-year period. The harvest level is being updated with the in progress forest inventory.

2007 – Integrated Landscape Plan for the Champagne and Aishihik Traditional Territory (CATT) originally made available publically in March 2006. It is a subordinate plant to the 2004 Strategic Forest Management Plan (SFMP) and introduces land use Zones and availability for forest harvesting. These zones include both CAFN Settlement Lands and non-Settlement Land. Three Zones are presented:

- Forest Management Zone shown in green (aka the Green zone – 93,700 ha) is the zone currently considered for Timber Harvest Project Planning. Most of the wood harvesting would be in this zone with accommodation for site-specific wildlife and habitat.
- Provisional Forest Management Zone (aka the Yellow Zone – 70,000 ha) is not currently targeted in Timber Harvest Project Planning.
- Conservation Forest Management Zone (aka the Orange Zone – 83,150 ha) in which no commercial harvesting is currently allowed. Significant amendments to the SFMP and the ILP would be required to allow harvesting in this zone.

These documents provide the forest planners with the scope for planning and wood supply analysis, their rules of engagement and are referenced in the *Forest Resources Act* 2008 (FRA) which came into effect in 2011 along with the regulations. The FRA applies to non-Settlement Land where as CAFN Settlement Land falls under the authority of CAFN and is regulated via the *Traditional Activities and Protection Act*.

During this time, inventory estimates were developed to allow a level of forest harvesting activity to occur in the Green Zone. The background data used in this timber supply analysis stemmed from earlier photo interpretation to provide a rough and broad estimate of standing timber. The Timber Harvest Level for the Champagne and Aishihik Traditional Territory is a binding

agreement on the allowable salvage harvest that was established in 2006 based on this analysis.

Spruce Bark Beetle, Yukon Forest Health – Forest Insect and Disease Bulletin 19 provides a recent history of the spruce bark beetle infestations and its dynamics - The most recent outbreak began in 1990 caused significant yet unquantified mortality. Large tracts of dead and dying mature white spruce were observable while the infestation was in progress. The harvest/salvage of this wood was made possible with a time limited salvage harvest (10-year period from 2006 to 2016). The extent that this salvage will continue to be available is now a key question as the standing dead trees are beginning to fall.

A Timber Supply Review or new forest inventory is in progress based on recent aerial photo interpretation at a finer resolution. This will provide better data on the volumes, distribution and condition of both dead and live trees.

2009 – Forest Health Report, Yukon Energy Mines and Resources uses a risk based approach to forest health; 2009 is the first year of publication. It provides an expanded history of various forest health issues. The spruce bark beetle is the most damaging forest pest targeting mature spruce in the Yukon. The Yukon outbreak began in 1990 and is (at the time of the report) still underway “It is by far the largest and longest lasting spruce beetle outbreak ever recorded in Canada.” “The intensity and duration of the current infestation are related directly to climatic stress …by the significant increase in temperature during the late 1980s and into the 1990s.

2012 Champagne and Aishihik - Yukon Forest Management Implementation Agreement “reaffirms the provisions included in the Strategic Forest Management Plan for the Champagne and Aishihik Traditional Territory and the Integrated Landscape Plan for the Champagne and Aishihik Traditional Territory (CATT) confirming guidance to the new Timber Supply Review.

The new Timber Supply Review will provide useful information on both dead and live trees and will be the object of public engagements before a revised final annual allowable cut (AAC) is set. The AAC will then be apportioned according to the types of use and license categories in accordance with the objectives of the Forest Management Implementation Agreement. Public consultation would also be conducted before allocations are made.

Current interim allowable harvest volume estimates are based on the earlier inventory and the salvage of dead white spruce. The allocations on non-Settlement Lands follow the process outlined in the **Wood Allocation Strategy (see Operational Policy Procedure June 2012 – Wood Allocation Strategy for Haines Junction):**

- A License is issued and provides the rights to a volume in the licensed area.

- A Timber Harvest Plan (THP) is prepared in accordance with the Act and is approved by Forest Management Branch.
- A Timber Cutting Permit is issued in accordance with the Act.
- YESAA applies to areas over 1,000 m^3 and is engaged.
- A site plan is prepared in accordance with the above and in accordance with the Act.
- A Cutting Permit is issued with the terms and conditions specifying time frames, stumpage and fees and reporting and completion requirements.
- A post assessment conducted by the Compliance Branch provides Closure to the license.

On Settlement Lands, the *Traditional Activities and Protection Act, The Timber Harvest Level for the Champagne and Aishihik Traditional Territory, the Forestry Implementation Agreement* as well as the SFMP and ILP provide some framework and legislation for harvesting activities. CAFN is currently in the process of developing additional forest policy framework, scheduled to be in place by 2015. This was one of the key objectives of the 2012 Forestry Implementation Agreement. (Per. Comm. Roger Brown CAFN 2013).

3.3 RISK MANAGEMENT STRATEGY FOR ENVIRONMENTAL/SOCIO-ECONOMIC AND REGULATORY APPROVALS

This risk management strategy for environmental and socio-economic regulatory approvals builds on the preliminary work undertaken as part of the environmental assessment and permitting phase. The objective is to define environmental and regulatory approval risks to the project. A summary of gaps and uncertainties and recommendations for further study and potential approvals schedules are provided.

Based on our preliminary work, we consider the overall risk to the Project to be low in relation to attainment of environmental/socio-economic regulatory permitting requirements.

3.3.1 Gaps and Uncertainties

Although some information from the FEED Study has been made available to the environmental team prior to release of the draft study, the effects assessment completed to date (January 31) does not incorporate the information provided in the draft FEED Study or the findings of the preliminary feedstock assessment as these activities were conducted and finalized concurrently. As these studies have been conducted concurrently, some updates to the effects assessment are required to reflect the conclusions of these studies (such as the plant site area, construction periods and activities, volumes of waste generated, water consumed). Further updates are likely

to be required depending on the decision of the steering committee on whether to proceed with the Project and at what size or scale.

At this stage (as directed by the Project team), no directed consultation with the Yukon Environmental and Socio-economic Assessment Board (YESAB) has been conducted. It is recommended that potential strategies and timelines be reviewed with YESAB prior to financial and board decisions to move forward so that their input can be considered.

Assessment of cumulative effects has not been completed in detail, as the Project will not be registered with YESAA until a decision to move forward is made by the steering committee and those providing financial support to the Project. Additional activities or projects could be initiated prior to that time. Based on preliminary review, no other activities or projects currently exist that would combine with this Project to cause a significant adverse environmental or socio-economic effect. Further study in relation to socio-economic effects on existing forest harvesting and traditional and current land use, activities and culture may be warranted, depending on the magnitude of harvesting proposed.

Further study of noise/sound quality effects from chipping should be completed once this activity's location and equipment/technology are defined. A set back from the nearest residence or other sensitive receptor (such as the school) of 500 m to 1,000 m is expected to be required to avoid annoyance from noise due to this operation. The preliminary air quality assessment indicates that the Project should comply with regulatory requirements, however this will need to be confirmed based on the emissions profile of the Project from the selected vendor.

3.3.2 Feedstock Harvesting

With regards to moisture content of green trees, limited samples were taken during a one-day field visit on January 17, 2013. The preliminary moisture contents of the green wood determined based on this sampling were higher than expected; these findings should be considered preliminary in nature. More volume of harvest would be needed to supply the feedstock using green wood; this has been partially adjusted in calculations presented in this report by assigning a 35% moisture content to all standing trees left in a block (to be harvested to meet the 2.0 MW_e feedstock needs). Further in-season moisture content analysis should provide a better indication of variability. Moisture content reduction strategies have also been identified for further study.

This is considered a concern as fewer large areas of standing dead wood (beetle kill) may be economically available over time than previously suspected. The new forest inventory of dead and live forests is intended to address that issue. In the event that current harvesters agree to supply the required feedstock for a 500 kW_e facility, minimal planning on the part of the Proponent would be required in harvesting operations. While harvesting for a 500 kW_e facility requires detailed planning of wood harvesting, storage and chipping location and activities to ensure compliance with procedures and continuous feedstock availability, the contracted harvesters could be expected to manage the majority of this planning. Depending on the

methods for hauling, storage and chipping, the effects assessment would be revised accordingly.

Harvesting feedstock for a plant larger than 500 kW_e would require an increase in harvesting, beyond current levels. Further study should be undertaken to define the activities and timelines for this harvesting (*e.g.*, types of equipment, blocks required annually and planned field studies, seasonality of harvesting required, wood storage and chipping locations). Once the activities and areas are defined, the additional scope of assessment of socio-economic and environmental effects will be modified.

The assumption that existing fuel wood harvesting will continue to operate as per the status quo and thus could supply the Project as part of this activity presents some risk. The risk to this assumption is that current harvesters could leave the Haines Junction area once the dead wood is depleted. Risk to supply may also increase as the dead wood is depleted, as the economic efficiency of using greenwood volumes is known to be less due to the requirement for drying. This has been accounted for in calculations by assigning a 35% moisture content to all standing trees left in a block and trees to be harvested to meet the 2.0 MW_e feedstock needs. A review of the harvester's business case and of operational moisture content reducing strategies are noted for further study.

3.3.3 Next Steps

The following steps are provided under the assumption that a decision to go forward with the Project is made. No environmental constraints have been identified in the desktop review. Preliminary consultation has indicated that there is community interest and support for the Project.

In consideration of the plant site itself, no environmental constraints are expected for the range considered (500 kW_e to 2.0 MW_e) that would result in denial of approval of the Project for environmental or socio-economic reasons. When the feedstock harvesting activities are combined with the plant operation, there is more uncertainty with the larger plant size in terms of scope of assessment and timeline for completion. However, as the requirements are still a small fraction of the previously estimated forest resource and when combined with current harvest levels, are well within the 2006 Timber Harvest Level for the Champagne and Aishihik Traditional Territory, the inclusion of the forest harvesting activities in the overall assessment is not expected to result in significant adverse environmental effects that cannot be mitigated (for the sizes of plant being considered).

It is recommended that the plant size be selected in consideration of FEED results (economics and technical constraints) and input from consultation with First Nations and the public as well as the expected timelines for permitting of the facility under different scenario (500 kW_e to 2.0 MW_e). Field studies should be defined for this site, as required, in order to finalize the impact assessment in relation to the plant.

Confirmation of the emissions profile and dispersion modeling should be completed during the vendor selection process. Modeling may need to be redone if emissions are higher than those estimated based on Community Power Corporation's (CPC) proposal or stack parameters are substantively different (much lower stack or lower velocity would result in worse ambient air quality predictions).

A strategy for regulatory permitting, which should allow for more timely consumption of beetle-killed wood, is to proceed with permitting of a 500 kW_e facility with minimal additional analysis of environmental issues associated with feedstock harvesting (assuming existing forest harvesting operations can provide the required feedstock and YESAB agrees to a DO level proposal for the plant). This may be justifiable and agreeable to YESAB and the public for the following reasons:

- In accordance with the CAFN strategic plan, CAFN is interested in pursuing regional economic development within its Traditional Territory by exploring opportunities in all economic sectors. CAFN has been actively investigating Biomass potential for 18-months prior to this FEED study.
- The Public and First Nations have not communicated any concerns that cannot be resolved and mitigated through planning.
- Some members of the community and CAFN leadership have expressed their desire to use the beetle killed wood before a catastrophic forest fire occurs or the resource loses its usefulness due to rot (although it is understood that not all members of the community may align with this view).
- Based on the FEED study, the feedstock supply for a 500 kW_e plant should be attainable through existing harvesters without increasing annual harvest area (by using waste from sawmill operations, slash being left in the blocks and at the landing).
- CAFN and the Yukon Government have developed a Strategic Forest Management Plan and Integrated Landscape Management Plan, which is applicable to Settlement and non-Settlement Lands. These plans as well as the Yukon *Forest Resources Act* and the Haines Junction Wood Allocation Strategy Operational Policy and Procedures (non-Settlement Lands) would be followed in harvesting for the Project.
- CAFN does not consider current regulatory/legislative tools to be sufficient to adequately manage forest resources on Settlement Lands and is thus in the process of developing a forest policy framework, scheduled to be in place by 2015. This was one of the key objectives of the 2012 Forestry Implementation Agreement. (pers. Comm. Roger Brown CAFN 2013).

As explained in the FEED study, modular designs are available for the plant. Following the installation and operation of the 500 kW_e plant, sufficient time would be allowed to monitor operational issues related to the plant and/or feedstock acquisition (either operational or environmental/socio-economic). Subsequent to this, a proposal could be submitted to the DO

for expansion. Assuming operation of the initial 500 kW_e plant is shown to cause no significant effects, permitting of an expansion may be relatively straightforward.
Additional studies surrounding feedstock-harvesting activities should be defined in consultation with the Forest Management Branch, Environment Yukon, The Alsek Renewable Resource Council (ARRC), CAFN and YESAB. Based on our work to date, we suggest the following may be warranted:

- Review of Heritage Resource Assessment process currently being undertaken in association with forest management.
- Development of a Heritage Resource Assessment plan for the life of the Project.
- Focused public, stakeholder and Aboriginal and First Nations consultation to discuss existing land use, traditional activities and culture, and local knowledge of the areas in terms of ecological and heritage resources (in relation to potentially harvestable areas).
- Bird surveys should be designed in consultation with Canadian Wildlife Service, Environment Canada, Environment Yukon, and ARRC. Multiple surveys may be required to target various bird species (e.g., Common Nighthawk, owls, early surveys for woodpeckers, breeding bird surveys).
- Rare plant surveys should be designed in consultation with Environment Yukon, multiple surveys may be required to ensure that early ephemeral species are captured as part of the survey.
- Additional wildlife surveys may be required depending on consultation with Environment Yukon. Surveys targeting bats and/or small mammals may be required.
- Fish and fish habitat surveys may be required depending on the location of the feedstock sites. Design of the survey would be conducted in association with input from regulatory agencies.

3.3.4 Preliminary Field Study and Permitting Schedule

Consultation with YESAB is recommended prior to a go decision on size of plant. This will help to ensure that any input from the regulators on required scope of assessment can be considered in the decision process. The schedule from that point is dependent on the required permitting path. Consultation with CAFN and the community of Haines Junction to confirm plant siting should be completed prior to finalizing the site. Site field surveys for wildlife and vegetation should be completed in 2013. Certain species (such as Woodpecker and owl surveys) are done early in the spring (likely May) while the regular breeding bird surveys would be done in June. Depending on the level of detail required by the regulators, some of the plant surveys may need to be done early in the spring to catch early ephemeral species. All wildlife and plant surveys and their timing depend on consultation with the regulators to confirm required scope.

Timing for a field heritage resource assessment could be as early as spring 2013, provided assessments are conducted in snow-free conditions. Following completion of these activities and assuming a DO proposal is possible, the initial proposal could be submitted by mid-2013. If additional environmental and socio-economic study of feedstock harvesting is required by YESAB (likely for 2.0 MW_e plant, may be required for smaller plant), these studies should be scoped and initiated following a go decision on the Project and are expected to take 6 to 12 months to complete depending on the scope. The overall schedule and YESAA process is summarized in Figure 3.1.

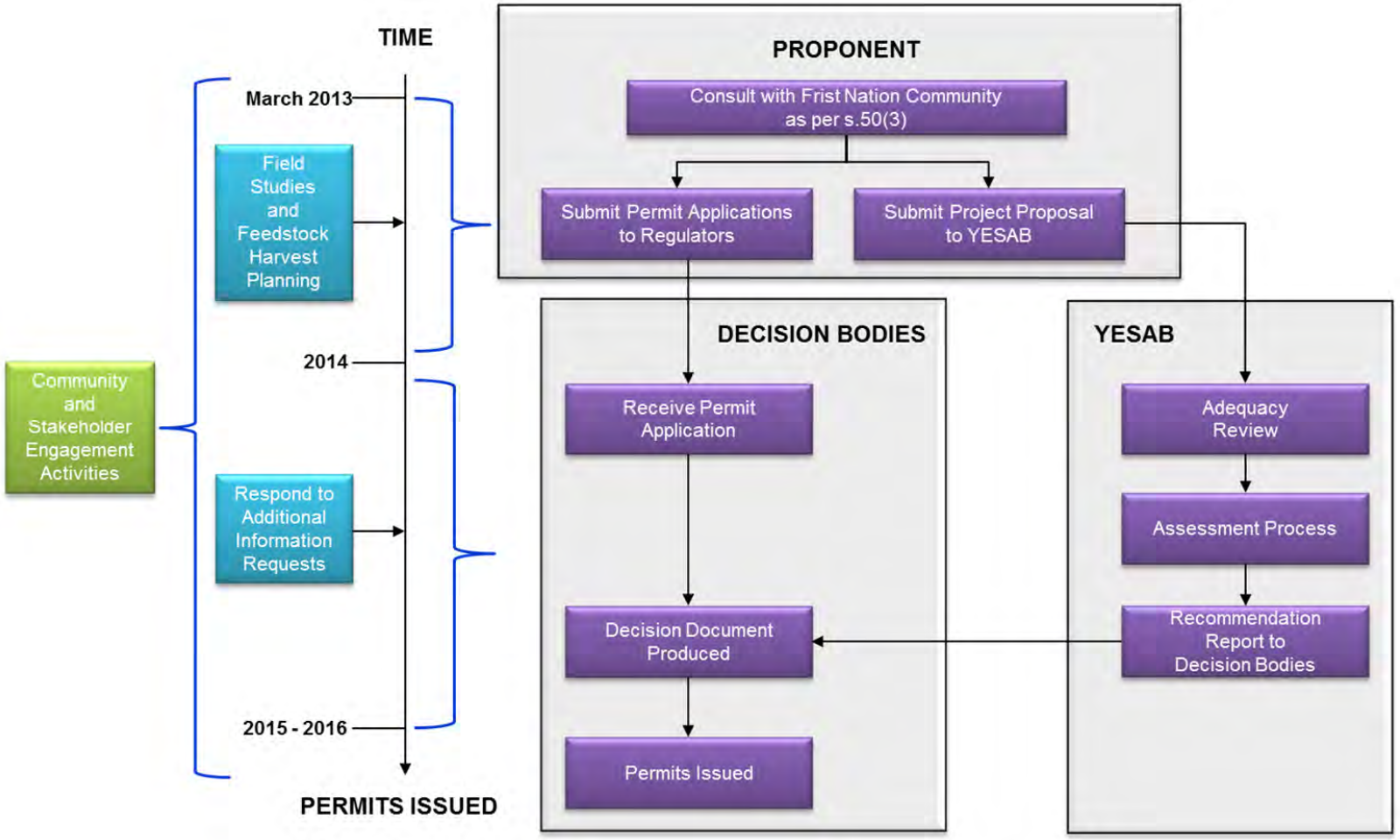


Figure 3.1 YESAA Simplified Process Flow Diagram for 2.0 MW Capacity

4.0 Risk, Financial & Operations Analysis

The Risk, Financial, and Operations Analysis section of the FEED focused on three critical areas, including: sources for project financing/funding, options for different business models for the formation of the new company (NEWCO), and financial assessment of the biomass plant (ROI, NPV, and sensitivities). Each of these topics is presented in the following subsections.

4.1 SOURCES OF PROJECT FINANCING

As part of the Phase 5 – Project Financing task, Stantec has conducted preliminary research into potential sources for project funding. At the kick-off meeting in Whitehorse on September 19, one potential source of funding discussed was Sustainable Development Technology Canada (SDTC). Stantec reviewed the workshop presentation for SDTC with the following comments.

4.1.1 Sustainable Development Technology Canada

SDTC operates two funds intended to stimulate investment in sustainable technologies. The first fund is the “SD Tech Fund™” which is 10 years old and aimed at development of emerging clean technologies. The key here is the word “emerging”. To be eligible, the Yukon biomass would have to be considered “unproven”[1].

The second fund managed by SDTC is the “NextGen Biofuels Fund™”. This fund is aimed at “large demonstration-scale facilities for next-generation renewable fuels and co-products.

Both of these funds were discussed with Paul Austin (SDTC, Vancouver office), to determine potential eligibility for the Yukon project.

Unfortunately, this project is likely to not qualify for either funding. The SD Tech Fund is strictly for new technologies or innovative use of clean technologies, and a proven biomass technology / waste heat application is not what SDTC is looking for in new applications. With regard to the NextGen Fund, it is for “first of a kind” type biofuel projects already in a continuous operation mode.

4.1.2 The ecoENERGY Innovation Initiative

“The ecoENERGY Innovation Initiative (ecoEII) received funding in Budget 2011, the Next Phase of Canada’s Economic Action Plan, for a comprehensive suite of research and development (R&D) and demonstration projects. The program’s objective is to support energy technology innovation to produce and use energy in a cleaner and more efficient way. This

[1] SDTC states in the presentation materials under the heading “SOI Don’ts” – Proven Technology = no need for SDTC

Initiative is a key component of the Government of Canada's actions to achieve real emissions reductions, while maintaining Canada's economic advantage and its ability to create jobs for Canadians. The ecoEII will also help in the search for long-term solutions to reducing and eliminating air pollutants from energy production and use."[2]

This funding source is currently engaged under the 'demonstration' division to support this FEED study. Continued funding from NRCan on the next phases of this project is possible and negotiations are ongoing.

4.1.3 Potential Funding Sources

Research indicates that there are other funding programs that may be applicable to the project. These will require direct follow-up with the applicable government agencies to determine if it is worthwhile to apply. Furthermore, once (if) a waste heat option is finalized, this may also lead to other funding opportunities.

From the Canadian Northern Economic Development Agency, there are the following programs:

4.1.3.1 Strategic Investments in Northern Economic Development (SINED)

SINED has been allocated $22 million funding per Territory for the years 2009-2014 as part of its Targeted Investment Program (TIP). The four areas of focus for TIP are building the knowledge base, enhancing the economic infrastructure base, capacity development, and economic diversification. It is possible that the Yukon project could qualify for funding as an economic diversification plan.

4.1.3.2 Community Economic Opportunities Program (CEOP)

The CEOP and CEDP funding provides project-based support and core operational support for First Nation communities for projects that lead to more community employment, greater use of land and resources, enhanced community infrastructure etc. The Yukon biomass project certainly will provide these economic benefits and may be a good candidate for this funding.

4.1.3.3 Community Infrastructure Improvement Fund (CIIF)

The CIIF program provides up to $1 million in funding for projects that improve community infrastructure. Recipients of the program must be not-for-profit entities, local/territory governments or First Nations. Infrastructure must be directly accessible to the public (i.e. district heating) and must be materially completed by March 31, 2014. There is some question whether the Yukon project would qualify due to restrictions pertaining to commercial activities.

[2] http://www.nrcan.gc.ca/energy/science/2003

Natural Resources Canada (NRCan), who is funding this Yukon feasibility study via its ecoEnergy Initiatives Program, may also have possible funding availability under grant programs as follows.

4.1.3.4 Aboriginal Economic Development in Forestry

The Canadian Forest Service (CFS) has been mandated by AFI to provide knowledge and facilitate coordination of federal support programs for Aboriginal economic forestry development, of which bioenergy is a priority focus. Limited multi-year funding may be available from AFI where it is determined that critical gaps exist in support from other programs that may pose a risk to project success. There is no formal application process involved. Instead, any funding will be subject to the CFS identifying the need and strategic value of the project as well as availability of the funding from AFI.

4.1.3.5 Biomass for Energy Program

Established in 2000, the Biomass for Energy Program focuses on research and development related to technologies used in the growing, harvesting and transportation of biomass feedstock. The program is also funded through the Canadian Forest Service.

The federal government Office of Energy Research and Development (OERD) offers another potential research and development grant program focusing on biomass technologies.

4.1.3.6 Bio-based Energy Systems and Technologies (BEST) Program

This program supports the research and development of technologies used to improve the supply, conversion and utilization of both existing and new biomass feedstock supply.

Finally, for taxable entities, accelerated Capital Cost Allowance provisions are available for capital assets used in the production of energy using renewable fuel sources. The provisions allow for an increased depreciation of equipment at a rate of 30% annually.

4.2 NEWCO BUSINESS MODELS

The purpose of this subsection is to provide a risk and qualitative analysis of the options available to NEWCO (Champagne and Aishihik First Nations, Yukon Energy and the Village of Haines Junction (VHJ)) for the ownership and operations of a 0.5 - 2.0 MW_e biomass energy system. The analysis is provided separately for both the feedstock harvesting (e.g. feedstock storage yard/wood chipping and logging) operations and the biomass plant operations.

Options:

Three ownership and operations options have been considered for each of the feedstock yard/logging operation and the biomass plant operation, resulting in a combined total of six options. These six possible options are provided in the following table.

Table 4.1 Business Model Options Analysis

	Feedstock Yard/Logging		Biomass Plant	
	Ownership	Operations	Ownership	Operations
Option 1	NEWCO	CAFN	NEWCO	NEWCO
Option 2	NEWCO	ISP	NEWCO	NEWCO
Option 3	NEWCO	CAFN	NEWCO	ISP
Option 4	NEWCO	ISP	NEWCO	ISP
Option 5	ISP	ISP	NEWCO	NEWCO
Option 6	NEWCO	CAFN	ISP	ISP

CAFN Champagne and Aishihik First Nations
ISP Independent Service Provider
NEWCO CAFN/Yukon Energy/Village of Haines Junction (a private entity)

Assumptions:

As part of this analysis, specific base assumptions have been made as follows:

- For options where an ISP is the owner, it is assumed that NEWCO will retain an option to acquire all assets at fair market value after a twenty-year period.
- For options where an ISP is the owner, it is assumed they will also be the primary operator. CAFN members will be used to the greatest extent possible and trained for eventual assumption of full operations over a maximum twenty-year period.
- Yukon Energy will hold a minority interest in NEWCO. They are interested in the plant operations but are not interested in the operations of the logging business.
- The Village of Haines Junction will hold a minority interest in NEWCO but will not participate in any of the operations.

4.2.1 Risk Analysis

The risk analysis used has been developed to show areas where actual results may differ from predicted. The risk analysis is semi-quantitative, with lower scores signifying a lower probability of occurrence and a lower severity of risk. Risk criteria have been broken out into two life-cycle categories reflecting the periods before and after the assets are placed into operations. The two categories are the "*design and construction period*" and the "*operations and transfer period*". The feedstock yard/logging operations and the biomass plant operations have been evaluated separately due to the distinctiveness of each of these project components.

Scoring:

The risk assessment considers both the probability of the risk occurring and the severity of impact if the risk does occur. The scoring uses a scale where 1=Low, 2= Medium and 3=High which can generally be interpreted as follows:

Table 4.2 Scoring Structure

Score	Probability	Severity
1 (Low)	*Unlikely* to occur for this project	Low impact unlikely to result in a loss that cannot be easily mitigated
2 (Medium)	*Possible* to occur for this project	Medium impact where the loss can mostly be mitigated
3 (High)	*Likely* to occur for this project	High impact where the loss may be significant

The total risk for each option is calculated as: **Total Risk = Probability x Severity**.

4.2.1.1 Feedstock Yard/Logging Analysis

The total risk scores for the feedstock yard/logging operations are:

Table 4.3 Risk Score Summary – Feedstock Yard/Logging

	NEWCO Owns/ NEWCO Operates	NEWCO Owns/ ISP Operates	ISP Owns/ ISP Operates
Design and Construction Period	16	18	14
Operations and Transfer Period	16	11	19
Total Risk Score	**32**	**29**	**33**

With the lower score reflecting lowest risk, Option 2 is the lowest risk option for feedstock yard/logging.

The following table shows the detailed scoring for the feedstock and logging ownership and operations options followed by a short narrative of the scoring rationale for each criterion.

Table 4.4 Risk Assessment – Feedstock Yard/Logging

FEEDSTOCK YARD / LOGGING RISK ASSESSMENT *(Low -1 , Medium - 2 , High - 3)*	OPTIONS								
	NEWCO / CAFN			NEWCO / ISP			ISP / ISP		
	Prob-ability	Sever-ity	Risk	Prob-ability	Sever-ity	Risk	Prob-ability	Sever-ity	Risk
DESIGN & CONSTRUCTION PERIOD									
Under or over designed (changes required to meet performance criteria or capex higher than necessary)	1	1	**1**	1	1	**1**	1	1	**1**
Constructability	2	2	**4**	2	2	**4**	1	1	**1**
Insufficient interest in RFP to stimulate competitive forces	1	3	**3**	1	3	**3**	1	3	**3**
Complexity of processes leading to increased time and cost	1	2	**2**	2	2	**4**	3	2	**6**
Permit/zoning risks	1	1	**1**	1	1	**1**	1	1	**1**
Scope / schedule creep	2	2	**4**	2	2	**4**	1	1	**1**
Default/breach of T&C's by consultants/contractors	1	1	**1**	1	1	**1**	1	1	**1**
Average Score			**16**			**18**			**14**
OPERATIONS & TRANSFER PERIOD									
Operational reliability standards not met	3	2	**6**	1	2	**2**	1	2	**2**
Operating cost variances	3	2	**6**	1	2	**2**	1	2	**2**
Electricity demand risk	1	1	**1**	1	2	**2**	1	2	**2**
Energy cost (feedstock) variation	0	0	**0**	0	0	**0**	0	0	**0**
Default/breach of T&C's by operator	1	1	**1**	1	3	**3**	1	3	**3**
Required maintenance not performed, diminishing value of asset	1	1	**1**	1	1	**1**	2	2	**4**
Market conditions change, increasing market value of the assets	1	1	**1**	1	1	**1**	3	2	**6**
Average Score			**16**			**11**			**19**
TOTAL RISK SCORE (**Lower** is better)			**32**			**29**			**33**

Following is an explanation of scoring for each life-cycle category:

Design and Construction Period:

The three options have close risk levels pertaining to the design and construction period. The risk of over or under designing the required facilities is quite low for all options primarily due to the requirements being low complexity. This is also true for overall constructability. Regarding tendering, the potential risk of there being insufficient interest in the project is again low as most consultants and contractors should have adequate capability to provide design and construction requirements. The risk level does differ between options when considering the complexity of processes. This is due primarily to the asset transfer back to NEWCO after twenty years if an ISP is owner, which can significantly increase time for contractual negotiations compared to a more standard arrangement. This option does, however, provide the lowest overall risk to NEWCO during the construction phase. Although permitting risk is not likely to be any different, the risks associated with scope and scheduling are lower where an ISP is owner. As the ISP is ultimately responsible for most construction risks, NEWCO will be effectively sheltered from this risk. Although there is possibly increased risk from a breach of terms and conditions by an ISP as an owner and/or operator, the fact that the project represents a longer term project with larger cash flows effectively makes it less likely that an ISP would default or breach contract than would a contractor in a design-build option with less at stake.

Operations and Transfer Period:

During the operating stage, the most significant period in the life cycle, the options where ISP is operator provide a lower risk exposure for NEWCO. The operating risk is primarily attributable to the entity responsible for operating the logging and feedstock operations. With NEWCO as operator, the lack of experience in these areas represents a high risk. The risk of electricity demand is low regardless of who is the owner. However, the severity of this risk will be greater where the ISP is operator as there is likely to be some form of contractual guarantee by NEWCO such as a take-or-pay agreement. This is not likely to be high however, due to the ability to keep workers active and stockpile feedstock if necessary. Other areas where an ISP operator provides a greater risk to NEWCO is the possibility, although small, that an ISP could default and/or breach the terms and conditions of the operating agreement. Although the operating agreement would most certainly contain recourse protection if a default or breach were to occur, the problems and lost time by key NEWCO personnel could be significant. Accordingly, this risk is likely to have serious impact if it were to occur.

Where the ISP is owner, it is assumed that the asset will be transferred back to NEWCO at fair market value (assumed net book value) after twenty years of operations. Due to potential, inaction, or uncontrollable market conditions, the eventual fair market value is likely to be different from predicted. The probability of this occurring is high, however the impact is considered only moderate at worst, especially if taking into consideration the impact in today's dollars. The condition of the asset at transfer is also highly dependent on the capital renewal

and maintenance plan of the ISP. The greater influence that NEWCO has over these areas, the more likely the asset condition will maintain a higher value. Therefore, where the ISP is owner (and NEWCO has least control) the risk will be greatest.

4.2.1.2 Biomass Plant Analysis

The total risk scores for the biomass plant operations are:

Table 4.5 Risk Summary – Biomass Plant

	NEWCO Owns/ NEWCO Operates	NEWCO Owns/ ISP Operates	ISP Owns/ ISP Operates
Design and Construction Period	24	24	15
Operations and Transfer Period	13	12	20
Total Risk Score	**37**	**36**	**35**

With the lower score reflecting lowest risk, Option 3 is the lowest risk for the biomass plant. The following table shows the detailed scoring for the logging and feedstock ownership and operations options followed by a short narrative of the scoring rationale for each criterion.

Table 4.6 Risk Assessment – Biomass Plant

BIOMASS PLANT RISK ASSESSMENT *(Low -1 , Medium - 2 , High - 3)*	OPTIONS								
	NEWCO / NEWCO			NEWCO / ISP			ISP / ISP		
	Prob-ability	Sever-ity	Risk	Prob-ability	Sever-ity	Risk	Prob-ability	Sever-ity	Risk
DESIGN & CONSTRUCTION PERIOD									
Under or over designed (changes required to meet performance criteria or capex higher than necessary)	2	3	**6**	2	2	**4**	1	1	**1**
Constructability	2	2	**4**	2	2	**4**	1	1	**1**
Insufficient interest in RFP to stimulate competitive forces	2	3	**6**	2	3	**6**	1	3	**3**
Complexity of processes leading to increased time and cost	1	2	**2**	2	2	**4**	3	2	**6**
Permit/zoning risks	1	1	**1**	1	1	**1**	2	1	**2**
Scope / schedule creep	2	2	**4**	2	2	**4**	1	1	**1**
Default/breach of T&C's by consultants/contractors	1	1	**1**	1	1	**1**	1	1	**1**
Average Score			**24**			**24**			**15**
OPERATIONS & TRANSFER PERIOD									
Operational reliability standards not met	2	2	**4**	1	2	**2**	1	2	**2**
Operating cost variances	2	2	**4**	1	2	**2**	1	2	**2**
Electricity demand risk	1	1	**1**	1	2	**2**	1	2	**2**
Energy cost (feedstock) variation	1	1	**1**	1	1	**1**	1	1	**1**
Default/breach of T&C's by operator	1	1	**1**	1	3	**3**	1	3	**3**
Required maintenance not performed, diminishing value of asset	1	1	**1**	1	1	**1**	2	2	**4**
Market conditions change, increasing market value of the assets	1	1	**1**	1	1	**1**	3	2	**6**
Average Score			**13**			**12**			**20**
TOTAL RISK SCORE (**Lower** is better)			**37**			**36**			**35**

Following is an explanation of the scoring for each life-cycle category:

Design and Construction Period:

The options where NEWCO is owner has a considerably higher risk level than does the ISP as owner option. This is primarily attributable to NEWCO having minimal knowledge and experience related to biomass generation systems. Although Yukon Energy has generation expertise, they do not have specific biomass experience. This fact impacts the risk that the project is over or under designed and constructability of the project. It is also quite likely that risk pertaining to insufficient interest in the RFP tender will be higher where NEWCO is operator. Where an ISP is owner, the project represents a longer term project with larger cash flows making it more attractive. Where the risk level is higher for an ISP owned project is regarding the complexity of processes, due primarily to the asset transfer back to NEWCO after twenty years. This can significantly increase the time required and complexity of contractual negotiations compared to a more standard arrangement. Where the risk associated with scope and scheduling is concerned, the ISP owned project is much less risky due to the ISP having the responsibility for most construction risks. There is however the possibly with an ISP operated project that they breach some terms and conditions. However, as the project is of a longer term nature, and with larger overall cash flows (as owner and operator), it is less likely that an ISP would default or breach contract.

Operations and Transfer Period:

Converse to the design and construction period, the option where ISP owns the biomass plant is riskier than where NEWCO is owner. This is largely a result of the requirement for the plant to be transferred back to NEWCO after twenty years, and the uncertainty regarding the condition and value of the asset at that time. Potential, action or inaction, or uncontrollable market conditions, can cause the eventual fair market value of the plant to be different from predicted. The probability of this occurring is high, however the impact is considered only moderate especially considering the impact in today's dollars. With the condition of the asset at year twenty being highly dependent on capital renewal and maintenance of the plant, the more control NEWCO has over these areas, the more likely the asset condition will maintain a higher value, making an ISP owned project riskier than a NEWCO owned project. Other areas where an ISP owner/operator provides a greater risk to NEWCO is regarding a potential default and/or breach of the terms and conditions of the operating/transfer agreements. Although the agreements would most certainly contain recourse protection for NEWCO, a default or breach could still create problems and lost time by key NEWCO personnel.

The option where the ISP is the operator does provide a lower risk exposure for NEWCO where operational reliability and cost variances are concerned attributed to the ISP greater knowledge and experience with biomass systems. The risk of electricity demand is low regardless of who the owners is, due mainly to the small size of generation output. However, the severity of this

risk will be greater where the ISP is operator as there is likely to be some form of contractual guarantee by NEWCO such as a take-or-pay agreement.

4.2.2 Risk Analysis Summary

The following table combines the three feedstock yard/logging and three biomass plant risk scores into a summary of the six possible options considered for these operations and ranks each option in terms of lowest risk.

Table 4.7 Risk Summary

	Feedstock Yard/Logging		Biomass Plant			
	Owner	Operator	Owner	Operator	TOTAL	RANKING
Option 1	NEWCO	CAFN	NEWCO	NEWCO		5
Risk Score	32		37		69	
Option 2	NEWCO	ISP	NEWCO	NEWCO		2
Risk Score	29		37		66	
Option 3	NEWCO	CAFN	NEWCO	ISP		4
Risk Score	32		36		68	
Option 4	NEWCO	ISP	NEWCO	ISP		1
Risk Score	29		36		65	
Option 5	ISP	ISP	NEWCO	NEWCO		6
Risk Score	33		37		70	
Option 6	NEWCO	CAFN	ISP	ISP		3
Risk Score	32		35		67	

Based on the analysis, Option 4 has the lowest risk profile. This option combines the benefits of NEWCO ownership control with the ISP industry specific operational expertise. Following very closely is Option 2, which substitutes NEWCO as operator for the biomass plant.

The deviation in scoring between the lowest and highest scores is five points (roughly 7%) suggesting that the risk profile deviation is not significant. Because of this, decision-making should be based on two criteria:

- Criteria 1 - The ability to control/mitigate the risks.
- Criteria 2 - The scale of the operation (0.5 MW versus 2.0 MW).

Referring back to the risk score summary previously provided in Table 1, it is clear that the risk profiles for NEWCO versus ISP as operator differ greatly between the design and construction and the operations and transfer periods. Where NEWCO is operator the greatest risk is during

the design and construction stages while with an ISP as operator the greatest risk is during the latter (and longer) operations and transfer stages. The greatest risks for NEWCO in the design and construction stage are the unfamiliarity with both the feedstock yard/logging and biomass requirements whereas the greatest risks where an ISP is operator are primarily due to not having control over operations. Much of the design and construction risk can be effectively mitigated by contracting the project and construction management to consultants with specific expertise. However, countering this is the increase in operations risk, which occurs as the scale of the operations increase. For example, with a smaller scale 0.5 MW operation the risks of NEWCO operating the plant is relatively low whereas for a larger scale 2.0 MW plant this risk is much higher. For the feedstock yard and logging operations, where NEWCO has no experience, the risk is high regardless of the plant size.

4.2.3 Financial and Operational Analysis

The qualitative financial and operations analysis used has been developed as a complimentary extension of the risk analysis to highlight NEWCO/CAFN and ISP specific strengths or weaknesses in knowledge and experience that are important to both the feedstock yard/logging operations and the biomass plant operations. The analysis is

Scoring:

The financial and operations criteria are scored using a simple scale from 1 to 3 as follows:

1 = *Low* level of knowledge and/or experience.

2 = *Medium* level of knowledge and/or experience.

3 = *High* level of knowledge and/or experience.

A separate evaluation was done for both the feedstock yard/logging operations and for the biomass plant operations due to the distinctive nature of each. Both evaluations used the same seven criteria as follows:

- Design and construction experience.
- Operations and maintenance experience.
- Industry and regulatory experience.
- Environmental and sustainability experience.
- Access to experienced labor.
- Administrative requirements (impact on NEWCO).

- Management and control (impact on NEWCO).

4.2.3.1 Feedstock Yard/Logging Analysis

The total qualitative financial and operations score for the feedstock yard/logging operations are:

Table 4.8 Financial and Operations Analysis – Feedstock Yard/Logging

FEEDSTOCK YARD / LOGGING FINANCIAL AND OPERATIONS ANALYSIS	OPTIONS Score (Low -1 , Medium - 2 , High - 3)		
	NEWCO / CAFN	NEWCO / ISP	ISP / ISP
Design and construction experience	1	2	3
Operations and maintenance experience	1	3	3
Industry/regulatory experience	2	3	3
Environmental/sustainability experience	1	3	3
Access to experienced labor	1	3	3
Administrative requirements (to NEWCO)	3	2	1
Management and control (to NEWCO)	3	2	1
TOTAL SCORE (**Higher** is better)	**12**	**18**	**17**

Following is an explanation of the scoring for each criterion:

Design and Construction Experience:

Design and construction of the feedstock yard/logging is an area where a slight advantage is held by the ISP due to their significant knowledge and experience specific to the industry. Although NEWCO will procure the design and construction from outside sources, they will still be required to ultimately oversee and approve design and construction. Where the ISP is operator but not owner, there could be benefit with them providing their experience as part of the design stage, but likely not during construction.

Operations and Maintenance Experience:

The ISP, with specific industry knowledge and experience will have a very significant advantage over NEWCO/CAFN who has minimal knowledge and experience in logging and biomass feedstock operations.

Industry Regulatory Experience:

The ISP, with specific industry knowledge and experience will have a significant advantage over NEWCO/CAFN who has minimal knowledge and experience in regulations pertaining to logging.

Experience in Environmental/Sustainability:

The ISP, with specific industry knowledge and experience will have a significant advantage over NEWCO/CAFN who have very minimal knowledge and experience in environmental and sustainability matters related to logging. Knowledge and experience in environmental and sustainability matters is fast becoming a critical requirement for businesses of all types.

Access to Experienced Labor:

The ISP, due to their presence in the feedstock yard/logging industry will also have good access to experienced labor while it is very unlikely that NEWCO/CAFN will have access to this type of skilled labor. Having access to skilled operators and maintenance staff is critical to reliability and efficient operations of the logging and feedstock operations. An advantage for a large ISP will be access to their own overall labor pool which may be deeper and more specialized. This provides added assurance where training, specialization and emergency staff replacement requirements are concerned.

Lower Administrative requirements (to NEWCO)

A disadvantage to outsourcing operations to an ISP is the increased administration burden required to oversee initial negotiations and the ongoing management of the contractual terms and conditions and the general relationship with the ISP. For the NEWCO owns and CAFN operates option there is minimal partnering so this is not a big issue. Where NEWCO owns and an ISP operates there is added administration for the ISP operating agreement. Where the ISP both owns and operates the transfer of assets back to NEWCO will require the most administrative resources for NEWCO.

Management and Control (to NEWCO):

The more ownership and responsibility for operations that NEWCO undertakes, the more management and control they will have. For the ISP own and operate option, NEWCO has little or no control over the physical assets and operations, however they do have contractual control inherent in the terms and conditions of the operations and transfer back agreements.

4.2.4 Biomass Plant Analysis

The total qualitative financial and operations score for the biomass plant operations are:

Table 4.9 Financial and Operations Analysis– Biomass Plant

BIOMASS PLANT FINANCIAL AND OPERTIONS ANALYSIS	OPTIONS		
	Score (Low -1 , Medium - 2 , High - 3)		
	NEWCO / CAFN	NEWCO / ISP	ISP / ISP
Design and construction experience	1	2	3
Operations and maintenance experience	1	2	3
Energy industry/regulatory experience	2	3	3
Environmental/sustainability experience	2	3	3
Access to experienced labor	1	2	3
Administrative requirements (to NEWCO)	3	2	1
Management and control (to NEWCO)	3	2	1
TOTAL SCORE (**Higher** is better)	13	16	17

Following is an explanation of the scoring for each criterion:

Design and Construction Experience:

Design and construction of the biomass plant is an area where a slight advantage is held by the ISP due to their significant knowledge and experience specific to the biomass industry. Although NEWCO has generation experience and will procure the design and construction from outside sources, they will still be required to ultimately oversee and approve design and construction. In the option where NEWCO owns and an ISP operates there could be some benefit with an ISP providing their experience as part of the design stage, but likely not during construction. Under Option 3, an ISP who has designed and constructed numerous biomass plant systems to satisfy many different requirements undoubtedly will have greater advantage and can be relied on to "get it right" with little to no risk.

Operations and Maintenance Experience:

NEWCO has good in-house capabilities via Yukon Energy but biomass systems would be new to the existing team. An ISP will draw on their significant capabilities to provide greater knowledge, innovation and solutions to problems that may arise.

Energy Industry/Regulatory Experience:

NEWCO has no energy and regulatory experience but is assisted by having Yukon Energy as a partner. The option where an ISP partners with NEWCO adds additional experience. Finally, an ISP, with specific biomass knowledge and experience is best equipped in specific biomass matters.

Experience in Environmental/Sustainability:

Knowledge and experience in environmental and sustainability matters has become a critical requirement for businesses of all types. In the utilities sector, an ISP brings the breadth and depth of knowledge and experience in these areas that NEWCO has only by way of the partnership with Yukon Energy. Adding the ISP experience to NEWCO would provide a similar level of expertise as an ISP can offer in these important areas.

Access to Experienced Labor:

Having access to skilled operators and maintenance staff is critical to reliability and efficient operations of utility systems. NEWCO has a well-trained staff via Yukon Energy. An advantage for an ISP will be their access to their own overall labor pool which may be deeper and more specialized, especially with biomass systems. This provides added assurance where training, specialization and emergency staff replacement requirements are concerned.

Lower Administrative Requirements (to NEWCO):

A disadvantage to outsourcing operations to an ISP is the increased administration burden required to oversee initial negotiations and the ongoing management of the contractual terms and conditions and the general relationship with the ISP. For the NEWCO owns and CAFN operates option there is minimal partnering so this is not a big issue. Where NEWCO owns and an ISP operates there is added administration for the ISP operating agreement. Where the ISP both owns and operates the transfer of assets back to NEWCO will require the most administrative resources for NEWCO.

Management and Control (to NSUH):

The more ownership and responsibility for operations that NEWCO undertakes, the more management and control they will have. For the ISP own and operate option, NEWCO has little or no control over the physical assets and operations, however they do have contractual control inherent in the terms and conditions of the operations and transfer back agreements.

Financial and Operations Analysis Summary:

The following table combines the three feedstock yard/logging and three biomass plant financial and operations analysis scores into a summary of the six possible options considered for these operations and ranks each option in terms of lowest risk.

Table 4.10 Financial and Operations Summary

	Feedstock Yard/Logging		Biomass Plant			
	Owner	Operator	Owner	Operator	TOTAL	RANKING
Option 1	NEWCO	CAFN	NEWCO	NEWCO		6
Score	12		13		25	
Option 2	NEWCO	ISP	NEWCO	NEWCO		2
Score	18		13		31	
Option 3	NEWCO	CAFN	NEWCO	ISP		5
Score	12		16		28	
Option 4	NEWCO	ISP	NEWCO	ISP		1
Score	18		16		34	
Option 5	ISP	ISP	NEWCO	NEWCO		3
Score	17		13		30	
Option 6	NEWCO	CAFN	ISP	ISP		4
Score	12		17		29	

Similar to the risk analysis, Option 4 places highest with Option 2 again being second. This is a confirmation of the importance of having industry experience specific to the feedstock yard/logging and biomass industries. Overall the deviation in scoring between the lowest and highest scores is ten points (roughly 29%) indicating that the industry experience is very critical to success. The difference between Option 4 and Option 2 is a much lower three points (8%) which indicates that NEWCO operating the biomass plant is less critical than having an ISP operate the feedstock yard/logging operations. This is logical as NEWCO has power generation knowledge, which, although not biomass specific, is at least beneficial where a smaller 0.5 MW operation is concerned, but would be less so where the plant size increases to 2.0 MW.

4.2.5 Summary of Analyses

Option 4 (NEWCO owns/ISP operates) ranks first in both the risk analysis (Table 5) and the financial and operations analysis (Table 8). However, following closely is Option 2 where NEWCO operates the plant. This is especially applicable where a smaller 0.5 MW plant is concerned.

The risk and financial and operations analysis demonstrates that “control”, “experience” and “scale” have the greatest impacts on risk and ultimately project success. NEWCO benefits greatly where they have most control over operations. However, total control also comes at the expense of not having the benefit of the ISP industry experience. Option 4 provides a trade-off where the lack of experience is addressed via an ISP. However, if the operation will be a smaller scale 0.5 MW plant, the benefit of an ISP operating the plant will not be as great, meaning that NEWCO should be able to operate the plant without much risk.

4.2.6 Conclusion

Applying this analysis to the size and scale of the biomass operation, the following ownership and operations models are the most appropriate for a smaller (0.5 MW) and larger (2.0 MW) plant operation.

Table 4.11 Recommended Owner/Operator Model

	Feedstock Yard/Logging		Biomass Plant	
Plant Size	**Owner**	**Operator**	**Owner**	**Operator**
0.5 MW	NEWCO	ISP	NEWCO	NEWCO
2.0 MW	NEWCO	ISP	NEWCO	ISP

As stated in the assumptions earlier in the report, where the ISP is the operator, the intention would be to increasingly employ workers from CAFN and provide training over a set period of time (i.e. 20 years).

4.3 FINANCIAL ANALYSIS

Using the preliminary engineering designs, financial analyses were prepared to determine the financial viability of the various installation scenarios. The results of these analyses are presented and explained in the following tables and charts.

It is important to note that the financial analyses do not currently include the capital cost for the district heating network. The capital cost for the installation of the network has been assumed to be covered under a separate project to be completed in conjunction with the biomass plant. The financial analyses do account for the O&M and revenue from operating the biomass plant in conjunction with the network (i.e., selling heat through the network)

The financial analyses were performed on multiple scenarios based on biomass plant size, building architecture, and vendors. Although only four options have been outlined in previous sections, ten different options were investigated for the financial analyses. Options #1 through #6 are all based on the technology offered by Community Power Corporation using the

preliminary engineering parameters discussed previously. The details of Options #1 through #6 are detailed below:

- Option #1 – Full Building Enclosure – 500 kW_e (Community Power Corp.).
- Option #2 – Full Architectural Enclosure – 500 kW_e (Community Power Corp.).
- Option #3 – Fuel Handling Enclosed – 500 kW_e (Community Power Corp.).
- Option #4 – Options for Expansion – 1 MW_e (Community Power Corp.).
- Option #5 – Options for Expansion – 2 MW_e (Community Power Corp.).
- Option #6 – Options for Expansion – 3 MW_e (Community Power Corp.).

Due to the savings in capital costs, the equipment provided by Proton Power was also analyzed, as described in Options #7 through #10 below. Options #7 through #10 are based on the replacing the CPC equipment with that provided by Proton Power. It should be noted that Proton Power has indicated it has the ability to provide containerized systems, but has not completed a project using this format to date (see Figure 4.1).

- Option #7 – Full Building Enclosure – 500 kW_e (Proton Power).
- Option #8 – Full Architectural Enclosure – 500 kW_e (Proton Power).
- Option #9 – Fuel Handling Enclosed – 500 kW_e (Proton Power).
- Option #10 – Options for Expansion – 2 MW_e (Proton Power).

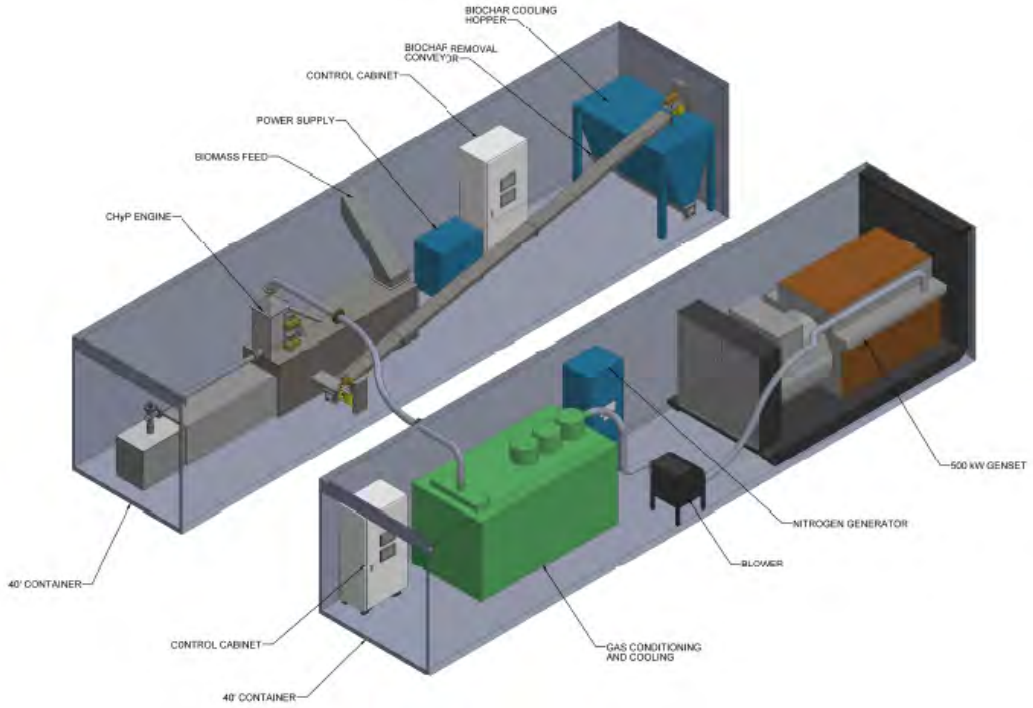


Figure 4.1 Potential Proton Power Containerized 500 kW_e Units

The primary difference between the inputs associated with CPC (Table 4.12) and those associated with Proton Power (Table 4.13) are the equipment costs and capacity factors (CPC has an 80% factor, Proton 92.5%). All other inputs remain the same, though in reality some variances may occur regarding the O&M costs.

Table 4.12 Financial Inputs: Options #1 - #6

Item	Option #1 500 kW_e	Option #2 500 kW_e	Option #3 500 kW_e	Option #4 1000 kW_e	Option #5 2000 kW_e	Option #6 3000 kW_e
CAPEX ($ Million)	$12.7	$13.5	$11.4	$22.5	$45.0	$67.5
Annual Fuel Consumption (ODT/yr)	3,000	3,000	3,000	6,000	12,000	18,000
Power (MWh/yr)	3,500	3,500	3,500	7,000	14,000	21,000
OPEX ($)	$285,000	$285,000	$285,000	$400,000	$630,000	$800,000

Table 4.13 Financial Inputs: Options #7 - #10

Item	Option #7 500 kW_e	Option #8 500 kW_e	Option #9 500 kW_e	Option #10 2000 kW_e
CAPEX ($ Million)	$8.5	$9.2	$7.3	$26.6
Annual Fuel Consumption (ODT/yr)	3,472	3,472	3,472	13,888
Power (MWh/yr)	4,052	4,052	4,052	16,208
OPEX ($)	$285,000	$285,000	$285,000	$630,000

In order to complete the financial analysis, several financial parameters needed to be defined. The financial assumptions outlined in Table 4.14 were employed to support this study. Assumptions for amortization, tax rate, and escalation are made on a consistent basis for all scenarios to facilitate comparison (Table 4.14). NEWCO's discount rate and electricity purchase price were assumed for the study.

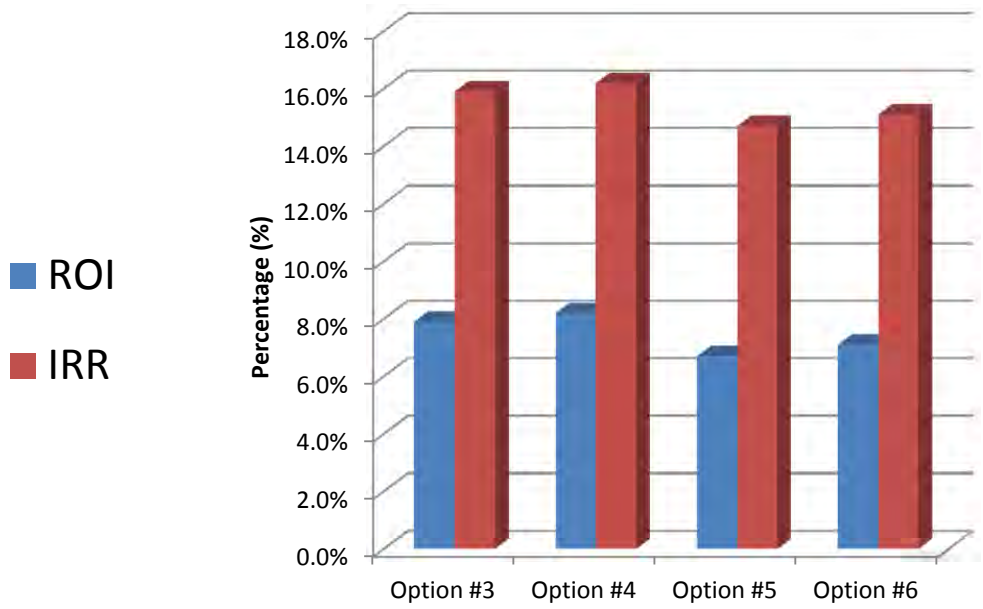
Using the base financial assumption, none of the ten (10) options proves viable. Each has ROE/ROI/NPVs that are negative. The main opportunity explored to make the options viable was to add a capital subsidy with could be achieve through funding grants. The amount of capital subsidy was taken as a percentage of total project costs to conduct this sensitivity.

Table 4.14 Financial Assumptions

Financial Assumptions			
Amortization:	Declining Balance:	20	Years
	Plant:	50.0	% (w/accelerated CCA class 43.2)
	Buildings:	4.0	% (w/CCA class 1)
	Equipment:	30.0	% (w/CCA class 43)
Capital Renewal Annual Rate:	Plant:	4.0	%
	Buildings:	2.0	%
	Equipment:	6.0	%
Weighted Average Cost of Capital:	WACC:	8	%
Inflation:	Annual Escalation:	3.0	%
	Feedstock Inflation Rate:	1.0	%
Equity:	NEWCO:	30	%
Long Term Debt :	Interest Rate :	5	%
Capital Subsidy (as % of Total Project):			
	Funding Low:	0	%
	Funding High:	80	%
Base Fuel Pricing:			
	Biomass:	Omitted	$/GMT
Biomass Power Sale Price:			
	Base:	$200	$/MWh
Biomass Heat Sale Price :			
	Base:	$185	$/MWh

The results of the financial analysis are provided in Table 4.15 in graphical and tabular form. The values of ROI and IRR were estimated using an assumed feedstock price of $50/GMT, 80% capital subsidy and an electricity selling price of $0.20/kWh, for a select number of options.

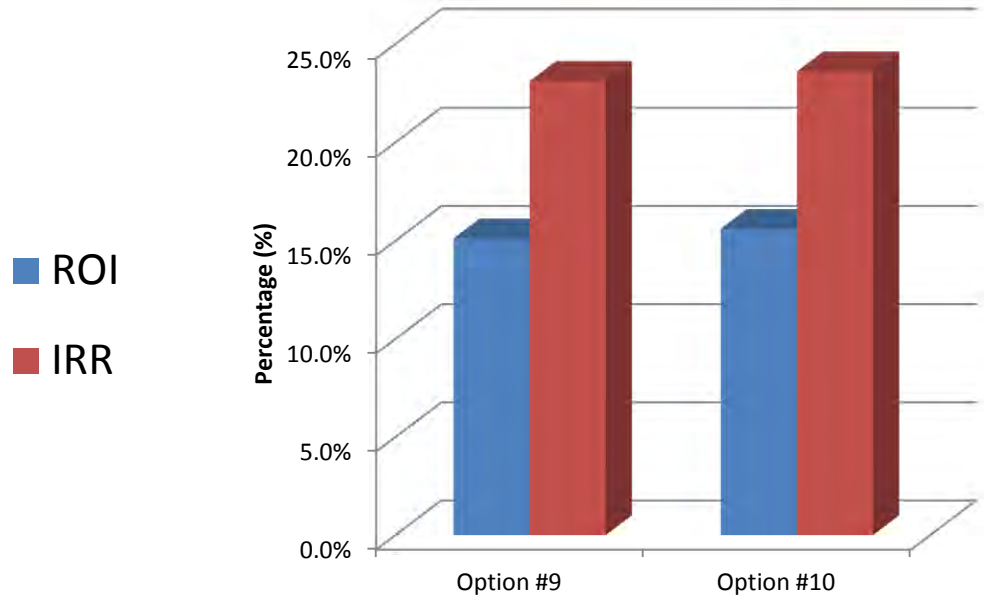
Table 4.15 Biomass Plant Return on Investment Performance: CPC



500 kW_e	**Item**	**Option #3 – 500 kW_e Fuel Enclosed $50/GMT, $200/MWh, 80% Capital Subsidy**
	Return on Investment (ROI)	7.9%
	Internal Rate of Return (IRR)	15.9%
1.0 MW_e	**Item**	**Option #4 - 1 MW_e Fully Enclosed $50/GMT, $200/MWh, 80% Capital Subsidy**
	Return on Investment (ROI)	8.2%
	Internal Rate of Return (IRR)	16.2%
2.0 MW_e	**Item**	**Option #5 - 2 MW_e Fully Enclosed $50/GMT, $200/MWh, 80% Capital Subsidy**
	Return on Investment (ROI)	6.7%
	Internal Rate of Return (IRR)	14.7%
3.0 MW_e	**Item**	**Option #6 - 3 MW_e Fully Enclosed $50/GMT, $200/MWh, 80% Capital Subsidy**
	Return on Investment (ROI)	7.1%
	Internal Rate of Return (IRR)	15.1%

Similar to the CPC ROI performance, the Proton Power could also reach positive ROIs with capital subsidy, although require significantly less due to their lower capital cost (note that only the 2 MW_e system was investigated for Proton Power and not 1 MW_e or 3 MW_e).

Table 4.16 Biomass Plant Return on Investment Performance: Proton Power



500 kW_e	**Item**	**Option #9 – 500 kW_e Fuel Enclosed $50/GMT, $200/MWh, 67% Capital Subsidy**
	Return on Investment (ROI)	15.1%
	Internal Rate of Return (IRR)	23.1%
2.0 MW_e	**Item**	**Option #10 – 2000 kW_e Fuel Enclosed $50/GMT, $200/MWh, 67% Capital Subsidy**
	Return on Investment (ROI)	15.6%
	Internal Rate of Return (IRR)	23.6%

As seen in the following two figures (Figures 4.2 and 4.3), the most viable options from each vendor in terms of ROE at the 0.5 MW_e capacity are CPC's Option #3 and Proton's Option #9. These refer to the plants with only fuel enclosure which have the lowest capital cost for this capacity. Therefore, the sensitivity analyses will only concentrate on these two options as book ends for project viability.

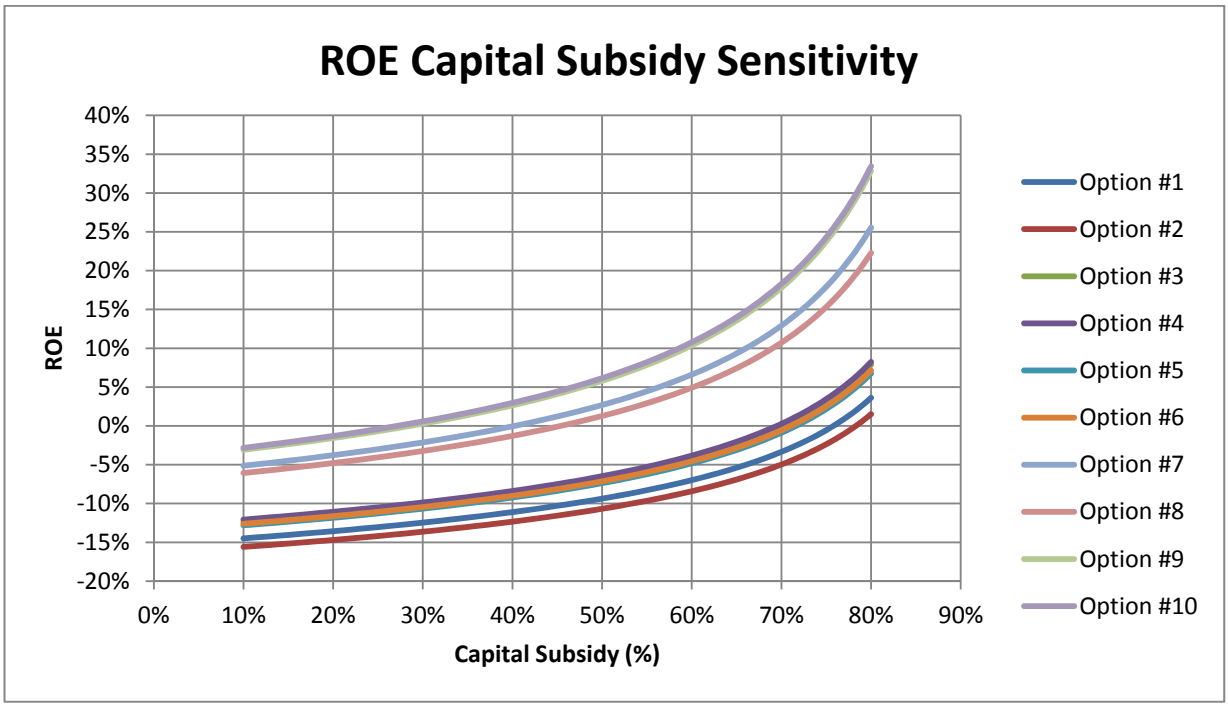


Figure 4.2 ROE Capital Subsidy Sensitivity

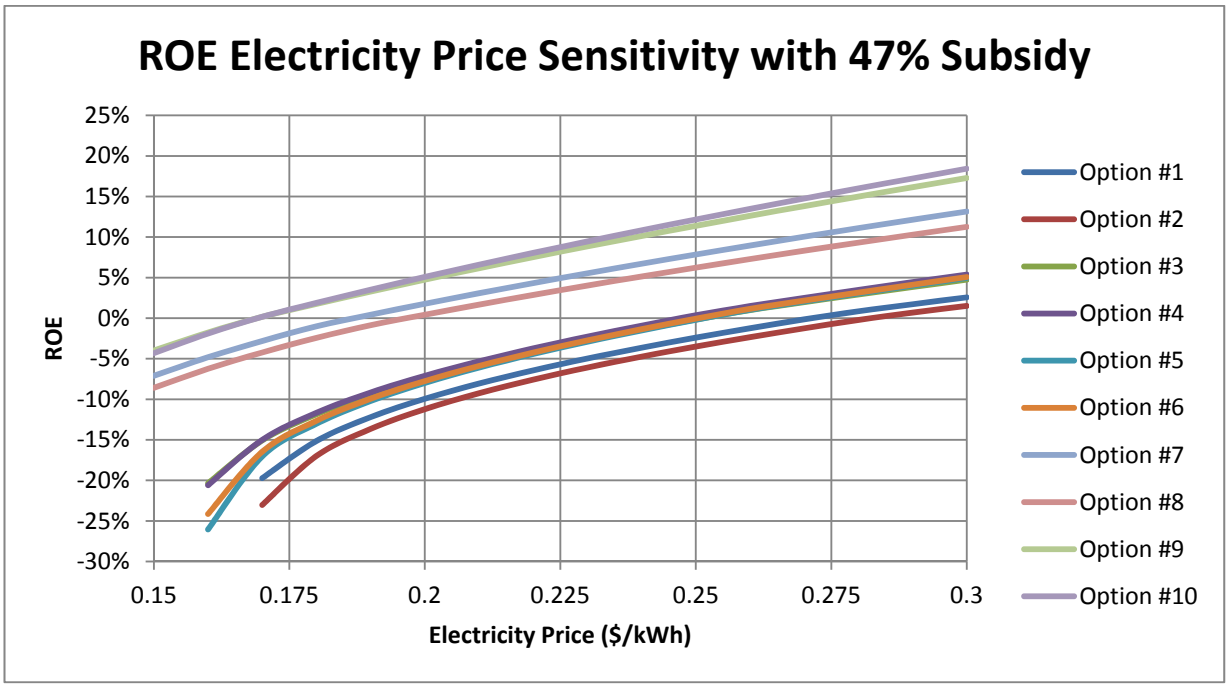


Figure 4.3 ROE Electricity Price Sensitivity

The previous figures also indicate the level of capital subsidy and/or electricity sale price required to achieve a desired ROE of 15%. In Figure 4.2, each option has no capital subsidy, and each option shows its lack of an ROE. As subsidies are increased, the Proton Power options pass over the 0% ROE mark with 30-40%subsidy, and achieve a 15% ROE at 67% for Option #9 and #10. The CPC options only start into positive ROE territory beyond the 70% subsidy mark.

In Figure 4.3, a combination of capital subsidy and increase in electricity sale price are considered to achieve a 15% ROE. The curves are based on the project achieving a 47% capital subsidy, and highlighting the impact of increasing the electricity sale price. For the best case scenario with Proton Power's Option #9, the electricity sale price would have to increase from $200/MWh to $280/MWh, to achieve the 15% ROE. For CPC, the project would only achieve a 5% ROE with 47% subsidy and a $300/MWh sale price.

4.3.1 Sensitivity Analyses

Four (4) additional variables affecting the success of biomass plant are fuel costs, O&M costs, district heating sales, and the district heating sale price. In order to understand the impact of these four (4) variables on the successful outcome of the installation, a range for each was considered and plotted based on impact to ROI and NPV. Each sensitivity analysis is presented in the following sub-section by variable, for each vendor.

4.3.1.1 Feedstock Price

For the two cases with fuel enclosures, Figure 4.4 was prepared to highlight the ROI and NPV for fuel costs from $50/GMT to $175/GMT. Fuel costs are market driven and subject to change outside the control of the facility design.

Similar to capital subsidy and electricity pricing, the project viability is strongly related to the feedstock pricing. Although there is no feedstock price that helps any option achieve a better financial viability, an increase to feedstock prices higher than would be available from existing operations (low end of the sensitivity, $50/GMT) would be detrimental to any gains from capital subsidy – doubling feedstock cost reduces ROE of Proton Power by half, to 7.5%.

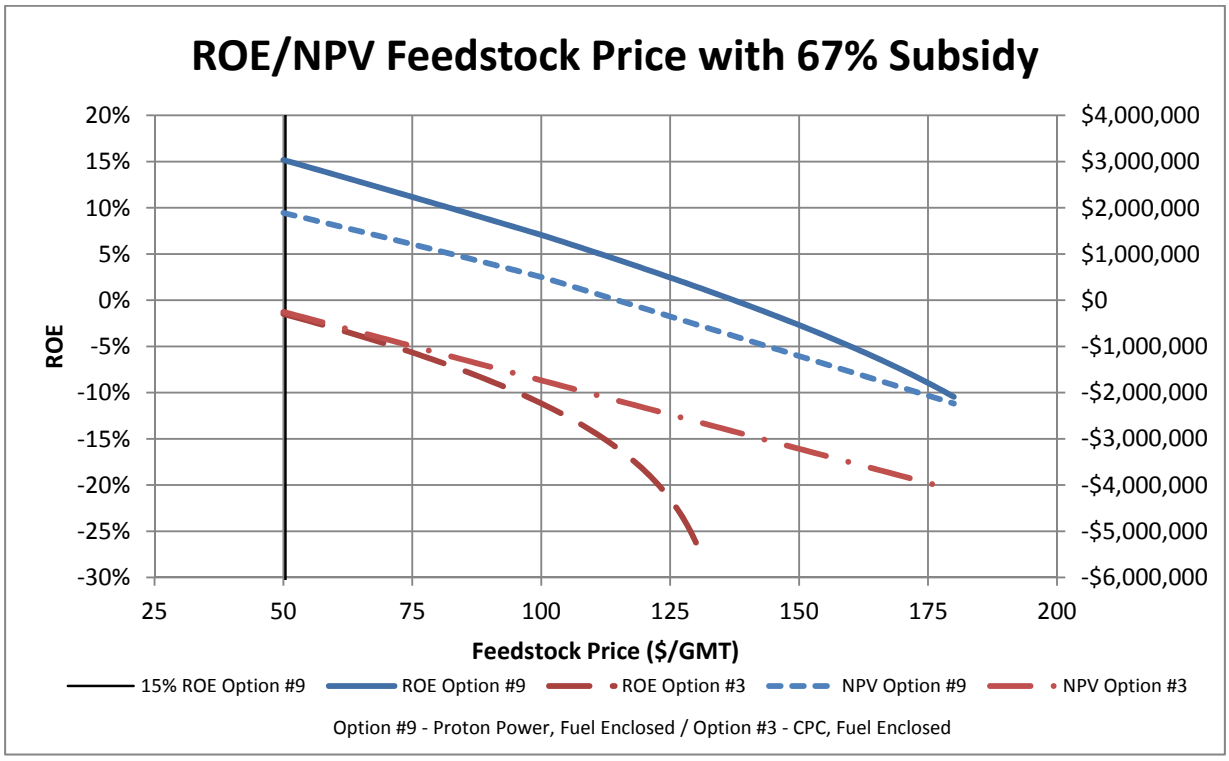


Figure 4.4 ROE/NPV Feedstock Price Sensitivity

4.3.1.2 Other Variables

For the two cases with fuel enclosures, Figure 4.5, 4.6, and 4.7 were prepared to highlight the ROI and NPV for plant O&M costs from $125,000 to $500,000 annually, district heating sales from 1,000 to 2,000 MWh annually, and district heating sale price from $110 to $250 / MWh. This variable are subject to change based on the facility/network design and vendor selected. The O&M costs in Figure 4.5 focuses on O&M specific to operating the biomass gasification system, O&M for the DH network and ORC are not considered.

Variations in O&M costs will affect the project's ROE by approximately 2.5% for every $50,000 annual. Similarly, an increase in DH sales by 500 MWh per year would increase the ROE by 2.5%. As the DH network is only projected to sell 1280 MWh/year, and the gasifier rejects over 5,000 MWh/year, the opportunity exists to expand the network in the future for increased sales.

The DH sale price in Figure 4.7 shows the impact of a variation in the sale price for 1,280 MWh per year. Currently valued based on the CTCG report at $185/MWh, this price will likely need to be indexed based on diesel fuel prices when the project is implemented. Current price offers a 2% savings over diesel.

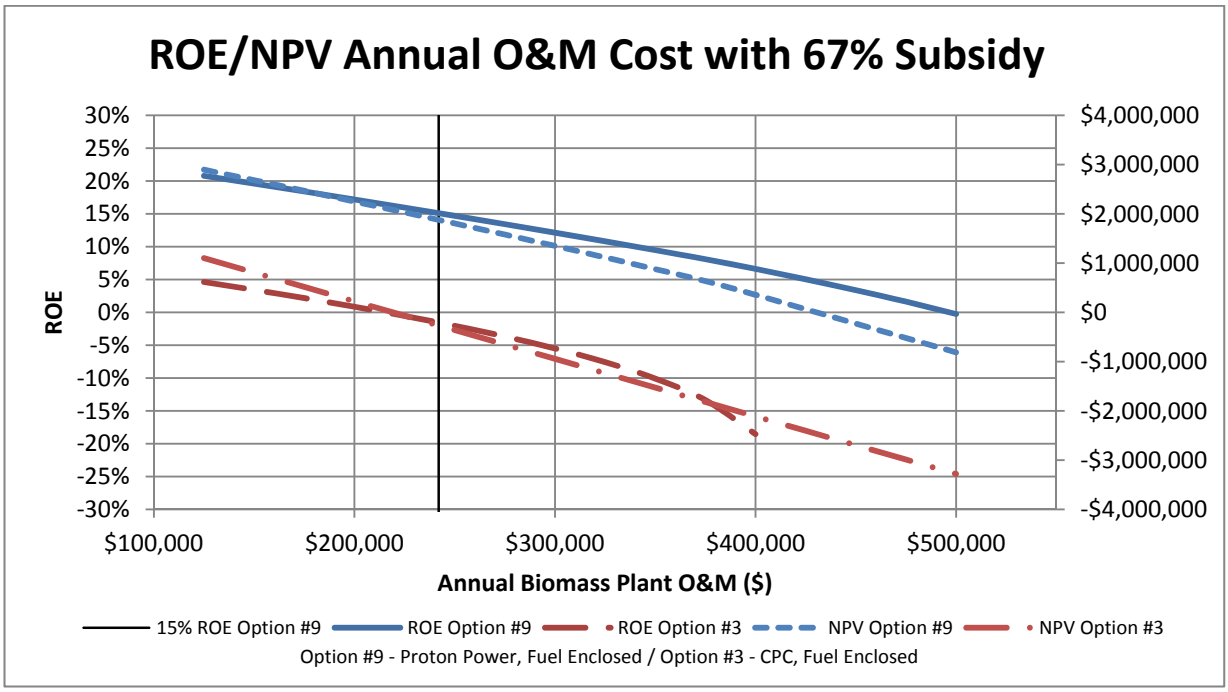


Figure 4.5 ROE/NPV Annual Plant O&M Price Sensitivity

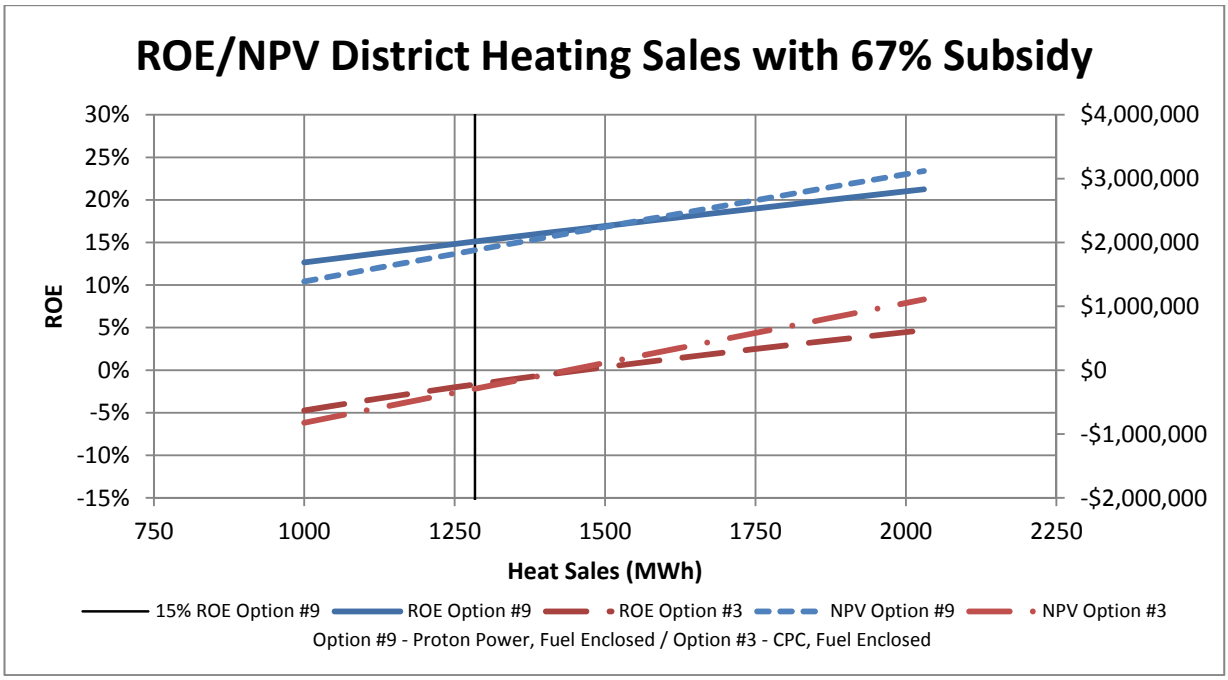


Figure 4.6 ROE/NPV District Heating Sales Sensitivity

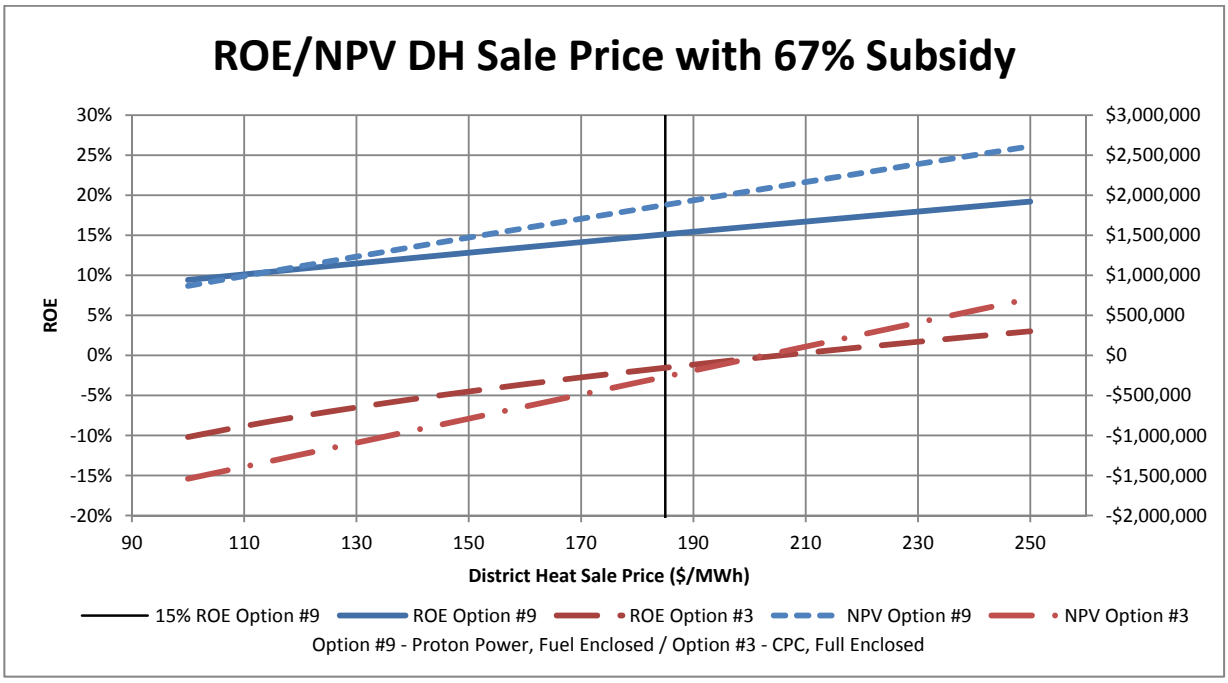


Figure 4.7 ROE/NPV District Heating Sale Price Sensitivity

4.3.1.3 Tornado Diagram

The figure on the following displays the impact of these key variables in a different manner. Figure 4.8 shows the results of independently adjusting the seven (7) key variables by ± 20% on the project ROE. The centerline of the graph represents the 15% ROE set point for Option #9 with 67% subsidy, while each bar is indicative of the positive or negative change in ROE resulting from a ± 20% change in a given variable. Table 4.17 shows the corresponding change in NPV for each variable as well as the specific ROE percentage. The variables are arranged from the most significant to the least significant based on the magnitude of their impact.

It is evident from Figure 4.8 that the most significant variable on the success of the project is the amount of capital subsidy provided, followed by electricity price potential, both discussed previously. Following these two factors, by decreasing influence, are project capital cost, plant O&M cost, district heat sale price, district heat annual sales and feedstock price.

The results of this analysis suggest that during the next level of study it will be vital to secure capital subsidies and or increases to the electricity sale price, as these are the greatest deciding factors in the outcome of the project. Further project definition through engineering can aid in acquiring a definitive value for capital and operating costs, as well as support firming up the DH system design and waste heat sale potential.

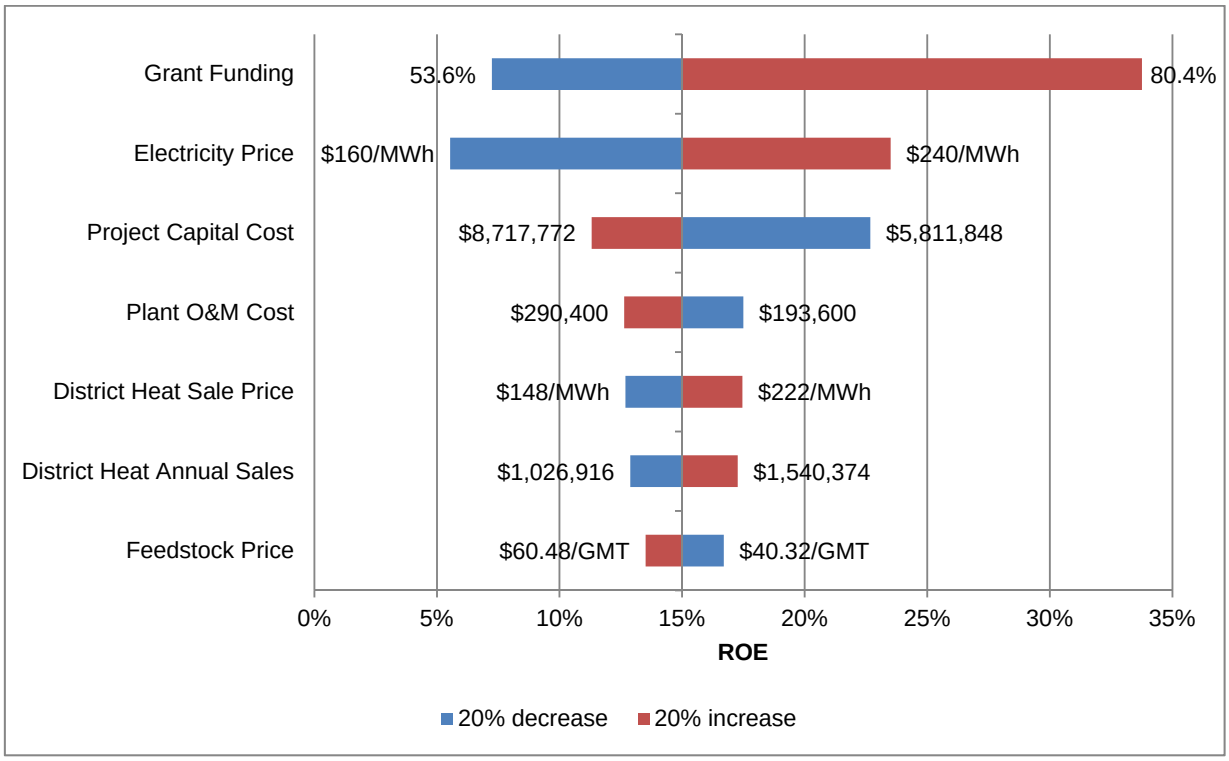


Figure 4.8 ROE/NPV District Heating Sale Price Sensitivity

Table 4.17 Tornado Diagram Results

	Variation	ROE	NPV
Grant Funding	+20%	33.76%	$2,804,710
	-20%	7.24%	$953,761
Electricity Price	+20%	23.51%	$3,233,005
	-20%	5.54%	$309,701
Project Capital Cost	+20%	11.31%	$1,548,366
	-20%	22.68%	$2,306,406
Plant O&M Cost	+20%	12.64%	$1,439,168
	-20%	17.50%	$2,306,886
District Heat Sale Price	+20%	17.46%	$2,298,968
	-20%	12.69%	$1,447,476
District Heat Annual Sales	+20%	17.27%	$2,312,515
	-20%	12.89%	$1,435,633

5.0 Next Steps

The FEED report outlines a series of challenges that exist for the project to be successful, whether it is feedstock security, technology risk or cost, or the need for financial support to bring the project to a reality. No project is without its challenges and, if financial support can be found, mitigation strategies could be developed to address requirements of regulators, enhanced policies (feedstock procurement) and the technical risks associated with the demonstration nature of the project.

Should the project partners decided to pursue the project to the next level of development to realize the potential for biomass gasification in the Yukon, the following sub-section outlines general tasks that would be required and a project implementation schedule.

5.1 NEXT LEVEL OF DEVELOPMENT

Looking beyond the conclusion of the FEED study, considered to be Phase 1 of the project, each area of the FEED will require additional work to bring greater definition and certainty to the project viability and requirements for support. With the completion of the FEED study, the project definition began to take shape but additional work and refinement needs to take place. To support bringing the project definition to the next level of study, work in each area of the project needs to be completed. The following statement of work includes, but is not limited to, phases of study to be completed ahead of detailed engineering and construction.

Phase 2 – Feedstock

Initial indications from the FEED show the potential to source feedstock from local sawmill and harvesting operations. The feedstock supply logistics and business models for this supply will have to be further refined in order to make the decision to proceed with detailed engineering.

- Procurement Logistics and Strategy.
    - Supplier Business Model.
    - Storage location options and retrieval*.
    - Chipping options and locations*.
    - Site Visits to Existing Operations.
    - Input to design.
    - Develop moisture content strategies*.
    - Alternative sources.

- Regulatory.
    - Security of supply w FMB*.
    - Confirm Strategy (who needs to be up to speed)*.
    - Regulatory approvals before EOI*.
- Procurement.
    - Expression of Interest (EOI) to Supply 500 kWe Plant*.
    - EOI Preparation*.
    - EOI Issued*.
    - Letters of Interest (LOI) Returned*.
    - LOIs Reviewed*.
    - Feedstock Assessment & Costing.
    - Procurement Plan.
    - Private Shortlisted Request for Proposal.
    - Formal Firm Proposals.
    - Procurement Contracting.

** Short-term items to support business case development (Phase 4)*

Phase 3 - Environmental Permitting

Based on the FEED study assessments completed, the current expectation is for a DO level assessment by YESAB. This needs to be confirmed and the proper impact assessment completed accordingly (including field studies, public consultation).

- Scoping Meeting with YESAB*.
- Field Surveys and Technical Analyses.
    - Wildlife and Wildlife Habitat (migratory birds, bats).
    - Wetlands and Vegetation.
    - Land Use/Traditional Use Consultation in Community (siting).
    - Archaeological and Heritage Resources.
- Impact Assessment Report.
    - Prepare Draft DO Proposal for Internal Review.
    - Client Review Period.
    - Preparation of Regulatory Draft DO Proposal.
    - Adequacy Review.
    - Respond to Information Requests from Adequacy Review.
    - DO Reviews Responses.

- Seeking Views and Information (public consultation).
- DO Reviews input from SVI.
- Potential further Information Requests.
- DO Prepares/Issues Recommendation or Referral.

- Permit Applications.

  - Community and Stakeholder Engagement*.
  - Prepare other Applications and Submit to Decision Bodies.
  - Decision Bodies Receive Recommendation from DO.
  - Review and Consideration by Decision Bodies.
  - Decision Bodies Issue Permits.

** Short-term items to support business case development (Phase 4)*

Phase 4 - Bridging Engineering & Business Case

The engineering and business case assessment completed as part of the FEED study provide direction on project approach and defined the project to the extent possible. With the knowledge gained, the next level of study can be completed ahead of detailed engineering to provide a Class 3 opinion of probable capital and operating costs as well as associated business case.

- Project Management & Local Support.

Bridging Engineering

- Engineering Design to support Waste Heat Integration.

  - Identification of buildings for the district heating network.
  - Contact building owners/operators to determine hook-up potential and assessment of current heat loads.
  - On-site assessment of buildings to determine building infrastructure requirements for energy transfer stations.
  - Heat load assessment to determine system sizing and which building to include in the network.
  - Prepare system design including but not limited to:
    - Main, distribution, and branch line sizing.
    - System control and metering infrastructure.
    - Energy transfer station sizing for each building.
  - Drawing and design package to support the development of a AACE Class 3 opinion of probable capital and operating cost for the system.

- Engineering Design to support Facility Design:
  - Gasification technology:
    - Develop and issue firm Request-for-Proposal for 500 kWe gasification technology.
    - Conduct bid comparison and select vendor for engineering design.
    - Plant design to support technology, grid interconnection, district heating interconnection, and fuel receiving.
  - Finalize site location:
    - Dependent on heating network design and feedstock storage requirements.
    - Conduct open house to solicit public input.
    - Select location, determine infrastructure requirements (grid interconnection, water/sewer), confirm land ownership and tax implications.
  - Materials Handling:
    - Confirm on-site/enclosed feedstock storage requirements.
    - Finalize fuel storage and reclaim method (loaders/bin, walking floor, other).
    - Support design, sizing and tie-in with selected technology vendor.
  - Plant Auxiliaries:
    - Confirm building/room sizing and infrastructure tie-in requirements.
    - Building services (lighting, HVAC).
  - Drawing and design package to support the development of an AACE Class 3 opinion of probable capital and operating cost for the system.
  - Project implementation schedule through to commercial handover.

Business Case

- Project support to develop business case, including:
  - Input into owner's applications for funding.
  - Determine model for heat sales and draft heat sale contract.
- Finalize business model and case as engineering is concluded, including:
  - Ownership model.
  - Sensitivity analyses.

Phase 5 - Detailed Engineering and Procurement

Phase 6 & 7 - Construction, Commissioning, Start-up, Commercial Handover

5.2 IMPLIMENTATION SCHEDULE

If the decision were made to proceed with the next level of development, three of the phases outlined above would need to start in 2013. Feedstock assessment will need to be further

defined and support the requirements of the YESAB submission for the project. In future years, the feedstock procurement strategy and final supply contracts will be critical project components. Environmental permitting will also need to begin in 2013 with a consultation with YESAB to ensure the project can proceed with a D.O. level screening and establish requirements for field studies, modelling, and other areas deemed critical. The environmental team will also support the public and First Nations consultation process on an on-going basis. The main driver for project refinement in 2013 will be the bridging engineering and business case refinement. This work, outlined above, will provide greater clarity to the facility design (looking at firm vendor quotes and cost savings measures) to arrive at a Class 3 opinion of probable capital cost. On the business case side, it will be necessary to secure draft heat contracts and power purchase pricing to provide greater certainty to future revenue streams. Confirmation of the potential revenue, along with plant and feedstock costing will facilitate the development of a more sound business case.

A high-level implementation schedule is presented in Table 5.1 for consideration. A more detailed potential implementation schedule (Gantt Chart) is presented in Appendix K.

The schedule in Appendix K represents a fast track schedule to indicate the scope of each phase and its earliest possible completion. Table 5.1 relaxes the need to complete more detailed feedstock activities and environmental permitting tasks (field studies) until 2014 instead of 2013. This reduces upfront costs, and facilitates further refinement of the business model ahead of proceeding with detailed engineering and ordering of equipment.

Table 5.1 Implementation Schedule

Phase	Task Description	2013	2014	2015	2016
2	Feedstock				
3	Environmental Permitting-DO Level				
4	Bridging Engineering & Business Case				
5	Detailed Engineering and Procurement				
6	Construction				
7	Start-up & Commissioning				

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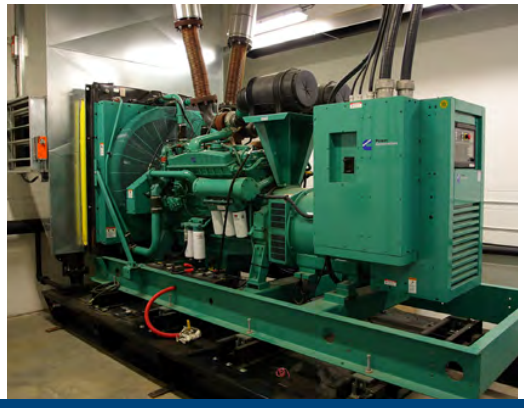
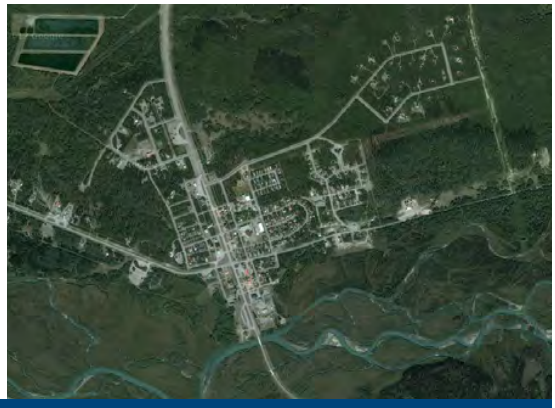
7.0 Appendices

APPENDIX A	**INTERIM REPORT # 1**
APPENDIX B	**INTERIM REPORT # 2**
APPENDIX C	**VENDOR PACKAGES**
APPENDIX D	**BASIS OF ESTIMATE – OPTION # 1**
APPENDIX E	**ARCHITECTURAL UPGRADE - OPTION # 2**
APPENDIX F	**BASIS OF ESTIMATE – OPTION # 3**
APPENDIX G	**500 kWe EXPANSION – OPTION # 4**
APPENDIX H	**IMPACT ASSESSMENT**
APPENDIX I	**ENGAGEMENT PLAN**
APPENDIX J	**FINANCIALS**
APPENDIX K	**IMPLEMENTATION SCHEDULE**





APPENDIX A

Interim Report #1

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

Stantec

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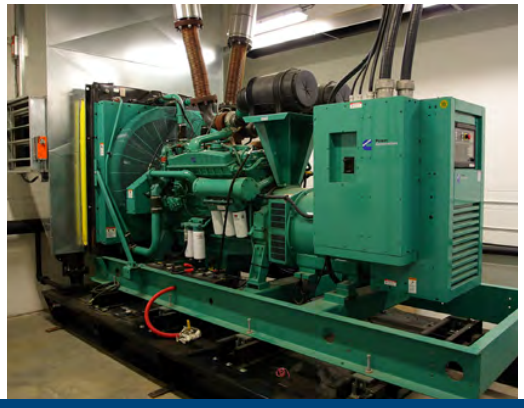
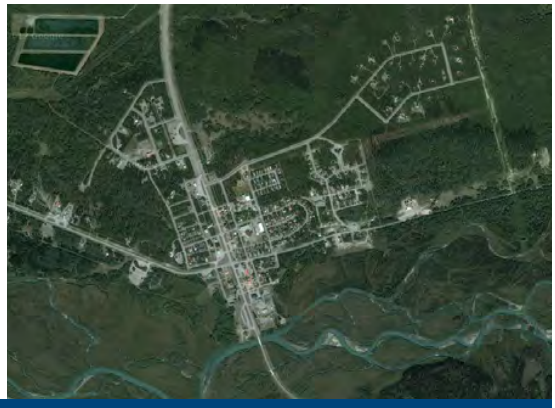
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.





REPORT

Interim Report #1 - Project Definition

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

October 18, 2012

This document has been prepared exclusively for the client and the project identified herein.
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.

Table of Contents

1.0 INTRODUCTION / STUDY PROGRESS 1.1
1.1 STUDY PROGRESS 1.1

2.0 CATALOG OF TECHNOLOGIES 2.1
2.1 GASIFICATION 2.1
2.1.1 Fixed Bed Gasification 2.2
2.2 FLUIDIZED BED GASIFICATION 2.4
2.3 PYROLYSIS 2.7
2.4 EXTERNALLY FIRED GAS TURBINE 2.11
2.5 WORKS CITED 2.14

3.0 TECHNOLOGY ASSESSMENT AND RECOMMENDATION 3.1
3.1 VENDOR TECHNOLOGIES 3.2
3.2 TECHNOLOGY SCREENING SUMMARY 3.13
3.3 TECHNOLOGY COSTING 3.13
3.4 TECHNOLOGY RECOMMENDATION 3.1

4.0 FEEDSTOCK CHARACTERIZATION 4.3
4.1 MOISTURE CONTENT 4.4
4.2 WOOD QUALITY CHARACTERISTICS 4.4
4.3 WORK CITED 4.5

5.0 ENGAGEMENT AND COMMUNICATION PLAN 5.1

6.0 REGULATORY APPROVALS STRATEGY 6.1
6.1 OVERVIEW OF THE PROJECT EFFECTS ASSESSMENT AND REGULATORY REGIMES 6.1
6.2 YUKON LICENSING AND PERMITTING 6.1
6.2.1 Power Facility 6.2
6.2.2 Feedstock/Harvest 6.6
6.3 YESAB 6.9
6.4 SCOPING OF THE ASSESSMENT 6.10
6.5 BASELINE CONDITIONS 6.13
6.6 EFFECTS & MITIGATION 6.15
6.6.1 Cumulative Effects Assessment 6.15
6.7 RESIDUAL EFFECTS AND EVALUATION OF SIGNIFICANCE 6.16
6.8 DETERMINATION OF SIGNIFICANCE 6.16
6.9 MITIGATION AND ADAPTIVE MANAGEMENT/MONITORING 6.19

7.0 SOURCES OF PROJECT FINANCING 7.1

TABLE OF CONTENTS

7.1 SUSTAINABLE DEVELOPMENT TECHNOLOGY CANADA 7.1
7.2 POTENTIAL FUNDING SOURCES 7.1
7.2.1 Community Economic Opportunities Program (CEOP) / 7.2
7.2.2 Community Infrastructure Improvement Fund (CIIF) 7.2
7.2.3 Aboriginal Economic Development in Forestry 7.2
7.2.4 Biomass for Energy Program 7.2
7.2.5 Bio-based Energy Systems and Technologies (BEST) Program 7.2

Appendix A – Draft Plan Comments

1.0 Introduction / Study Progress

Stantec Consulting Ltd. (Stantec), in partnership with AFGOR Inc. (AFGOR), has been contracted to carry out Yukon Energy Corporation's (YEC) Front End Engineering Design (FEED) Study for the Yukon Bioenergy Demonstration Project in Haines Junction, Yukon. The objective of the study is a draft report to be delivered on January 15, 2013 covering the following project results:

- Evaluation and selection of a preferred technology for a small-scale bioenergy demonstration project in Yukon.
- Completion of a preliminary design for a preferred project location in Haines Junction, Yukon.
- Clearly defined business model.
- Identified additional funding sources.
- Business case analysis that will clarify the financial viability of the project.
- Technical, financial and regulatory risk management strategies.
- Drafted baseline conditions and impact assessment to form part of the project proposal submission to the Yukon Environmental and Socio-Economic Assessment Board related the bioenergy facility.
- Description of all environmental requirements associated with the project, as well as an outline of foreseeable potential project impacts, and mitigations that will be implemented to reduce project effects. The status and timelines for obtaining all required environmental approvals will also be outlined.
- Overview of engagement activities undertaken throughout 2012, and the results / outcomes of these activities (e.g. issues, challenges and opportunities identified), and a defined engagement and technology transfer strategy for the detailed design and subsequent phases of the project.

1.1 STUDY PROGRESS

This interim report is the first of two to be completed during the study, and represents project findings to date. Each chapter of this report represents progress in different areas of the project to meet the overall project objective. The three main areas of focus for the project are Engineering/Feedstock, Environmental/Engagement & Consultation, as well as Business

Planning. Progress to date in these three (3) areas is outlined below and forms the basis for this report.

- Engineering/Feedstock
    - Catalogue of Technologies (Task 6)
    - Technology Vendors
    - Technology Screening (Task 9)
    - Technology Costing (Task 7)
    - Technology Recommendation
    - Feedstock Characterization and Pre-processing (Task 10/11)
- Environmental / Engagement & Consultation
    - Engagement and Communications Plan (Task 16)
    - Regulatory Approvals Strategy (Task 36)
- Business Planning
    - Potential Funding Sources (Task 42)

2.0 Catalog of Technologies

The production of electricity through the conversion of biomass can be accomplished using a variety of different processes and a multitude of feedstocks. The production of bioenergy not only employs a previously underutilized fuel source, but also mitigates the effects of energy production on the environment. When selecting the appropriate technology, it is important to keep in mind the available feedstocks, required amount of generated electricity, environmental standards, capital cost, and process efficiency (McKendry, 2001). Accordingly, with timber being the sole feedstock at the present time, and the target energy production range being 2-4 MW, three different types of biomass conversion options will be investigated: gasification, pyrolysis and an externally fired gas turbine.

2.1 GASIFICATION

Gasification is a well-proven process that can be performed using either of two technologies – a simple system based on a fixed bed gasifier or fluidized bed technology of increased complexity. Within each of these types, further process options must be examined. Gasification involves the conversion of biomass to a gaseous fuel by heating in a gasification medium like air, oxygen or steam at temperatures greater than 800°C. Using this method, the chemical energy from carbon is converted into a combustible gas in two stages, unlike combustion where oxidation is complete in a single step. The quality of the product gas can be easily manipulated and allows for it to be more versatile in energy applications when compared to its biomass source.

The reactions associated with gasification are as follows:

Partial oxidation	$C + \frac{1}{2}O_2 \leftrightarrow CO$	$\Delta H = -268\ MJ/kgmole$
Complete oxidation	$C + O_2 \leftrightarrow CO_2$	$\Delta H = -406\ MJ/kgmole$
Water gas reaction	$C + H_2O \leftrightarrow CO + H_2$	$\Delta H = +118\ MJ/kgmole$

It can be seen above that the complete oxidation of carbon involves the greatest release of energy while partial oxidation accounts for 66% of the energy released during complete oxidation. The products from these reactions can then undergo further manipulation through the following reactions:

Water gas shift	$CO + H_2O \leftrightarrow CO_2 + H_2$	$\Delta H = -42\ MJ/kgmole$
Methane formation	$CO + 3H_2O \leftrightarrow CH_4 + H_2O$	$\Delta H = -88\ MJ/kgmole$

Because all of these reactions are reversible, altering the pressure, temperature and species concentrations allows for the tailoring of the product gas quality for the specific application. The resulting gas is therefore a mixture of carbon monoxide, carbon dioxide, methane, hydrogen and steam as well as unreacted nitrogen if air is used.

The source of oxygen in the reactions has a particular impact on the end result. While air is the most commonly used source, pure oxygen and steam can also be used. The calorific value (CV) of the gas is greatly affected by the oxygen source and typically will fall in the ranges seen below:

Low CV	4-6 MJ/Nm^3	Air and steam/air
Medium CV	12-18 MJ/Nm^3	Oxygen and oxygen/steam
High CV	40 MJ/Nm^3	Hydrogen and hydrogenation

For applications involving syngas combustion or use as engine fuel, low CV gas is most common while the higher CV gases are used as feedstock for further conversion into methane and methanol. Due to the cost of oxygen, air is normally utilized for processes up to 50MW. The overall efficiency of the gasification process is between 75% and 80%.

2.1.1 Fixed Bed Gasification

Fixed bed gasifiers are the customary method employed for gasification and operate at temperatures around 1000°C. Airflow direction distinguishes fixed bed gasifier types from one another. The two considered for this application are the updraft and downdraft configurations.

The updraft gasifier receives biomass feed through the top while the air is fed into the bottom of the unit through a grate. Above the grate, the residual solid remaining after the release of volatiles (or char) formed higher in the gasifier is combusted resulting in an internal temperature of approximately 1000°C. Ash falls through the grate at the bottom as hot gasses pass upwards into the reduction section. Further up in the devolatilization zone, the biomass is pyrolyzed. Here a fair amount of tar is formed and condenses partially on the biomass near the top of the gasifier and can leave in the product gas. In the top section the feed is dried and the gases are cooled to between 200°C and 300°C. The temperature is usually controlled by the addition of steam to the air or through humidification. The low temperature of the product means a high overall efficiency but also a high level of tar content in the product gas. A schematic of an updraft gasifier can be seen in Figure 1-1.

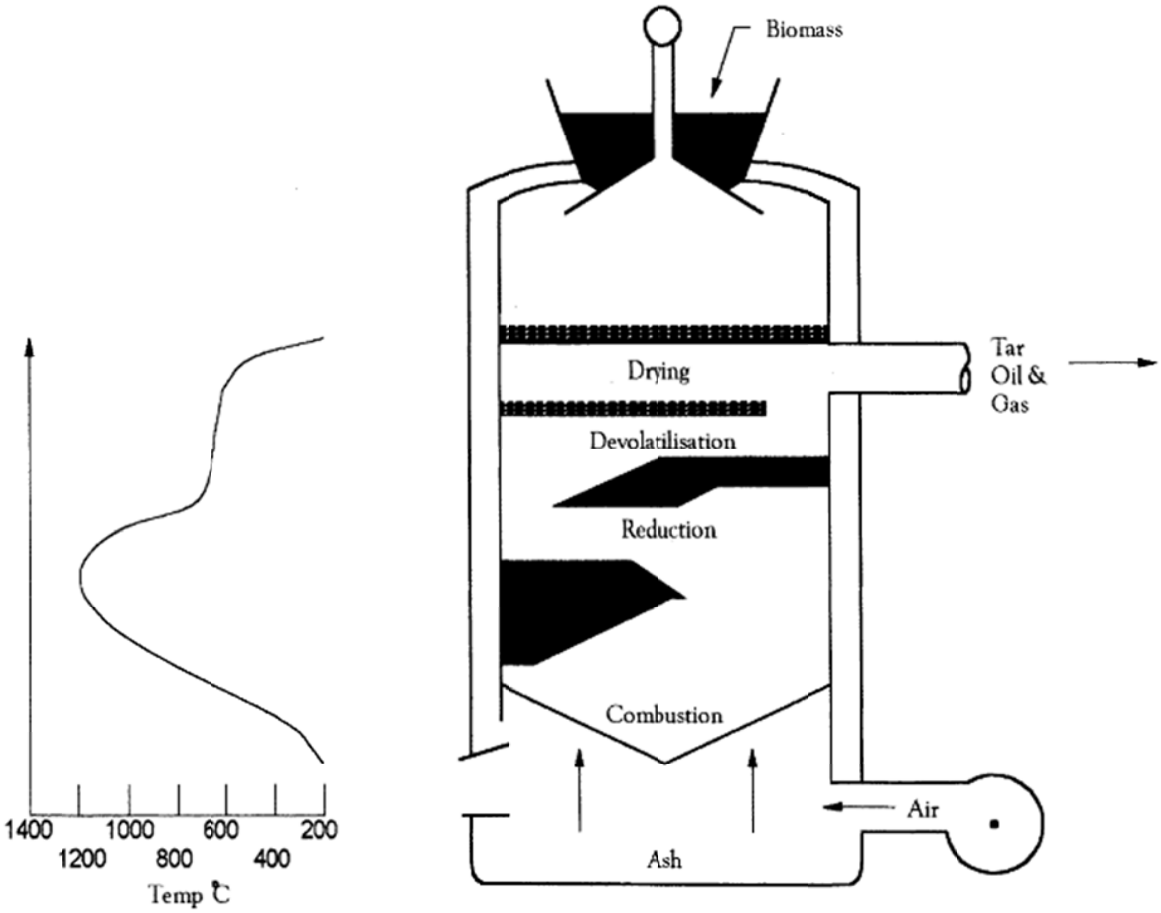


Figure 1-1: Schematic of Updraft Gasifier (McKendry, 2001)

The downdraft gasifier uses a co-current flow where the biomass feed and air move in the same direction. Since the gases leave the unit at a temperature between 900°C and 1000°C, the overall energy efficiency is low, resulting from the high heat content carried by the product gas. However, the heating of the gas allows for the partial cracking of tars formed during gasification and enables the production of gas with low tar content. While the tar content may be lower in a downdraft gasifier than the updraft design, the particulate content in the gas is much higher. A schematic of a down draft gasifier can be seen in Figure 1-2.

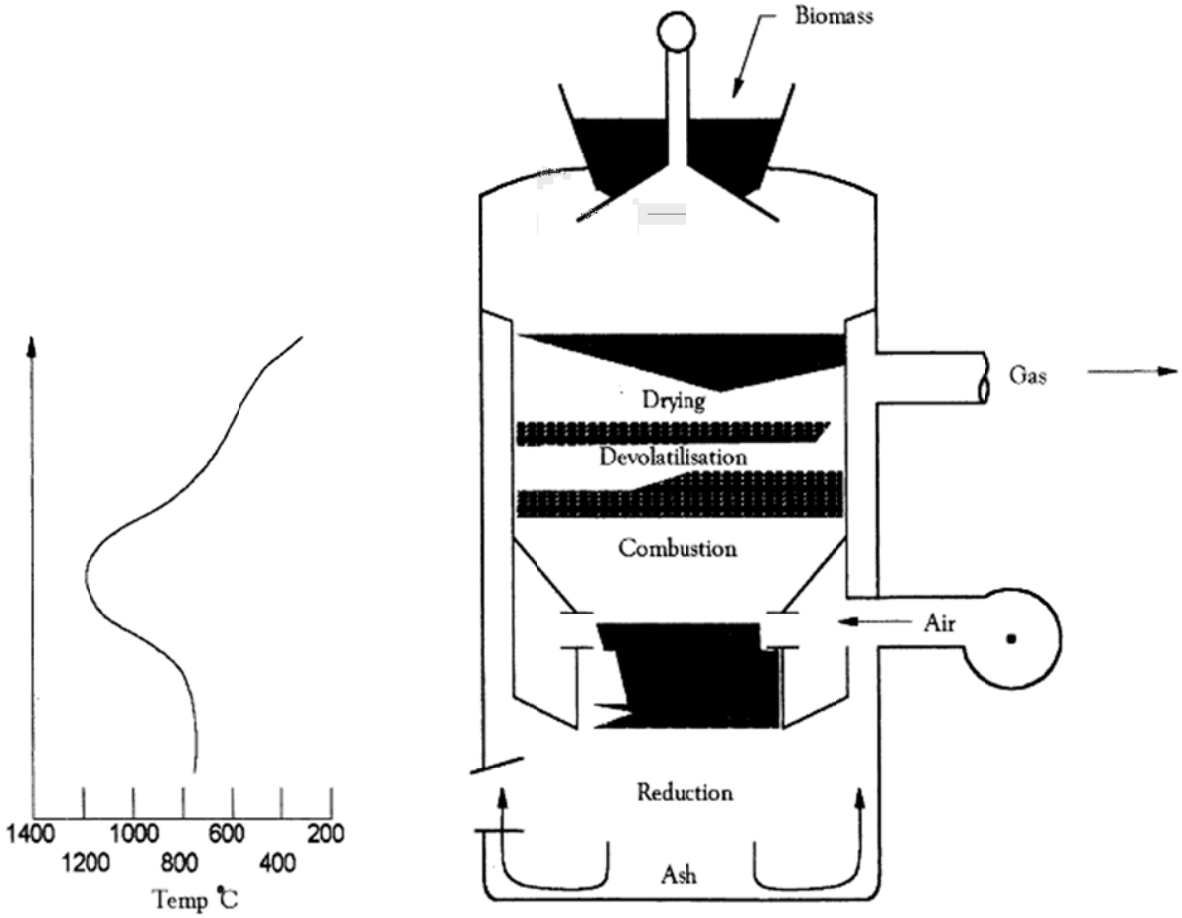


Figure 1-2: Schematic of Downdraft Gasifier (McKendry, 2001)

2.2 FLUIDIZED BED GASIFICATION

Fluidized bed gasification uses a bed of fine-grained material into which air is presented, thus fluidizing the bed material and guaranteeing close mixing of the bed material, combustion gas, and biomass feedstock. This mixing allows for a uniform temperature distribution in the gasification zone, which is the primary advantage over fixed bed gasifiers. The two foremost types of fluidized bed gasifiers are the circulating fluidized bed and bubbling bed types.

Circulating fluidized bed gasifiers are best suited for high capacity feed rates and are used in the paper industry for the gasification of bark and other forestry residues. The bed material circulates between the reaction vessel and a cyclone separator. (McKendry, 2001). The separator removes the ash while the bed material and char are returned to the reaction vessel, which helps to extend the solids residence time (Li, Grace, Lim, Watkinson, Chen, & Kim, 2004). A schematic of a circulating fluidized bed gasifier can be seen in Figure 1-3.

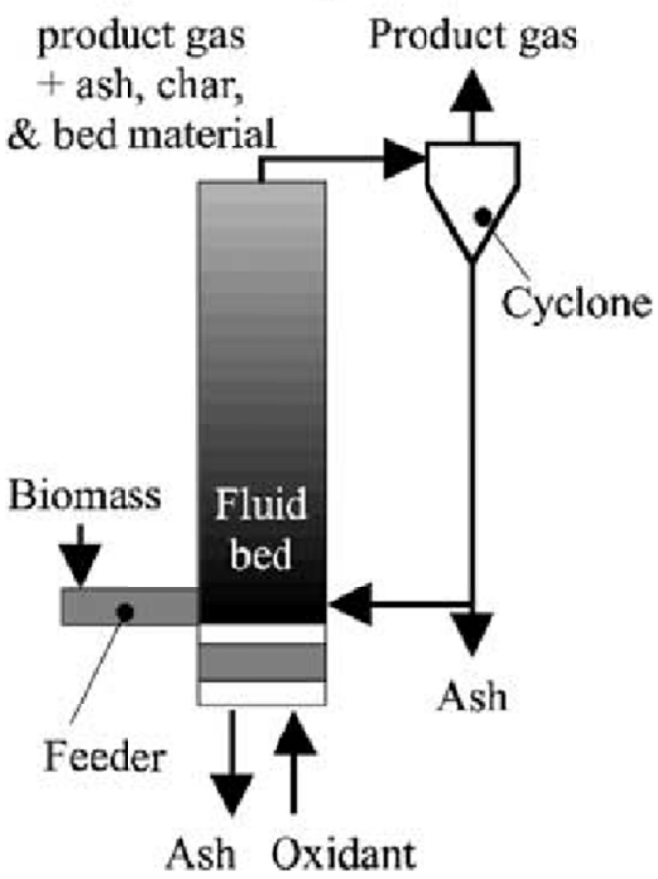


Figure 1-3: Circulating Fluidized Bed (Bridgwater, Toft, & Brammer, 2002)

Bubbling fluidized bed gasifiers are made up of a vessel with a grate located at the bottom for the introduction of air. The moving bed of fine-grained material is found just above the grate and is where the biomass feedstock is introduced. The bed temperature is maintained between 700°C and 900°C and is controlled by the air to biomass ratio. The biomass is then pyrolyzed in the hot bed forming a char with the gaseous compounds. Here the high molecular weight compounds are cracked via contact with the hot bed material resulting in a product gas with low tar content. A schematic of a bubbling fluidized bed gasifier can be seen in Figure 1-4.

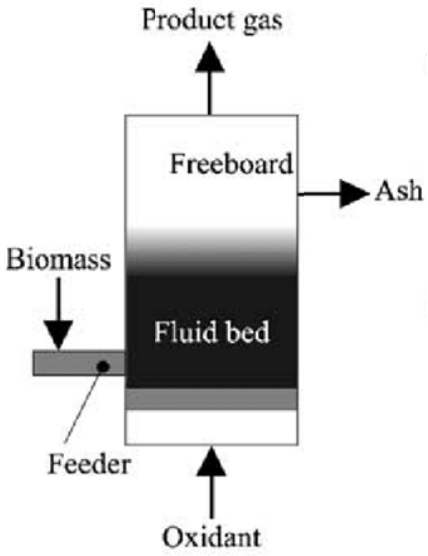


Figure 1-4: Bubbling Fluidized Bed (Bridgwater, Toft, & Brammer, 2002)

A major disadvantage to fluidized bed gasifiers is the potential for the slagging of the bed material. This is caused by the high ash content of the biomass. To avoid slagging, the bed temperature can be lowered, which results in an increased loss of char with the removal of ash. The amount of gas cleaning required is determined by the actual end-use of the gas. Fluidized bed gasifiers also produce a higher particulate load than fixed bed units. Some of these particles can be removed using cyclones. Depending on the amount of cleaning necessary, more sophisticated equipment may be needed. (McKendry, 2001). A summary of the advantages and disadvantages of different types of gasifiers can be seen in Table 1-1.

Table 1-1: Properties of Gasification Reactor Types (McKendry, 2001)

Reactor type	Advantages	Disadvantages
Fixed bed, updraft	Simple, inexpensive process Exit gas temperature about 250°C Operates satisfactorily under pressure High carbon conversion efficiency Low dust levels in gas High thermal efficiency	Large tar production Potential channeling Potential bridging Small feed size Potential clinkering
Fixed bed, down draft	Simple process Only traces of tar in product gas	Minimum feed size Limited ash content allowable Limits to scale up capacity Potential for bridging and clinkering
Fluidized bed, circulating	Flexible process Up to 850°C operating temperature	Corrosion and attrition problems Poor operational control using biomass
Fluidized Bed, bubbling	Flexible feed rate and composition High ash fuels acceptable Able to pressurize High CH_4 in product gas High volumetric capacity Easy temperature control	Operating temperature limited by ash clinkering High product gas temperature High tar and fines content in gas Possibility of high C content in fly ash

2.3 PYROLYSIS

Biomass can also be converted into a liquid fuel through a process called fast pyrolysis. (Brammer, Lauer, & Bridgwater, 2005). Pyrolysis is the thermal breakdown of biomass in the absence of oxidizing agents where the volatile components present in the biomass feed are vaporized in primary reactions by heating, leaving behind a char and ash residue. Pyrolysis always produces a gas, vapour that can be collected as a liquid and a solid char. Fast pyrolysis processes are designed and operated to maximize the liquid fraction at up to 75 wt% on a dry biomass feed basis. (Bridgwater, Toft, & Brammer, 2002). When compared to gas and solid, liquids have a high energy density and are easier to transport and store. The pyrolysis method has been used for commercial production of a variety of fuels, solvents, chemicals and other products from biomass feedstock. (Vamvuka, 2011). The liquid fuel or bio-oil possesses a lower heating value of approximately 16 MJ/kg and can be employed as a fuel in boilers, diesel engines or gas turbines for the production of heat, power or combined heat and power. (Brammer, Lauer, & Bridgwater, 2005). The bio-oil is a homogeneous mixture of organic

compounds and water in a single phase. The fuel properties compared to diesel and heavy fuel oil can be found in Table 1-2 below.

Table 1-2: Comparison of Pyrolysis Liquid and Conventional Fuel Oil Characteristics (Bridgwater, Toft, & Brammer, 2002)

		Bio-oil	Diesel	Heavy Fuel Oil
Composition	%C	48.5	86.3	86.1
	%H	6.4	12.8	11.8
	%O	42.5	-	-
	%S	-	0.9	2.1
Density	kg/m^3 at 15°C	1220	854	963
Viscosity	cSt at 50°C	13	2.5	351
Flash point	°C	66	70	100
Ash	wt%	0.13	<0.01	0.03
Sulphur	wt%	0	0.15	2.5
Water	wt%	20.5	0.1	0.1
LHV	MJ/kg	17.5	42.9	40.7
Acidity	pH	3	-	-

A principal advantage of fast pyrolysis is the possibility of storing the bio-oil intermediate. This separation is referred to as de-coupling and is unique to fast pyrolysis since the energy is stored in liquid form. De-coupling allows for the pyrolysis conversion step and the diesel engine generation step to operate independently. Peak load or seasonal power requirements can benefit from this scenario since a small fast pyrolysis plant could operate continuously to produce bio-oil that would be stored for engine use when needed.

Fast pyrolysis involves rapid heating of the biomass feedstock to a temperature of approximately 500°C followed by rapid quenching of the vapours in order to reduce secondary reactions. (Bridgwater, Toft, & Brammer, 2002)**.** The structural components of biomass, including hemicelluloses, cellulose, lignin and extractives, pyrolyze at different rates and by different pathways and mechanisms. The rate and extent of component breakdown are dependent on the reactor type, temperature, pressure, particle size and heating rate. Dehydration, cracking, isomerization, dehydrogenation, aromatization, coking and condensation reactions all occur during pyrolysis to produce water, carbon oxides, other gases, charcoal, organic compounds, tars and polymers. This complex reaction pathway can be seen Figure 1-5.

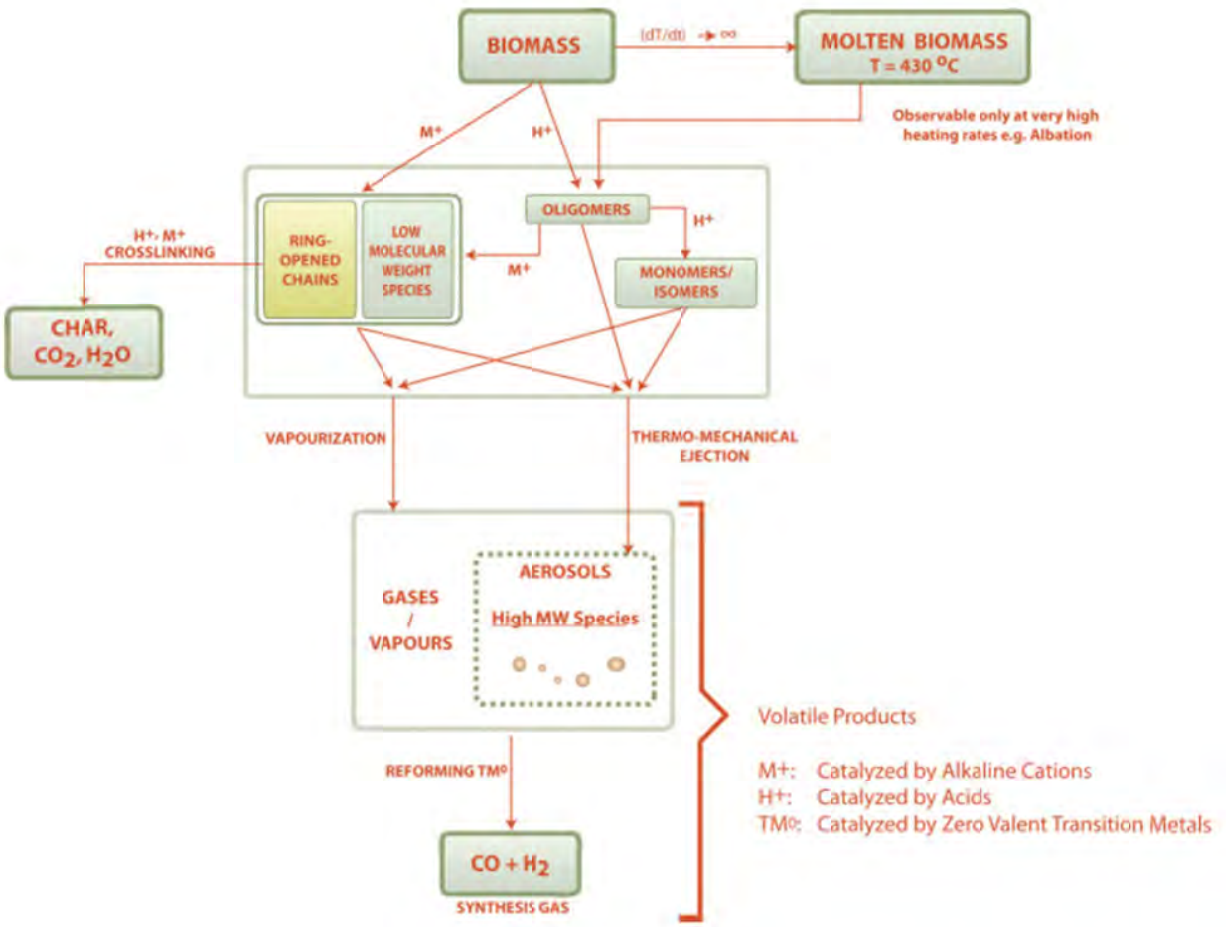


Figure 1-5: Mechanisms of Pyrolysis (Vamvuka, 2011)

Modern pyrolysis reactor configurations include fixed beds, moving beds, suspended beds, fluidized fixed beds, entrained flow reactors, stationary vertical shaft reactors, horizontal shaft kilns, inclined rotating kilns, single and multihearth reactors and a host of other designs. Fluidized beds are the most popular configurations, due to their ease and reliability of operation and ease of scaling to commercial plant sizes. They provide good temperature control and very efficient heat transfer to biomass particles. Liquid yields are typically 75 wt% on dry feed, with 10-15% char and gas making up the balance. Secondary reactions of the volatiles in the biomass matrix and additional heat supply from the in-bed heaters cause additional vapour cracking to char and non-condensable gases. The residence time of the reactants can be controlled by the flow of fluidizing gas, while special attention must be given to the system separating coke from the reaction products. (Vamvuka, 2011) Fluidized bed arrangements have been the most common reactors for fast pyrolysis, specifically the bubbling type. (Bridgwater, Toft, & Brammer, 2002). A comparison of reactor types can be seen in Table 1-3.

Table 1-3: Advantages and Disadvantages of Biomass Pyrolysis Systems (Vamvuka, 2011)

Reactor type	Advantages	Disadvantages
Fluid type	Good solids mixing High heat transfer rates Good temperature control Ease of scaling	Heat transfer to bed must be proven at large scale Max particle sizes up to 6 mm If circulating, increased complexity of system, char attrition and reactor wear
Entrained flow		Low heat transfer rates Limited gas/solid mixing Small particle sizes required
Rotating cone	Good solids mixing No carrier gas required Ease of scaling Small investment cost	Heat transfer to bed must be proven at large scale Small particle sizes required
Vacuum reactor	No carrier gas required Lower temperature required Can process larger particles	Low heat transfer rates Solids residence time high Liquid yield rather low
Ablative reactor	Heat transfer gas not required Lower temperature required Can process larger particles Compact design and intensive system	Reaction rates limited by heat transfer to the reactor Char abrasion Scaling is costly

Most fast pyrolysis processes demand a finely divided, substantially dry feed and some feed pretreatment is therefore typical before the reactor. Exceptions are ablative and vacuum pyrolysis, which both have the advantage of tolerating much larger feed sizes. In the majority of reactor setups particle size is constrained by a need to limit secondary reactions of the primary pyrolysis vapours with char formed at the particle surface. This is because the char catalyzes secondary reactions that reduce the liquids yield. The majority of feedstocks must also be dried before entering the reactor. Feed moisture content must be limited to improve liquid product yield and quality though some moisture enhances fuel properties such as viscosity. A maximum feed moisture content of 10% is usually specified while 7% moisture content is preferred (Bridgwater, Toft, & Brammer, 2002). A typical fast pyrolysis process is depicted in Figure 1-6 showing the necessary preparation steps, alternative reactors and product collection. (Bridgwater T. , 2006).

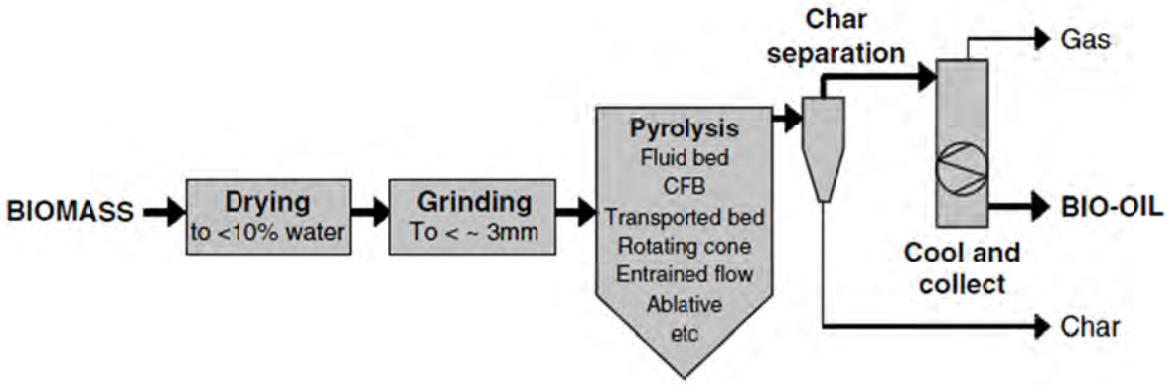


Figure 1-6: Conceptual fast pyrolysis process (Bridgwater T. , 2006)

Most development for electricity generation is focused on the use of raw pyrolysis liquids in gas turbine or diesel engine applications and has been successfully carried out. Pyrolysis liquids are very different from conventional diesel fuels but crude pyrolysis oil has been shown to burn well in engines. Ignition happens to be difficult but pilot-ignition has proven to solve this problem by using a small amount of an auxiliary fuel to ignite the main fuel. Less development has been done using gas turbines and fast pyrolysis. Earlier tests on a combustor rig designed to simulate a slurry-fed gas turbine revealed problems including entrained char in the bio-oil which blocked fuel injection systems; ash fouling downstream of the gas turbine; corrosion to turbine components; and increased smoke emissions. 1996 tests by Orenda in Canada have evaluated the firing of a 2.5 MW_e industrial gas turbine with better results. The turbine has been run successfully for several hours entirely on pyrolysis liquids while flame tunnel tests are examining the long-term resistance of turbine parts to corrosive attack from alkali metals in the ashes entrained in pyrolysis liquids. (Bridgwater, Toft, & Brammer, 2002).

2.4 EXTERNALLY FIRED GAS TURBINE

The burning of biomass in air, otherwise known as combustion, is used over a wide range of outputs to convert the chemical energy stored in biomass into heat, mechanical power, or electricity by employing a variety of process equipment such as stoves, furnaces, boilers, steam turbines, turbo-generators, etc. Combustion of biomass produces hot gases at temperatures of 800-1000°C. It is possible to burn any type of biomass but in practice combustion is only possible for biomass with a moisture content of <65%, unless the biomass is pre-dried.

The scale of combustion plants ranges from very small domestic heating applications to large scale industrial plants in the range of 100-300+ MW. Net bio-energy conversion efficiencies for biomass combustion power plants range from 20% to 40%. The higher efficiencies are obtained with systems over 100MW_e or when biomass is co-combusted in coal-fired power plants. (McKendry, 2001).

In the United States and around the world, direct combustion is the most common method of converting biomass resources into heat, power or combined heat and power. (Peterson & Hase, 2009) It contributes to over 97% of bioenergy production in the world. (Zhang, Xu, &

Champagne, 2010). A direct combustion system burns biomass to generate hot flue gas, which is either used directly to provide heat or fed into a boiler to generate steam. In a boiler system, the steam can be used to provide heat for industrial processes while a steam turbine can be used to generate electricity. (Peterson & Hase, 2009).

Fouling and corrosion of the combustor are typical issues associated with biomass combustion. These are considered to be detrimental because of the resulting reduction in heat transfer in the combustor. Fouling is commonly associated with the presence of alkali metals and some other elements (such as silicon, sulphur, chlorine, calcium and iron) in the biomass ash. With a series of complex reactions, these elements are deposited in the forms of chlorides, silicates or sulphates on the wall of the combustor or the surface of the heat transfer elements. (Zhang, Xu, & Champagne, 2010).

The two primary types of direct combustion boiler systems for biomass utilization are fixed-bed and fluidized-bed systems (Peterson & Hase, 2009), with increasing carrier gas velocity within the reactor. A higher gas velocity translates to an intensive mixing of the feedstock, which enhances the combustion efficiency and the heat exchange rate. (Zhang, Xu, & Champagne, 2010).

In a fixed-bed system, the biomass is fed onto a grate where it combusts as air passes through the fuel, releasing the hot flue gases into the heat exchanger section of the boiler to generate steam. (Peterson & Hase, 2009). The simplest fixed-bed system is comprised of one combustion room with a grate. As soon as the biomass feed is added to the furnace, it is pyrolyzed into volatile gases and chars. Primary and secondary air supplies are provided under and above the grate for the combustion of chars and volatile gases, respectively. The heat generated through the combustion of chars is responsible for providing enough heat for the pyrolysis of newly added biomass. Due to the high content of volatile matter in biomass fuels, a greater secondary air supply is required than the primary air supply. A fixed-bed biomass combustion system is typically operated at around 850-1400°C. Some common examples of fixed-bed systems include manual-fed, spreader-stoker, underscrew, through-screw, static grate, and inclined grate. (Zhang, Xu, & Champagne, 2010).

A fluidized-bed system, in contrast, feeds the biomass into a hot bed of suspended, incombustible particles, where the biomass combusts to release the hot flue gas. Manufacturers of fluidized-bed systems claim that this technology produces more complete combustion of the feedstock, resulting in reduced SO_2 and NO_2 emissions and improved system efficiency. Fluidized-bed boilers also can utilize a wide range of feedstocks. Fluidized-bed systems, however, have greater parasitic loads than stokers. (Peterson & Hase, 2009). The bed material is typically composed of silica sand, limestone, dolomite, or other non-combustible materials while the operating range is 700-1000°C. The bed materials act as the heat transfer media which are fluidized by the air flow coming from the bottom of the unit. The biomass which is amalgamated with the moving medium has high combustion efficiency. Fluidized-bed systems can be divided into bubbling fluidized bed and circulating fluidized bed, much like the aforementioned gasifiers. As a result of the high mixing intensity created by the upward-flowing air at a high velocity, circulating fluidized bed systems behave more efficiently than bubbling fluidized bed. In a circulating fluidized bed combustor, fuel particles and the bed materials are

separated from the fast flowing gas stream in the cyclone and then re-enter the reactor. Circulating fluidized-bed systems display several advantages, including the adaptation to various fuels with different properties, sizes, shapes and moisture (up to 60%) and ash content reaching 50%. (Zhang, Xu, & Champagne, 2010).

Electricity production via steam turbine has a conversion efficiency of 15% to 35% depending upon the manufacturer. The efficiency of a direct combustion biomass system is influenced by such things as moisture content of the biomass, combustion air distribution and amounts, operating temperatures and pressures, fuel feed handling, gas cleaning, distribution and mixing, and furnace retention time. (Peterson & Hase, 2009).

To circumvent the issues involved in gas cleaning, the fuel can be burned in a separate combustor and the turbine gases can be heated indirectly in a high-temperature gas-gas heat exchanger (Bridgwater A. , 1995). Externally fired gas turbines not only allow for this possibility of burning “dirty” fuel, it also utilizes the waste heat from the turbine in a recuperative process. (Kautz & Hansen, 2007), see Figure 1-7. However, an important concern with this method is the loss of efficiency due to the indirect heating of the turbine working gases as well as the temperature limit enforced by the heat exchanger materials. Despite the fact that indirect heating can improve the turbine reliability, there are costs gained in flue gas treatment and the gas-gas heat exchanger. (Bridgwater A. , 1995). Unfortunately, the costs of future commercial indirectly-fired gas turbines are difficult to predict and it is challenging to say confidence which combustion technology would provide the lowest generating costs. Indirectly-fired gas turbines do however appear to be a competitive energy-conversion technology for biomass in the future. The power-spectrum range for such gas turbines is 30-2000kW, making it necessary to purchase multiple units to reach the desired electricity production (Kautz & Hansen, 2007).

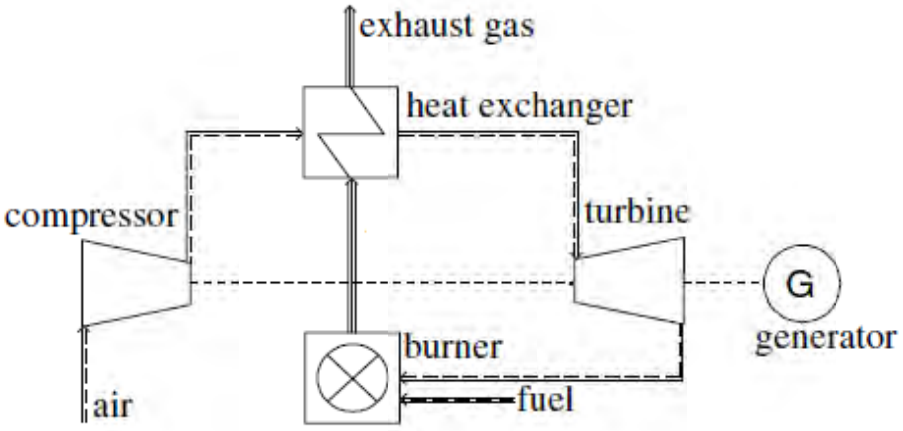


Figure 1-7: Externally Fired Gas Turbine (Kautz & Hansen, 2007)

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3.0 Technology Assessment and Recommendation

Throughout the world one can find biomass gasification taking place from a scale suitable to heat a home, to that to power a country. The focus of this study is to concentrate on a gasification technology capable of producing a syngas for clean-up that can then be introduced to a reciprocating engine in the capacity range of 2 – 4 MW. Although the technology should be innovative, it must be at or near commercialization to facilitate its installation in a northern community (i.e., not for research but practical/reliable use). Several technologies also require the use of steam which is not available nor considered for generation. Two other biomass technologies are showcased for comparison (external fired gas turbine and pyrolysis-oil/ethanol/bio-oil).

To facilitate screening of the technologies, a ranking or scoring system has been established to support the technology recommendation. The criterion used for the ranking system as well as the points awarded by criterion are outlined in Table 3-1. The ranking system does not include items impacting all the biomass systems, such as feedstock availability, socio-economic viability, job creation, or permitting requirements as these are common to all the systems at this level of evaluation.

Table 3-1: Screening Criterion

Level of Development	R&D / Pilot – 0 Pst.	Demonstration – 3 Pts.	Commercial – 5 Pts.
Capacity Range	Outside 2-4 MW_e – 0 Pts.	Within 2-4 MW_e* - 5 Pts.	
Use of Engine for Power	No – 0 Pts.	Yes – 5 Pts.	
Gasification Complexity**	Advanced – 0 Pts.	Standard – 3 Pts.	Direct Comb. – 5 Pts.
Installation Base	1 Installation – 0 Pts.	2 Installations – 3 Pts.	More than two – 5 Pts.
Steam Required	Yes – 0 Pts.	No – 5 Pts.	
Achievable Score	**Minimum – 0 Pts.**	**Maximum – 30 Pts. (100%)**	

* Includes modular units capable of entering range (i.e. if maximum size is 1 MW_e, two units could be installed to enter desired range). Units significantly larger than the range will be excluded due to uncertainties regarding scale-down.

** Complexity is based on system design. Advanced is representative of dual bed or pressurized gasifiers, BFBs, and CFBs; Standard represents draft gasifiers (low to medium Btu syngas) to clean-up and the engine; Direct Combustion is for the externally fired gas turbine.

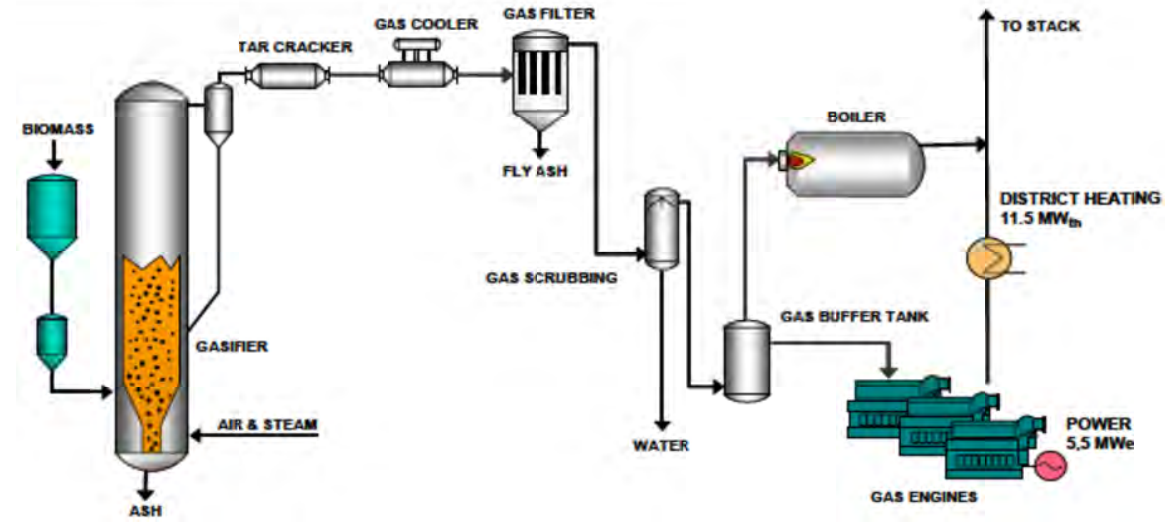
3.1 VENDOR TECHNOLOGIES

This sub-section presents the catalog of technologies considered and provides technology information as well as screening assessment.

Developer / Company:	Andritz-Carbona	**Location:**	Skive, Denmark
Owner:	I/S Skive Fjernvarme	**Status:**	Operational
Technology:	Bubbling Fluidized Bed	**Tech Status:**	Commercial
Capacity:	5.5 MW_e, 11 MW_{th}	**Application:**	CHP w/ District Heating

The Carbona plant was installed in 2005 as a demonstration unit for a new type of gasifier. Supported by the USDOE, the plant has achieved commercial operations and sells heat and power to the city of Skive. The installation is the only one by Andritz-Carbona, and in its current form supplies both boilers for steam generation and reciprocating engines. It is unclear if the unit can be scaled down, but is an advanced gasification system requiring steam.

Level of Development	Commercial – 5 Pts.
Capacity Range	Outside 2-4 MW_e – 0 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Advanced – 0 Pts.
Installation Base	1 Installation – 0 Pts.
Steam Required	Yes – 0 Pt.
Score	**10 Pts. (33%)**



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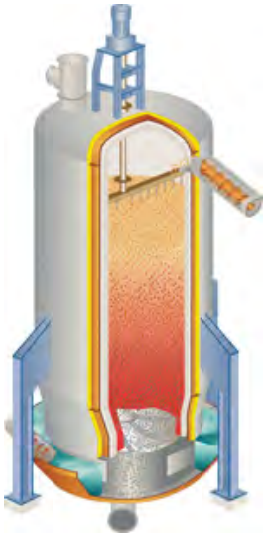
Technology Assessment and Recommendation
October 18, 2012

Developer / Company:	Babcock & Wilcox Vølund	**Location:**	Harboøre, Denmark 3 x Japan
Owner:	Babcock & Wilcox Vølund	**Status:**	Operational
Technology:	Updraft Gasifier	**Tech Status:**	Commercial
Capacity:	Harboøre: 1 MW_e, 3.5 MW_{th} Kani-city: 2 MW_e, 8 MW_{th} Yamagata: 2 MW_e, 8 MW_{th}	**Application:**	CHP w/ District Heating ORC

B&W Vølund's updraft gasifier has an extensive installation base using biomass and waste feedstocks. Majority of systems are steam based, with three noted above using reciprocating engines as desired. Reports indicate this updraft gasifier is Advanced from a complexity standpoint (complicated clean-up system and requires water treatment plant) as well the gasifier requires steam.



Level of Development	Commercial – 5 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Advanced – 0 Pts.
Installation Base	More than two – 5 Pts.
Steam Required	Yes – 0 Pt.
Score	**20 Pts. (67%)**

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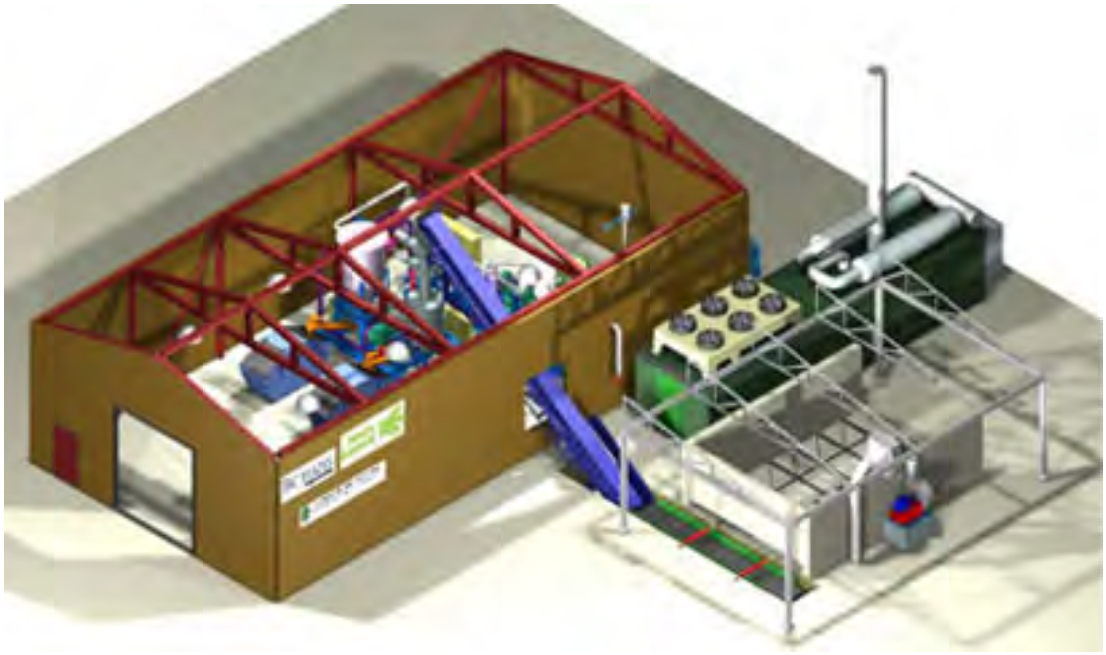
October 18, 2012

Developer / Company:	Biomass Engineering Ltd.	**Location:**	5 units in UK
Owner:	Various	**Status:**	Operational
Technology:	Downdraft Gasifier	**Tech Status:**	Commercial
Capacity:	Cumbria: 1 MW_e Mossborough: 0.25 MW_e,	**Application:**	CHP w/ District Heating

Biomass Engineering Ltd. has several installations of their downdraft gasifier operating In the UK. All units are equal or less than 1 MW_e in size. The two installations noted above are the only ones identified as having used a reciprocating engine, although testing has been conducted on a micro gas turbine as well. The downdraft gasifier does not require steam.

Level of Development	Commercial – 5 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Standard – 3 Pts.
Installation Base	2 Installations – 3 Pts.
Steam Required	No – 5 Pt.
Score	**26 Pts. (87%)**



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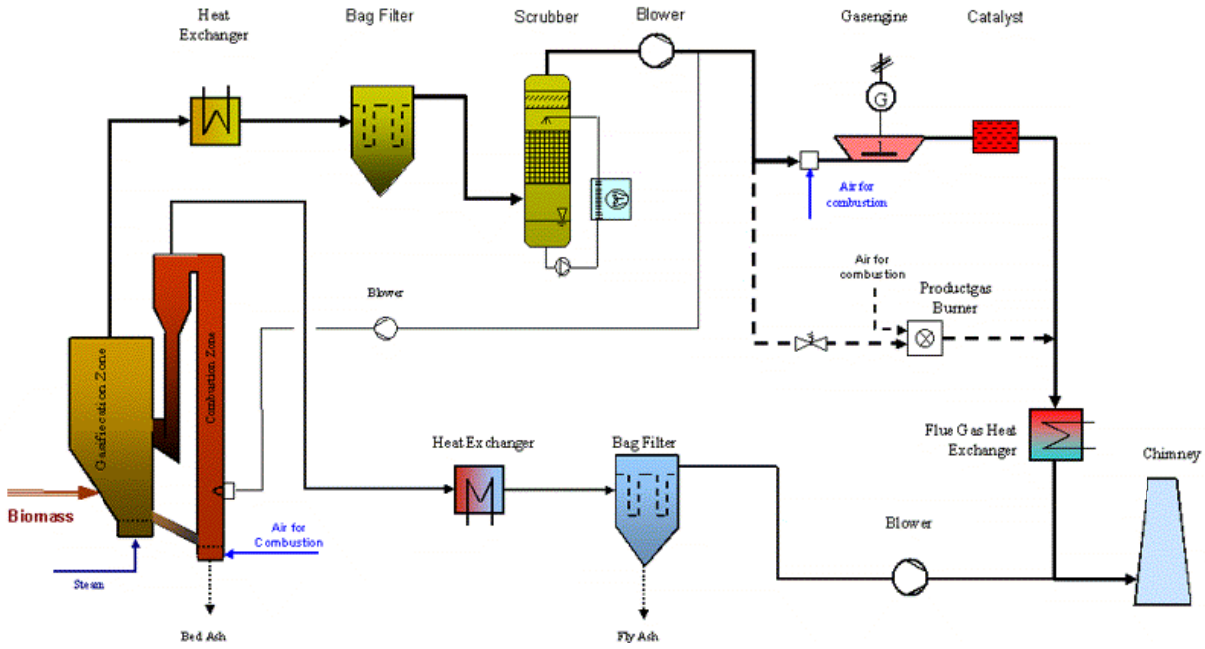
October 18, 2012

Developer / Company:	FICFB (Vienna University and Repotec)	**Location:**	Güssing, Austria Oberwart, Austria
Owner:	Various	**Status:**	Operational
Technology:	Dual Bed (BFB & CFB)	**Tech Status:**	Demonstration
Capacity:	Güssing: 1 MW_e Oberwart: 2.7 MW_e,	**Application:**	CHP w/ District Heating ORC

Fast Internally Circulated Fluidized Bed (FICFB) was developed with dual fluidized beds (CFB combustor, BFB gasifier) to produce a high calorific value syngas. Although it has achieved this objective, the unit is advanced in complexity and is likely to enter the market in large-scale applications. The units have been run with reciprocating engines and organic Rankine cycle (ORC).

Level of Development	Demonstration – 3 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Advanced – 0 Pts.
Installation Base	2 Installations – 3 Pts.
Steam Required	Yes – 0 Pt.
Score	**16 Pts. (53%)**



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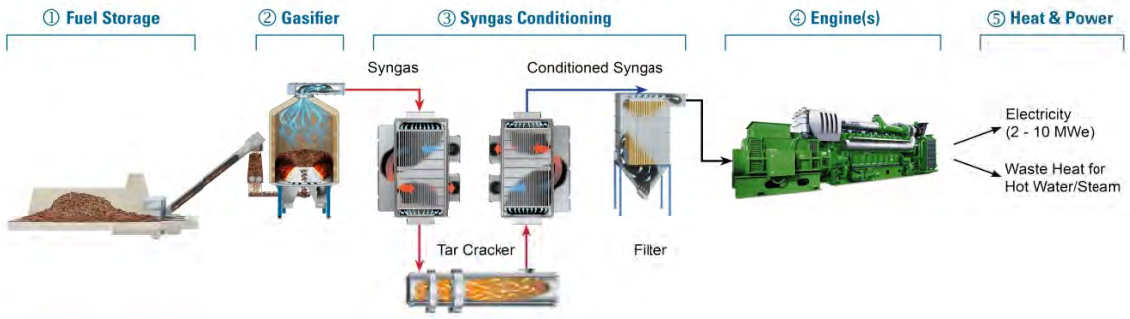
October 18, 2012

Developer / Company:	Nexterra Systems Corp.	**Location:**	Multiple – Oak Ridge, Vancouver, Victoria, North Carolina, New Westminster, UBC
Owner:	Various	**Status:**	Operational
Technology:	Dual Bed (BFB & CFB)	**Tech Status:**	Demonstration CHP
Capacity:	UBC: 2 MW_e, 3 MW_{th}	**Application:**	CHP w/ District Heating

Nexterra is the most recognizable Canadian gasification vendor. With installations of their gasifier throughout Canada and the USA, they have developed a solid platform for biomass gasification (low-medium calorific value syngas). Their most recent installation on the University of British Columbia campus is their first CHP using a reciprocating engine. The complexity of the system is Standard with an updraft gasifier and syngas clean-up. Nexterra's gasifier is well proven and does not require steam.

Level of Development	Demonstration – 3 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Standard – 3 Pts.
Installation Base	1 Installations – 0 Pts.
Steam Required	No – 5 Pt.
Score	**21 Pts. (70%)**

Nexterra Advanced Biomass Heat and Power System



SIMPLIFIED ILLUSTRATION

① Fuel Storage - wood residue delivered to storage facility and conveyed to gasifier.
② Gasification Technology - gasification process converts wood residue into clean, renewable synthetic gas or "syngas."
③ Syngas Conditioning Technology - syngas is conditioned and upgraded to meet fuel specification for engine.
④ Engine(s) - high-efficiency internal combustion engine(s) operates on syngas instead of natural gas to generate electricity & heat.
⑤ Heat & Power - systems will generate heat & electricity at small-scale (2 - 10 MWe) economically with efficiencies of up to 65%.

Developer / Company:	Pyroforce Energietechnologie AG	**Location:**	Nidwalden, Switzerland Güssing, Austria
Owner:	Pyroforce	**Status:**	Operational (Güssing not)
Technology:	2-zone downdraft	**Tech Status:**	Demonstration
Capacity:	Nidwalden: 1.2 MW_{el} Güssing: 0.35 MW_{el}	**Application:**	Syngas to engines

Pyroforce has a pilot/demonstration unit at an industrial site in addition to the two locations above. The Pyroforce system is based on a modular technology in a sense that each gasifier is only 150 kW_e and multiple units are used to achieve the required capacity. The gasifiers do not require steam.

Level of Development	Demonstration – 3 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Standard – 3 Pts.
Installation Base	2 Installations – 3 Pts.
Steam Required	No – 5 Pt.
Score	**24 Pts. (80%)**

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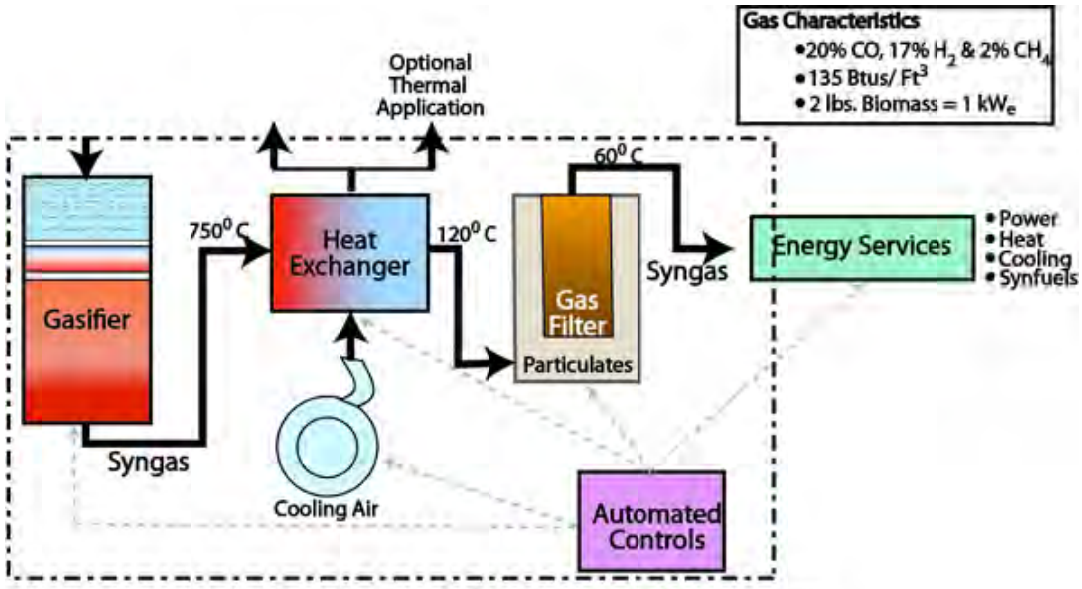
Technology Assessment and Recommendation
October 18, 2012

Developer / Company:	Community Power Corporation (Afognak Native Corporation, Alaska)	**Location:**	33 locations in North America
Owner:	Various	**Status:**	Operational
Technology:	Downdraft Gasification	**Tech Status:**	Commercial
Capacity:	25 kW_e and 100 kW_e	**Application:**	Power, CHP

Community Power Corporation (CPC) develops modular gasification systems using a downdraft gasifier. They are available in 25 and 100 kW_e capacities, which can be combined to achieve any overall capacity (max. 3 MW_e). Complexity is low with a high degree of automation, and not steam or water wash requirements. CPC development was supported by the USDOE and NREL.

Level of Development	Commercial – 5 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Standard – 3 Pts.
Installation Base	More than two – 5 Pts.
Steam Required	No – 5 Pt.
Score	**28 Pts. (93%)**

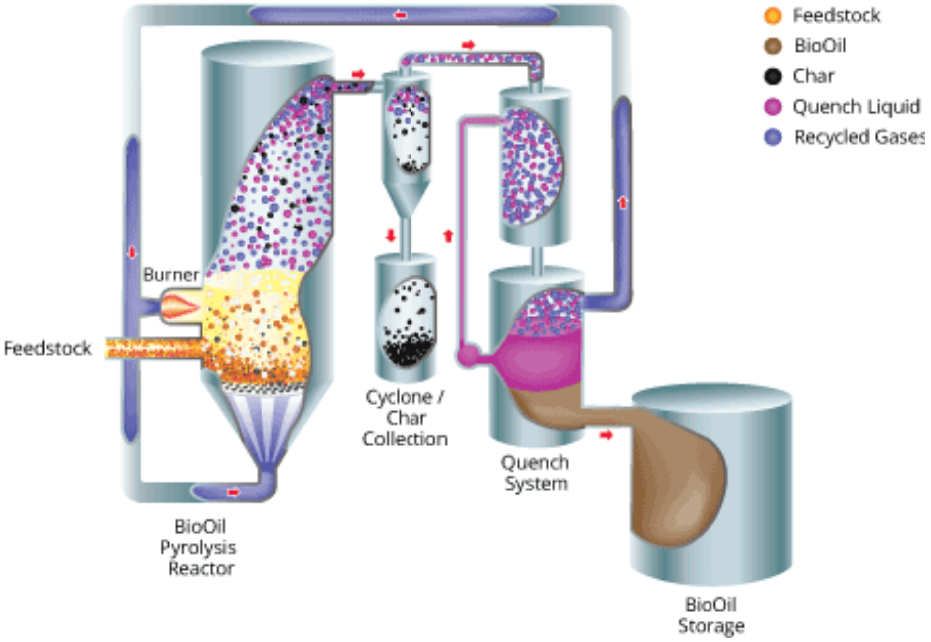


CPC BioMax® GASIFICATION MODULE SCHEMATIC

Developer / Company:	Dynamotive Energy Systems	**Location:**	West Lorne, Ontario Guelph, Ontario
Owner:	Dynamotive Energy Systems	**Status:**	Operational
Technology:	Fast Pyrolysis	**Tech Status:**	Commercial
Capacity:	2.5 MW_e (West Lorne) 5 MW_e (Guelph)	**Application:**	Electricity, Specialty Products

Dynamotive's patented fast pyrolysis involves the rapid heating of a biomass feedstock in the absence of oxygen. Prepared feedstock is heated to a lower temperature than other pyrolysis systems thus having the benefit of higher overall energy conversion efficiency. Gas turbines are used commercially to produce electricity but leftover BioOil often results and is typically further processed into other chemicals. (Dynamotive, 2012)

Level of Development	Commercial – 5 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Engine for Power	No – 0 Pts.
Gasification Complexity	Advanced – 0 Pts.
Installation Base	2 Installations – 3 Pts.
Steam Required	No – 5 Pts.
Score	**18 Pts. (60%)**



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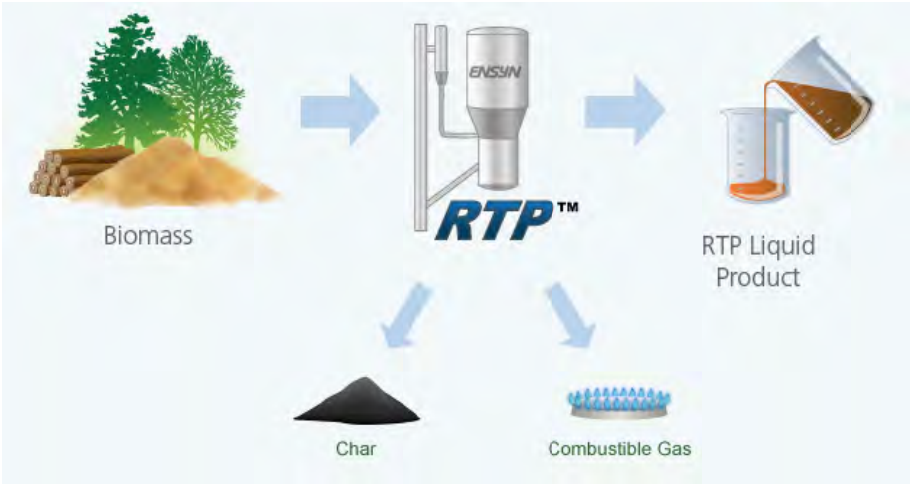
Technology Assessment and Recommendation
October 18, 2012

Developer / Company:	Ensyn	**Location:**	Tuscany, Italy Sabah, Malaysia Renfrew, Ontario
Owner:	Ensyn	**Status:**	Under Development, Operational (Ontario)
Technology:	Fast Pyrolysis	**Tech Status:**	Commercial
Capacity:	11-13 MW_e (Italy) 28-34 MW_e (Malaysia)	**Application:**	Power, CHP

Ensyn's patented Rapid Thermal Processing (RTP) technology uses heat to thermally crack carbon-based feedstock into high yields of higher-value liquids. Ensyn operates a fuel production facility in Renfrew, Ontario which produces commercial quantities of RTP liquids for clients. The RTP Renewable Fuel Oil can be injected directly into a turbine or diesel engine in a variety of combinations depending on the required output (Envergent Technolgies, 2010).

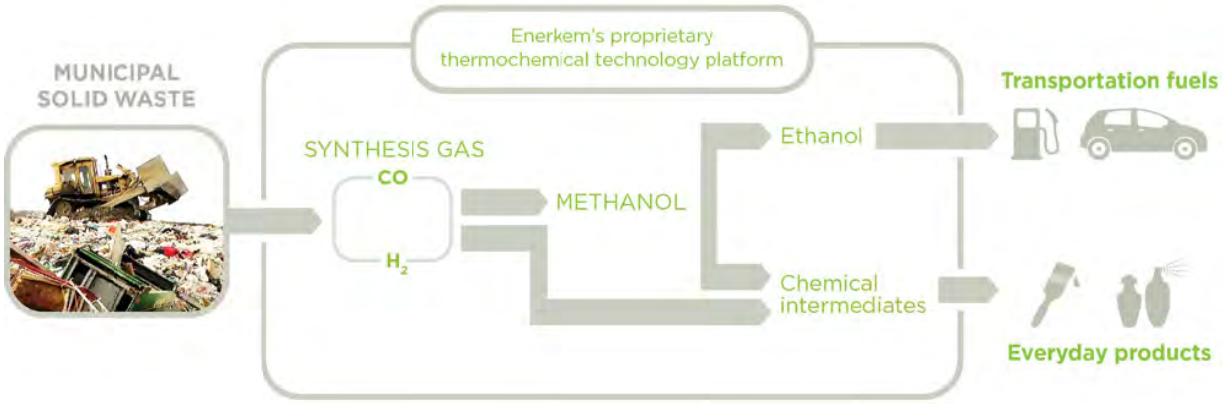
Level of Development	Commercial – 5 Pts.
Capacity Range	Outside 2-4 MW_e – 0 Pts.
Use of Engine for Power	Yes – 5 Pts.
Gasification Complexity	Advanced – 0 Pts.
Installation Base	1 Installation – 0 Pts.
Steam Required	No – 5 Pts.
Score	**15 Pts. (50%)**



Developer / Company:	Enerkem	**Location:**	Edmonton, Alberta Pontotoc, Mississippi Varennes, Québec
Owner:	Various	**Status:**	Under Development
Technology:	Bubbling Fluidized Bed	**Tech Status:**	Commercial
Capacity:	10 Million gallons/yr	**Application:**	Ethanol/Methanol Production

Enerkem currently operates two plants in addition to the three commercial scale plants that are under development – a demonstration facility in Westbury, Quebec and a pilot plant in Sherbrooke, Quebec. The three commercial scale plants will convert municipal solid waste into methanol and cellulosic ethanol. Enerkem's primary focus is the production of cellulosic ethanol of which methanol is an intermediate product (Enerkem, 2010).

Level of Development	Commercial – 5 Pts.
Capacity Range	Outside 2-4 MW_e – 0 Pts.
Use of Engine for Power	No – 0 Pts.
Gasification Complexity	Advanced – 0 Pts.
Installation Base	1 Installation – 0 Pts.
Steam Required	No – 5 Pts.
Score	**10 Pts. (33%)**



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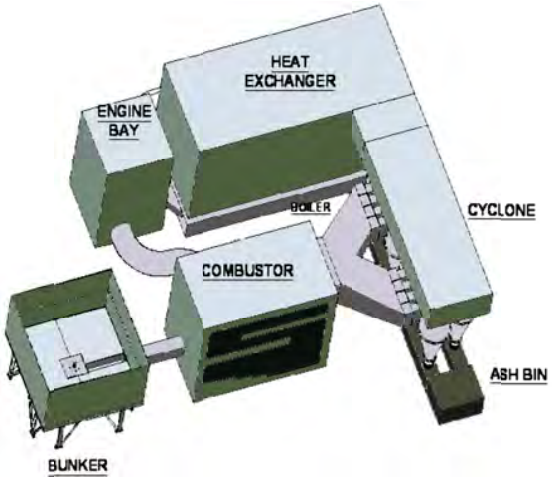
October 18, 2012

Developer / Company:	(1) Talbott's (2) Entropic	**Location:**	(1) Shropshire, England (2) University of Manitoba
Owner:	(1) Talbott's (2) Entropic	**Status:**	Operational
Technology:	Indirect Fired	**Tech Status:**	Demonstration
Capacity:	100 kW_e, 200kW_{th}	**Application:**	CHP

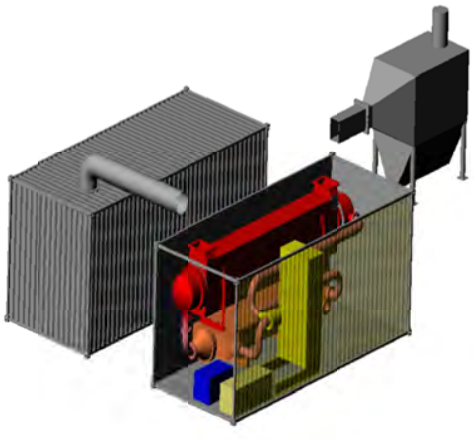
Tallbott's manufactures over 40 different systems at its UK factory with over 4000 installations worldwide. The BG100 generator was officially launched and installed at Harper Adams University College in Shropshire, England in 2006. The unit has been discontinued due to operations issues. They have since released a BG250 (250 kW_e, 600 kW_{th}), and have a BG25 and BG50, 25 kW_e and 50 kW_e respectively.

A similar product is available from Entropic in Port Coquitlam, BC, with their 100 kW_e version.

Level of Development	Demonstration – 3 Pts.
Capacity Range	Within 2-4 MW_e - 5 Pts.
Use of Micro Turbine for Power	Yes – 5 Pts.
Gasification Complexity	Direct Comb. – 5 Pts.
Installation Base	1 Installation – 0 Pts.
Steam Required	No – 5 Pts.
Score	**23 Pts. (77%)**



(1) Talbott's BG250


(2) Entropic HBC100

3.2 TECHNOLOGY SCREENING SUMMARY

A summary of the technology scorecards is presented in Table 3-2 on the following page. Reviewing each vendor's score, the top scores, greater than 20 pts, were ranked from one (1) to six (6). Given the criteria considered, the smaller, more modular systems in the smaller capacity ranges took the top two rankings: (1) Community Power Corp., and (2) Biomass Engineering Ltd. The other downdraft unit, Pyroforce ranked third (3) followed by the alternative external fired gas turbine unit (4) Talbott's/Entropic. The final two rankings represent the larger updraft systems: (5) Nexterra, and (6) B&W Vølund.

3.3 TECHNOLOGY COSTING

To provide an indication of installed costs for the unit, publically available information was compiled for the vendor installations. This information is not recommend for direct comparison purposes due to the lack of detail available, if any is available, as it is challenging to determine what equipment and installations costs are being included. Table 3-3 presents the findings for the installed costs summary for consideration.

Table 3-3: Vendor Published Costs per MW_e Installed ($ CAD 2012, 2.5%/yr inflation)

Vendor	Technology	Published Cost per MW_e
Andritz-Carbona	Bubbling Fluidized Bed	**$9.3M**
Babcock & Wilcox Vølund	Updraft Gasifier	**$7.0M**
Biomass Engineering Ltd.	Downdraft Gasifier	**$8.2M**
FICFB	Dual Bed	**$7.2M**
Nexterra	Updraft Gasifier	**$8.5M**
Pyroforce	2-Zone Downdraft	**$8.2M**
Community Power Corp.	Downdraft Gasifier	**$8.1M**
Dynamotive	Fast Pyrolysis	**$40M (21 x$10^6$ L/yr)**
Ensyn	Fast Pyrolysis	**$100M (87 x$10^6$ L/yr)**
Enerkem	Bubbling Fluidized Bed	**$80M (36 x$10^6$ L/yr)**
Talbott's	Indirect Fired	**$10.1M**

An average cost for the top six vendor's average out to approximately \$8.4M/MW_e. Using this as a baseline, and assuming some cost reduction for economies of scale, a 2 - 4 MW_e installation will have an approximate installed cost of \$16M - \$32M. This is primarily the cost of the biomass plant itself, and would exclude any waste heat recovery project.

Table 3-2: Summary of Vendor Scorecards

Technology	Developer/ Owner	Level of Development	Capacity Range	Engine for Power	Gasification Complexity	Installation Base	Steam Required	Score	Rank	Elec. Eff.*
Bubbling Fluidized Bed	Andritz-Carbona	5	0	5	0	0	0	10 (33%)		
Updraft Gasifier	Babcock & Wilcox Vølund	5	5	5	0	5	0	20 (67%)	6	
Downdraft Gasifier	Biomass Engineering Ltd.	5	5	5	3	3	5	26 (87%)	2	
Dual Bed	FICFB	3	5	5	0	3	0	16 (53%)		
Updraft Gasifier	Nexterra	3	5	5	3	0	5	21 (70%)	5	26%
2-Zone Downdraft	Pyroforce	3	5	5	3	3	5	24 (80%)	3	
Downdraft Gasifier	Community Power Corp.	5	5	5	3	5	5	28 (93%)	1	20%
Fast Pyrolysis	Dynamotive	5	5	0	0	3	5	18 (60%)		
Fast Pyrolysis	Ensyn	5	0	5	0	0	5	15 (50%)		
Bubbling Fluidized Bed	Enerkem	5	0	0	0	0	5	10 (33%)		
Indirect Fired	Talbott's	3	5	5	5	0	5	23 (77%)	4	13%

3.4 TECHNOLOGY RECOMMENDATION

The technology summary in the previous section ranked three (3) technologies as front runners based on their current installation base and applicability to general project requirements. In order to make a meaningful recommendation it is also important to assess as many known considerations as possible. Although this study is in its early stages (technology-wise), there are several other aspects for consideration to formalize a recommendation.

Feedstock supply: The supply of fuel is critical to the project and is being evaluated on an on-going basis. From the standpoint of technology, the supply requirements are directly related to the capacity of the unit. In this case, a 2 – 4 MW_e installation is currently under consideration and will require 30,000 – 50,000 GMT/yr of fuel (to be confirmed (TBC)). This is not a large amount of fuel, but is more than is currently available and will have to be secured.

Trained operators: There is currently no biomass thermal or gasification plant in Haines Junction or the Yukon, and it can be assumed that finding multiple skilled operators for the new plant will be a challenge. The larger and more complex the plant becomes, the greater the challenge to staff and maintain the plant for the long-term.

Plant Efficiency: Thermal power generation projects are not extremely efficient. Typical small/medium scale boiler/steam turbine units may reach approximately 20-25% gross plant efficiency, depending on unit size and equipment. A gasification unit in the same scale has the potential to achieve higher efficiencies (up to 40%) depending on the arrangement and unit performance. In either case, straight power generation will be discarding more than half of the heat input to the system as waste heat. This loss will have a large impact on the financial viability of the project, and is the principle driver for projects to consider cogeneration (waste heat recovery).

Waste heat recovery is already under consideration for this project, but is currently being sized as a result of the power generation capacity. Although this is a typical approach if the power requirement is fixed, in this case, it may not be the driving force due to the preliminary and unconfirmed sizing of the required electrical generating capacity. In most cogeneration applications, it is the waste heat usage that drives the size of the power generation unit to support its development. Furthermore, if there is variability to the heat load, than the peak heat load is not necessarily used to size the system (i.e., the existing system meets peak requirement and the new system deals with the baseload). Using Haines Junction district heating studies as an example, the peak load is 1.2 MW_{th} yet the average load is 300-500 kW_{th} (TBC). Assuming a gasification plant is 80% efficient, 40% to electricity and 40% to waste heat, the generation capacity of the unit should only be 300 - 500 kW_e as opposed to 2 – 4 MW_e.

Combining the vendor rankings and giving consideration to the aspects above, Stantec provides the following path forward for consideration. As the 2 – 4 MW_e plant capacity is the focus of the study, the project should base the plant on an updraft gasification design, and issue Requests for Quotation (RFQ) to B&W Volund and Nexterra.

If there is the opportunity to refine the desired size of the power plant and make it smaller, the RFQ should be extended to the other technology vendors. As a sensitively analysis to the main focus of the study, Stantec recommends this be undertaken. With respect to the aspects above: a smaller unit size would have a better opportunity to secure a feedstock supply (less volume), operation of the small units (CPC and Talbott's) are significantly less complicated than the other technologies considered (more automated/less hands-on); and the plant can be easily tailored to suit a viable use of the waste heat, maximizing the efficiency and sustainability of the unit. This approach is keeping with the results of the 2011 biomass workshop and at the conclusion of the FEED study, would give the project a fallback position if the 2 – 4 MW_e unit is determined to not be economically viable/accepted or the small units become more attractive.

4.0 Feedstock Characterization

Characterization of the feedstock is the first step to understanding the potential impacts to the biomass power plant. The feedstock can impact several areas of the plant's operations, including: pre-processing requirements, materials handling requirements/arrangements, and technology specific issues (gasification, syngas clean-up, emissions, waste streams). The preliminary data below represents a desktop analysis and preliminary results from AGFOR on-site assessment the week of October 8 – 12. These characterizations are based on publically available information and will be refined as the project progresses.

Based on preliminary assessments the majority, if not all, of the biomass feedstock will be White Spruce. Beyond the species, it is important to note that most of the available feedstock is dead. The chemistry provided in the tables below is for live wood (green) wood. Dead wood will have lost some of the volatiles and other chemicals, furthermore will have a very low moisture content (less than 25%, most likely 10 – 15%. Live / green wood can also be harvested, and maybe required to support moisture content requirements of the 2 – 4 MW biomass plant. The green wood does grow in low moisture conditions compared to other Canadian climates, and can be expected to have moisture content of approximately 35%. Blending of these two sources will be able to provide some level of moisture control. Biomass drying is not perceived to be a preprocessing requirement at this time based on these findings.

The following tables (5-1, 5-2, and 5-3) present the chemical properties of the available species that will be used and refined to support the development of the project.

Table 5-1: Proximate Analysis for White Spruce (Isenberg, 1980)

	Volatile Matter (wt%)	Fixed Carbon (wt%)	Ash (wt%)
White Spruce (Bark)	72.5	24.0	3.5

Table 5-2: Ultimate Analysis for Spruce, Popular, Pine (Francescato, 2008)

	% Dry Weight								Energy
	C	H	O	N	K	S	Cl	Ash	MJ/Kg
Spruce (with Bark)	49.8	6.3	43.2	0.13	0.13	0.015	0.005	0.6	18.8
Poplar	47.5	6.2	44.1	0.42	0.35	0.031	0.004	1.8	18.5
Pine	51.1	5.91	38.2	0.1				4.7	18.9

Table 5-3: Ultimate Analysis for Spruce, Popular, Pine (ECN Phyllis, 2008)

	mg/Kg Dry Weight								
	Al	**As**	**B**	**Ca**	**Cd**	**Cr**	**Cu**	**Fe**	**Hg**
Spruce*		0.3			0.6	0.9	4		
Poplar	10		6	4200	0.3		13	30	0
Pine*		0.3			0.6	0.9	4		
	Mg	**Mn**	**Na**	**Ni**	**P**	**Pb**	**Zn**		
Spruce*				3.9		9.8	303		
Poplar	490	17	17		320	1.4	36		
Pine*				3.9		9.8	303		

* these values were general ones given to conifers i.e. not specific to species

4.1 MOISTURE CONTENT

When compared to fossil fuels, biomass has a relatively low heating value. This is due to its distinct characteristics – high moisture and high oxygen content. For typical biomass fuels, high moisture content is one of the biggest disadvantages. Although the combustion reactions are exothermic, the evaporation of water is endothermic. The heating value of the fuel is negatively correlated with the relative amount of water even when the moisture content is within the maximum acceptable limit.

Figure 5-1 displays the negative linear relationship between the moisture content and the heating value. As the moisture content increases, both the higher heating value (HHV) and the lower heating value (LHV) decrease. HHV and LHV are used to describe the heat production of a unit quantity of fuel during its complete combustion. Another important characteristic of biomass fuel is its elevated oxygen content. Usually, the oxygen content of biomass is as high as 35 wt% on a dry basis.

4.2 WOOD QUALITY CHARACTERISTICS

Beetle-killed wood retains 40% moisture for the first few years until the tree "greys" and the moisture content drops to around 30%. Some of the documentation from BC suggests that the moisture content of beetle-killed pine in cool, dry environments may drop to 13% - 18% over the proposed 20-year shelf life (Lewis & Hartley, 2006)

The above are all subject to microclimate and the moisture fluctuations.

The Haines Junction area meets the cool, dry environment criteria which reinforces preliminary findings to October 2012. The principle difference lies in the species: Pine in BC and White Spruce in the Haines Junction area. Moisture content is more a function of effect of climate on wood than of two coniferous species.

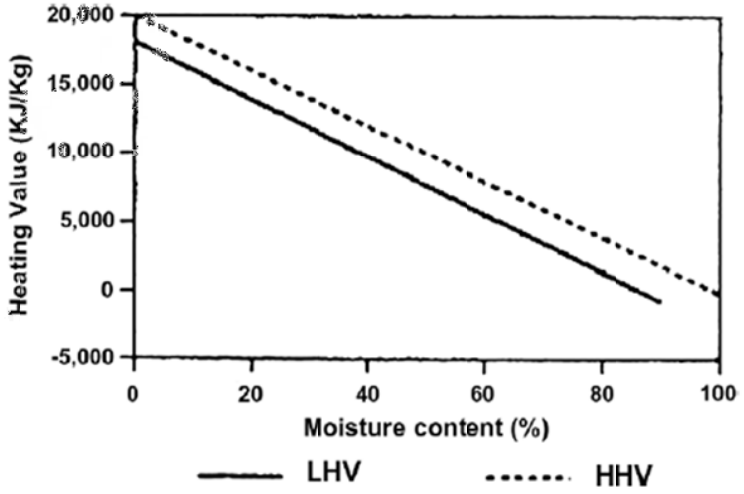


Figure 5-1: Relationship Between Heating Value and Moisture Content of Biomass Fuel (Zhang, Xu, & Champagne, 2010)

4.3 WORK CITED

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5.0 Engagement and Communication Plan

Stantec received a copy of the draft engagement and communications plan developed by the Steering Committee on 26 September 2012. The document was developed to provide a framework from which to build on as the project develops.

Elements of the plan were brought to action sooner than anticipated with the requirement for AGFOR to begin their assessment of the biomass feedstock. Gaston Damecour was in the Yukon to commence the assessment the week of October 8 – 12. During this time, Gaston had to engage several stakeholders as well as the Forestry Management Branch to understand the feedstock harvesting requirements.

In the coming weeks, Stantec will document and use Gaston's experience to refine the engagement and execution plan in consultation with the Steering Committee. A kick-off meeting with the Communications team (Janet, Tanis, & Amy) is currently scheduled for October 19, with the focus to identify a draft timeline for project activities. Identification of tentative dates and activates is requested by the Steering Committee for October 22.

General comments to the draft plan can be found in Appendix A.

6.0 Regulatory Approvals Strategy

6.1 OVERVIEW OF THE PROJECT EFFECTS ASSESSMENT AND REGULATORY REGIMES

Yukon government, First Nation government, and Federal government regulatory approvals and decisions are required before any construction activities may be undertaken for any project that may emerge from this and other related feasibility studies. These approvals and decisions, however, may only be made after the required screening assessment by the Executive Committee of the Yukon Environmental and Socio-economic Assessment Board (YESAB) of a Project Proposal submitted pursuant to the Yukon Environmental and Socio-economic Assessment Act (YESAA).

While such a project will have several activities which would make it assessable under YESAA, a screening level assessment by the YESAB Executive Committee would be required in accordance with Item 55 of Schedule 3 of the Assessable Activities, Exceptions and Executive Committee Projects Regulations as the Project will involve cutting 20,000 m^3 or more of standing or fallen trees or removing that amount of fallen or cut trees. The power plant (principle project) on its own would only trigger an assessment at the Designated Office level, but the principal project's interdependence1 with the accessory project, consisting of local feedstock procurement, raises the level of assessment.

Pending the issuance of a favorable YESAB Executive Committee screening (report and) recommendation, decision documents would be issued by any federal, first nation, and/or territorial government that will issue authorizations for the project to proceed (e.g., Air Emissions Permit, Timber Permit). Once the decision documents are issued permitting/licensing applications can be processed by the appropriate authority and authorizations subsequently issued to begin construction and commence operations.

6.2 YUKON LICENSING AND PERMITTING

The follow tables outline the Territorial, First Nations, and Federal government authorizations that may be required for the construction and operation of the proposed Biofuel Power Facility and the operation and maintenance of the associated feedstock. This list will be amended based as the technical aspects of the facility and harvesting become further defined as the Project progresses. The information below has been based on the Permit and Authorization Guide for Yukon Activities (2005) and information currently available for the Government of Yukon, Champagne and Aishihik First Nations, and Federal Government agencies online.

[1] **Interdependence** – if the principal project could not proceed without the undertaking of another project, the two may be considered to form a single project.

6.2.1 Power Facility

Facility or Activity	Act or Regulation	Approval/Permit Required	Lead Agency	Comments
Air Emissions greater than 5Mbtu-hr	YG Environment Act, Air Emissions Regulation	Air Emissions Permit	Environment Yukon	
Release of Air Pollutants	YG Environment Act, Air Emissions Regulation	Air Emissions Permit	Environment Yukon	
Ozone Depleting Substance Use	YG Environment Act, Air Emissions Regulation	Ozone Depleting Substances/halocarbons permit	Environment Yukon	Requirement to be determined based on design
Special Waste Management	YG Environment Act, Special Waste Regulations	Special Waste Facility, Disposal and Generator Permit	Environment Yukon	Requirement to be determined based on design
Solid Waste Disposal	YG Environment Act, Solid Waste Regulations	Facility Permit	Environment Yukon	
Storage Tank/Petroleum Tank Use	YG Environment Act, Storage Tank Regulations	Application for Operation, Closure, Abandonment or Renovation to Storage Tanks/Permit	Community Services, Protective Services	Requirement to be determined based on design
Water Use or Deposit of (Water) Waste	Waters Act	Water Use License	Yukon Water Board	Requirement to be determined based on water use quantities
Potable Water Supply	Public Health Act, Drinking Water Regulation	Drinking/Potable Water Permit	Health and Social Services, Public Health and Safety	

Land Acquisition, Title to Land	Land Titles Act	Issuance of Title	Justice	Requirement to be determined based on land parcel
Tenure for Land Lease or Agreement of Sale	Territorial Lands Act	Application for Land	Energy, Mines & Resources	Requirement to be determined based on land parcel
Tenure for Land Lease	CAFN Lands Act	CAFN Lands Disposition (Lease for commercial or industrial purposes)	CAFN heritage, Lands and Resources	Commercial lease of land requires CAFN Lands Committee review of application and Chief and Council approval
Temporarily Using or Occupying Commissioner's Land	Territorial Lands Act	Land Use Permit	Energy, Mines & Resources	Requirement to be determined based on land parcel
Temporarily Using or Occupying CAFN Settlement Land	CAFN Lands Act	CAFN Lands Disposition (easement, right of way)	CAFN heritage, Lands and Resources	
Facility Construction	YG Land Services	Building Permits	YG Community Services, Building Safety	
	Building Standards Act	Plumbing Permit	YG Community Services, Building Safety	

	Public Health & Safety Act, Sewage Disposal Systems Regulation	Sewage Disposal Permit	Health & Social Services, Environmental Health Services	Requirement to be determined based on design
	Electrical Protection Act	Electrical Permit	YG Community Services, Building Safety	
	Gas Burning Devices Act	Gas Installation Permit	YG Community Services, Building Safety	Requirement to be determined based on design
Clearing or Installing a Utility Right-of-Way	Territorial Lands Act	Land Use Permit, Disposition Approval	Energy, Mines & Resources	Requirement to be determined based on design
Construction of New Road Access	Territorial Lands Act	Land Use Permit	Energy, Mines & Resources	Requirement to be determined based on site location
Construct Road Access on Highway Right-of-Way	Highways Regulation	Access Permit	Highways & Public Works	Requirement to be determined based on site location
Temporary use of CAFN Settlement Land / use or alteration of resources on surface of land	CAFN Traditional Activities Protection Act	TAPA Permit	CAFN Heritage, Lands and Resources Dept.	Permits issued by Director
Activities in a Habitat Protection Area	Wildlife Act, Wildlife Regulation	Permission for Activity	YG Environment	Requirement to be determined based on site location
Activities in a Wildlife Area	Wildlife Area Regulation	Wildlife Permit	YG Environment	Requirement to be determined based on site location

Harmful Alteration, Disruption or Destruction of Fish Habitat	Fisheries Act	Fisheries Act Authorizations S.35.2	Fisheries and Oceans Canada (DFO)	Requirement to be determined based on site location and construction
Destruction of Fish by Means other than Fishing	Fisheries Act	Fisheries Act Authorizations S.32	Fisheries and Oceans Canada (DFO)	Requirement to be determined based on site location and construction
Obstruction of Fish Passage	Fisheries Act	Fisheries Act Authorization S.22	Fisheries and Oceans Canada	Requirement to be determined based on site location and construction
Bridge Crossing	Waters Act; Territorial Lands Act; Navigable Waters Act (as necessary)	Water License; Land Use Permit; Navigable Water Authorization	Yukon Water Board; Energy, Mines & Resources; Transport Canada	Requirements to be determined based on site location and construction
Navigable Water work	Navigable Water Protection Act; Territorial Lands Act	Application for an Approval of Proposed Works	Fisheries and Oceans Canada (DFO); Energy, Mines & Resources	Requirements to be determined based on site location and construction

***Also of note:** Yukon Forest Resources Act and regulations concerning the construction and operation of a wood processing facility.

6.2.2 Feedstock/Harvest

Facility or Activity	Act or Regulation	Approval/Permit Required	Lead Agency	Comments
Timber Harvesting	Timber Harvest Plan, Forest Resources Act	Timber Resource License	YG Forestry	
Timber cutting on CAFN Settlement Land for commercial purposes	CAFN Traditional Activities Protection Act	TAPA permit	CAFN (Heritage, Lands and Resources Department)	
Burn Wood Refuse	Forest Protection Act, Forest Protection Regulation	Burning Permit	Community Services, Protective Services	
Land Acquisition, Title to Land	Land Titles Act	Issuance of Title	Justice	Requirement to be determined based on land parcel
Tenure for Land Lease or Agreement of Sale	Territorial Lands Act	Application for Land	Energy, Mines & Resources	Requirement to be determined based on land parcel
Temporarily Using or Occupying Commissioner's Land	Territorial Lands Act	Land Use Permit	Energy, Mines & Resources	Requirement to be determined based on land parcel
Construction of New Road Access	Territorial Lands Act	Land Use Permit	Energy, Mines & Resources	Requirement to be determined based on site location

Construction of new road access – forest resource use	Yukon Forest Resources Act; Forest Resource Road Regulations	Forest Resource Road License/permit	Energy, Mines & Resources	Requirement to be determined based on site location
Construct Road Access on Highway Right-of-Way	Highways Regulation	Access Permit	Highways & Public Works	Requirement to be determined based on site location
Activities in a Habitat Protection Area	Wildlife Act, Wildlife Regulation	Permission for Activity	YG Environment	Requirement to be determined based on site location
Activities in a Wildlife Area	Wildlife Area Regulation	Wildlife Permit	YG Environment	Requirement to be determined based on site location
Transportation of Bulk Commodity	Bulk Commodity Haul Regulations	Bulk Commodity Haul Agreement	Highways & Public Works	Requirement to be determined based on transportation quantities
Oversize Trucking	Highways Act	Over Dimensional or Over Weight Vehicle Permits	Highways & Public Works	Requirement to be based on transportation methods

Assessment of historic resources as part of the timber harvest planning or road construction	Historic Resources Act	Archaeological permit	Department of Culture and Tourism	Required to conduct heritage assessments in the field
Other research projects	Examples: Scientists and Explorers Act (Yukon) Fisheries Act Migratory Birds Act CAFN TAPA based TK policy	Various authorizations	Canadian Wildlife Service; Dept Fisheries and Oceans; Yukon Culture and Tourism; Yukon Environment; CAFN	Quite likely necessary if project will include fish and wildlife monitoring

Note: The intent of this chapter is to provide a draft regulatory strategy from which to build on as the project develops and more definitive information becomes available. Stantec is committed to working with YEC and CAFN to define regulatory requirements on and on-going basis of the biomass plant and the feedstock supporting it.

6.3 YESAB

The scope of Stantec's work includes the delivery of a draft Project Proposal for the Biofuel Power Facility that meets the requirements as set out by the Yukon Environmental and Socio-economic Assessment Act (YESAA). Based on preliminary discussions with the Project Team, this submission will be designed for an Executive Committee level assessment. The Feedstock Harvest component of the Project will not be included in the Project Proposal at this time, but will be addressed in a separate technical and regulatory recommendation report aimed at informing a Yukon Environmental and Socio-economic Board (YESAB) submission at a future date. Assessment methods to be used are based on a structured approach that align with YESAB's direction which first assesses potential Project-specific effects and then potential cumulative effects. The following is Stantec's understanding of the assessment process based on YESAA and previous project and professional experience.

.1 **Scoping of Assessment**: identification of Valued Environmental and Socio-economic Components (VCs) relevant to the Project and the assessment including scoping the geographic and temporal boundaries for each VC.

.2 **Baseline Conditions**: baseline analysis including a reviewing current and potential future VC conditions. Examination of the possible interactions between the Project and VCs with a focus on identifying potential effects of concern to be carried forward for assessment.

.3 **Effects Assessment and Mitigation**: after baseline conditions without the Project and proposed mitigations are considered, assessment of the significance of the residual effects that remain. Qualitative and quantitative approach to positive and adverse effects on VCs.

a. **Cumulative Effects Assessment**: consideration of the potential cumulative effects arising from Project effect interactions with other projects, past, existing or future. To be considered a cumulative effect, the other past, existing and future projects being considered in the assessment must affect a VC that is also being affected by the principal project; in this way the projects act cumulatively upon a valued component.

b. **Residual Effects**: summaries of the type and extent of any residual environmental effects of the Project after implementation of the proposed mitigation, including characterization with rationale as to whether adverse residual environmental and socio-economic effects are significant or not significant, as defined in S. 58 of YESAA. Included as part of mitigation are any plans for responding to any known or predicted residual effects, and procedures

for identifying and responding to effects that were not predicted or foreseen.

.4 **Monitoring and Adaptive Management**: development of recommendations for monitoring and adaptive management of residual Project-specific and cumulative effects.

6.4 SCOPING OF THE ASSESSMENT

This step includes:

- Identifying issues of concern related to the Project,
- Selecting VCs for further examination that include both Environmental and Socio-economic,
- Identifying potential sources and pathways of effects from the Project to each VC selected,
- Identifying spatial and temporal boundaries for assessing effects of the Project for each selected VC; and
- Identifying other actions and effects pathways that may act cumulatively with the Project to affect the same VCs.

As stated in Stantec's Project Proposal, a number of Valued Components have been anticipated for various phases or activities associated with the physical works of the proposed Project. From a preliminary perspective, these can be defined as follows:

Table 6.1: Potential Interactions of the Power Facility with the Environment

Phases, Activities or Physical Works Associated with the Power Facility	Atmospheric Environment*	Water Resources	Freshwater Environment	Terrestrial Environment	Health and Safety	Land Use and Infrastructure	Archaeological and Heritage Resources	Traditional and Aboriginal Resources	Transportation	Labour and Economy	Effects of Environment on Project
Construction	1	1	0	1	1	1	1	1	1	1	1
Operation	1	1	0	1	1	1	0	1	1	1	1
Decommissioning and Abandonment	1	1	0	0	1	1	0	0	0	1	1

KEY
0 = No interaction. The environmental effects are not significant and not considered further in the assessment.
1 = Interaction occurs; however, based on past experience and professional judgement the interaction would not result in significant environmental effect, even without mitigation; or interaction would not be significant due to application of codified environmental protection practices that are known to effectively mitigate the predicted environmental effects. The environmental effects are not significant and not considered further in the assessment.
2 = Interaction could result in environmental effect of concern even with mitigation; the potential environmental effects are considered further in this assessment.

*Stantec assessment methodology incorporates air quality, greenhouse gases and acoustic quality under the Atmospheric VC.

Table 6.2: Potential Interactions of the Feedstock Harvest with the Environment

Phases, Activities or Physical Works Associated with the Feedstock Harvest	Atmospheric Environment	Water Resources	Wildlife Resources*	Vegetative Resources*	Health and Safety	Land Use and Infrastructure*	Archaeological and Heritage Resources*	Traditional and Aboriginal Resources*	Transportation	Labour and Economy	Effects of Environment on Project
Construction	1	1	2	2	1	2	2	2	1	1	1
Operation	1	1	2	2	1	2	2	2	1	1	1
Decommissioning and Abandonment	0	0	1	1	0	0	0	0	0	0	1

KEY
0 = No interaction. The environmental effects are not significant and not considered further in the assessment.
1 = Interaction occurs; however, based on past experience and professional judgement the interaction would not result in significant environmental effect, even without mitigation; or interaction would not be significant due to application of codified environmental protection practices that are known to effectively mitigate the predicted environmental effects. The environmental effects are not significant and not considered further in the assessment.
2 = Interaction could result in environmental effect of concern even with mitigation; the potential environmental effects are considered further in this assessment.

*Rankings subject to change as substantial unknowns exist regarding the site location. If feedstock harvesting represents a large footprint, higher rankings for wildlife, traditional pursuits, heritage/cultural uses, tourism (including viewscapes and related tourism land uses such as guiding, outfitting, etc.). There may be substantial unknowns regarding the possible mitigation measures.

The scope of this assessment will be focused on components that could be linked to the Project; as set out in the YESAB Guide to Assessment, both project-specific issues and regional issues that are relevant to the project need to be considered in the establishment of VCs. Therefore Valued Components have potential to be modified throughout the feasibility study, to be finalized upon its completion. Similarly, determination of VCs and environmental and socio-economic scoping requires input from local communities and interested parties; in this case, that may involve field studies and consultation that may not be completed by the end date of this Project phase. This should be noted and VCs revisited when a final Project Proposal for the Feedstock and Facility components is completed.

Other scoping considerations include the identification of spatial and temporal boundaries for the assessment of the Project effects on selected VCs. At this time, both of these boundaries have yet to be determined as the Project location, phases and schedule have not been set. However, YESAB Guides provide definitions which will be adhered to when they are chosen:

Construction Phase: This phase generally consists of the estimated time required to complete the construction of the Project, including commissioning of the facilities.

Construction Footprint Area: Construction Footprint Area is the geographic area needed for construction and operation of the physical infrastructure associated with Power facility (i.e. power access, access road, the plant, office, log storage yard, chipping plant, chip storage – conveyor, hopper, etc.).

Operation Phase: The time period following construction, through the life of the relevant components of the project, during which time the project will be used for its primary purpose of power generation.

Decommissioning Phase: The time period following operation when the Facility is no longer being utilized for its primary purpose; this may include transitioning the facility to another use or closure and abandonment.

Project Study Region: A Project Study Region for examining potential environmental and socio-economic effects has yet to be defined. Once defined, the extent of a baseline assessment for each VC required will be added.

6.5 BASELINE CONDITIONS

For use in assessing the Project's environmental and socioeconomic effects, the baseline conditions for the selected VCs will be considered through a desktop analysis. Baseline conditions will be characterized using published data and information generated in the Feasibility Study. Information may also be obtained through consultation with interested and informed parties and potential field surveys (to be conducted as required at a later date and not as part of the scope of Stantec's current assignment).

In summary, baseline conditions for each VC are proposed to be based on:

- **Atmospheric Environment:** (Air quality, greenhouse gases and sound quality)- for air: inferred from existing ambient data measured in Whitehorse as well as any available local qualitative or quantitative information (existing sources of emissions in the area); for greenhouse gases: existing provincial inventory of GHG emissions as reported to Environment Canada; for sound: inferred based on monitoring data for areas of similar land use based on Stantec's professional judgment;

- **Water Resources:** Summary of existing municipal water supply in the area of the Project and discussion of any nearby surface or groundwater resources based on readily available data.

- **Wildlife Resources:** Summary of existing wildlife in the Project area based on readily available previously conducted studies and local information.

- **Vegetative Resources:** Summary of existing vegetation on the Project site based on a qualitative assessment of the site and any readily available desktop information (recommendations for field assessment requirements to be provided).

- **Health and Safety:** Summary of existing Yukon Energy health and safety program, records.

- **Land Use and Infrastructure:** Summary of existing land use and infrastructure on the Project site and directly adjacent sites.

- **Archaeological and Heritage Resources:** Summary of readily available documentation on archaeological and heritage resource potential on the Project site.

- **Traditional and Aboriginal Resources:** Summary of readily available documentation and discussion of any information obtained through consultation on traditional and aboriginal use of the Project site.

- **Transportation:** Summary of readily available information on traffic volumes and road way level of service designations in Haines Junction.

- **Labour and Economy:** Summary of readily available information on existing employment stats, economic drivers in Haines Junction.

- **Effects of Environment on the Project:** Summary of readily available climatic data (wind speeds, precipitation levels, temperature normal).

6.6 EFFECTS & MITIGATION

Once baseline data is collected for each VC, the assessment will consider the effects of the Project, as well as other actions which may act cumulatively with the Project, on the selected VCs. Effects are examined for the construction, operation and decommissioning phases of the Project. Where required, mitigation to minimize environmental effects on each VC will be included in the assessment. Further details summarizing VC-specific effects will be incorporated as existing conditions are established through site determination process.

6.6.1 Cumulative Effects Assessment

The cumulative effects assessment (CEA) is integral to the assessment approach and examines the likely effects of the Project in combination with the likely effects of other past, existing and future projects and activities.

The assessment of potential cumulative effects will be conducted for all environmental and socio-economic VCs. Each assessment begins with a screening that involves determining whether or not all three of the following conditions are met:

- The Project results in a demonstrable or measureable residual environmental effect on the VC.
- The Project-specific residual environmental effect on the VC does or is likely to act in a cumulative fashion with the effects of past, existing or future projects and activities in the area (i.e. there is not spatial or temporal overall of effects).
- There is a reasonable expectation that the Project's contribution to cumulative environmental effects will affect the viability or sustainability of the VC.

Cumulative effects assessment proceeds beyond a screening-level assessment for an effect only when all three of these conditions are met. Although YESAA does not require that a project proposal submission to the Executive Committee consider cumulative effects, it is standard practice in environmental assessment and will be included as part of the submission. The cumulative effects analysis conducted is designed to assist in determinations regarding whether there will be any significant adverse cumulative environmental or socio-economic effects.

The cumulative effects framework suggested by YESAB is similar to that of a federal assessment and includes:

- The identification of regional VCs.
- The compilation of cumulative effects VC baseline information.

- The determination of spatial boundaries for the assessment.
- Identification of other projects and activities and a determination regarding their residual effects.
- The determination of the temporal boundaries of the assessment.
- Identification of potential cumulative effects, the characterization of such effects and identification of mitigation measures.
- Determination of significance of identified cumulative effects.
- Consideration of other Projects including:
  - Other projects for which proposals have been submitted under Subsection 50(1) of YESAA;
  - Existing or proposed activities in or outside Yukon that are known to the Designated Office, Executive Committee or Panel of the Board from information provided to it or obtained by it under YESAA.
  - Those projects whose effects are likely to act in combination with the anticipated effects of the proposed Project.

Similar to other assessment frameworks, where adverse cumulative effects are considered likely, mitigation measures will be designed and determinations made regarding the significance of the residual adverse cumulative effects after the application of those mitigation measures.

6.7 RESIDUAL EFFECTS AND EVALUATION OF SIGNIFICANCE

Significance will be evaluated by comparing residual effects against VC thresholds such as standards or guidelines, targets, or acceptable limits of change. Land use objectives or trends may also be used, as per local regulatory guidance. YESAB Guides detail further acceptable criteria that can be used to evaluable the significance of adverse residual effects from the Project after recommended mitigation measures are considered.

6.8 DETERMINATION OF SIGNIFICANCE

Adverse and likely effects are critical in the determination of significance in the assessment process. In relation to YESAA, this determination must include the recognition of traditional and local knowledge including:

- The need to protect the rights of Yukon Indian persons under final agreements.

- The special relationship between Indian Yukon persons and the wilderness environment of Yukon.

- The cultures, traditions, health and lifestyles of Yukon Indian persons and other residents of Yukon.

Similar to federal assessment practice, YESAB Guides detail the following criteria to evaluate the significance of adverse residual environmental and socio-economic effects:

Direction or Nature of the Effect: Positive, neutral, or negative/adverse; in the case of socio-economic effects, effects may at times be considered to be both positive and negative.

Magnitude of the Effect (level of detectability of effect):

- Low (effect unlikely to be detectable or measurable, or below established thresholds of acceptable change; for some environmental assessments, less than 5% of the VC population or area is affected).

- Moderate (effect could be detectable within normal range of variation with a well-designed monitoring program,10 or below established thresholds of acceptable change; for some environmental assessments, from 5 to 10% of the VC population is affected).

- High (effect would be readily detectable without a monitoring program and outside normal range of variation, or exceeds established thresholds of acceptable change; for some environmental assessments, greater than 10% of the VC population or area is affected).

Geographic or Socio-Economic Extent of the Effect:

- Low (effect extends only within the Construction Footprint Area).

- Moderate (effect extends beyond footprint and is within the Project Study Region; for socio-economic effects, extends to include the community of Mayo).

- High (effect extends beyond Project Study Region and is within Yukon, or extends outside Yukon.

Duration of the Effect (how long the effect would last):

- Low (short-term effects lasting less than one year, or not materially beyond the duration of the construction phase of the Project).
- Moderate (medium-term effects lasting from 1 to 10 years, or no more than one-generation span of the species affected).
- High (long-term effect lasting more than 10 years or more than one generation of the species affected; effects lasting throughout a major portion of the operations phase of the Project).

Frequency of the Effect (how often the impact would occur):

- Low (never, once, seldom).
- Moderate (occasionally).
- High (continuously - on a regular basis or at regular intervals).

Reversibility of the Effect (is the effect reversible and if so can it be reversed in the short or long term):

- Complete Reversibility (immediate, or reversible over very short periods i.e., less than one year).
- High Reversibility (good probability of effect being reversible, periods 1 to 10 years or no more than one-generation span of the species affected).
- Low Reversibility (Irreversible, or reversible over the period of more than one generation of the species affected).

Ecological or Socio-Economic Context (sensitivity to environmental or socio-economic disturbance, capacity to adapt to change):

- Low (VC is resilient to imposed change).
- Moderate (VC has some capacity to adapt to imposed change).
- High (VC is fragile and has low resilience to imposed change).

The assessment of significance for environmental effects determines a clear overall direction of change (positive, neutral or negative/adverse) for the VC. In contrast, the assessment of significance for socio-economic effects must also consider the following:

- The relevance of perceptions in affecting how people view changes.
- Differing perspectives and values among different groups of people about their community and region, as well as their individual and family circumstances.
- The problems inherent in assessing separately effects on different aspects or components (i.e., different VCs) of people‘s lives that each contribute to an overall —effectll on any group of people, i.e., effects may be either positive or negative, depending on the people affected, and may be both positive and negative when different groups are affected differently or when different VCs are considered for the same group.

Definitions for the likeliness of adverse residual effects will be distilled from the above and identified by the Project Team as the study progresses.

6.9 MITIGATION AND ADAPTIVE MANAGEMENT/MONITORING

The Executive Committee level screenings require suggested monitoring methods in order to manage effects. Monitoring effects is necessary in order to determine the success and suitable of mitigation measures, and to ensure predicted effects were accurate. Unanticipated effects will also be identified through monitoring and adaptive management designs.

7.0 Sources of Project Financing

As part of the Phase 5 – Project Financing task, Stantec has conducted preliminary research into potential sources for project funding. At the kick-off meeting in Whitehorse on September 19th, one potential source of funding discussed was Sustainable Development Technology Canada (SDTC). Stantec reviewed the workshop presentation for SDTC (attached) and provide the following comments.

7.1 SUSTAINABLE DEVELOPMENT TECHNOLOGY CANADA

SDTC operates two funds intended to stimulate investment in sustainable technologies. The first fund is the "SD Tech Fund™" which is ten years old and aimed at development of emerging clean technologies. The key here is the word "emerging". To be eligible, the Yukon biomass would have to be considered "unproven"[2].

The second fund managed by SDTC is the "NextGen Biofuels Fund™". This fund is aimed at "large demonstration-scale facilities for next-generation renewable fuels and co-products.

Both of these funds were discussed with Paul Austin (SDTC, Vancouver office), to determine potential eligibility for the Yukon project.

Unfortunately this project is likely to not qualify for either funding. The SD Tech Fund is strictly for new technologies or innovative use of clean technologies, and a proven biomass technology / waste heat application is not what SDTC is looking for in new applications. With regard to the NextGen Fund, it is for "first of a kind" type biofuel projects already in a continuous operation mode.

7.2 POTENTIAL FUNDING SOURCES

Research indicates that there are other funding programs that may be applicable to the project. These will require direct follow-up with the applicable government agencies to determine if it is worthwhile to apply. Furthermore, once (if) a waste heat option is finalized, this may also lead to other funding opportunities.

From Canadian Northern Economic Development Agency there are the following programs.
Strategic Investments in Northern Economic Development (SINED)

SINED has been allocated $22 million funding per Territory for the years 2009-2014 as part of its Targeted Investment Program (TIP). The four areas of focus for TIP are building the knowledge base, enhancing the economic infrastructure base, capacity development, and

[2] SDTC states in the presentation materials under the heading "SOI Don'ts" – Proven Technology = no need for SDTC

economic diversification. It is possible that the Yukon project could qualify for funding as an economic diversification plan.

7.2.1 Community Economic Opportunities Program (CEOP) /

The CEOP and CEDP funding provides project-based support and core operational support for First Nation communities for projects that lead to more community employment, greater use of land and resources, enhanced community infrastructure etc..

7.2.2 Community Infrastructure Improvement Fund (CIIF)

The CIIF program provides up to $1 million in funding for projects that improve community infrastructure. Recipients of the program must be not-for-profit entities, local/territory governments or First Nations. Infrastructure must be directly accessible to the public (i.e. district heating) and must be materially completed by March 31, 2014. There is some question whether the Yukon project would qualify due to restrictions pertaining to commercial activities.

From Natural Resources Canada (NRCan), who is funding this Yukon feasibility study via its ecoEnergy Initiatives Program, may also have possible funding availability under grant programs as follows.

7.2.3 Aboriginal Economic Development in Forestry

The Canadian Forest Service (CFS) has been mandated by AFI to provide knowledge and facilitate coordination of federal support programs for Aboriginal economic forestry development, of which bioenergy is a priority focus. Limited multi-year funding may be available from AFI where it is determined that critical gaps exist in support from other programs that may pose a risk to project success. There is no formal application process involved. Instead, any funding will be subject to the CFS identifying the need and strategic value of the project as well as availability of the funding from AFI.

7.2.4 Biomass for Energy Program

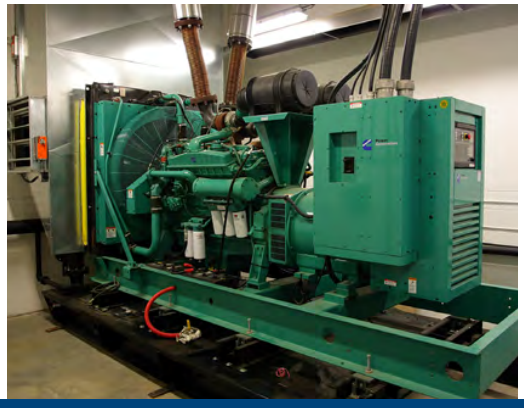
Established in 2000, the Biomass for Energy Program focuses on research and development related to technologies used in the growing, harvesting and transportation of biomass feedstock. The program is also funded through the Canadian Forest Service.

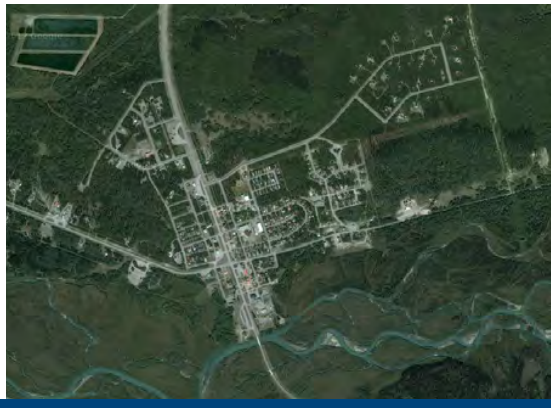
As part of the federal government Office of Energy Research and Development (OERD) is another potential research and development grant program focusing on biomass technologies.

7.2.5 Bio-based Energy Systems and Technologies (BEST) Program

This program supports the research and development of technologies used to improve the supply, conversion and utilization of both existing and new biomass feedstock supply.

Finally, for taxable entities, accelerated Capital Cost Allowance provisions are available for capital assets used in the production of energy using renewable fuel sources. The provisions allow for an increased depreciation of equipment at a rate of 30% annually.





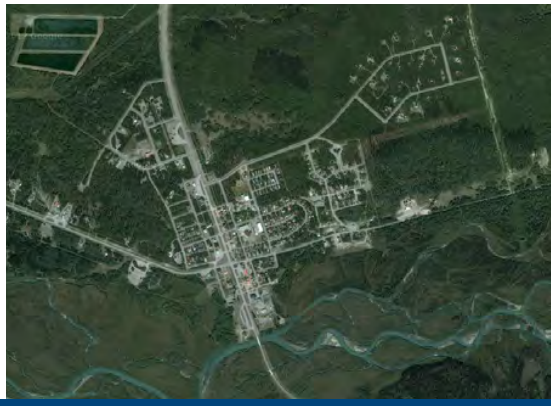
APPENDIX B

Interim Report #2

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

This document has been prepared exclusively for the client and the project identified herein.
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.



REPORT

Interim Report #2 - Vendor Site Visits

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

December 3, 2012

This document has been prepared exclusively for the client and the project identified herein.
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.

Stantec

INTERIM REPORT #2 – VENDOR VISITS
FRONT END ENGINEERING DESIGN (FEED) STUDY

Table of Contents

1.0 INTRODUCTION / REPORT OBJECTIVE 1.1
1.1 REPORT OBJECTIVE 1.1

2.0 NEXTERRA VISIT – NOVEMBER 5, 2012 ..... 2.1
2.1 PROJECT OVERVIEW 2.1
2.2 SITE TOUR 2.2
2.3 OVERALL IMPRESSION 2.6

3.0 ENTROPIC VISIT – NOVEMBER 6, 2012 ..... 3.1
3.1 PROJECT OVERVIEW 3.1
3.2 SITE TOUR 3.1
3.3 OVERALL IMPRESSION 3.3

4.0 CPC VISIT – NOVEMBER 6, 2012 ..... 4.1
4.1 PROJECT OVERVIEW 4.1
4.2 SITE TOUR 4.2
4.3 OVERALL IMPRESSION 4.6

5.0 FINANCIAL ASSESSMENT 5.1
5.1 NEXTERRA 5.1
5.2 COMMUNITY POWER CORPORATION 5.1

6.0 PATH FORWARD 6.4

1.0 Introduction / Report Objective

Stantec Consulting Ltd. (Stantec), in partnership with AFGOR Inc. (AFGOR), has been contracted to carry out Yukon Energy Corporation's (YEC) Front End Engineering Design (FEED) Study for the Yukon Bioenergy Demonstration Project in Haines Junction, Yukon. The objective of the study is a draft report to be delivered on January 26, 2013 covering the following project results:

- Evaluation and selection of a preferred technology for a small-scale bioenergy demonstration project in Yukon.
- Completion of a preliminary design for a preferred project location in Haines Junction, Yukon.
- Clearly defined business model.
- Identified additional funding sources.
- Business case analysis that will clarify the financial viability of the project.
- Technical, financial and regulatory risk management strategies.
- Drafted baseline conditions and impact assessment to form part of the project proposal submission to the Yukon Environmental and Socio-Economic Assessment Board related the bioenergy facility.
- Description of all environmental requirements associated with the project, as well as an outline of foreseeable potential project impacts, and mitigations that will be implemented to reduce project effects. The status and timelines for obtaining all required environmental approvals will also be outlined.
- Overview of engagement activities undertaken throughout 2012, and the results / outcomes of these activities (e.g. issues, challenges and opportunities identified), and a defined engagement and technology transfer strategy for the detailed design and subsequent phases of the project.

1.1 REPORT OBJECTIVE

This interim report is the second of two to be completed during the study, and represents project findings with respect to vendor site visits completed in November. This report seeks to highlight findings from the vendor site visits, as well as provide a high level financial assessment of the

vendor installations. The financial assessment is drawn from information provided by the vendors/owners, as well as publically available information.

The vendor site visits were completed on November 5 and 6, 2012. A site visit of Nexterra's installation at the University of British Columbia (UBC) was completed on November 5, while visits to Entropic at the University of Manitoba (U of M) and Community Power Corporation (CPC) at the Pineland Forest Nursery in Hadashville, Manitoba was completed on November 6, 2013.

A six (6) person team represented the project during the visits, three (3) from Stantec and three (3) from the Steering Committee. Stantec representatives included Chris van Driel (Project Manager), Rick Grey (Mechanical Lead), and Michael Wright (Electrical, Instrumentation, and Controls Lead). Steering Committee (SC) representatives included Shannon Mallory (Deputy Project Manager – Yukon Energy (YEC)), Ray Well (SC Co-Chair, Champagne and Aishihik First Nations (CAFN)), and Hector Campbell (SC member, YEC).

This report is broken into five chapters, one (1) for each site visit, one (1) for the financial assessments, and the final chapter to summarize the path forward.

2.0 Nexterra Visit – November 5, 2012

The site visit for Nexterra took place at 10:00 am on Monday, November 5, 2012 on the UBC campus. The visit was facilitated by Phil Beaty, Vice President, Strategic Relationships, for Nexterra, and Brent Sauder, Director, Strategic Initiatives for UBC. Initially the group met in a conference room on campus to discuss the university's experience during the project's development and execution. This was followed by a guided tour of the facility with the Nexterra representative and operating staff only. During the visit the plant was operational.

2.1 PROJECT OVERVIEW

This project was kick-started by John Grace of UBC based on his academic research into gasification and more specifically gas conditioning/clean-up. UBC and Nexterra wanted a demonstration sized plant to prove the concept and facilitate R&D at the university. Based on the UBC concept, GE came in as a partner and supported the development.

UBC is unique in that it is its own municipality with its own substation. The challenge in BC is the low power rates brought on by their hydro resources. That said; UBC still had the desire to demonstrate a BC technology in BC. On the waste heat side, they are also in the process of converting their existing steam district heating system over to hot water.

For UBC the social license was the first step, with five (5) sites initially under consideration. Faculty members were quick to get onboard for the research ability, and the community soon adopted a "yes, in my backyard" mentality. In the end the unit was located on the edge of the campus in order to reduce truck traffic for fuel deliveries. During full operation, UBC receives three (3) trucks a day, with enough storage for a three (3) day weekend.

On the permitting side UBC requested the strictest emission regulations be met. To that end, UBC requested that the system be designed and will be tested to meet Metro Vancouver requirements, as well as those in the USA jurisdictions of San Joaquin Valley and Massachusetts. The facility is further equipped with a local and external air shed monitoring system.

Building construction was initially completed using standard steel building formats. During the project's development UBC worked with FP Innovations and selected a new construction method – cross linked timber or CLT. The current facility uses CLT for the roof and walls of the building.

The Nexterra system does require trained operators to run the facility. Operators would require similar skills to that of boiler operators, and if a hot water system was installed, they would not require steam tickets. That said, a 4th to 3rd class ticket would be a starting point for skilled

operator requirements. Although the system is fairly automated, skilled operators are required to react quickly in an upset condition. As a minimum, the system requires two (2) full-time staff on-site 24 hours a day / 7 days a week. Currently the UBC plant operates in eight (8) hours shifts, requiring a minimum of eight (8) trained operators to support the plant.

2.2 SITE TOUR

Following the sit-down discussions, the group toured the plant installation. The following photos follow the sequence of the tour with highlights as noted for information.

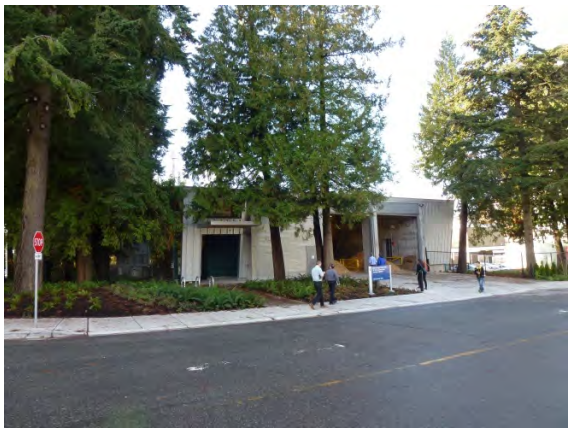


Figure N1: Building Exterior

Figure N2: Fuel Receiving

Located directly on campus, the facility's architectural design made it difficult to distinguish between other buildings on campus. Plant footprint is approximately 90' x 180'. Fuel is received and unloaded using walking-floor transport trucks.

Figure N3: Gasifier Fuel

Figure N4: Fuel Rejects

Figure N5: Fuel Reclaim System

Figure N6: Fuel Processing

The Nexterra unit currently runs on chips brought in through a third party. Fuel is reclaimed from the fuel bunker and processed with a disc screen (for size and contaminant control) and a magnet (to prevent metals from entering with the fuel).

Figure N7: Biomass Dryer

Figure N8: Fuel on Dryer Belt

After fuel processing, the biomass is fed to a single pass dryer. Fuel is wet when received (approximately 40%) and needs to be dried to 20% moisture content by weight, before entering the gasifier. Both bottom and fly ash from the unit is sent to landfill, spent activated carbon (from the filtration system) is disposed of by burning in the oxidizer.

Figure N9: Metering Bin Ahead of Gasifier

Figure N10: Single Nexterra Gasifier

Following the dryer, fuel is fed to the day bin for storage and then onto the metering bin prior to being fed into the gasifier. For UBC, Nexterra installed two parallel gas paths to facilitate the generation of electricity and heat using the engine, and a second path using an oxidizer to generate heat and steam to service the district energy network.

Figure N11: Thermal Oxidizer

Figure N12: Thermal Stack

Figure N13: Water Heater

Figure N14: Electrostatic Precipitator

Figure N15: Cross Laminated Timbers

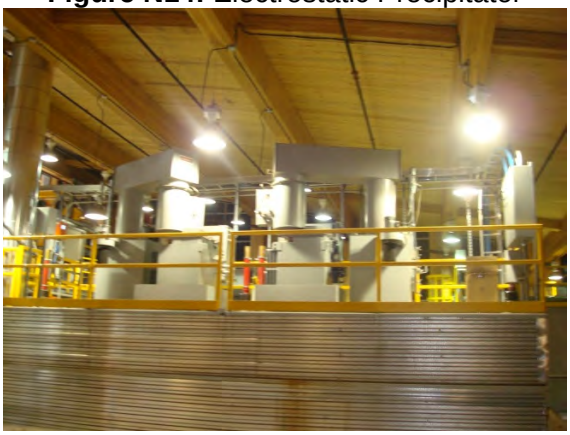


Figure N16: Auxiliary Equipment

Due to the proprietary nature of the installation, photos could not be taken of the syngas clean up equipment. Rather than entering the oxidizer and water heater as shown above, the syngas for the engine enters a series of vertical vessels used to cool the gas and reheat it, before and after the tar cracker. The tar cracker, as its name suggests, is used to 'crack' and breakdown tars that are present in the syngas (to prevent damage to the engine).

Figure N17: 2 MW_e Jenbacher Engine

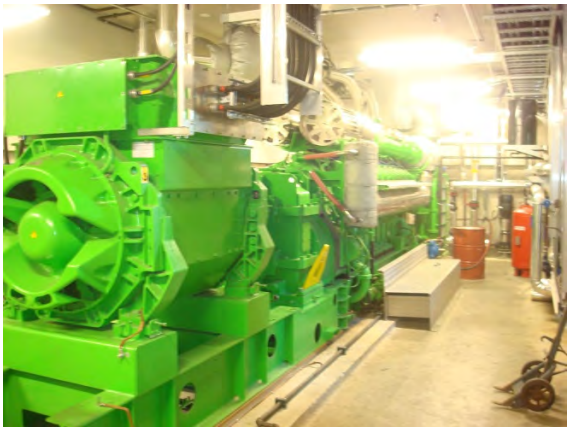


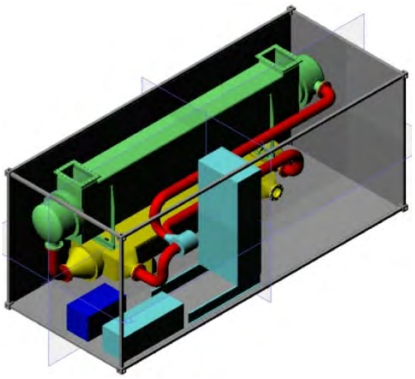
Figure N18: 2 MW_e Jenbacher Engine

After the tar cracker the gas is cleaned by injecting a sorbent and collecting the particulate in a filtration system (bag house). From the filtration system the gas is feed to the Jenbacher reciprocating engine. The UBC installation features a Jenbacher 620 GS, a 20-cylinder reciprocating engine capable of delivering approximately 3.3 MW_e of electricity on natural gas. As the biomass syngas has a lower calorific value then natural gas, the unit is derated and limited in the peak power it can generate. The 620 is guaranteed to generate the 2 MW_e based on syngas from Nexterra.

2.3 OVERALL IMPRESSION

General impression of the group following the visit was that the installation was very large and more complex than expected. The size of the facility, number of operators, and perceived complexity of operation did not seem appropriate for a unit to be located in Haines Junction. The capital cost, maintenance requirements, parts availability, and service technician/operator skill set were also of concern. Mr. Beaty re-iterated that the UBC unit was the first of its kind and Nexterra is not actively marketing it. It will be more than a year before annual performance numbers are available, and only then would Nexterra begin to entertain installing their second unit.

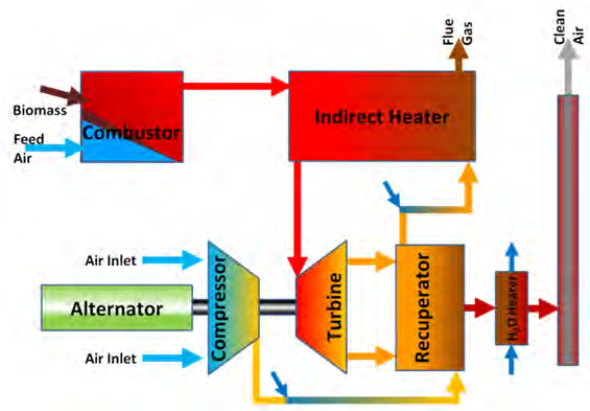
3.0 Entropic Visit – November 6, 2012



The site visit for Entropic took place at 9:00 am on Tuesday, November 6, 2012 on the University of Manitoba (U of M) campus. The visit was facilitated by Dr. Eric Bibeau, NSERC/Manitoba Hydro Industrial Research Chair in Alternative Energy and co-founder of Entropic. Initially the group met in Dr. Bibeau office on campus to discuss the Entropic's technology and product development. This was followed by a guided tour of the installation with Dr. Bibeau. During the visit the plant was not operational and it was unclear when it would achieve "demonstration" status.

3.1 PROJECT OVERVIEW

Entropic is in the R&D stages of their technology. The concept is to design a biomass system with a small footprint that can compete on a conventional technology's price point of \$4M/MW_e. Using the price point as a basis Dr. Bibeau and this team are trying to apply a hybrid Brayton Cycle to achieve high efficiency power generation in a modular package of 250 kW_e.



The Entropic design builds upon that of the indirect fired Brayton Cycle. The principle difference is in the thermodynamics in that they inject water at critical points in the process to increase unit efficiency. Although only currently theoretical in models, the team at U of M are trying to get their unit up and running. Should they be successful, the hybrid design touts the benefits of maximized energy transfer through increase mass through the turbine, decreased turbine inlet temperature (therefore reduced stress on the unit), maximize equipment capacities, and overall increase in efficiency – to double that of a standard externally fired unit.

3.2 SITE TOUR

Following the sit-down discussions, the group toured the plant installation. The following photos follow the sequence of the tour with highlights as noted for information.

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INTERIM REPORT #2 – VENDOR VISITS
FRONT END ENGINEERING DESIGN (FEED) STUDY

Entropic Visit – November 6, 2012
December 3, 2012

Figure E1: Unit is Located Inside the Trailer

Figure E2: Unit Inside the Trailer

The Entropic unit is located inside a trailer/container in a private research area of the university campus. The unit occupies approximately a third of the container.

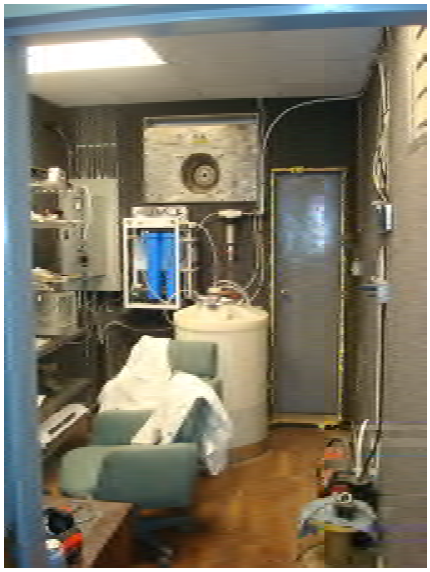

Figure E3: Control Room and Water Treatment Area

Figure E4: Unit from Rear of Trailer

The control room and water treatment area are located in the back quarter of the trailer. Water treatment requires the use of a reverse-osmosis (RO) unit to purify the water before use. Water is injected into the air/syngas and must be pure of contaminants.

Figure E5: 100 kW_e Micro-Turbine

Figure E6: Propane Combustion Chamber

In contrast to the Jenbacher which occupies and entire room, the micro-turbine used by Entropic was significantly smaller and more compact. The unit as shown contains the air compressor, turbine, and generator/alternator. As the unit is not yet operational, it is currently fired on propane instead of biomass for testing purposes. No biomass handling equipment was available for review.

3.3 OVERALL IMPRESSION

General impression of the group following the visit was that this technology/vendor was not appropriate for future consideration. The technology is not near a viable status for consideration on this project, though appears promising.

4.0 CPC Visit – November 6, 2012

The site visit for Community Power Corporation (CPC) took place at 1:00 pm on Tuesday, November 6, 2012 at Pineland Forest Nursery in Hadashville, Manitoba. The visit was facilitated by Carl Peterson, Field Engineer, for CPC. This unit is located on and integrated to Pineland's operations, but is owned by Manitoba Hydro. Jeremy Langner is the Project Manager for Manitoba Hydro (MH), but was unavailable at the time of the site visit. Mr. Langner did provide Stantec with some information on the project as a follow-up to the visit. The General Manager of Pineland, Trevor Stanley, was also unable to attend the site visit, but joined the group later in the evening to answer questions and discuss the project. The tour of the unit took place immediately upon arrival, with questions & answers carrying the group through until departure. During the visit the plant was operational.

4.1 PROJECT OVERVIEW

The following overview was developed from follow-up information provided by Mr. Langner.

The CPC system is manufactured in a series of five (5) 20 ft. shipping containers. Shipping the unit in this containerized form allows the majority of the work to be performed at the manufacturer's facility. The Pineland system was installed in June and July 2012, and Manitoba Hydro/CPC/Pineland have been testing it ever since. The unit has been run to peak capacity and has been able to generate a maximum of approximately 120 kW_e of electricity gross, with about 20 kW_e of parasitic loss. Pineland is also recovering heat off of the engine's cooling jackets and exhausts, and sending this to a thermal loop to heat greenhouses. The heat supplements Pineland's existing 2 MWth biomass boiler, located in an adjacent building.

The CPC system uses a stainless steel downdraft gasifier with air injection points throughout the fixed bed. There is a vibrating grate that can dump material if required. The temperature profile is precisely controlled throughout the bed to insure good gas quality. This allows the filtration system to be very simple – filter bags with backup carbon safety filters. This filters out a very fine carbon dust from the gas. The gas is then sent to two (2) 8.1 L V8 spark-ignition engines, each connected to a 65 kW_e alternator. Another feature of the system is the biomass dryer that uses heat from the gas cooling heat exchanger to dry the feedstock. This allows MH/Pineland to accept up to 45% moisture content, and dry down to approximately 15% moisture.

With regards to fuel rates and flows, MH currently pays in the range of $55 to $65 per tonne as delivered for their biomass supply. The wood chips come from several sources within 2 hours or less of the project site. The fuel consumption is stated by CPC as 90 kg of dry biomass per

hour, however, MH have not been running consistently enough to determine a more accurate figure. The CPC system can accept ¼" x ¼" through 2" x 2" chips.

As far as maintenance costs are concerned, MH does not have enough data to provide concrete figures. It will highly depend on the number of oil changes per month. CPC has specified an oil change every 10 days. MH are also budgeting the equivalent of 1 hour per day of daily checks, and 2 to 3 man-days per month spent on gasifier maintenance. During this initial start-up phase, these numbers are expected to be higher.

Operating efficiency is also difficult to determine giving the limited operating hours. Assuming MH/Pineland are burning 90 kg/hr for 100 kW of output (net), and the biomass has a higher heating value of 20 MJ/kg (dry), MH would have a net electrical efficiency of approximately 20%. MH believes that the total efficiency will be at least double when they include the heat.

In a discussion with the Mr. Peterson, CPC typically provides four weeks of commissioning and start-up services. This includes two (2) weeks on-site for commission the unit and systems, one (1) week of full-time training for site personnel, and one (1) week of field supervision following the training. Beyond the four (4) weeks, Mr. Peterson indicated that CPC monitor the unit remotely for any system warnings or errors. As for the level of skill required to operate the units, Mr. Peterson indicated that the majority of operators are ex-electricians or ex-mechanics. Ex-electricians are preferred give the system electronics and potential advantage when troubleshooting problems, but both have been successful at operating the units.

4.2 SITE TOUR

Upon arriving the group toured the plant installation. The following photos follow the sequence of the tour with highlights as noted for information.

Figure C1: Plant Exterior

Figure C2: Fuel Receiving

The five (5) container system is located on a concrete pad next to the fuel storage/receiving building.

Figure C3: Fuel Storage Interior

Figure C4: Fuel Bin (3 Days Storage)

The existing fuel storage building was retrofitted with the new fuel bin for the CPC plant. The bin is loaded from the top, and can hold sufficient fuel for three (3) days of operation.

Figure C5: Auger Supplying Biomass

Figure C6: Biomass Dryer

An auger carries the biomass from the bin to the biomass dryer located in the first of the five (5) containers. The dryer is used to dry the incoming biomass fuel, and uses hot air from the syngas cooling process to dry the fuel. The desired moisture content is around 15% (16.5% during the visit).

Figure C7: Downdraft Gasifier

Figure C8: Gasifier Bottom Ash

Following the biomass dryer, fuel and air enter the gasifier. Ash is collected at the bottom of the gasifier and conveyed to a storage bin outside the container. Bins need to be checked regularly, and emptied approximately every two (2) days (48 hours).

Figure C9: Downdraft Gasifier

Figure C10: Gasifier Bottom Ash

Leaving the gasifier, the hot syngas is cooled using fresh/filtered air, which is in-turn, sent to the biomass dryer to dry the incoming biomass. The cooled syngas is sent to the container above to be filtered.

Figure C11: Carbon Filters

Figure C12: Fly Ash Collection

The filters are located in the container above the gasifier in a series of five (5) cabinets (four (4) online, one (1) offline for cleaning. Fly ash that is collected is sent to the barrels on the outside of the unit that need to be emptied every 100 hours.

Figure C13: Engine #1 (Front of Container)

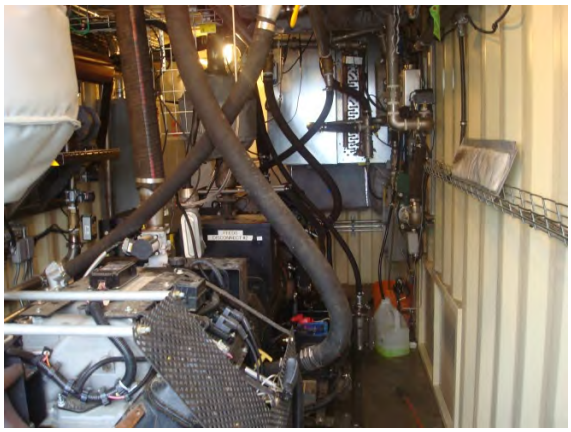

Figure C14: Engine #2 (Rear of Container)

Cleaned syngas from the filters in delivered to the two engines in the final process container. The two V8 spark ignition engines are located in the same container (with little room to spare).

Figure C15: Control Room/Container

Figure C16: Heat Recovery

The final container of the set houses the control room and all the units' electrical equipment. The control interface is a custom built interface to support unit operations. The CPC unit does integrate waste heat recovery in its operation by way of hot water being sent to the existing biomass boiler house hot water heater. The hot water displaces the need to use their biomass boiler. The hot water loop is currently running with 40°C - 60°C temperature difference, but will be looking to achieve 50°C - 70°C once running consistently.

4.3 OVERALL IMPRESSION

General impression of the group following the visit was that this technology/vendor was the most appropriate of the three for Haines Junction. Apart for the small capacity (100 kW_e) the plants simplicity, operations, level of operator skill required, and proven heat recovery potential make is a strong candidate for installation in the Yukon.

5.0 Financial Assessment

Before attending the site visit, Stantec envisioned being able to provide the Steering Committee (SC) with a detailed breakdown of the vendor's installation for review and comparison. Unfortunately, the vendor's/owner's of the systems were not interested in sharing these details with the project team. Some information has been received on general project parameters and Stantec has tried to pull together some online resources to fill in the blanks. The following subsections outline the finding for the Nexterra UBC installation and the CPC Pineland installation. Entropic data is not available and therefore not considered.

5.1 NEXTERRA

Data for Nexterra was achieve through two sources, the first being Phil Beaty of Nexterra[1] and the second publically available information from UBC during their Board of Governors approval process. During this process, Nexterra re-iterated that they "are not currently marketing the Nexterra/GE Jenbacher high efficiency CHP solution. Accordingly we are not offering typical price and delivery information."

From the UBC documentation[2]:

Equipment Procurement	$12,500,000
Field Installation	$3,800,000
Building Design & Construction	$6,400,000
Site Services	$1,200,000
Landscape and Office Relocation	$1,300,000
Contingency	$800,000
Total Project Capital Cost	**(2009) $26,000,000** **(2012 @ 2.0%/yr) $28,100,000**

Of this projected capital cost, 23% was to be provided by UBC and other private sources, while 29% was to be received through Provincial funding programs, and the remaining 48% through Federal government funding (mainly Clean Energy Fund, SDTC, and NRCan). Recent correspondence with Nexterra puts a new project capital cost at $18M - $20M but excludes the building, foundations, and balance of plant equipment (which is not detailed).

5.2 COMMUNITY POWER CORPORATION

Data for CPC was achieved through two sources, the first being Jeremy Langner with Manitoba Hydro[3] regarding the Pineland installation and the second, a publically available pre-feasibility

[1] Personal correspondence, Phil Beaty to Chris van Driel, Nexterra Site Visit, 16 November 2012
[2] The University of British Columbia, Request for Decision, 9 September 2009, Bioenergy Research and Demonstration Project.
[3] Personal correspondence, Jeremy Langner to Chris van Driel, Pineland Forest Nursery Presentation, 27 November 2012

study[4] conducted by Manitoba Hydro using a BioMax 100 as an option for combined heat and power at another location.

From the Manitoba Hydro documentation:

Capital Cost	
Equipment Procurement[4]	$500,000
Biomass Storage and Handling[4]	$84,000
Heat Recovery[4]	$60,000
Foundation, Piping, Interconnection[3]	$130,000
Contingency	$80,000
Total Project Capital Cost	**(2010) $854,000** **(2012 @ 2.0%/yr) $889,000**

Operating Cost	
Average O&M ($20/MWh x 782.6 MWh)	$15,653
Fuel Cost ($60/tonnes x 596 tonnes)	$35,772
Contingency (5%)	$2,571
Total Project Operating Cost	**(2010) $54,000** **(2012 @ 2.0%/yr) $56,000**

Fuel cost of $60/tonnes is in line with the average values of $55 - $65/tonne provided for Pineland.

Revenue	
Electricity ($53/MWh x 782.6 MWh)	$41,500
Thermal ($45/MWh x 1171 MWh)	$52,700
Contingency (5%)	$5,000
Total Project Revenue	**(2010) $99,200** **(2012 @ 2.0%/yr) $103,200**

Simple Payback	
Project Revenue	$103,200
Operating Cost	$56,000
Total Project Revenue	**$47,200**
Project Capital Cost	$889,000
Simple Payback	**19 Years**

[4] Manitoba Hydro, Bioenergy CHP and District Heating, Pre-feasibility Study for Providence College, July 2010

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INTERIM REPORT #2 – VENDOR VISITS
FRONT END ENGINEERING DESIGN (FEED) STUDY

Financial Assessment
December 3, 2012

Using the Manitoba Hydro data as a baseline, Stantec has altered the figures to provide a relative comparison to the figures expected if the site was to be in the Yukon. These figures are not firm, but used to highlight the potential outlook for the project. Stantec's options are limited to provide this information as little background data or details were provided on where the figures were drawn from in the initial study or the basis for their assumptions. The Yukon Construction Factor and Average O&M increases are assumed values as little basis is provided for a more thorough analysis. Fuel cost of $125/tonnes is in line with current expectations for fuel pricing (to be confirmed), and electricity and thermal heating pricing derived from previous biomass reports by Morrison Hershfield.

Capital Cost	
Equipment Procurement[4]	$500,000
Biomass Storage and Handling[4]	$84,000
Heat Recovery[4]	$60,000
Foundation, Piping, Interconnection[3]	$130,000
Contingency	$80,000
Total Project Capital Cost	(2012 @ 2.0%/yr) $889,000
Yukon Construction Factor	**(x1.75) $1,556,000**
Operating Cost	
Average O&M ($40/MWh x 783 MWh)	$31,000
Fuel Cost ($125/tonnes x 600 tonnes)	$75,000
Contingency (5%)	$5,000
Total Project Operating Cost	**$111,000**
Revenue	
Electricity ($200/MWh x 783 MWh)	$157,000
Thermal ($150/MWh x 1171 MWh)	$176,000
Contingency (5%)	$17,000
Total Project Revenue	**$350,000**
Simple Payback	
Project Revenue	$350,000
Operating Cost	$111,000
Total Project Revenue	**$239,000**
Project Capital Cost	$1,556,000
Simple Payback	**7 Years**

6.0 Path Forward

Based on the impressions of the project team during the site visits, it was clear that Entropic unit was not to be considered moving forward, and that the path forward regarding unit capacity should be re-considered. As such the Steering Committee was asked to confirm their desire to continue pursuing a 2 – 4 MW_e unit using Nexterra as one of the main technology providers. Following a Steering Committee meeting, the decision was made to revise the technologies under consideration and allow for a 500 kW_e to 2 MW_e unit to be considered. This would facilitate the smaller units, namely CPC and similar vendors, to offer a multiple of their current offering to achieve a capacity that could be considered.

Currently a Request for Quotation has been issued to a series of vendors, including Nexterra and CPC, to respond with budgetary quotes for the installation of a system in Haines Junction, Yukon.

ONE TEAM. INTEGRATED SOLUTIONS.

Stantec Consulting Ltd.
Suite 202, 107 Main Street
Whitehorse YT Y1A 2A7

Tel: (867) 633-2400
Fax: (867) 633-2481

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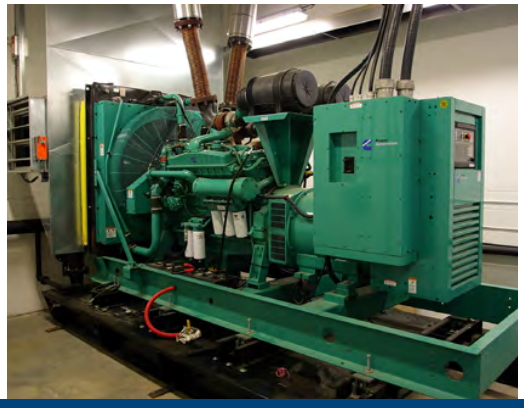

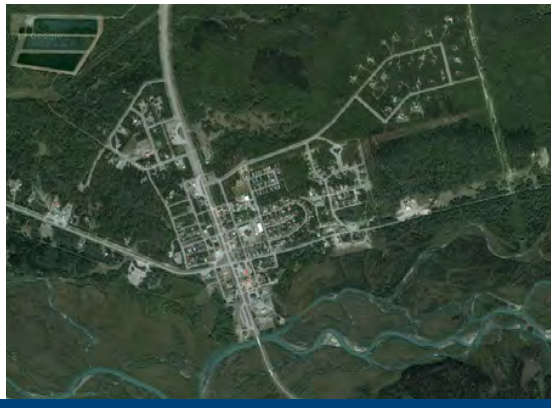

APPENDIX C

Vendor Packages

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

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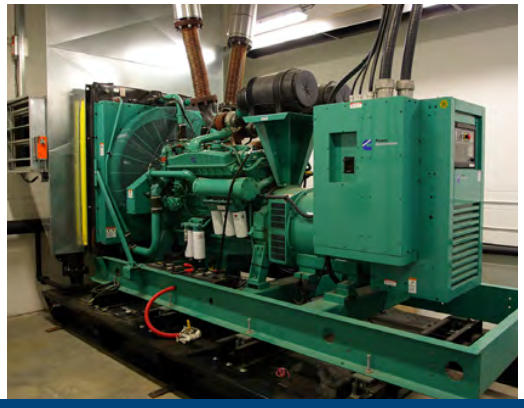

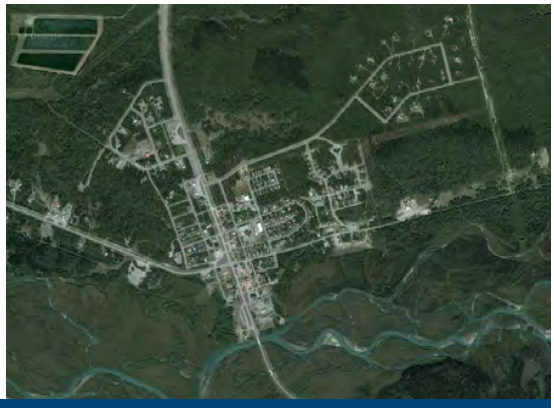

APPENDIX D

Basis of Estimate - Option #1

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

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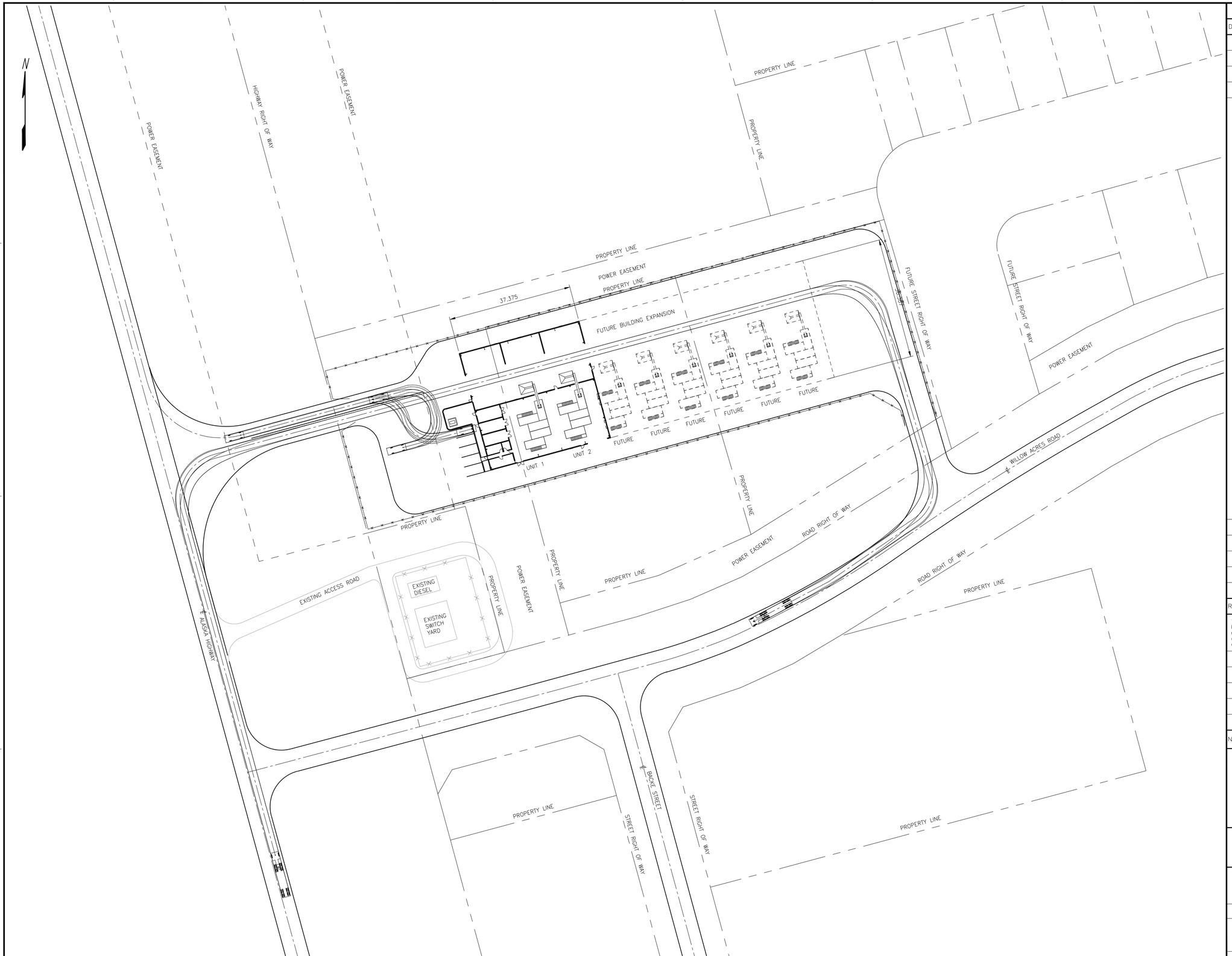

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YUKON BIOENERGY DEMONSTRATION PROJECT

SITE LAYOUT
PROPOSED BIOENERGY PROJECT

JOB No.	DWG. No.	REV
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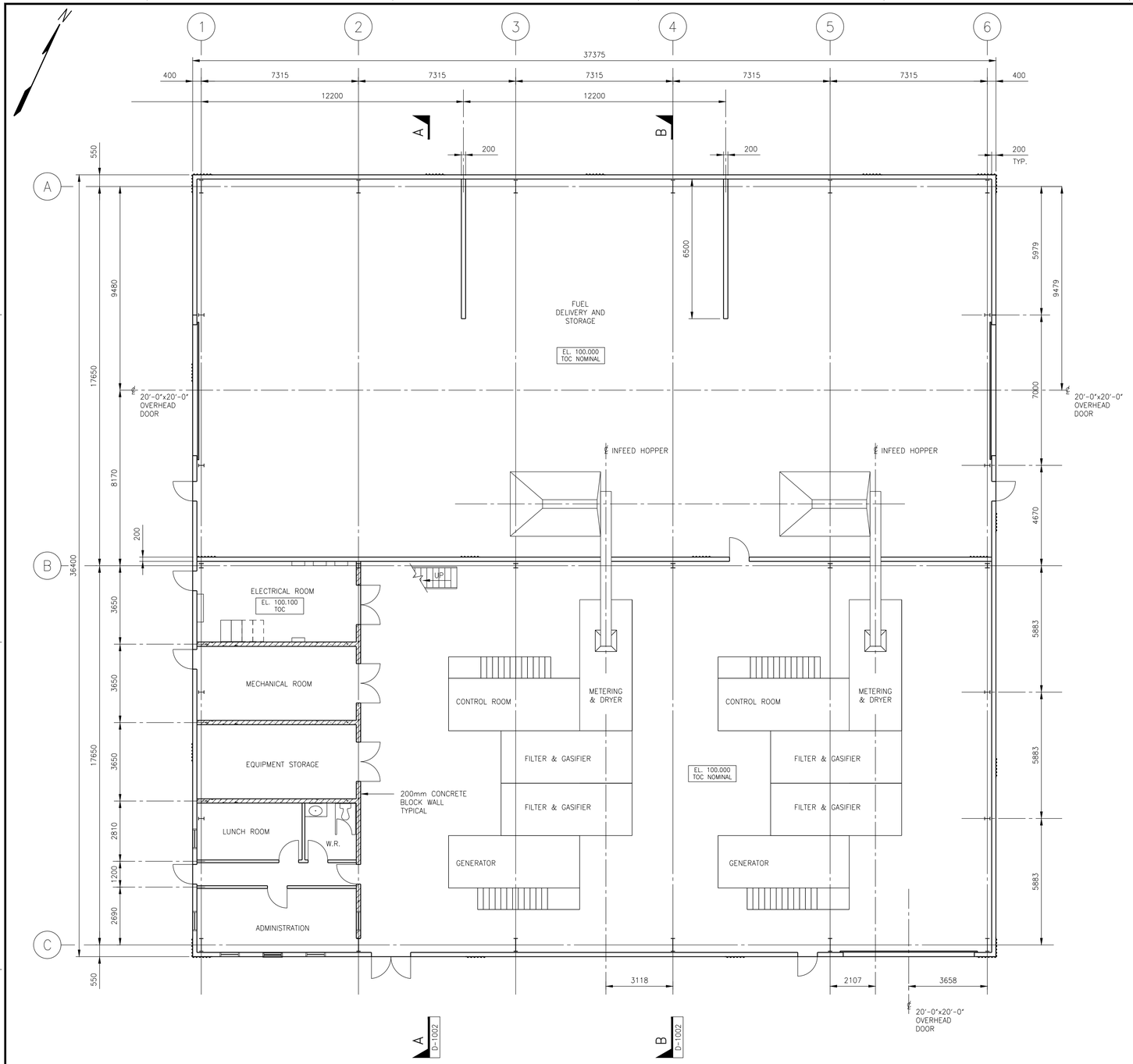

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YUKON BIOENERGY DEMONSTRATION PROJECT

GENERAL ARRANGEMENT
PLAN
OPTION 1
UNITS IN BUILDING

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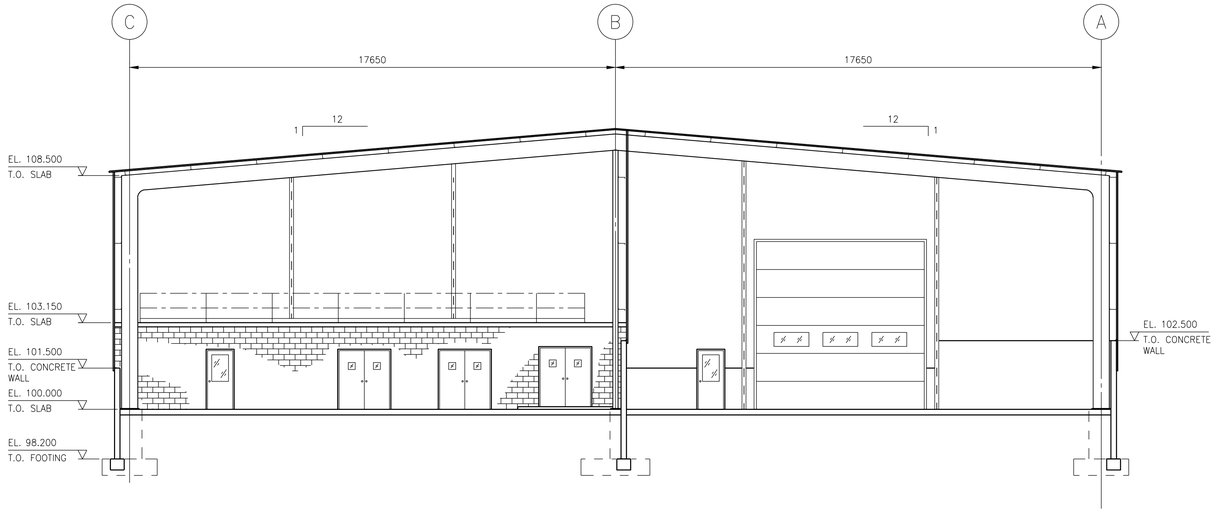

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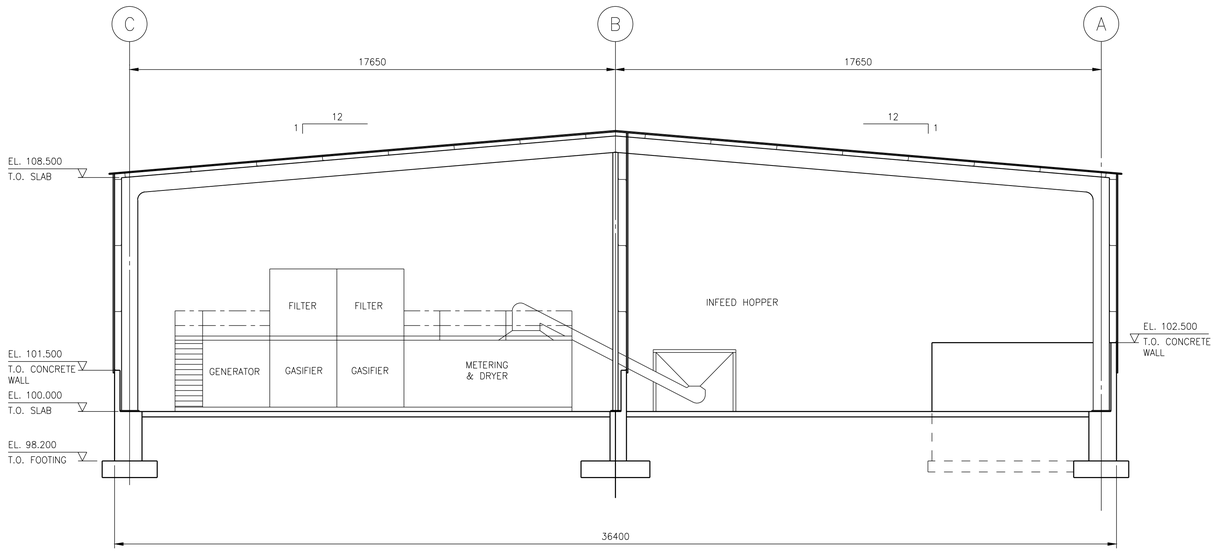
D-1002



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YUKON BIOENERGY DEMONSTRATION PROJECT

GENERAL ARRANGEMENT
SECTIONS
OPTION 1
UNITS IN BUILDING

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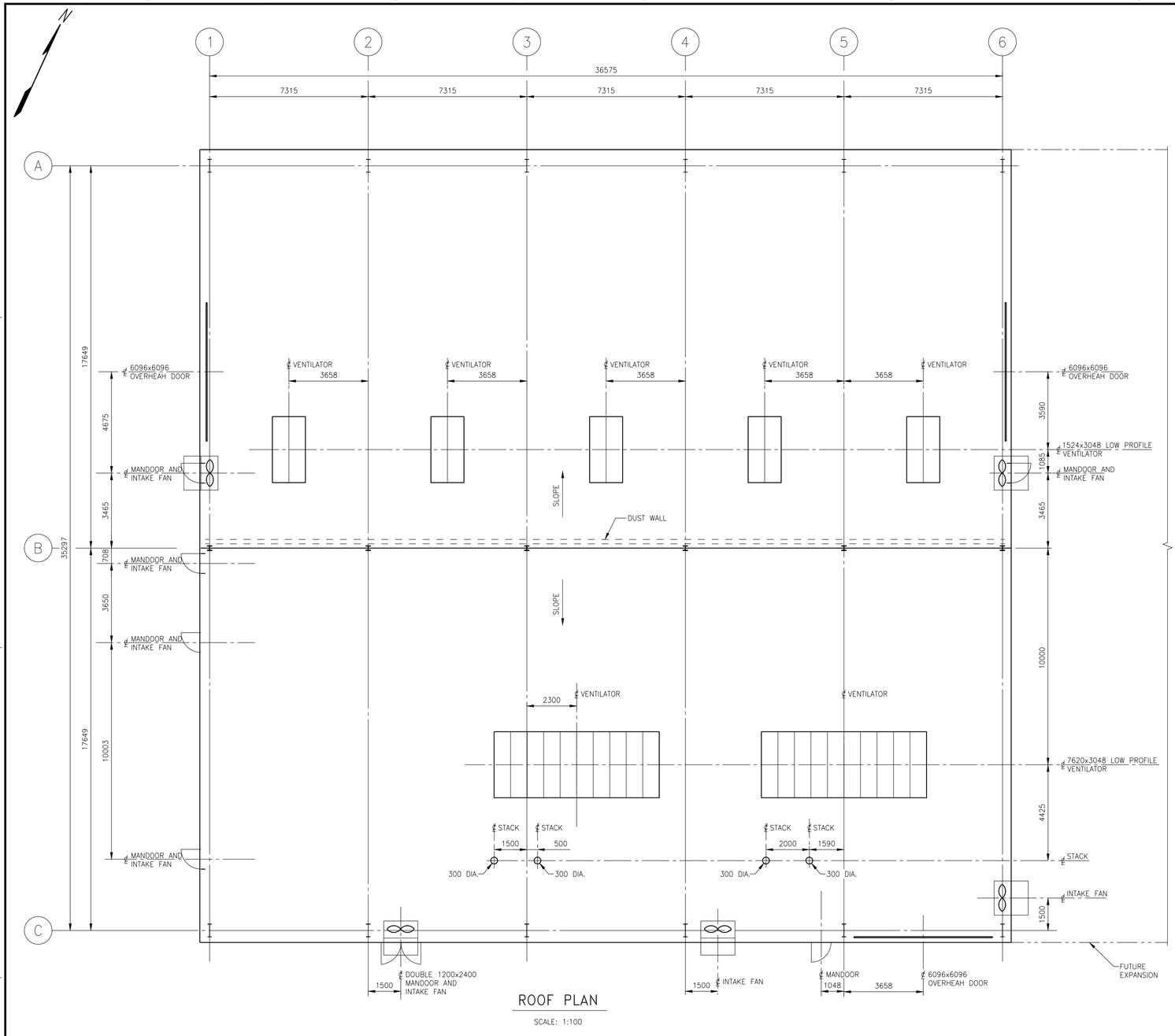

ROOF PLAN

SCALE: 1:100

NOTES:

1. FOR BUDGET PRICING, USE SUPPLIER'S STANDARD BUILDING PACKAGE SPECIFICATIONS.
2. BUILDING SUPPLY TO INCLUDE:
   A. ALL STRUCTURAL AND MISCELLANEOUS STEEL COLUMNS, ROOF BEAMS, PURLINS, GIRTS, SAG RODS, BRACING AND TIES, FRAMED OPENINGS AND EDGE ANGLES.
   B. COLUMN ANCHORAGE, ALTHOUGH THERE WILL BE A 1200 DADO WALL (BY OTHERS) COLUMNS WILL BE FOUNDED AT SLAB LEVEL (EL. 100).
   C. METAL ROOF, COMPLETE WITH INSULATION (R50) FLASHING AND TRIM.
   D. METAL WALL PANEL, COMPLETE WITH INSULATION (R30) FLASHING AND TRIM. UNINSULATED METAL DUST WALL (COMPLETE WITH GIRTS) WILL BE REQUIRED ADJACENT TO COL LINE B
   E. ALL DOORS (MANDOORS 900x2100 NOMINAL) EXCEPT WHERE NOTED).
   F. WEATHER HOODS AT FANS (1500 WIDE x 1000 PROJECTIONS). FANS WILL BE SUPPLIED BY MECHANICAL CONTRACTOR.
   G. ROOF-TOP VENTILATORS.
3. PROVIDE SEPARATE DELIVERY PRICE FOR HAINES JUNCTION, YUKON.
4. FRAME ON LINE 6 TO BE DESIGNED FOR FUTURE EXPANSION TO EAST (7315 BAY)

REFERENCE DRAWINGS

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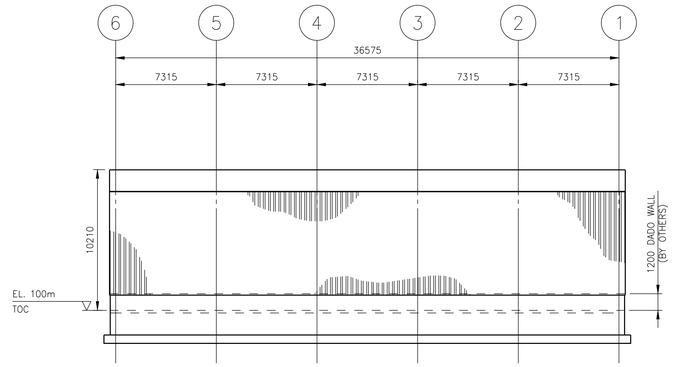
YUKON BIOENERGY DEMONSTRATION PROJECT

BUILDING FINISHES
ROOF PLAN

JOB No.	DWG. No.	REV
133545658	D-2001	A

NOTES:

1. SEE DRAWING D-2001 FOR NOTES



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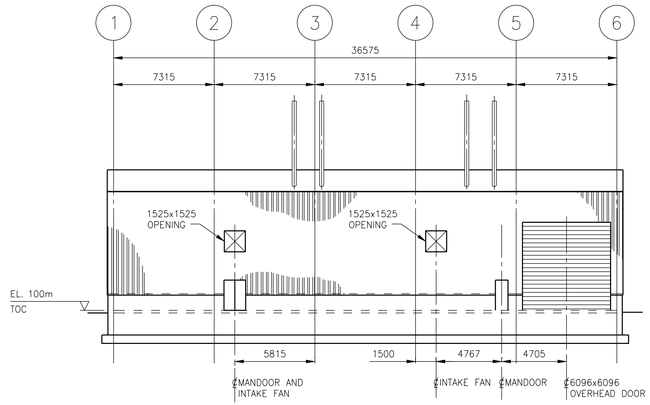

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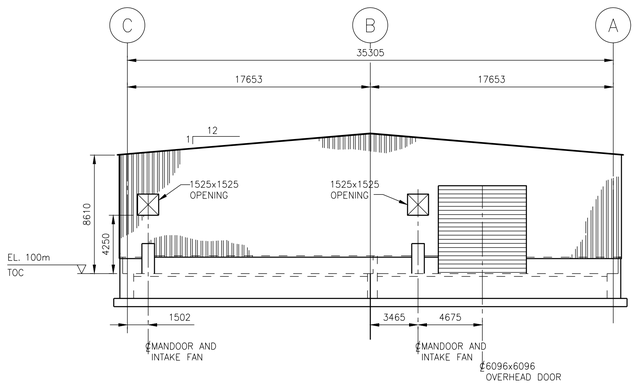

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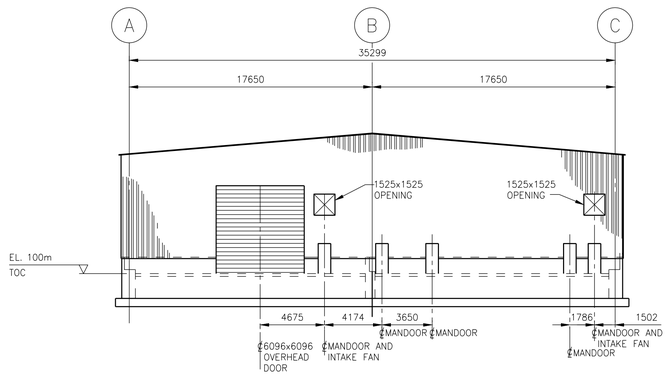

WEST ELEVATION

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YUKON BIOENERGY DEMONSTRATION PROJECT

BUILDING FINISHES
BUILDING ELEVATIONS
–
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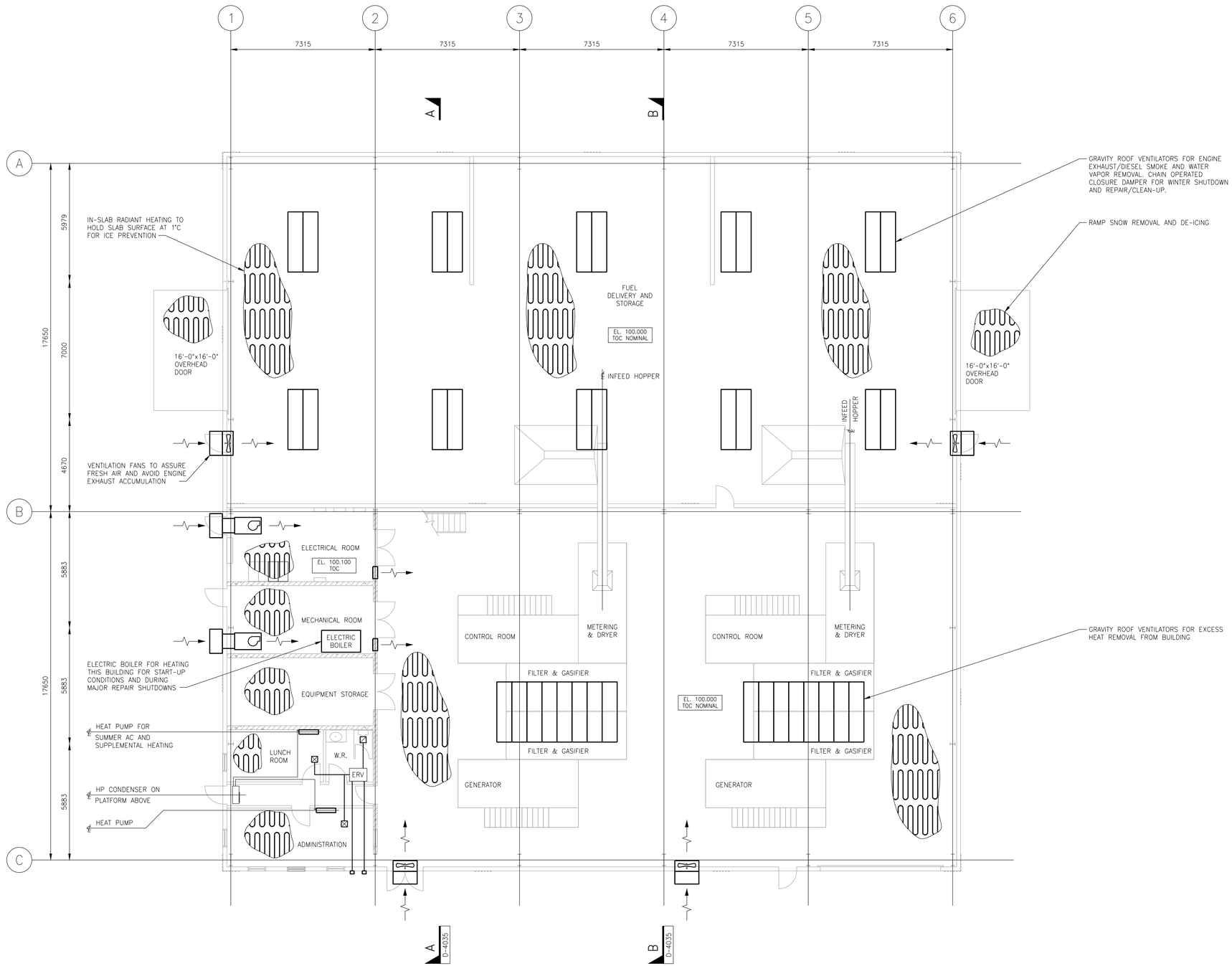

PLAN AT EL. 100.000 TOC (UNO)

SCALE: N.T.S.

REFERENCE DRAWINGS

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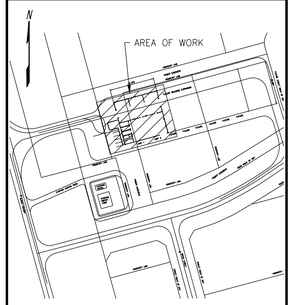

KEY PLAN

NOTES:

1. IN SLAB RADIANT HEAT SOURCE IS LOW GRADE DISTRICT HEATING RETURN WATER TO INCREASE RECOVERED HEAT EFFICIENCY.
2. HEAT REJECTION OF PLANT WHEN DISTRICT HEATING LOAD IS OFF TO BE DEVELOPED FURTHER DURING EQUIPMENT SELECTION. (RADIATOR DIRECTED VERTICALLY TO VENT THROUGH GRAVITY ROOF VENTS?)

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
B	OCTOBER 18, 2013 CLIENT	FINAL REPORT
A	FEBRUARY 01, 2013 CLIENT	INFORMATION

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No.	DATE	BY	REVISIONS	DES.	DFTG.

DESIGNED KJC	DRAWN BCF
CHECKED DESIGN / DFTG.	DATE OCT. 17, 2013
	SCALE N.T.S.
APPROVED	SPEC.
P.M. CGV / P.T. __	

Stantec

YUKON BIOENERGY DEMONSTRATION PROJECT

HVAC CONCEPTUAL DIAGRAM
PLAN
OPTION 1
UNITS IN BUILDING

JOB No.	DWG. No.	REV.
133545658	D-4031	B

Oct 18, 2013 3:22pm dgillies

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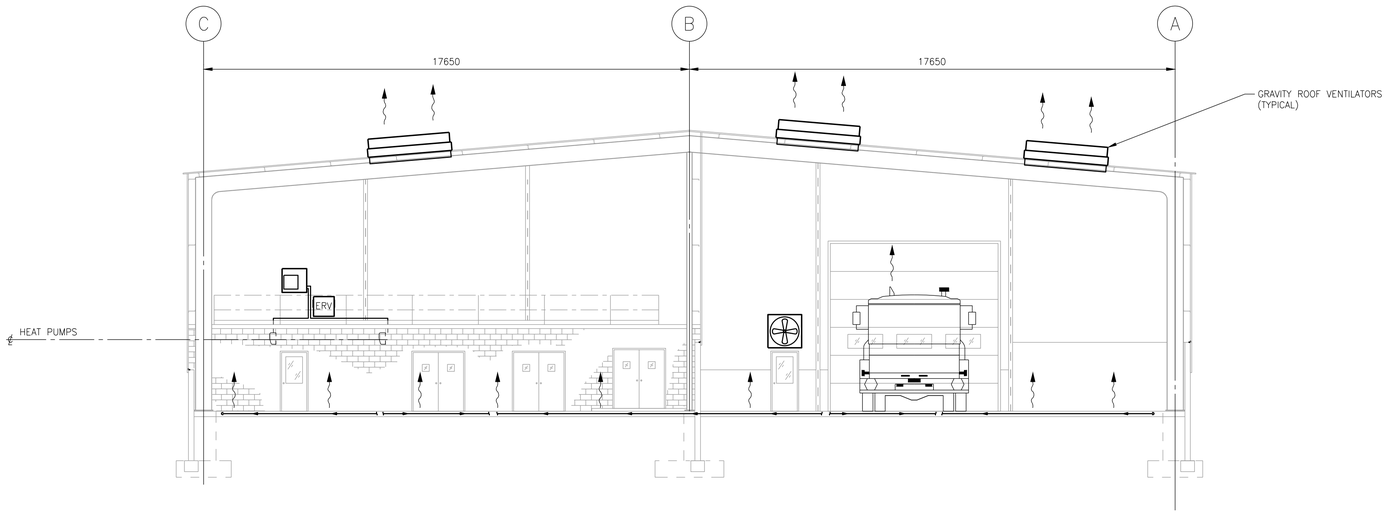
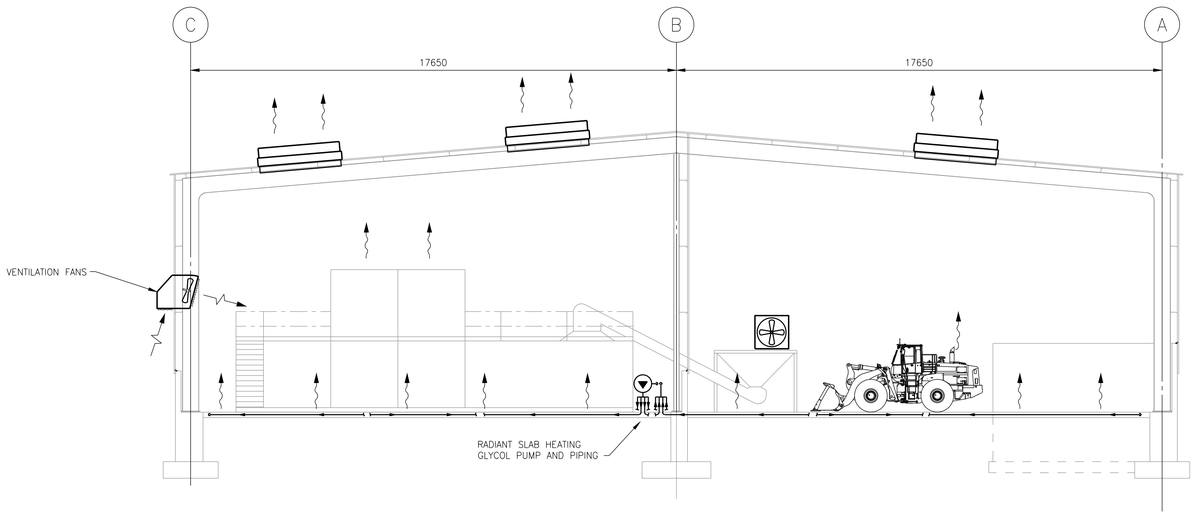


SECTION A
SCALE: N.T.S.
REF. DWG.D-4031
D-4035



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REF. DWG. D-4031
D-4035

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DWG. No.	TITLE	BY
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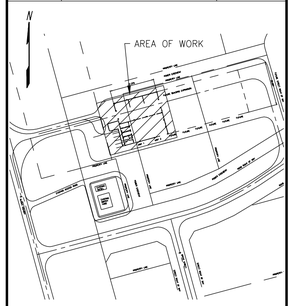

KEY PLAN

PRELIMINARY
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A	FEBRUARY 01, 2013 CLIENT	INFORMATION

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	SCALE N.T.S.
APPROVED	SPEC.
P.M. CGV	P.T. __

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YUKON BIOENERGY DEMONSTRATION PROJECT

HVAC CONCEPTUAL DIAGRAM
SECTION
OPTION 1
UNITS IN BUILDING

JOB No.	DWG. No.	REV
133545658	D-4035	B

Oct 18, 2013 3:23pm dgillies

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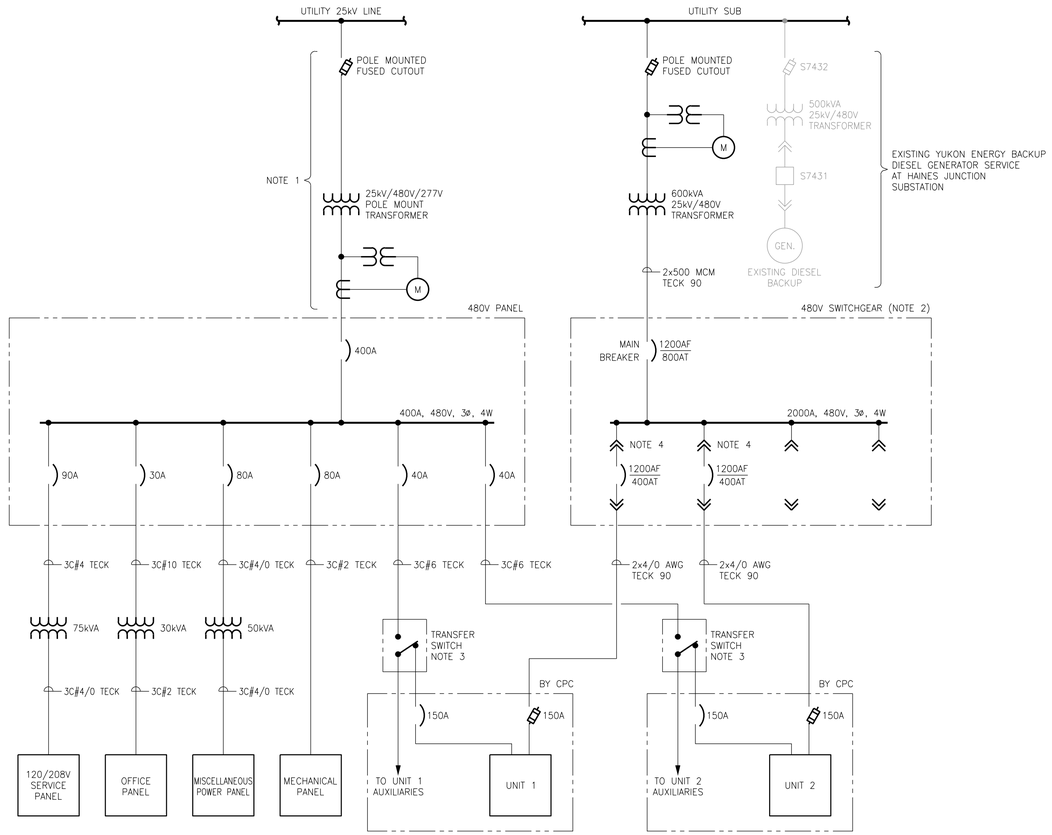

REFERENCE DRAWINGS

DWG. No.	TITLE	BY

NOTES:

1. UTILITY TO PROVIDE SERVICE ENTRANCE TO BUILDING COMPLETE WITH POLE MOUNTED TRANSFORMER, FUSED CUTOUTS AND METERING. THIS WILL PROVIDE INDEPENDENT POWER TO THE BUILDING AND PROVIDE BACKUP TO THE GENERATOR AUXILIARIES.
2. 480V SWITCHGEAR USED TO PARALLEL THE GENERATOR OUTPUTS SHALL HAVE A MAIN BREAKER, 2 UNIT BREAKERS AND 2 PREPARED SPACES.
3. MANUAL TRANSFER SWITCHES SHALL BE USED TO SWITCH BETWEEN SELF-GENERATED AUXILIARY POWER OR UTILITY SUPPLIED AUXILIARY POWER.
4. INTERLOCK CONTROL LOGIC SHALL BE IMPLEMENTED BETWEEN SWITCHGEAR BREAKERS AND THEIR CORRESPONDING UNIT GENERATOR TO PREVENT UNIT OPERATION ON AN OPEN BUS.

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B	OCTOBER 18, 2013 CLIENT	FINAL REPORT
A	FEBRUARY 01, 2013 CLIENT	INFORMATION

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APPROVED	SPEC.
P.M. CGV / P.T. __	

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YUKON BIOENERGY DEMONSTRATION PROJECT

YUKON ENERGY
SINGLE LINE

JOB No.	DWG. No.	REV.
133545658	D-5700	B

Oct 18, 2013 3:27pm dgillies

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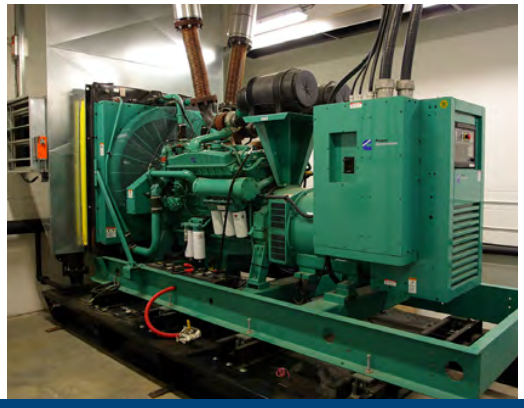
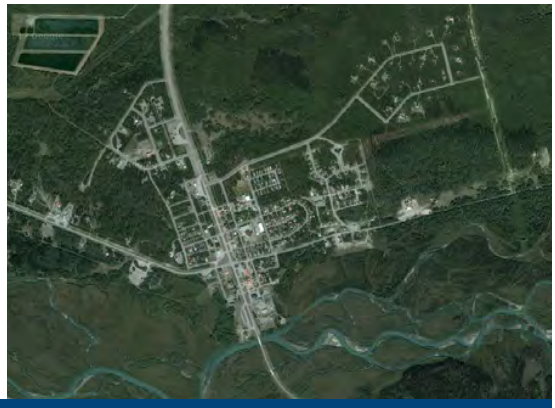
Client: **Yukon Energy**
Project: **Haines Junction BioEnergy Demonstration**
Project No: **133545658**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary OPTION 1

Prepared by: **TEAM**
Date: **March 6, 2013**
Revision No.: **0**
Issue Date: **March 4, 2013**
Checked:

Area	Line	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	1	**PROJECT TOTAL, BASE SCOPE**						**$12,727,154**
-	2	Civil - Structural	00 hrs	$562,428	$1,001,238	$195,250	$1,235,200	$3,528,066
-	3	Mechanical & HVAC	1,532 hrs	$168,520	$199,500	$5,205,000	$192,476	$5,765,496
-	4	Electrical	3,373 hrs	$371,089	$172,531	$238,465	$74,197	$856,282
-	5	**Sub Total**	**4,905 hrs**	**$1,102,037**	**$1,373,269**	**$5,638,715**	**$1,501,873**	**$10,149,844**
-	6	Preliminary Engineering @ 3% (Class III Estimate)						$152,647.33
-	7	Detail Engineering @ 10% Direct Construction Cost						$508,824.42
-	8	Construction Management @ 2.5% Direct Construction Cost						$127,206.11
-	9	Site Construction Support by Engineering @ 1% Direct Construction Cost						$50,882.44
-	10	Commissioning Costs @ 1.5%						$76,323.66
-	11	Escalation Allowance @ 5%						$254,412.21
-	12	Capital Spares - 5% of CPC equipment cost						$250,000
-	13	**Sub Total**						**$11,570,140**
-	14	Contingency @ 10%						$1,157,014.04





APPENDIX E

Architectural Upgrade - Option #2

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

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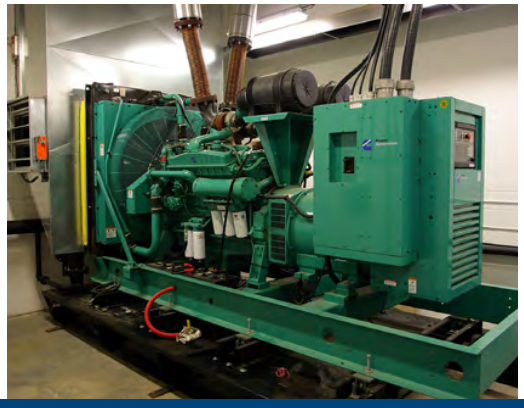
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.

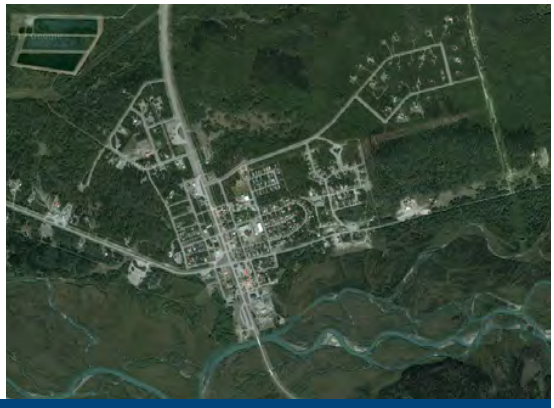
Client: **Yukon Energy**
Project: **Haines Junction BioEnergy Demonstration**
Project No: **133545658**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary OPTION 2

Prepared by: **TEAM**
Date: **March 6, 2013**
Revision No.: **1**
Issue Date: **March 4, 2013**
Checked:

Area	Line	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	1	**PROJECT TOTAL, BASE SCOPE**						**$13,494,160**
-	2	Civil - Structural	00 hrs	$617,073	$1,094,838	$203,150	$1,631,800	$4,094,958
-	3	Mechanical & HVAC	1,532 hrs	$168,520	$199,500	$5,205,000	$192,476	$5,765,496
-	4	Electrical	3,373 hrs	$371,089	$172,531	$238,465	$74,197	$856,282
-	5	**Sub Total**	**4,905 hrs**	**$1,156,682**	**$1,466,869**	**$5,646,615**	**$1,898,473**	**$10,716,737**
-	6	Preliminary Engineering @ 3% (Class III Estimate)						$169,654.10
-	7	Detail Engineering @ 10% Direct Construction Cost						$565,513.66
-	8	Construction Management @ 2.5% Direct Construction Cost						$141,378.41
-	9	Site Construction Support by Engineering @ 1% Direct Construction Cost						$56,551.37
-	10	Commissioning Costs @ 1.5%						$84,827.05
-	11	Escalation Allowance @ 5%						$282,756.83
-	12	Capital Spares - 5% of CPC equipment cost						$250,000
-	13	**Sub Total**						**$12,267,418**
-	14	Contingency @ 10%						$1,226,741.80





APPENDIX F

Basis of Estimate - Option #3

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

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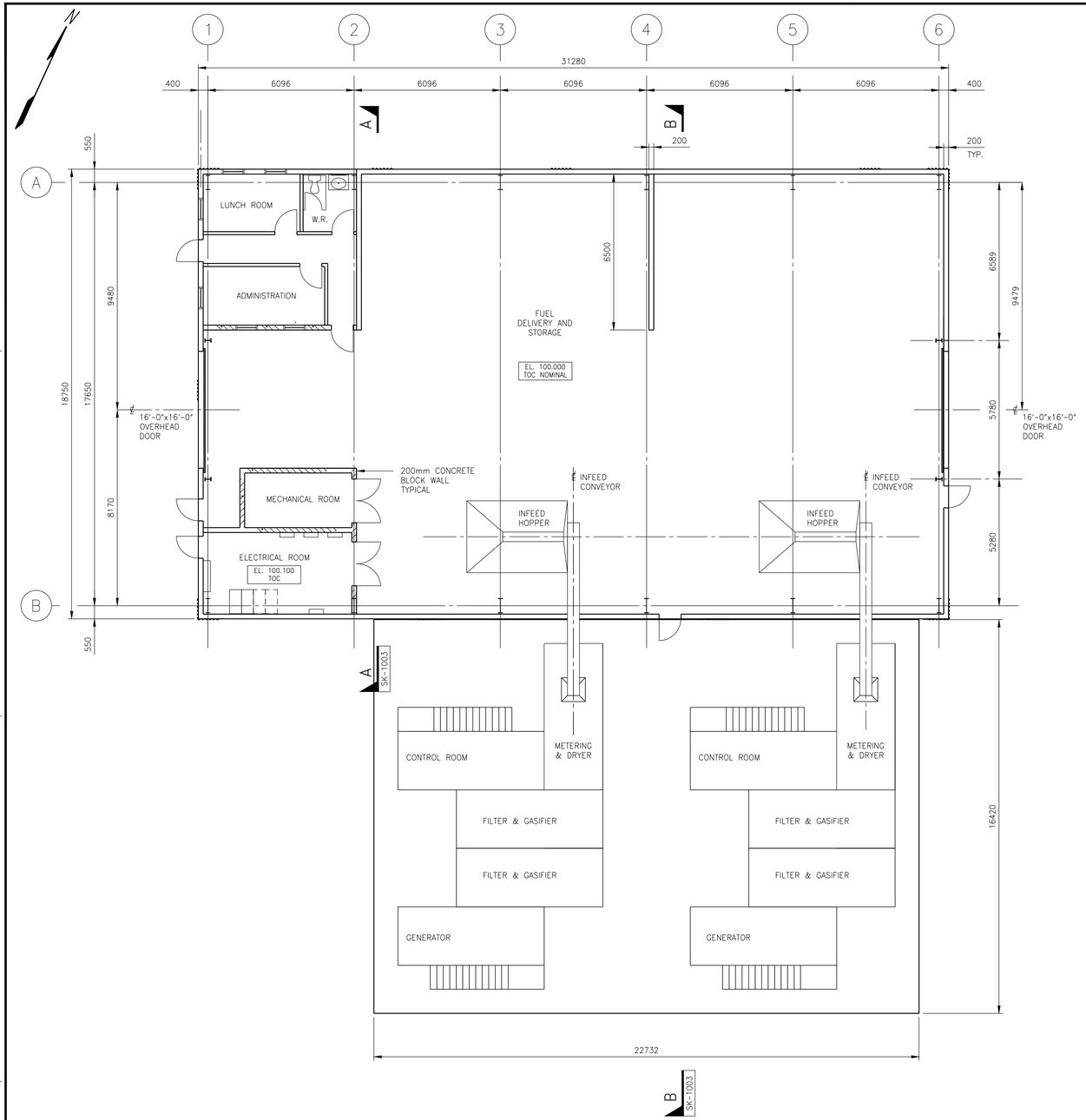

PLAN AT EL. 100.000 TOC (UNO)

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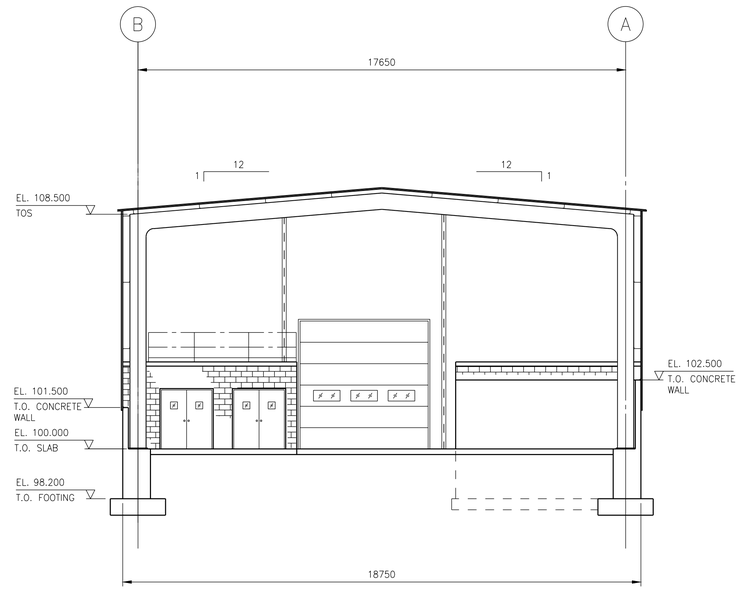
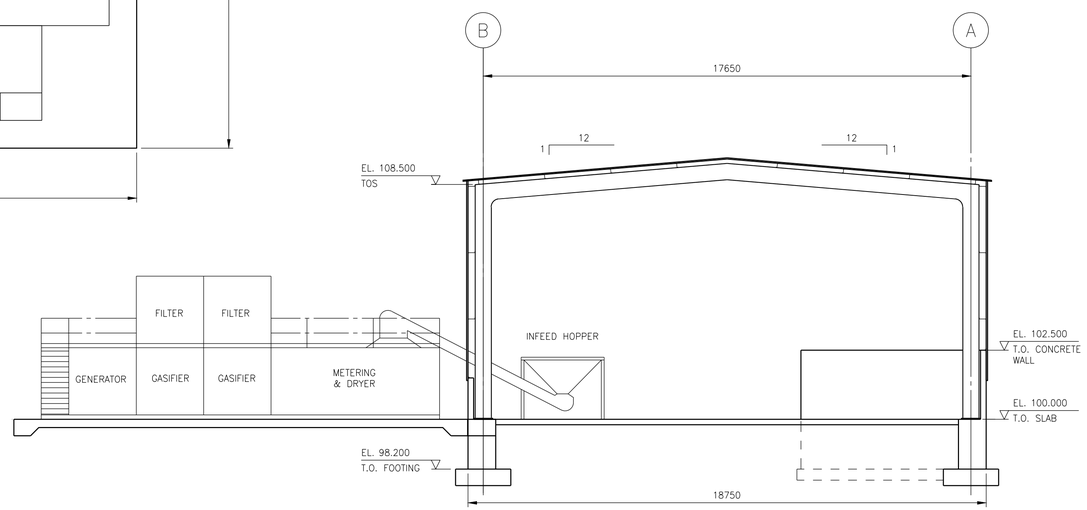


SECTION A

SCALE: 1:100

REF. DWG. SK-1003



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SCALE: 1:100

REF. DWG. SK-1003

REFERENCE DRAWINGS

DWG. No.	TITLE	BY

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CHECKED	DATE OCT. 17, 2013
DESIGN / DFTG.	SCALE 1:100
APPROVED	SPEC.
P.M. CGV	P.T. __

Stantec

YUKON BIOENERGY DEMONSTRATION PROJECT

GENERAL ARRANGEMENT
PLAN AND SECTIONS
OPTION 2
UNITS OUTDOORS

JOB No.	DWG. No.	REV
133545658	D-1003	A

Oct 18, 2013 3:16pm daillies

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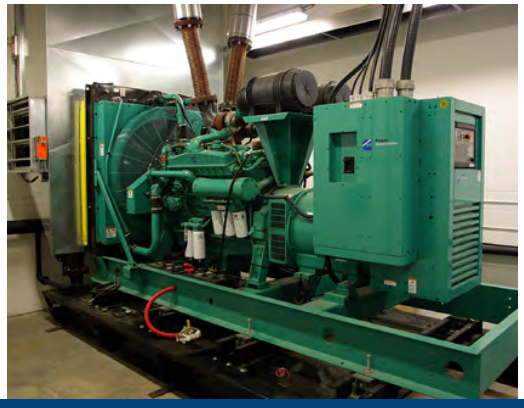
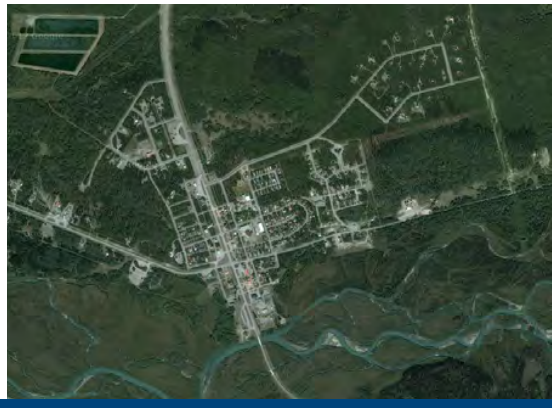
Client: **Yukon Energy**
Project: **Haines Junction BioEnergy Demonstration**
Project No: **133545658**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary OPTION 3

Prepared by: **TEAM**
Date: **March 4, 2013**
Revision No.: **1**
Issue Date: **March 4, 2013**
Checked:

Area	Line	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	1	**PROJECT TOTAL, BASE SCOPE**						**$11,402,782**
-	2	Civil - Structural	00 hrs	$399,213	$714,346	$167,750	$846,626	$2,624,934
-	3	Mechanical & HVAC	1,869 hrs	$205,634	$117,600	$5,204,000	$84,301	$5,611,535
-	4	Electrical	4,229 hrs	$463,036	$151,271	$238,235	$85,447	$937,990
-	5	**Sub Total**	**6,099 hrs**	**$1,067,883**	**$983,217**	**$5,609,985**	**$1,016,374**	**$9,174,458**
-	8	Preliminary Engineering @ 3% (Class III Estimate)						$122,831.35
-	9	Detail Engineering @ 10% Direct Construction Cost						$409,437.84
-	10	Construction Management @ 2.5% Direct Construction Cost						$102,359.46
-	9	Site Construction Support by Engineering @ 1% Direct Construction Cost						$40,943.78
-	11	Commissioning Costs @1.5%						$61,415.68
-	13	Escalation Allowance @ 5%						$204,718.92
-	14	Capital Spares - 5% of CPC equipment cost						$250,000
-	15	**Sub Total**						**$10,366,165**
-	16	Contingency @ 10%						$1,036,616.54





APPENDIX G

500 kWe Expansion - Option #4

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

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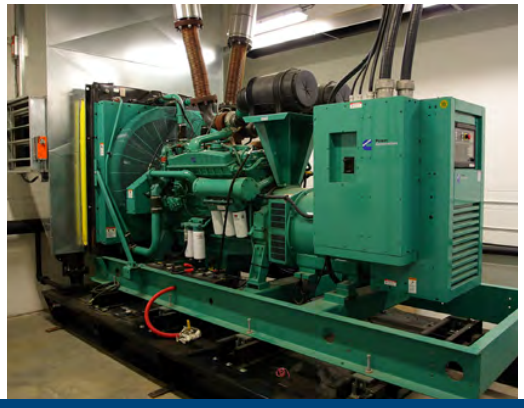
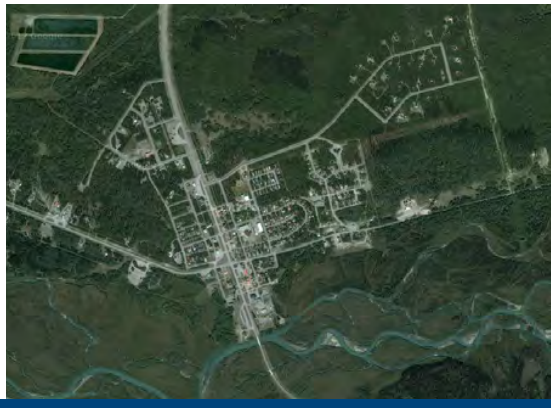
Client: **Yukon Energy**
Project: **Haines Junction BioEnergy Demonstration**
Project No: **133545658**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary OPTION 4 Expa
4 X 250kW Units

Prepared by: **TEAM**
Date: **March 6, 2013**
Revision No.: **1**
Issue Date: **March 4, 2013**
Checked:

Area	Line	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	1	**PROJECT TOTAL, BASE SCOPE**						**$22,484,173**
-	2	Civil - Structural	00 hrs	$648,841	$1,226,438	$229,250	$1,390,000	$4,703,094
-	3	Mechanical & HVAC	3,715 hrs	$408,694	$376,500	$10,210,000	$302,428	$11,297,622
-	4	Electrical	5,983 hrs	$658,369	$283,829	$320,748	$101,033	$1,363,979
-	5	**Sub Total**	**9,699 hrs**	**$1,715,905**	**$1,886,767**	**$10,759,998**	**$1,793,461**	**$17,364,695**
-	6	Preliminary Engineering @ 3% (Class III Estimate)						$368,538.46
-	7	Detail Engineering @ 10% Direct Construction Cost						$1,228,461.54
-	8	Construction Management @ 2.5% Direct Construction Cost						$307,115.39
-	9	Site Construction Support by Engineering @ 1% Direct Construction Cost						$122,846.15
-	10	Commissioning Costs @ 1.5%						$184,269.23
-	11	Escalation Allowance @ 5%						$614,230.77
-	12	Capital Spares - 5% of CPC equipment cost						$250,000
-	13	**Sub Total**						**$20,440,157**
-	14	Contingency @ 10%						$2,044,016





APPENDIX H

Impact Assessment

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

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DRAFT FOR
NRCAN SUBMISSION

Environmental and Socioeconomic Impact Assessment (EIA): Haines Junction Biomass Energy Project

Prepared for:

Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Prepared by:

Stantec Consulting Ltd.
845 Prospect Street
Fredericton, NB E3B 2T7

Project No. 133545658
May 24, 2013

EXECUTIVE SUMMARY

Project Overview

The Project considered in this assessment is a 0.5 MW to 2 MW biomass energy plant located in Haines Junction, Yukon Territories. The plant would generate electrical power which would be supplied to the grid as well as thermal energy which would be used to heat local buildings. The plant would be primarily fueled by beetle killed wood to be harvested from areas within approximately 50 to 70 km. This assessment was drafted in consideration of preliminary information available based on the Front End Engineering Design Study which included a preliminary feedstock harvesting study. The objective of the draft assessment is to establish the scope of assessment for the Project and provide preliminary findings on potential environmental and socio-economic effects associated with the plant for use in the decision making process by the Project steering committee. Further development of this assessment will occur if a go decision is made on the Project with the final objective of providing a complete proposal to the Yukon Environmental and Socio-economic Assessment Board (YESAB). In particular, detailed assessment of forest harvesting has not been completed as details of these activities have not yet been fully defined.

Project Description and Schedule

The Proponents of the Project are Yukon Energy Corporation (YEC) and Champagne and Aishihik First Nations (CAFN). A number of other partners have been instrumental in the development of the Project.

Regulatory and Policy Context

The Project will require a *Yukon Environmental and Socio-economic Assessment Act* (*YESAA*) submission although the level of assessment may be different depending on the scale of project to be registered. This is discussed in the strategy section of the FEED Study for consideration by the steering committee.

First Nations and Community Consultation

A summary of the First Nations and Community Consultation Plan is provided in Chapter 2.0 of this assessment. To date, one open house has been held. Questions and feedback from this event indicate that there is support for the Project in the community and that the scope of studies planned should address community issues and concerns.

Effects Assessment

The assessment of potential effects has been completed based on expected effects from this Project, desktop literature review and in consideration of initial consultation with First Nations and the public on their interests and values. Valued Components (VCs) have been identified for environmental and socio-economic aspects and baseline conditions have been established based on desktop literature review and consultation. Preliminary findings for each VC have been developed in consideration of the plant operation and will require updates once the Project location and infrastructure are finalized. Updates will also include a more detailed assessment of feedstock harvesting activities.

The Atmospheric Environment has been identified as a VC and defined to include air quality, sound quality and greenhouse gas (GHG) emissions. In consideration of existing conditions and estimated Project emissions of air contaminants, ambient air quality is expected to remain well below regulatory objectives during operation of the plant. Annoyance from noise is not expected to be caused by the plant if it is located at least 500 m from residences (to avoid sleep disturbance). If the plant is located in a building this distance could be less. Further study is recommended to include confirmatory predictions using vendor information and a baseline sound pressure level survey in the area where the plant will be located. The chipping operation will likely need to be located 500 to 1,000 m from residences and sensitive receptors (such as the school or other areas of frequent land use) to avoid annoyance.

Minimal influence on water resources is expected as the plant will use little to no water (depending on vendor) and should be located at least 30 m away from surface water sources. Feedstock (in chip form) will be stored indoors to avoid siltation to surface water run-off.

Significant environmental effects on vegetation and wildlife are not expected based on the species documented in Haines Junction. Field work will be done as a confirmatory measure once the site is chosen.

Additional consultation is required in relation to traditional ecological knowledge and traditional activities and culture to confirm any constraints that should be considered.

Known and documented heritage resources have been confirmed and will be avoided in locating the plant. A field survey would be conducted prior to initiating any ground breaking activities.

Transportation infrastructure is not expected to be noticeably influenced as a result of the Project. Truck traffic is estimated at 3 to 15 trucks per week to supply feedstock during Operation. Similar or less traffic is expected during Construction.

The Project will require resources for construction and operation, therefore a positive effect on labour and economy is expected. Planning of forest harvesting will include consideration of existing land users to ensure that other land users such as existing harvesters, trappers, outfitters and wilderness tourism are not negatively affected.

Human health and well-being should not be affected by the Project. The plant would be operated within applicable regulations which have been developed to protect human health and well-being.

TABLE OF CONTENTS

EXECUTIVE SUMMARY 1

1.0 INTRODUCTION 1
1.1 PROJECT OVERVIEW 1
1.1.1 Project Purpose 2
1.1.2 Project Benefits 3
1.2 PROPONENT INFORMATION 3
1.2.1 Project Team 3
1.2.2 Policies and Visions on Environmental and Sustainable Development 4
1.3 REQUIRED AUTHORIZATIONS AND REGULATORY APPROVALS 5
1.3.1 *YESAA* Screening Requirements 5
1.3.2 Applicable Legislation, Regulations, and Permits 6

2.0 FIRST NATIONS, OTHER GOVERNMENT AND COMMUNITY CONSULTATIONS 11
2.1 CONSULTATION REQUIREMENTS 11
2.2 CONSULTATION OVERVIEW AND APPROACH 11
2.3 PUBLIC CONSULTATION PLAN 12
2.4 CONSULTATION TECHNIQUES 13
2.5 KEY CONCERNS RAISED DURING CONSULTATION 14
2.6 KEY CONCERNS ANALYSIS 15

3.0 PROJECT DESCRIPTION 16
3.1 PROJECT LOCATION 16
3.1.1 Local Climate 16
3.1.2 Study Area Boundaries 16
3.1.3 Village Services 16
3.1.4 Traditional Territory 21
3.1.5 Yukon Land Use Planning Region 21
3.1.6 Consistency with Other Plans 22
3.2 PROJECT INFRASTRUCTURE AND TECHNOLOGY 22
3.2.1 Gasifier and Engine Technology 22
3.2.2 Waste Heat Uses 26
3.2.3 Fuel Harvesting and Handling 28
3.2.4 Auxiliary Infrastructure 28
3.3 EMISSIONS AND WASTES 30
3.3.1 Air Contaminant and GHG Emissions 30
3.3.2 Sound Emissions 32
3.3.3 Construction and Operational Solid Wastes 32
3.4 PROJECT PHASES AND SCHEDULING 32
3.5 ALTERNATIVES 33

4.0 DESCRIPTION OF EXISTING ENVIRONMENTAL AND SOCIO-ECONOMIC CONDITIONS 34
4.1 ENVIRONMENTAL CONDITIONS 34
4.1.1 Study Area and Physiography 34
4.1.2 Surficial Geology, Terrain, and Soils 34
4.1.3 Transportation 35
4.1.4 Groundwater Resources 35

4.1.5 Traditional Ecological Knowledge 35
4.1.6 Additional Existing Conditions 36
4.2 SOCIO-ECONOMIC CONDITIONS 36
4.2.1 Champagne Aishihik First Nation 36
4.2.2 Labour and Economy 36
4.2.3 Public Health and Well-being 37
4.2.4 Land Use and Infrastructure 37

5.0 ENVIRONMENTAL AND SOCIO-ECONOMIC EFFECTS ASSESSMENT 38
5.1 ASSESSMENT APPROACH 38
5.1.1 Valued Environmental and Socio-Economic Components 38
5.1.2 Project Interactions with the Bio-Physical and Human Environment 44
5.1.3 Description of Effects Mechanisms 44
5.1.4 Temporal and Spatial Boundaries 44
5.1.5 Mitigation of Project Effects 45
5.1.6 Characterization of Residual Effects 45
5.1.7 Determination of Significance of Residual Effects 46
5.1.8 Project Interactions with Other Projects (Cumulative Effects) 46
5.1.9 Cumulative Effects Assessment Methods 46
5.1.10 Mitigation of Cumulative Effects 46
5.1.11 Characterization of Residual Cumulative Effects 46
5.1.12 Effects Monitoring and Adaptive Management 46
5.2 ATMOSPHERIC ENVIRONMENT 47
5.2.1 Scope of the Assessment 48
5.2.2 VC Existing Conditions 54
5.2.3 Potential Project VC Interactions 57
5.2.4 Assessment of Cumulative Effects 73
5.2.5 Determination of Significance 74
5.2.6 Summary Consultation Influence on the Assessment 75
5.2.7 Effects Monitoring and Adaptive Management 75
5.3 TERRESTRIAL ENVIRONMENT 77
5.3.1 Scope of the Assessment 77
5.3.2 VC Existing Conditions 83
5.3.3 Potential Project VC Interactions 89
5.3.4 Assessment of Cumulative Effects 98
5.3.5 Determination of Significance 99
5.3.6 Summary Consultation Influence on the Assessment 99
5.3.7 Effects Monitoring and Adaptive Management 100
5.4 FRESHWATER RESOURCES 100
5.4.1 Scope of the Assessment 100
5.4.2 Existing Conditions 100
5.4.3 Regulatory/Policy Setting 103
5.4.4 Key Issues and Identification of Effects 105
5.4.5 Mitigation Measures 105
5.4.6 Summary Consultation Influence on the Assessment 105
5.4.7 Effects Monitoring and Adaptive Management 106
5.5 HERITAGE RESOURCES 106
5.5.1 Scope of the Assessment 106
5.5.2 VC Existing Conditions 111
5.5.3 Potential Project VC Interactions 121

5.5.4 Assessment of Cumulative Effects 128
5.6 TRADITIONAL ACTIVITIES AND CULTURE 129
5.6.1 Scope of the Assessment 129
5.6.2 VC Existing Conditions 131
5.6.3 Potential Project VC Interactions 132

6.0 ASSESSMENT OF EFFECTS OF ACCIDENTS AND MALFUNCTIONS 135

7.0 EFFECTS OF THE ENVIRONMENT ON THE PROJECT 136
7.1.1 Influence of Consultation on the Assessment 136
7.1.2 Potential Effects on the Project 136
7.1.3 Extreme Weather Events 137
7.1.4 Forest Fire 137
7.1.5 Climate Change 138

8.0 SUMMARY OF SIGNIFICANCE 139
8.1.1 Accidents and Malfunctions ..... **Error! Bookmark not defined.**

9.0 REFERENCES 141

LIST OF TABLES

Table 1.3.1 Bioenergy Facility Regulatory Requirements 7
Table 1.3.2 Feedstock Harvesting Regulatory Requirements 9
Table 2.3.1 Consultation Levels 12
Table 2.4.1 Consultation Events To-Date 14
Table 3.3.1 Estimated Emissions During Operation of the Project 31
Table 5.1.1 Potential Interactions of the Project with the Environment 39
Table 5.2.1 Ambient Air Quality Standards and Objectives 50
Table 5.2.2 Measurable Parameters for Atmospheric Environment 52
Table 5.2.3 Estimated Existing Space Heating Emissions – Haines Junction 56
Table 5.2.4 Potential Project Environmental Effects to the Atmospheric Environment 57
Table 5.2.5 Summary of Residual Project-Related Environmental Effects on the Atmospheric Environment 59
Table 5.2.6 Model Inputs – Source Parameters 65
Table 5.2.7 Model Inputs – Air Contaminant Emission Rates 66
Table 5.2.8 Ambient Background CAC Concentrations Used for Modelling 67
Table 5.2.9 Maximum Predicted Ground-level Concentrations – Scenario 1 68
Table 5.2.10 Maximum Predicted Ground-level Concentrations – Scenario 2 68
Table 5.2.11 Maximum Predicted Ground-level Concentrations – Scenario 3 69
Table 5.2.12 Potential Cumulative Environmental Effects to the Atmospheric Environment 73
Table 5.3.1 Measurable Parameters for Terrestrial Environment 79
Table 5.3.2 Highly Invasive Plant Species in Yukon Territory 84
Table 5.3.3 Additional Wildlife Species at Risk and Species of Conservation Concern in Yukon Territory 87
Table 5.3.4 Potential Project Environmental Effects to the Terrestrial Environment 89

Table 5.3.5 Summary of Residual Project-Related Environmental Effects on the Vegetation and Wetland Resources 92
Table 5.3.6 Potential Cumulative Environmental Effects to the Terrestrial Environment 98
Table 5.4.1 Freshwater Fish Species in Yukon Territory 100
Table 5.4.2 Fish Species Found within the Alsek River Basin, Yukon Territory 103
Table 5.5.1 Measurable Parameters for Heritage Resources, Traditional Activities and Culture 110
Table 5.5.2 Potential Project Environmental Effects to the Heritage Resources 121
Table 5.5.3 Summary of Residual Project-Related Environmental Effects on the Heritage Resources, Traditional Activities and Culture 123
Table 5.6.1 Measurable Parameters for Traditional Activities and Culture 130
Table 5.6.2 Potential Project Environmental Effects to Traditional Activities and Culture 132

LIST OF FIGURES

Figure 3.1.1 Project Location 17
Figure 3.1.2 Preliminary Range of Sites for Waste Heat Use 19
Figure 3.2.1 Simplified Block Diagram of a Gasification System 23
Figure 3.2.2 SFMP Landscape Units and Resource Management Zones 29
Figure 3.4.1 Project Phases and Schedule 33
Figure 5.2.1 Maximum Predicted 1-hour Nitrogen Dioxide Ground-level Concentrations – Scenario 1 70
Figure 5.2.2 Maximum Predicted 1-hour Nitrogen Dioxide Ground-level Concentrations – Scenario 2 71
Figure 5.2.3 Maximum Predicted 1-hour Nitrogen Dioxide Ground-level Concentrations – Scenario 3 72
Figure 5.3.1 Terrestrial Environment 85
Figure 5.5.1 Champagne and Aishihik First Nations Traditional Territory 113
Figure 5.5.2 Historic Sites and Structures 119

1.0 INTRODUCTION

The Project considered in this assessment is a 0.5 MW to 2 MW biomass energy plant located in Haines Junction, Yukon Territories. The plant would generate electrical power which would be supplied to the grid as well as thermal energy which would be used to heat local buildings. The plant would be primarily fueled by beetle-killed wood to be harvested from areas within approximately 50 to 70 km.

1.1 PROJECT OVERVIEW

The Champagne and Aishihik First Nations (CAFN), the Dakwakada Development Corporation, Yukon Energy Corporation Cold Climate Innovation of the Yukon Research Centre, and the Village of Haines Junction are investigating the potential for a biomass fuelled energy plant in the community of Haines Junction, Yukon Territories (herein referred to as "the Project"). The plant would provide some much-needed renewable electricity for the territory as well as building heating for one or more buildings in Haines Junction via the waste heat from the power plant exhaust gases. Use of combined heat and power technology will maximize the efficiency of the process and use of the renewable resource. Currently the size of the facility is still under consideration with 0.5 MW to 2 MW electrical output being reviewed. There is potential to start with a small demonstration type project of 0.5 MW, gain operating experience and potentially proceed with expansion of the site up to 2 MW as local expertise is developed. The long term vision of the Project Team includes diverse options including further district heating which could include a greenhouse project utilizing waste heat that could supply regional need for vegetables and decrease local reliance on the Alaska Highway for food transport. The production of renewable energy plus the added benefits of increased forest resource use and possible agricultural use could create additional employment opportunities for the local community and help the region become more self-sufficient.

The Project described and assessed herein is based on preliminary information available at the Front End Engineering and Design (FEED) stage and includes the following primary components:

- construction and operation of a 0.5 MW to 2 MW bioenergy plant using gasification and reciprocating engine technology, located in Haines Junction; and
- fuel processing and handling equipment to be located at or nearby the bioenergy plant (sufficient to process approximately 10,000 to 40,000 m^3 biomass annually).

The power and waste heat transmission linear infrastructures are not assessed in detail as the final locations for this infrastructure are not available at the front end engineering design (FEED) stage. It is currently anticipated that waste heat from electrical generation would be used to heat the Haines Junction School and possibly other buildings, depending on the size of unit selected.

The activities associated with forest feedstock harvesting are presented at a high level in this report; however, site specific environmental assessment is beyond the scope of this assessment. Recommendations for further study and assessment are noted where identified by the environmental assessment team. Follow-up and monitoring are identified based on the information available during the FEED stage of the Project.

1.1.1 Project Purpose

The purpose of the Project is to install and operate a bioenergy plant to increase the use of local biomass as a fuel and to support energy security and the local forest industry. Local agriculture may also be developed in the form of greenhouses that are heated by using the waste heat from the biomass plant. Biomass is a locally available, renewable resource. It is considered an economical choice in the Yukon Territory by Yukon Energy, and is alignment with Yukon Government policies including the Yukon Energy Strategy and the Yukon Climate Change Action Plan. The forests surrounding Haines Junction incurred substantive levels of spruce beetle kill in the 1990's and those areas are the primary targeted feedstock for this Project. The shelf life of that wood is not currently well understood however it is currently considered by some to be a major forest fire threat and has been shown to be suitable fuel for the technology proposed for this Project.

Biomass or wood based fuels are considered greenhouse gas or carbon neutral (are not considered to contribute to increased GHGs in the atmosphere). This is because trees and other vegetation sequester carbon dioxide, a greenhouse gas as they live and grow, and store it until they die and decay, or are harvested and burned. Although burning wood and other biomass produces carbon dioxide, essentially no more is produced through burning than was consumed by the tree as it lived; therefore, as long as new trees are allowed to grow in place of those harvested over the long term, the carbon balance is maintained. The use of biomass along with other forms of renewable energy (such as wind, hydroelectric and solar) are considered key mitigating actions to reduce global GHG emissions.

According to the 2011-12 CAFN Annual Report (CAFN 2012a), the CAFN Council has identified special focus on three pillars: Wellness and Healing; Economic Development; and building vibrant Traditional Culture. This Project would support the pillar of economic development through the creation of facility and forest harvesting related employment opportunities. The CAFN is striving to develop the Project in consideration of traditional culture, wellness and healing as well. CAFN signed a Memorandum of Understanding with the Village of Haines Junction (VOHJ) and Dakwakada Development Corporation (DDC). The CAFN, VOHJ and DDC have a strategic interest in creating a business opportunity to generate electrical energy and provide low cost heating. This Project aligns with the objectives of the Memorandum of Understanding (MOU) which include:

- working together to develop a renewable energy development strategy for CAFN Traditional Territory that respects and reflects economic, environment and community interests;
- promoting an equal relationship that fosters dialogue to assess energy project potential and identification of priorities; and
- enhancing economic opportunities for CAFN in their Traditional Territory.

Members of the CAFN community and members of the public have also voiced a genuine concern for the increasing risk of forest fire in the area due to the large volume of trees killed by the Spruce Bark Beetle, in the area surrounding Haines Junction, as these trees are lower in moisture than green wood. In terms of CAFN's readiness to harvest the forest resources in a strategic fashion, the CAFN has completed a Strategic Forest Management Plan as well as an Integrated Landscape Plan for their Traditional Territories (CAFN 2005, EMR 2006). These documents include assessment of forest

resources, management priorities and guidelines for timber harvest project planning. Therefore, the CAFN is ready from a planning perspective to proceed with responsible execution of additional forest harvesting as required. Through this type of project, the CAFN will have an additional viable use for forest biomass available on their Traditional Territories and will be able to put their planning tools into action. Harvesting priorities include spruce bark beetle-killed areas and areas most sensitive to forest fire or which pose a larger risk of loss in the event of fire (near communities).

1.1.2 Project Benefits

The Project benefits are summarized as follows:

- use of a renewable, Yukon based fuel resource;
- maximizing the energy outputs of the resource through combined heat and electricity generation;
- reducing the local reliance and consumption of fossil fuels (buildings to be heated by the Project currently burn diesel for heating);
- reduction in some emissions of air contaminants through an associated reduction in fossil fuel use for local building heat;
- economic opportunities in Haines Junction associated with plant and forest based jobs; and
- creation of an additional use for forest harvested biomass surrounding Haines Junction.

1.2 PROPONENT INFORMATION

1.2.1 Project Team

The Proponents of the Project include Yukon Energy Corporation (YEC) and Champagne and Aishihik First Nations (CAFN). The current plan for Project ownership is that CAFN would be the majority owner of the Project, likely in partnership with YEC. The ultimate structure of ownership and operational control of the Project is one of the primary tasks of the feasibility studies currently underway. The evaluation is considering the risks associated with various models for ownership and operation of both the plant and harvesting operations. In any event it is expected that CAFN members will be used to the greatest extent possible and trained for eventual assumption of full operations over a maximum 20 year period. Yukon Energy will hold a minority interest in the Project in relation to the plant, but are not interested in the operations of the logging business.

Consideration of outsourcing operations to an independent service provider is part of the overall risk assessment and feasibility study for the Project. In terms of the plant site, Yukon Energy has expertise and experience in ownership and operation of generating facilities, although this would be their first involvement with biomass. CAFN does not have previous generation experience, however they have expertise is forest harvesting and forest resource management as demonstrated through their leadership in the development of the Strategic Forest Management Plan (SFMP) and have a strong interest in providing jobs to CAFN community members as part of the Project. Thus the Proponents are

considering the best ownership and operational scenario, to minimize risk to the Project and maximize community gains.

Established in 1987, Yukon Energy is a publicly owned electrical utility that operates as a business, at arms-length from the Yukon government. They are the main generator and transmitter of electrical energy in Yukon and work with their parent company Yukon Development Corporation to provide Yukoners with a sufficient supply of safe, reliable electricity and related energy services.

There are almost 15,000 electricity consumers in the territory. Yukon Energy directly serves about 1,700 of these customers, most of whom live in and around Dawson City, Mayo and Faro. Indirectly, they provide power to many other Yukon communities (including Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin) through the Yukon Electrical Company Limited. Yukon Electric buys wholesale power from Yukon Energy and sells it to retail customers in the territory.

Yukon Energy has the capacity to generate approximately 132 megawatts of power. Ninety two megawatts of that are provided by our hydro facilities in Whitehorse, Mayo and Aishihik Lake (40 megawatts at Whitehorse, 37 megawatts at Aishihik and 15 megawatts at Mayo), 39 megawatts by diesel generators (which we currently only use as back-up) and 0.8 megawatts by two wind turbines located on Haeckel Hill near Whitehorse.

Yukon Energy is regulated by the *Business Corporations Act*, the *Public Utilities Act* and the *Yukon Water Act*. Our headquarters are located near the Whitehorse Rapids hydro plant in Whitehorse, with community offices in Mayo, Faro and Dawson City (Yukon Energy 2013).

CAFN established itself as a self-governing First Nation in 1993, after more than 20 years of negotiations. CAFN's rights to the Yukon portion of its traditional lands and resources were confirmed with the signing of the Champagne and Aishihik First Nations Final Agreement between CAFN, the Government of Canada and the Government of Yukon.

CAFN was one of the first four Yukon First Nations to conclude their final agreements. In addition, the self-government agreement provides CAFN with the power to enact laws on a wide range of matters affecting the rights of its citizens. On September 17, 1998 the Champagne and Aishihik First Nations made history by passing three acts: the *Income Tax Act*, *Fish and Wildlife Act*, and the *Traditional Pursuits Act*. These acts became effective on January 1, 1999.

A variety of municipal services, (housing, roads, water and sewer) as well as social services (health, nutrition, employment and training) are fully administered by the First Nations' government. The Department of Lands and Resources, which also includes Heritage and Economic Development, manages CAFN's traditional lands and integrates education and training of its citizens.

CAFN has undergone radical change in the last 100 years. Not long ago, the Southern Tutchone people of this region lived as part of the land. Today, they are working on the establishment of their own government and CAFN is becoming the steward of its homeland as it builds a sustainable economy.

1.2.2 Policies and Visions on Environmental and Sustainable Development

YEC and CAFN have converging values when it comes to environmental responsibility and sustainable development and both organizations have environmental stewardship ingrained in their policies, guiding principles and values. Further information on YEC's environmental policy can be found on their website at http://www.yukonenergy.ca/about/policies/environmental/.

CAFN has published a number of strategic plans in relation to sustainable development that will directly guide the implementation of this Project including their Vision Statement and Strategic Plan. CAFN's guiding documents can be accessed on their website at http://www.cafn.ca/.

CAFN's Land Claim Agreement provides for the ownership of some 2,427 square kilometers of land. It also continues to provide guaranteed access to fish and wildlife resources. Most importantly, the agreement establishes the CAFN government as co-managers of all natural and cultural resources in its traditional territory. CAFN is now a full partner on the Kluane National Park Management Board, the Alsek Renewable Resources Council and has representation on numerous other regional and territorial boards that make recommendations on heritage, educational, environmental and economic issues.

1.3 REQUIRED AUTHORIZATIONS AND REGULATORY APPROVALS

Yukon government, First Nation government, and federal government regulatory approvals and decisions are required before any activities (construction and operation) may be undertaken for any project that may emerge from this and other related feasibility studies. These approvals and decisions, however, may only be made after the required assessment by the Yukon Environmental and Socio-economic Assessment Board (YESAB) of a Project Proposal submitted pursuant to the Yukon *Environmental and Socio-economic Assessment Act* (*YESAA*).

1.3.1 *YESAA* Screening Requirements

While this type of project will have several activities which would make it assessable under *YESAA*, a screening level assessment by the YESAB Executive Committee would be required in accordance with Item 55 of Schedule 3 of the Assessable Activities, Exceptions and Executive Committee Projects Regulations as the Project will involve cutting 20,000 m^3 or more of standing or fallen trees or removing that amount of fallen or cut trees. The power plant (principal project) on its own would only trigger an assessment at the Designated Office level (Executive Committee assessment required for wood-fired electrical generating stations with a production capacity of 5 MW or more), but the principal project's interdependence with the accessory project, consisting of local feedstock procurement, raises the level of assessment to a screening.

The expected biomass consumption for the plant ranges from 10,000 m^3 to 40,000 m^3 annually (0.5 to 2 MW). Therefore the smaller plant may only require a Designated Office (DO) proposal submission. The requirements will be confirmed through consultation with YESAB prior to submission.

1.3.2 Applicable Legislation, Regulations, and Permits

Pending the issuance of a favorable YESAB Executive Committee screening or DO decision, the proponent is able to pursue any required federal, First Nation, and/or territorial government authorizations for the project to proceed (*e.g.*, Air Emissions Permit, Timber Permit). Once the decision documents are issued, the permitting/licensing applications can be processed by the applicable authority and authorizations subsequently issued to begin construction and commence operations.

The territorial, First Nations, and federal government authorizations that may be required for the construction and operation of the proposed Bioenergy Facility and associated feedstock harvesting are shown in the following tables (Tables 1.3.1 and 1.3.2). This list will be amended based as the technical aspects of the facility and harvesting become further defined as the Project progresses. The information below is based on the Permit and Authorization Guide for Yukon Activities (2013) and information currently available for the Government of Yukon (YG), Champagne and Aishihik First Nations and Federal Government agencies online.

The Strategic Forest Management Plan and Integrated Landscape Plan for the CAFN Traditional Territory (TT) are the overarching guiding documents for forest management and harvesting in CAFN TT as set out in the provisions under Chapter 17 of the CAFN Final Agreement. Timber harvesting activities and associated feedstock harvesting activities should be assumed to require consistency with their direction, otherwise the activities would not get authorized. Higher performance standards exist in this plan than exist under other forms of regulation.

Renewable Resource Councils (RRCs) are local management bodies in the Yukon established in areas where individual land claim agreements have been signed. RRCs are a voice for local community members in managing renewable resources, such as fish, wildlife, habitat and forestry matters, specific to their Traditional Territory. RRCs provide strong input into planning and regulation by the territorial, federal and First Nations governments. RRCs also play an important advisory role to the territorial management board for fish and wildlife by raising awareness of specific issues and providing local and traditional information.

The Alsek Renewable Resource Council (ARRC) is the applicable RRC for the Haines Junction community and surrounding CATT. The ARRC's jurisdiction is the Champagne and Aishihik Traditional Territory (CATT) which includes the Yukon communities of Haines Junction, Canyon Creek, Takhini, Mendenhall, Silver City, Kloo Lake, Aishihik and Klukshu (YFWMB 2013).

The ARRC began its work in 1995 after the signing of the Champagne and Aishihik First Nations (CAFN) Final Agreement. The Final Agreement created the ARRC as the "primary instrument for local renewable resources management."

Table 1.3.1 Bioenergy Facility Regulatory Requirements

Facility or Activity	Act or Regulation	Approval/Permit Required	Lead Agency	Comments
Air Emissions greater than 5 Mbtu-hr	• *Yukon Government Environment Act* • *Air Emissions Regulation*	• Air Emissions Permit	• Environment Yukon	
Release of Air Pollutants	• *Yukon Government Environment Act* • *Air Emissions Regulation*	• Air Emissions Permit	• Environment Yukon	
Ozone Depleting Substance Use	• *Yukon Government Environment Act* • *Air Emissions Regulation*	• Ozone Depleting Substances/ Halocarbons Permit	• Environment Yukon	Requirement to be determined based on design.
Special Waste Management	• *Yukon Government Environment Act* • *Special Waste Regulations*	• Special Waste Facility • Disposal and Generator Permit	• Environment Yukon	Requirement to be determined based on design.
Solid Waste Disposal	• *Yukon Government Environment Act* • *Solid Waste Regulations*	• Facility Permit	• Environment Yukon	Requirement to be determined based on design.
Storage Tank/Petroleum Tank Use	• *Yukon Government Environment Act* • *Storage Tank Regulations*	• Application for Operation, Closure • Abandonment or Renovation to Storage Tanks/Permit	• Community Services, Protective Services	Requirement to be determined based on design.
Water Use or Deposit of (Water) Waste	• *Waters Act*	• Water Use License	• Yukon Water Board	Requirement to be determined based on water use quantities.
Potable Water Supply	• *Public Health Act* • *Drinking Water Regulation*	• Drinking/Potable Water Permit	• Health and Social Services • Public Health and Safety	
Land Acquisition, Title to Land	• *Land Titles Act*	• Issuance of Title	• Justice	Requirement to be determined based on land parcel.
Tenure for Land Lease or Agreement of Sale	• *Territorial Lands Act*	• Application for Land	• Energy, Mines & Resources	Requirement to be determined based on land parcel.
Tenure for Land Lease	• *CAFN Lands Act*	• CAFN Lands Disposition (lease for commercial or industrial purposes)	• CAFN Heritage, Lands and Resources	Commercial lease of land requires CAFN Lands Committee review of application and Chief and Council approval.

Table 1.3.1 Bioenergy Facility Regulatory Requirements

Facility or Activity	Act or Regulation	Approval/Permit Required	Lead Agency	Comments
Temporarily Using or Occupying Commissioner's Land	• *Territorial Lands Act*	• Land Use Permit	• Energy, Mines & Resources	Requirement to be determined based on land parcel.
Temporarily Using or Occupying CAFN Settlement Land	• *CAFN Lands Act*	• CAFN Lands Disposition (easement, right-of-way)	• CAFN Heritage, Lands and Resources	
Facility Construction	• *Yukon Government* Land Services	• Building Permits	• YG Community Services • Building Safety	
	• *Yukon Government Forest Resources Act*	• Timber Resource Processing Permit	• Forest Management Branch	Requirement for construction, operation of any timber processing facility.
	• *Building Standards Act*	• Plumbing Permit	• YG Community Services, Building Safety	
	• *Public Health & Safety Act* • *Sewage Disposal Systems Regulation*	• Sewage Disposal Permit	• Health & Social Services • Environmental Health Services	Requirement to be determined based on design.
	• *Electrical Protection Act*	• Electrical Permit	• YG Community Services, Building Safety	
	• *Gas Burning Devices Act*	• Gas Installation Permit	• YG Community Services, Building Safety	Requirement to be determined based on design.
Clearing or Installing a Utility Right-of-Way	• *Territorial Lands Act*	• Land Use Permit, Disposition Approval	• Energy, Mines & Resources	Requirement to be determined based on design.
Construction of New Road Access	• *Territorial Lands Act*	• Land Use Permit	• Energy, Mines & Resources	Requirement to be determined based on site location.
Construct Road Access on Highway Right-of-Way	• *Highways Regulation*	• Access Permit	• Highways & Public Works	Requirement to be determined based on site location.
Temporary Use of CAFN Settlement Land / Use or Alteration of Resources on Surface of Land	• *CAFN Traditional Activities Protection Act*	• TAPA Permit	• CAFN Heritage, Lands and Resources	Permits issued by Director.
Activities in a Habitat Protection Area	• *Wildlife Act* • *Wildlife Regulation*	• Permission for Activity	• YG Environment	Requirement to be determined based on site location.
Activities in a Wildlife Area	• *Wildlife Area Regulation*	• Wildlife Permit	• YG Environment	Requirement to be determined based on site location.

Table 1.3.1 Bioenergy Facility Regulatory Requirements

Facility or Activity	Act or Regulation	Approval/Permit Required	Lead Agency	Comments
Harmful Alteration, Disruption or Destruction of Fish Habitat	• *Fisheries Act*	• Fisheries Act Authorizations S.35.2	• Fisheries and Oceans Canada	Requirement to be determined based on site location and construction.
Destruction of Fish by Means Other than Fishing	• *Fisheries Act*	• *Fisheries Act* Authorizations S.32	• Fisheries and Oceans Canada	Requirement to be determined based on site location and construction.
Obstruction of Fish Passage	• *Fisheries Act*	• *Fisheries Act* Authorization S.22	• Fisheries and Oceans Canada	Requirement to be determined based on site location and construction.

Table 1.3.2 Feedstock Harvesting Regulatory Requirements

Facility or Activity	Act or Regulation	Approval/Permit Required	Lead Agency	Comments
Timber Harvesting	• *Timber Harvest Plan, Forest Resources Act and Regulation*	• Timber Resource License	• Energy, Mines and Resources • Forest Management Branch	
Timber Cutting on CAFN Settlement Land for Commercial Purposes	• *CAFN Traditional Activities Protection Act*	• TAPA Permit	• CAFN Heritage, Lands and Resources	
Burn Wood Refuse	• *Forest Protection Act* • *Forest Protection Regulation*	• Burning Permit	• Community Services, Protective Services	
Land Acquisition, Title to Land	• *Land Titles Act*	• Issuance of Title	• Justice	Requirement to be determined based on land parcel.
Tenure for Land Lease or Agreement of Sale	• *Territorial Lands Act*	• Application for Land	• Energy, Mines & Resources	Requirement to be determined based on land parcel.
Temporarily Using or Occupying Commissioner's Land	• *Territorial Lands Act*	• Land Use Permit	• Energy, Mines & Resources	Requirement to be determined based on land parcel.
Construction of New Road Access	• *Territorial Lands Act (see below)*	• Land Use Permit	• Energy, Mines & Resources	Requirement to be determined based on site location.
Construction of New Road Access – Forest Resource Use	• *Forest Resources Act – Forest Resource Road Regulations*	• Forest Resource Road Licence/Permit	• Energy, Mines & Resources	Requirement to be determined based on site location.

Table 1.3.2 Feedstock Harvesting Regulatory Requirements

Facility or Activity	Act or Regulation	Approval/Permit Required	Lead Agency	Comments
Construct Road Access on Highway Right-of-Way	• *Highways Regulation*	• Access Permit	• Highways & Public Works	Requirement to be determined based on site location.
Activities in a Habitat Protection Area	• *Wildlife Act* • *Wildlife Regulation*	• Permission for Activity	• YG Environment	Requirement to be determined based on site location.
Activities in a Wildlife Area	• *Wildlife Area Regulation*	• Wildlife Permit	• YG Environment	Requirement to be determined based on site location.
Transportation of Bulk Commodity	• *Bulk Commodity Haul Regulations*	• Bulk Commodity Haul Agreement	• Highways & Public Works	Requirement to be determined based on transportation quantities.
Oversize Trucking	• *Highways Act*	• Over Dimensional or Over Weight Vehicle Permits	• Highways & Public Works	Requirement to be based on transportation methods.
Assessment of Historic Resources as Part of the Timber Harvest Planning or Road Construction	• *Historic Resources Act*	• Archaeological Permit	• Department of Culture and Tourism	Required to conduct heritage assessments in the field.
Other Research Projects	Examples: • *Scientists And Explorers Act* (Yukon) • *Fisheries Act* • *Migratory Birds Act* • CAFN TAPA Based Traditional Knowledge Policy	Various Authorizations	• Canadian Wildlife Service • Fisheries and Oceans Canada • Yukon Culture and Tourism • Yukon Environment • CAFN	Quite likely necessary if project will include fish and wildlife monitoring.

2.0 FIRST NATIONS, OTHER GOVERNMENT AND COMMUNITY CONSULTATIONS

2.1 CONSULTATION REQUIREMENTS

Section 50(3) of the *Yukon Environmental and Socio-Economic Assessment Act* (YESAA) lists the following First Nations and stakeholder consultation requirements:

> *"Before submitting a proposal to the Executive Committee, the proponent of a project shall consult any first nation in whose territory, or the residents of any community in which, the project will be located or might have significant environmental or social economic effects."*

Section 3 of YESAA states:

> *"Where, in relation to any matter, a reference is made in this Act to consultation, the duty to consult shall be exercised:*
>
> *(a) by providing, to the party to be consulted,*
>
> *(i) notice of the matter in sufficient form and detail to allow the party to prepare its views on the matter,*
>
> *(ii) a reasonable period for the party to prepare its views, and*
>
> *(iii) an opportunity to present its views to the party having the duty to consult; and*
>
> *(b) by considering, fully and fairly, any views so presented."*

2.2 CONSULTATION OVERVIEW AND APPROACH

The overarching aim of Project consultation efforts is to generate awareness, understanding and support within the local communities of Haines Junction and Champagne and Aishihik First Nations, and to reach an accurate and complete understanding of the concerns and interests that local communities and interested stakeholders may have with regard to the construction and operation of a biomass energy generation facility. The goals of Project consultation efforts are as follows:

- create and maintain awareness and understanding of the project among the general public, decision-makers, key stakeholders, and interested First Nations (particularly Haines Junction residents and Champagne and Aishihik First Nations citizens), including potential costs and benefits, and timelines and opportunities for engagement;
- identify stakeholders and potentially interested First Nations, build and maintain strong relationships with those groups, and ensure that engagement occurs at the right level, at the right time, in the right way;
- identify, document and monitor issues and concerns that arise during the engagement process

- identify planning, design and management measures that can be used to avoid, mitigate or resolve potential negative environmental and socio-economic impacts;
- encourage the sharing of traditional land use and traditional knowledge information by interested and potentially affected First Nations groups; and
- provide early notification of the project and ensure that there are adequate opportunities for First Nations, stakeholder and public input.

2.3 PUBLIC CONSULTATION PLAN

The project involves consultation and relationship-building over a number of different phases spanning several years. As the Project progresses from the initial feasibility assessment through the internal assessment of potential environmental and socio-economic effects and then into the external impact assessment process, the Project Team will consult with interested First Nations, stakeholders and the general public through a mix of targeted meetings, open house sessions and information updates on Project partner websites. The depth of consultation will depend on stakeholders as shown in Table 2.3.1 below.

Table 2.3.1 Consultation Levels

Consultation Level	STAKEHOLDER TYPE
Collaborate	Stakeholders that are responsible for driving the Project.
Involve	Stakeholders who have a high-level of engagement with the Project and are involved in the decision-making process.
Consult	Stakeholders who need to have a good understanding of the Project and will be invited to provide input at critical points (*e.g.*, Federal, Territorial, and FN Resource Management Agencies, FN citizens and local residents, industry, land users and owners, planning groups and committees, NGOs, ENGO).
Inform	Stakeholders who require a broad level of awareness of the project Stakeholders who may be influential or important.

To cultivate relationships with First Nations and key stakeholders that have an active interest in the Project, meetings will be held to provide updates on the Project, discuss planned work, listen to concerns and assess areas of interest. The Project Team may also choose, where appropriate, to engage with particular First Nations and stakeholder groups when planning and conducting specific Project tasks.

The project will be located within the traditional territory of the CAFN and they are the primary First Nation that will be engaged with regard to the Project. While it is highly unlikely that the Project will have an effect on the traditional territories of other First Nations, there is potential that the following First Nations and First Nations associations may express some interest in the Project and may request more information and dedicated meetings:

- Carcross/Tagish First Nation;
- Council of Yukon First Nations – Natural Resources and Environment;
- Kluane First Nation;

- Kwanlin Dun First Nation;
- Little Salmon Carmacks First Nation;
- Ta'an Kwäch'än Council; and
- White River First Nation.

As the Project progresses, the Project Team will communicate by letter with interested First Nations at key regulatory milestones to disseminate Project documentation and keep those groups up-to-date.

Following submission of the project proposal, YESAB will conduct their formal First Nation and public consultation review process. During that process, the Project Team may be asked to respond to queries or concerns. The Project Team will continue to meet with stakeholders and First Nation groups to resolve ongoing issues as appropriate and public meetings may be held to provide further opportunities for participation and input.

Under YESAA, the knowledge and views of Yukon First Nations and their citizens will be sought out by regulators. Notification will be sent to all First Nations whose territory the project may be located on or where the project might have significant environmental or socio-economic effects. First Nations will have the opportunity to participate and share their views and information during the comment period for the assessment.

In the YESAA, it is explicitly stated that traditional knowledge is a factor that must be considered and incorporated into an impact assessment. Specific meetings will be held with the CAFN to plan and carry out required traditional land use or traditional knowledge studies. These studies will provide essential Project-specific information for integration into the environmental and socio-economic impact assessment.

2.4 CONSULTATION TECHNIQUES

The following are techniques available for use by the Project Team to engage interested First Nations, stakeholders and the general public:

- letters and email correspondence;
- face to face meetings;
- workshops and open houses:
    - project information sheets and posters (distributed to local government offices, libraries, local recreational centers, community bulletin boards, schools, First Nation band offices);
- radio and television advertisements;
- targeted media interviews;
- website and social media; and

- advertisements in community newspapers.

All feedback from First Nations and stakeholders will be tracked in a shared information management system. Speeches and presentations will be documented in a similar manner; the identities of those who attended the event and the nature of feedback received will be documented. Information on communications activities will be available on demand to the Project team and the data will be regularly updated. Public consultation completed to date is summarized in Table 2.4.1. Some more informal meetings with individual stakeholders have also been completed to date.

Table 2.4.1 Consultation Events To-Date

Location	Description	Date	Venue
Haines Junction, Yukon	Open House geared engaging CAFN members and Haines Junction residents, building support, disseminating information and gathering preliminary issues and concerns.	January 23, 2013	Da Ku Cultural Centre 280 Alaska Highway Haines Junction, Yukon

2.5 KEY CONCERNS RAISED DURING CONSULTATION

The first open house for the Project was held in Haines Junction on Jan. 23, 2013. A detailed summary has been prepared by the Proponent and will be considered in the development of future public and First Nations communications as well as in shaping the Project in the next stages. The open house included presentations on the technologies being considered, the preliminary feedstock availability assessment, environmental issues being considered and the waste heat recovery component of the Project.

Approximately 75 to 80 members of the community attended including CAFN members and general public as well as representatives from the Village of Haines Junction and Forest Management Branch. Questions and comments received during the session are summarized as follows and have been considered in the development of this assessment:

- concern that the engines be the most efficient available were raised;
- use of generated heat during the summer;
- proximity of the biomass plant to the Village and noise levels;
- pros and cons of using a gasification system versus a conventional steam system;
- effect of cold climate of Haines Junction on functioning of biomass plant;
- whether live trees will be used as fuel in addition to beetle-killed trees;
- whether the technology will be available in all CAFN communities;
- what is the capacity of the ‘green zone’ to regenerate (related to the Forest Management Zones defined in the local Integrated Landscape Plan);

- maximum distances that a biomass plant can be located from inhabited areas and still be economic;
- potential impacts on wood supplies for wood cutting industry and whether price of firewood will increase;
- location of plant;
- need for heating and jobs in the local communities;
- forest fire concerns;
- ash disposal;
- plant size and capacity to utilize beetle-killed wood;
- whether similar plants could be located in Burwash and Destruction Bay;
- cost of heating infrastructure;
- responsibility for hiring and maintenance;
- which businesses (CAFN and non-businesses) may realize benefits; and
- whether excess heat could be stored during summer for the winter.

2.6 KEY CONCERNS ANALYSIS

No new issues were raised during the first consultation event beyond those aspects that are either currently being evaluated or are planned for subsequent stages of the Project. Overall, First Nations and public in attendance were supportive of the Project and concerns were focused around avoiding issues with current harvesting activities (competition for forest resources), maximizing local job development and addressing the growing risk of forest fire from dead standing trees in beetle kill zones.

3.0 PROJECT DESCRIPTION

This chapter provides an overview of the project location and study area characteristics, the Project technology and infrastructure and the schedule for permitting, construction, operation and eventual decommissioning.

3.1 PROJECT LOCATION

The geographic location of the Project is in the Village of Haines Junction in the Yukon Territory. The Project location is shown in Figure 3.1.1. The community of Haines Junction has its beginnings as a highway construction camp built in 1942 at the junction of the Alaska Highway and Haines Road.

3.1.1 Local Climate

The Climate in the Ruby Ranges Ecoregion, which includes the Haines Junction area and a large swath of the Champagne and Aishisik Traditional Territory (CATT – Figure 3.1.1), is characterized as the driest in the Yukon Territory. This ecoregion receives only 250-300 mm of precipitation annually, resulting from a rain shadow produced by the St. Elias Mountains to the west (Yukon Ecoregions Working Group, YEWG 2004). The Shakwak Valley, where Haines Junction is situated, experiences the coldest temperatures of the Ecoregion, ranging from -30° to -35° C in January (YEWG, 2004). Permafrost is present in most of the ecoregion, except in the southern portion in and around Haines Junction (YEWG 2004). Climate in the Yukon Southern Lakes Ecoregion is also relatively arid. Only 200 to 325 mm of precipitation occurs in the Yukon Southern Lakes, again due to the rain shadow from the St. Elias-Coast Mountains. Mean annual temperature ranges from -1° to -4°C throughout the ecoregion, and is colder in the northwest than in the southeast, with the lowest temperatures occurring in January ranging from -21° to -25°C (YEWG 2004). Permafrost underlies less than a quarter of the area within the ecoregion, in part due to the arid climate described above (YEWG 2004).

3.1.2 Study Area Boundaries

The preliminary study area is focused on the Village of Haines Junction as the specific plant site has not yet been chosen, nor have the areas for additional harvesting been finalized. The location of the plant site will likely be within 400 m of larger buildings in Haines Junction as this is the approximate limitation for use of waste heat from the plant. The village and key buildings being considered for waste heat use are shown in Figure 3.1.2. The potential location being used for FEED is also shown in Figure 3.1.2. This location is considered as the preliminary site location in this assessment and is a greenfield site (has not been recently developed). Excluding the harvesting area(s), the plant and construction activities will cover an area of approximately 2.8 hectares (ha).

3.1.3 Village Services

The following description of services has been gathered from Haines Junction's Integrated Community Sustainability Plan and CAFN's Integrated Community Sustainability Plan (Village of Haines Junction 2007, CAFN 2009a).

Figure 3.1.1 Project Location

Figure 3.1.2 Preliminary Range of Sites for Waste Heat Use

Recreational facilities in Haines Junction include an arena, curling rink, swimming pool, outdoor basketball court and a skateboard park. There is also a community library with public internet access, a youth centre, and a community hall. Haines Junction is served by a local community Health Centre, a volunteer ambulance service, a locally based social worker, and a locally based counselor. Recently, a Seniors' Centre has opened with limited hours.

The RCMP operates a detachment in Haines Junction and the local Haines Junction Community Justice Committee provides alternative justice systems.

There is a volunteer fire department, with staff trained in first aid and CPR. St. Elias Community School offers kindergarten to Grade 12 and the Haines Junction campus of Yukon College offers full-time academic upgrading programs and delivers a variety of continuing education courses. The campus's location near the St. Elias Mountains provides opportunities for such courses as avalanche training, wilderness guiding and wilderness survival. Youth employment training, early childhood courses and office administration are also offered.

The Yukon Electrical Co. Ltd. supplies hydroelectric power from Aishihik Lake, with diesel generator back-up. The village has a piped water supply that is also available to some properties owned by CAFN. Other areas use trucked-in, chlorinated well water or personal wells.

3.1.4 Traditional Territory

The CAFN's Land Claim Agreement provides for the ownership of some 2,427 square kilometers of land. It also continues to provide access to fish and wildlife resources. CAFN is a full partner on the Kluane National Park Management Board, the Alsek Renewable Resources Council and has representation on numerous other regional and territorial boards that make recommendations on heritage, educational, environmental and economic issues.

Haines Junction is not a traditional CAFN settlement but is located on well used travel routes. The original name for the area was Dakwakada, meaning high cache, which indicates that the area was an important hunting and fishing region. The community only gradually became a place where CAFN people permanently settled in the 1940s and 1950s after Haines Junction began to grow as a regional centre. The number of First Nation residents increased sharply beginning in the 1960s when the federal government relocated families from Champagne and Aishihik to the community.

3.1.5 Yukon Land Use Planning Region

In Yukon, the Umbrella Final Agreement introduced a new regional land use planning process. Currently there are eight planning regions in Yukon with borders generally following the traditional territories of Yukon First Nations. The Project is located in the Kluane planning region (Kluane and Champagne & Aishihik TT). The region does not yet have an approved regional land use plan. The objectives of regional planning in the Yukon (under the Final Agreements) are:

- Minimizes actual or potential land use conflicts. These conflicts will likely grow worse without planning;

- Recognizes and promotes the cultural values of Yukon First Nations people. Certain cultural activities are intrinsically linked to the land;

- Ensures Sustainable Development by developing social, cultural, economic and environmental policies that apply to the management, protection and use of land, water and resources in an integrated and coordinated manner;

- Spells out how and where land uses may or may not occur, and so increase the land use certainty. In some cases, land use plans may help avoid legal action between different land users (YLUPC 2011).

Both YESAA and Land Use Plans are concerned with how and where development occurs and YESAB is an important component in implementing land use plans. In reviewing proposed projects, YESAB must consult The Yukon Land Use Planning Council (YLUPC) as to whether the project conforms to the land use plan, and how the project can conform to the plan, if it doesn't already. Although conformity with the plan does not determine whether a project can proceed or not, it will be factored into the decision (YLUPC 2011).

3.1.6 Consistency with Other Plans

The Project would be executed in harmony with planning tools used by Champagne and Aishihik First Nations including the Integrated Community Sustainability Plan (ICSP) (CAFN 2009a) published in 2009 and the Strategic Forest Management Plan (SFMP) and the Integrated Landscape Plan (ILP) (EMR 2006). The ICSP included a number of focus areas that are consistent with this Project including energy efficiency upgrades, renewable energy generation and potential for incorporation of a community greenhouse. The Village of Haines Junction completed its Integrated Community Sustainability Plan in 2007 with similar priorities noted in comparison to the CAFN ICSP.

Details of requirements for the Project to proceed in conjunction with the SFMP and ILP are outlined in each VC section as applicable. As this plan relates to forest management, further specifics of how the Project would ensure consistency with the ILP will be confirmed in the next stage of study.

3.2 PROJECT INFRASTRUCTURE AND TECHNOLOGY

The technology for the Project is the use of a biomass gasification process to fuel a reciprocating engine. This technology has been selected as a gasifier is the only biomass technology that will allow for the use of a reciprocating engine which can be used to generate electricity without steam while also generating waste heat that can be used for building heating. Steam boiler and steam turbine combinations can also be used for these purposes but require more advanced training for operators and this expertise is not readily available in the Yukon, especially in small communities such as Haines Junction. Thus, the gasifier/reciprocating engine combination is considered the best choice for small Yukon communities wishing to use a combined heat and electrical power generating technology. The gasifier and engine technology is discussed further in the following section.

3.2.1 Gasifier and Engine Technology

Gasification is a process that converts a carbon-containing solid material into a gas (called synthetic gas or simply “syngas”) for use in applications such as electricity generation, heating, or chemical manufacturing. The chemical reactions to produce syngas take place in a vessel known as a gasifier. The temperature, pressure, and concentration of certain chemical species in the gasifier affect the chemical composition of the syngas. In general, syngas formed from biomass or woody material contains carbon monoxide, carbon dioxide, methane, hydrogen, steam, and unreacted nitrogen if air is used.

A simple block diagram of a gasification system is provided in Figure 3.2.1.

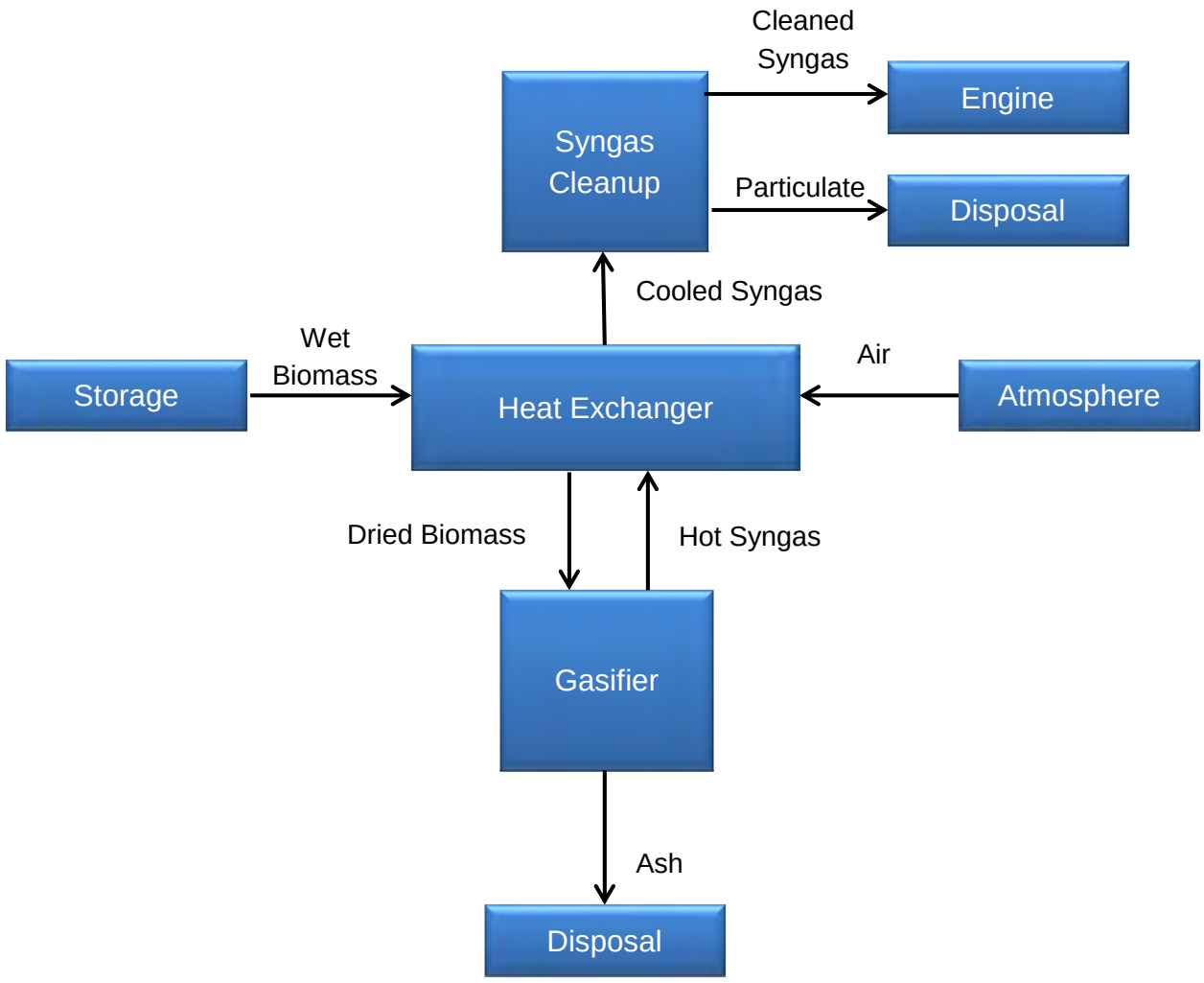


Figure 3.2.1 Simplified Block Diagram of a Gasification System

In a gasifier, the biomass feedstock is added in chip form (feedstock must be chipped using a mobile or stationary chipper) to the vessel along with air (a source of oxygen). In applications where the presence of nitrogen would be undesirable, pure oxygen or hydrogen is used instead. Temperatures in a gasifier can vary from 200°C to 1,000°C. Hot syngas from the gasifier is typically passed through a

heat exchanger to dry the incoming feedstock and cool the gas. This cooled gas is then filtered to minimize the particulate concentration and tar in the gas. This clean-up stage is important to decrease the wear on downstream equipment, such as a reciprocating engine. As an added benefit, the syngas cleanup reduces the release of particulate matter to the atmosphere. Ash is also generated by the gasifier and is collected for disposal in a landfill that is capable of handling such waste. This ash (sometimes called biochar due to its natural origin) could also potentially be used for other applications such as soil application or as a component of asphalt.

The FEED study is currently considering a biomass gasification system to generate 0.5 MW_e to 2 MW_e (megawatt of electric energy) using a reciprocating gas engine. Further details are available in the FEED study.

3.2.1.1 Case Studies

As this technology is quite novel (use of a gasifier, reciprocating engine combination), the following case studies are briefly described to provide additional details of potential technologies and required infrastructure. As part of the FEED study, the Project team visited three organizations to study their gasification systems and evaluate the potential for these systems to meet the Haines Junction Project objectives.

The Community Power Corporation (CPC) operates a 100 kW_e system at Pineland Forest Nursery in Hadashville, Manitoba. The system is housed in five shipping containers (each 6 m in length) with a separate fuel storage building. In addition to electricity generation, heat is recovered and used to heat greenhouses on-site. The system includes a stainless steel downdraft gasifier, a heat exchanger to dry incoming biomass, carbon filters to clean the syngas, and two V8 spark ignition engines for electricity generation. The control interface and electrical equipment are housed in a control room. The biomass supply is wood chips.

The exterior of the plant is shown in Photo 1.

Photo 1: Exterior of CPC Gasifier Plant

On the other end of the capacity envelope being considered for this Project, Nexterra operates a gasification system on the Vancouver campus of the University of British Columbia (UBC) for the production of electricity (2 MW_e) and heat. The system, including wood chip storage, is housed in a building, approximately 27 m x 55 m (90 feet by 180 feet), on the campus. Following screening, woodchips are dried in a single pass dryer then stored in bins. An updraft gasifier converts the biomass to syngas and ash. Nexterra uses a proprietary syngas cleanup system that includes tar cracking (for the breakdown of tar) and a bag house filtration system. The cleaned syngas is fed either to a 20 cylinder reciprocating engine to generate with a capacity of 2 MW_e or to a thermal oxidizer to generate heat and steam for district energy network.

The engine used to generate electricity from Nexterra syngas is shown in Photo 2.

Photo 2: Engine Used by Nexterra System

The FEED study completed by Stantec is based on a combination of CPC 100 kW_e units to form a 0.5 MW_e facility. Three options for a 0.5 MW_e facility were considered in the FEED Study.

3.2.2 Waste Heat Uses

Cleantech Community Gateway (CTCG) completed a study to review options for waste heat use from several electrical production scenarios, entitled *Haines Junction Bioenergy Project – Evaluation of Waste Heat Potential* (CTCG 2012). These options are considered integral to the development of the Project in relation to the biomass energy plant sizing and siting. Three options for the use of recovered heat were evaluated by CTCG: District Energy System (DES), Organic Rankin Cycle (ORC), and Controlled Environment Agriculture (CEA, *i.e.*, greenhouses). Each option is summarized in the following paragraphs.

For a 0.5 MW_e system that produces hot water, CTCG recommended that the hot water be used to heat one building such as the Haines Junction School or another building of similar heat requirement. The school's peak heat demand is 360 kW, which is slightly less than the peak thermal output of a 0.5 MW_e system. According to the CTCG report, in order for the use of waste heat to be economical, the length of the heat supply pipe between the power plant and the school must be approximately 350 m or less. The FEED study preliminary site selected was based on this parameter and review of available parcels of land.

The feasible radius for heating several select local buildings is provided in Figure 3.1.2.

CTCG noted that a 3 MW_{th} (megawatt thermal energy) power plant would be required to meet the peak heating requirements of the seven buildings identified as potential DES customers:

- Haines Junction School;
- Fire Hall;
- Convention Centre;
- Arena Complex;
- Swimming Pool and Community Hall Complex;
- YK Government Administration Building; and
- CAFN Cultural Centre and Kluane National Park Visitor Information Centre.

When considering the economics of a Direct Energy System (DES), a smaller network including the school, convention centre, arena complex, and the swimming pool and community hall has a lower risk and better economics.

An Organic Rankine Cycle (ORC) generator can be used to generate additional power using the waste heat. Two ORC generators were considered in the CTCG study. With respect to technical risk, district energy systems are considered to have low technical risk when designed and installed correctly. Integration of an ORC generator would require more substantive innovation, development, and testing, the cost of which is not currently known. Hence there is a higher technical risk and capital cost with the ORC generator than the DES. The CTCG concluded that the ORC option is not recommended for this Project.

Controlled Environment Agriculture (CEA) seeks to control lighting, temperature, nutrients, hydroponics, and air control in a greenhouse. Such a system in Haines Junction could potentially create a local food supply. CTCG made assumptions based on a CEA system in Alaska (Chena Hot Springs) and used standardized inputs to model the potential viability of a CEA greenhouse for Haines Junction. The results of the assessment indicate that a greenhouse with dimensions of 10.7 m by 47.5 m (35 ft by 156 ft) could supply Haines Junctions with 100% of its demand for tomatoes, cucumbers, and lettuce.

The CTCG found that a greenhouse is not likely to be economically feasible in Haines Junction without some form of subsidy or strategy to decrease operating costs. However, with respect to the socioeconomic impacts, a greenhouse may be of value to the community, potentially resulting in an increase in health and overall community wellness that may be worth the investment.

3.2.3 Fuel Harvesting and Handling

Biomass would be harvested from green forest management zones (Figure 3.2.2) as defined in the CAFN Integrated Landscape Plan (ILP).The specific areas associated with this Project will be further defined in the next stage of the Project. Chipping of the harvested trees would be required to prepare the feedstock for gasification. The chipping could be done with a mobile chipper at the roadside, at the plant or at a dedicated secondary log storage and chipping site. The logistics of chipping have not been finalized. These would also be confirmed in the next stage, as suppliers/harvesters are confirmed. The chips would be stored inside at the plant, with capacity for approximately 7 days being kept onsite.

3.2.4 Auxiliary Infrastructure

Auxiliary infrastructure associated with the gasifier/reciprocating engine system include electrical equipment (*e.g.*, transformer, metering) and building space for offices and feedstock storage (and gasifier/engines if not in self-contained shipping containers).

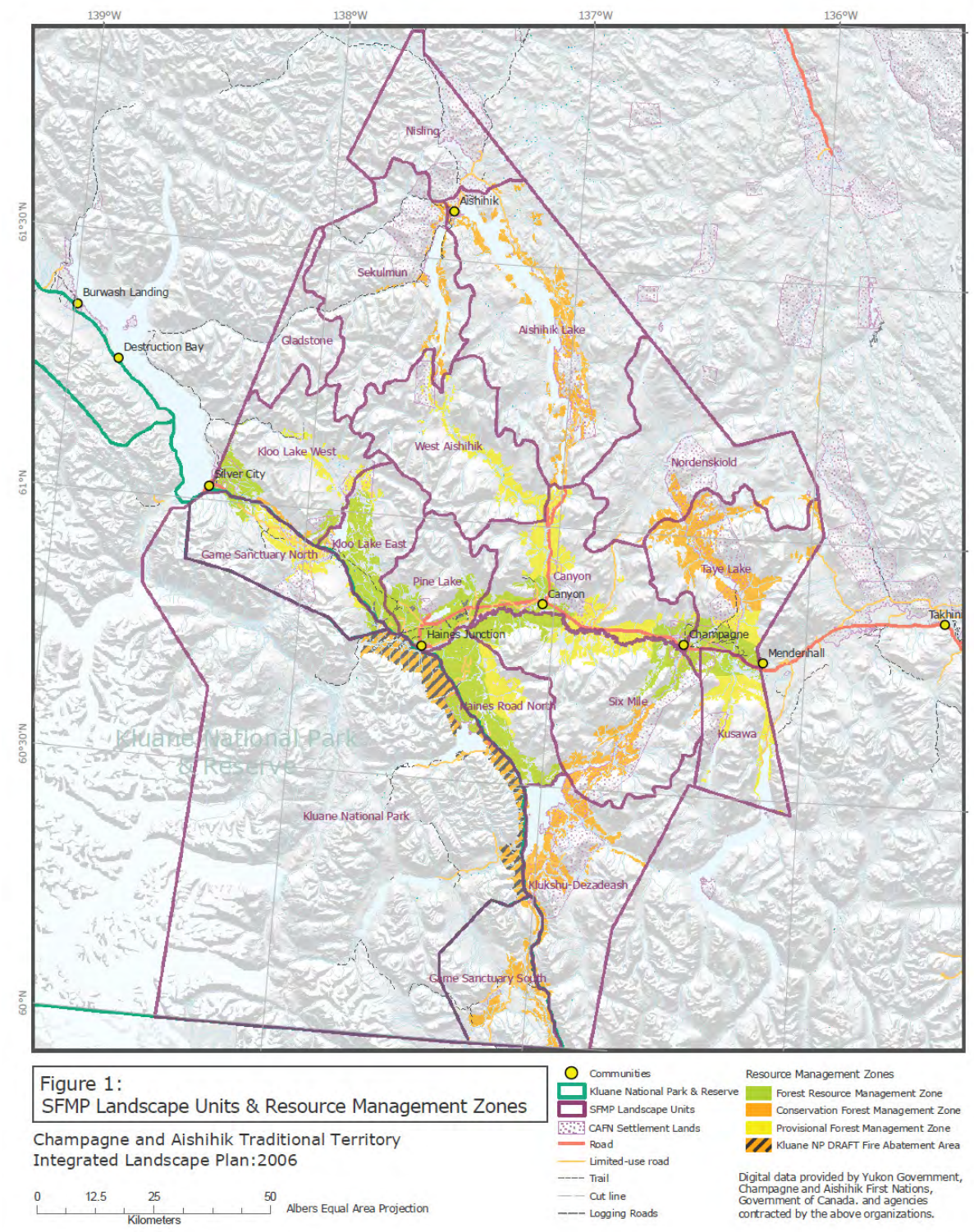


Figure 3.2.2 SFMP Landscape Units and Resource Management Zones

3.3 EMISSIONS AND WASTES

3.3.1 Air Contaminant and GHG Emissions

3.3.1.1 Construction

Since the Project involves modest construction requirements due to its relatively small scale, the releases of air contaminants and greenhouse gases to the atmosphere due to construction activities are expected to be small.

There will be nominal (essentially zero) emissions from the use of heavy construction equipment (*e.g.,* heavy-duty trucks) at the site, as well as some limited amounts of fugitive dust associated with ground preparation activities at the plant site. The transportation of construction materials and equipment to and from the Project site will also result in releases air contaminants and greenhouse gases to the atmosphere. Emissions from these sources, however, are not expected to be substantive and are expected to be generally confined to the Project site.

Forest harvesting construction activities may also result in moderate amounts of combustion gases and fugitive dust emissions from mobile equipment in the event that construction of new logging roads are required. Based on the preliminary feedstock harvesting assessment completed (as part of the FEED study), no new roads would be required to supply a 0.5 MW_e plant.

3.3.1.2 Operation

Operation of the Project will result in emissions of combustion gases and particulate matter to the atmosphere from the engine exhaust stacks. Two operational scenarios are considered for the Project, since the specific size of the operation is not yet confirmed. Based on the FEED study the size of the plant may range from 0.5 MW to 2 MW (electric energy). Therefore the emissions are estimated for the 0.5 MW and 2 MW cases to establish the range of emission rates for each air contaminant.

Where the Project is in the early design stages, multiple vendors are still being considered to supply the biomass gasifier and engine equipment. The air contaminant emissions estimates provided below are based on information provided by a specific vendor currently being considered for the Project (Community Power Corporation (CPC) 2012). The vendor emissions are for a 0.1 MW unit and have been scaled up for the scenarios below. Direct scaling is considered conservative as in practice 0.5 MW can be achieved using four (4) 0.1 MW units while emissions have been based on five units. The greenhouse gas (GHG) emissions are estimated by mass balance using the fuel consumption data from the vendor information. For assessment purposes, the units were assumed to operate continuously (*i.e.*, 24 hours per day, 365 days per year).

Estimated emissions for both Project operational scenarios considered are provided in Table 3.3.1.

Table 3.3.1 Estimated Emissions During Operation of the Project

Air Contaminant/GHG[1]	Scenario 1 0.5 MW Case (t/a)	Scenario 2 2 MW Case (t/a)
Nitrogen Oxides (NO_X)	2.8	11.2
Carbon Monoxide (CO)	1.2	4.6
Sulphur Dioxide (SO_2)	0.4	1.4
Total Suspended Particulate Matter (TSP)	0.012	0.048
Particulate Matter < 2.5 Microns ($PM_{2.5}$)	0.012	0.048
Carbon Dioxide (CO_2)[2]	6,700	26,780

Notes:
1. Estimates are based emissions information provided in vendor proposal for 0.1 MW, directly scaled up for larger units.
2. CO_2 emissions associated with biomass combustion are reported separately under the Environment Canada reporting program as these emissions are considered part of the global carbon cycle.

The operation of the Project which would supply heating to local buildings in addition to generation of electricity is expected to offset some air contaminant and greenhouse gas emissions currently resulting from diesel combustion for space heating of community buildings.

The releases of other GHGs (CH_4 and N_2O) from the operation of the Project are expected to be nominal, and are therefore not considered further in the assessment.

Releases of other air contaminants, specifically hazardous contaminants such as volatile organic compounds (VOCs), polycyclic aromatic hydrocarbons (PAHs) and dioxins and furans from the Project could occur in small amounts and are expected to be similar to that of other modes of biomass combustion.

Emissions of the hazardous air contaminants with largest expected emissions, *i.e.*, the air contaminants with the highest US EPA AP-42 biomass combustion emission factor, were estimated (US EPA 2003). Based on the US EPA AP-42 Emission Factors, benzene (C_6H_6) and formaldehyde (HCHO) are the air contaminants that are likely to be released in the highest quantities during Operation of the Project. Benzene emissions are estimated to range from 0.11 t/a to 0.44 t/a and formaldehyde emissions are estimated to range from 0.12 t/a to 0.47 t/a, depending on the scale of the Project (0.5 MW and 2 MW scenarios considered in the estimates). The emissions were estimated using the AP-42 emission factors and the energy input from the biomass fuel from the CPC proposal (CPC 2012). Discussion of how these emissions compare to other forms of heat and energy is provided in the Atmospheric Environment Section 5.2.

The gasification process is operated with relatively dry biomass (15% moisture) at a high temperature and the syngas produced is cleaned and filtered prior to combustion, which helps to reduce the release particulate matter to the atmosphere. The combustion of syngas in an internal combustion engine also serves to reduce emissions of hydrocarbons as a result of higher operating pressures and temperatures than that of a boiler. In addition, the annual volume of biomass consumed during Operation is relatively small.

Further details on the emissions from the Project and are provided in Section 5.2 of this document.

3.3.2 Sound Emissions

During Construction, the potential exists for unwanted sound ("noise") to be generated that could be considered to be a nuisance to nearby residents and land users, primarily as a result of the operation of heavy equipment required to complete construction activities. Equipment deliveries and construction traffic accessing the site, although not expected to be substantive, may result in slightly increased traffic levels in the community and possibly increased sound pressure levels at nearby locations.

During Operation of the Project, the potential exists for noise to be generated from the plant as well as harvesting operations. The biomass energy plant components will be housed within buildings and/or containers to reduce the resulting sound emissions from the gasifier and engines. The wood chipper location is currently unknown, as is the technology to be used.

The estimated sound pressure level from the operation of a 0.5 MW gasification plant is 81 dB_A at 4.5 m (10 feet), based on the maximum sound pressure level provided by CPC (CPC 2012).

The estimated sound pressure level from the operation of a 2 MW gasification plant is 87 dB_A at 4.5 m (10 feet), based on the maximum sound pressure level provided by CPC (CPC 2012).

Wood chipping of whole trees is known to be a noisy activity. A UK study on sound emissions from mobile chippers found that at a distance of 8 m of the chipper, sound pressure levels (based on 11 chippers) ranged from 89 to 99 dB_A (Health and Safety Laboratory 2008).

These sound pressure levels are used to estimate sound pressure levels at various distances from the Project, in Section 5.2.

3.3.3 Construction and Operational Solid Wastes

Solid waste generated during the construction phase would be disposed of in an approved landfill.

Operational solid wastes may include particulate matter collected by the syngas cleaning system (if required based on the design), char removed from the gasifier, and wastes associated with maintenance activities (*e.g.*, oily rags, cleaners). All wastes generated would be disposed of in an approved landfill.

3.4 PROJECT PHASES AND SCHEDULING

The Project schedule depends on the size of biomass plant selected following the FEED Study review. Preliminary schedules for the potential envelope of Project sizes are provided in Figure 3.4.1.

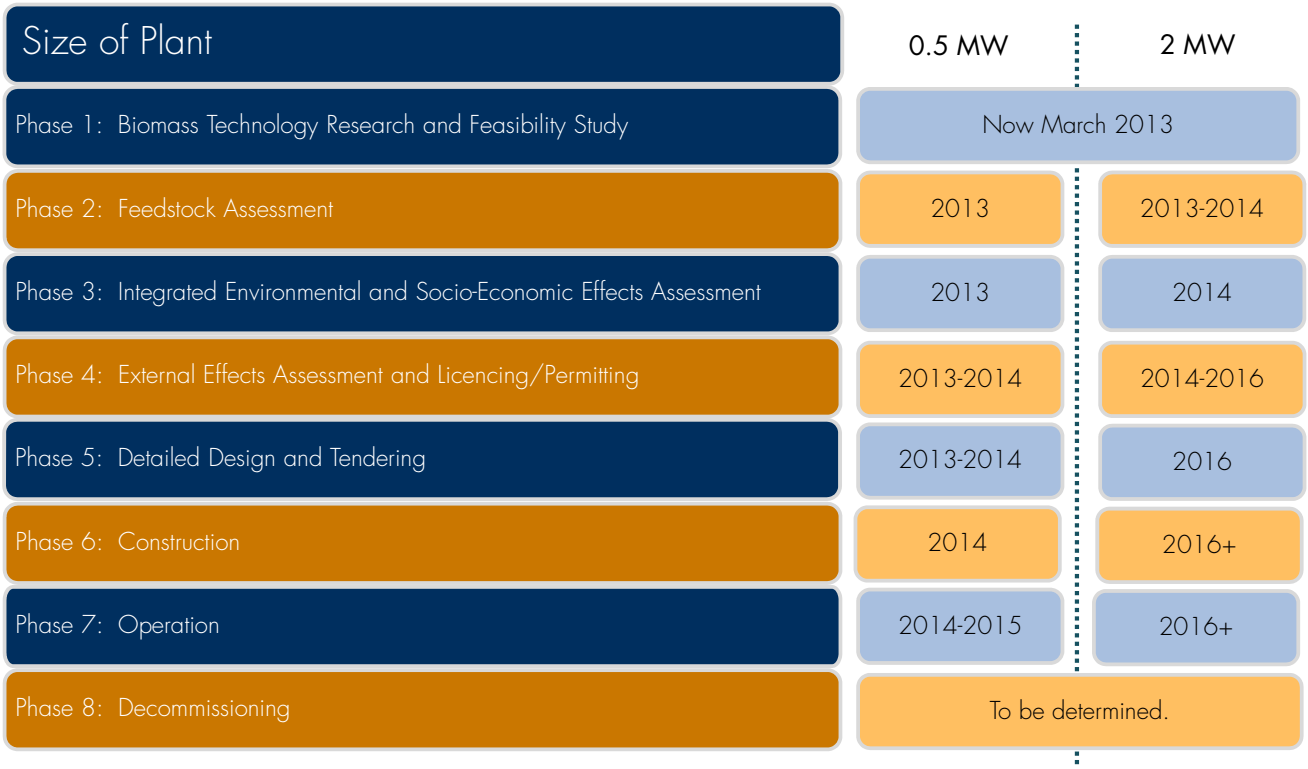


Figure 3.4.1 Project Phases and Schedule

3.5 ALTERNATIVES

Gasifier and reciprocating engine technology is the ideal choice for northern communities who wish to generate combined heat and power as steam is not required. Steam plants and systems require operators with power engineering certification and these professionals are not readily available in northern communities. Gasifer, reciprocating engine systems can be operated by trained mechanics or electricians which is more suited to the existing work force in the north. As the site has not been selected, an alternatives discussion will be delayed until siting is finalized. Alternatives for siting are being considered based on technically feasible locations (close enough for heat recovery), visually acceptable, appropriate land use and sufficient set-backs to limit noise complaints. Traditional and current activities and culture will also play an important role in Project siting, with areas of importance for these activities to be defined through the consultation process.

4.0 DESCRIPTION OF EXISTING ENVIRONMENTAL AND SOCIO-ECONOMIC CONDITIONS

Existing conditions for environmental and socio-economic conditions in relation to the Project location and valued components are summarized in this Chapter. This information is provided for use in the assessment of potential environmental and socioeconomic effects from the Project.

4.1 ENVIRONMENTAL CONDITIONS

A summary of existing environmental conditions in the vicinity of the Project is provided in this chapter. The summary is based on existing literature and sources of information that are available in the area of the Project. Field reconnaissance has not been conducted at this time.

4.1.1 Study Area and Physiography

The Village of Haines Junction is located at kilometer (km) 1,632 of the Alaska Highway at the intersection of Haines Highway. Haines Junction is approximately 158 km west of Whitehorse, the capital city of Yukon Territory. The village is located between mountain ranges of the Kluane Ranges, the Dezadeash Range, and the Ruby Range. The Auriol Range (of the Kluane Ranges) is the closest range to the village and is situated approximately 5.5 km southwest of Haines Junction. The village situated within Shakwak Valley, which covers the area from Pine Lake southwest to the Auriol Range. Haines Junction is located north of the main branch of Dezadeash River. The village is the gateway to Kluane National Park and Reserve.

4.1.2 Surficial Geology, Terrain, and Soils

EBA Engineering Consultants Ltd. (2003) encountered alternately clayey tills and fine grained glaciolacustrine depositing consisting of silt and clay with occasional sand and gravel lenses during drilling of well No. 5 in Haines Junction. During the drilling program an artesian sand and gravel aquifer was encountered below the alternating layers at a depth of 329 m continuing to 369.2 metres below ground level.

Bedrock geology in the Ruby Ranges is characterized by three geological terranes and two faults, with highly metamorphosed sedimentary and granitic rocks covering most of the area (YEWG 2004). The surficial geology of the ecoregion is comprised of steep bedrock exposures, colluvium and talus slopes at high elevation, moraine and glaciofluvial gravelly sands at mid-elevation, and silt-clay deposits from the Lake Sekulmun-Aishihik glacial lake retreat at lower elevations (YEWG 2004). Bedrock geology in the Yukon Southern Lakes ecoregion is divided up into three zones; coarse-grained, crystalline metamorphic and granitic rocks in the east and west and mafic volcanic, limestone and clastic sediments in the central zone. Surficial geology in characterized by deposits laid down during the most recent glacial retreat period, the McConnell, and vary throughout the ecoregion (YEWG 2004:210).

4.1.3 Transportation

The Yukon Government (YG) Transportation and Planning Branch conducts annual traffic counts and publishes a summary report to inform interested parties (Government of Yukon 2011a). The following average summer daily traffic (ASDT), and average annual daily traffic (AADT) are considered relevant to the Project. The Alaska Highway South of Haines Junction has an ADT of 579 (based on 70 days of counts) while the Alaska Highway to the North was counted at 491 AADT and a ASDT count of 720, showing a notable increase due to summer tourism. Haines Road counts for 2011 were 227 AADT and 370 for ASDT. Traffic counts east of Haines Junction on the Alaska Highway show a slight decline from 1994 to 2011 (0.8% decrease).

4.1.4 Groundwater Resources

The location of the biomass plant will be within Haines Junction, although the exact location is not finalized. Based on technical constraints for the use of waste heat from the plant, the plant must be located within approximately 400 m of larger buildings within the village (*e.g.*, the school and cultural centre).

The Village of Haines Junction has five developed municipal wells. As of 2012, well number 3 and well number 5 are the only wells currently being used as supply wells. In 2010 the total water consumption of the village was 140,088 cubic metres (m^3) (J. Gibson Environmental Consulting 2011). The municipal water system has recently undergone upgrades to increase production and storage capacity of water for the village. The upgrades factored in population growth and increased industry in the area. As part of the upgrades, well No. 4 was decommissioned.

There are ten private wells located in and around Haines Junction. These wells are associated with business (*e.g.*, gas station, motel), a subdivision, the school, the experimental farm, and some private residences.

All the wells in Haines Junction have been installed in overburden materials; there are no known bedrock wells. According to a 2003 report by EBA Engineering Consultants Ltd. (EBA Engineering Consultants Ltd. 2003), the aquifers in the area have component of dips from south to north.

Groundwater samples were collected following a pump test on well number 5 (conducted by EBA Engineering Consultants Ltd. in July 2003). They reported that the analytical results were below the Canadian Council of Ministers of the Environment (CCME) Canadian Drinking Water Quality Guidelines for all parameters.

Areas to be harvested as sources of feedstock have not been identified at this time. Once selected, information regarding groundwater resources at these sites, if available/applicable, will be included in this report.

4.1.5 Traditional Ecological Knowledge

Minimal published information is available on traditional ecological knowledge. and formal consultation has not been conducted specifically to define relevant Traditional Ecological Knowledge (TEK). Details

on TEK in the area will be provided as part of the next stage of the assessment based on consultation with CAFN and the Haines Junction community.

4.1.6 Additional Existing Conditions

The existing conditions for the VCs being considered in detail in this assessment are summarized in Chapter 5 as follows:

- Atmospheric Environment, including air quality, greenhouse gas emissions and sound quality are discussed in Section 5.2.2.
- Terrestrial Environment including vegetation, wildlife and wetland habitat are summarized in Section 5.3.2.
- Freshwater Resources are summarized in Section 5.4.2.
- Heritage Resources are summarized in Section 5.5.2; and
- Traditional Activities and Culture are summarized in Section 5.6.2.

4.2 SOCIO-ECONOMIC CONDITIONS

4.2.1 Champagne Aishihik First Nation

The Champagne and Aishihik First Nations (CAFN) is a self-governing First Nation with Traditional Territories in the Yukon Territory and Northern British Columbia. CAFN has a total population of approximately 1,238 (as of June 2012) with 712 people residing in the Yukon Territory.

The CAFN was named after two of its historic settlements: Champagne, located on the Dezadeash River; and Aishihik, situated at the headwaters of the Alsek River drainage. Formerly, the Southern Tutchone population was located throughout the region in other villages including Kloo Lake, Klukshu, Canyon, Shäwshe and Hutshi.

Their main administrative center is located in Haines Junction. The CAFN also maintains an office in Whitehorse.

Of the Yukon's fourteen First Nations, the CAFN is one of the largest in the Yukon. Its traditional territory covers 41,000 square kilometers, 29,000 of which are located in the Yukon and 12,000 in British Columbia. The easterly portion of CAFN's traditional territory lies in the Yukon River watershed where the Yukon River flows into the Bering Sea, while the larger, westerly portion lies in the Alsek River watershed where the Alsek River flows into the Gulf of Alaska. Much of Kluane National Park (Yukon) and all of Tatshenshini-Alsek Park (BC) lie within CAFN's traditional territory.

4.2.2 Labour and Economy

Occupations in Haines Junction are predominantly trades, sales and service, business, and management. Other occupations in the village include science, government, industry, processing and manufacturing, health, and arts, culture, and sports.

4.2.3 Public Health and Well-being

YEC has a comprehensive health and safety program that has been developed in accordance with the Yukon Occupational Health and Safety Act and regulations. Yukon Energy has entrenched health and safety training and procedures in every day operation and ensures that policies, practices, and procedures are clear to employees, and are consistently applied. Training on safe practices and procedures is a responsibility taken very seriously. Ongoing reviews, regular inspections and periodic audits are conducted to identify areas for improvement in health and safety practices with the goal of continuous improvement in mind.

4.2.4 Land Use and Infrastructure

The Village of Haines Junction does not have a land use plan (VOHJ 2007). The proponent will consider acceptable land use when planning for the Project and will consult with the Village in locating the Project.

5.0 ENVIRONMENTAL AND SOCIO-ECONOMIC EFFECTS ASSESSMENT

The overall assessment approach is described in this section.

5.1 ASSESSMENT APPROACH

The approach to the effects assessment includes scoping, studying the potential Project-environment interactions, estimating releases to the environment, assessing the potential environmental effects, establishing significance of the effects, and providing consideration of follow-up and monitoring that may be required.

Scoping of the assessment includes:

- identifying issues of concern related to the Project,
- selecting Valued Components (VCs) for further examination that include both Environmental and Socio-economic aspects;
- identifying potential sources and pathways of effects from the Project to each VC selected;
- identifying spatial and temporal boundaries for assessing effects of the Project for each selected VC; and
- identifying other actions and effects pathways that may act cumulatively with the Project to affect the same VCs.

5.1.1 Valued Environmental and Socio-Economic Components

A number of Valued Components have been anticipated for various phases or activities associated with the physical works of the proposed Project. Based on currently available Project information, these are defined as in Table 5.1.1. Consideration has been given to the plant as well as the feedstock harvesting activities.

Table 5.1.1 Potential Interactions of the Project with the Environment

Phases, Activities or Physical Works Associated with the Power Facility	Atmospheric Environment	Groundwater Resources	Freshwater Environment	Vegetation Environment	Wildlife Resources	Human Health and Wellbeing	Land Use and Infrastructure	Heritage Resources	Traditional Activities and Culture	Transportation	Labour and Economy	Effects of Environment on Project
Plant Site												
Construction	1	1	0	1	1	1	1	2	1	1	1	1
Operation	2	1	0	1	1	1	1	0	1	1	1	1
Decommissioning and Abandonment	1	1	0	0	0	1	1	0	0	0	1	1
Forest Feedstock Harvesting												
Construction	1	0	2	1	1	1	1	2	1	1	1	1
Operation	1	0	2	2	2	1	1	2	2	1	1	2
Decommissioning and Abandonment	1	0	1	1	0	0	0	0	0	0	1	0

KEY

0 = No interaction. The environmental effects are not significant and not considered further in the assessment.

1 = Interaction occurs; however, based on past experience and professional judgement the interaction would not result in significant environmental effect, even without mitigation; or interaction would not be significant due to application of codified environmental protection practices that are known to effectively mitigate the predicted environmental effects. The environmental effects are not significant and not considered further in the assessment.

2 = Interaction could result in environmental effect of concern even with mitigation; the potential environmental effects are considered further in this assessment.

The current scope of impact assessment does not include detailed assessment of potential interactions of Feedstock Harvesting with the environment; however, Table 5.1 above has been drafted based on expected interactions with both the plant site and feedstock harvesting. There are unknowns regarding the possible mitigation measures required for harvesting activities. The higher rankings are focused on wildlife, traditional pursuits, trapping, and heritage/cultural values and other land use (guiding, recreational uses, outfitting, wilderness tourism).

Based on the rankings provided in Table 5.1.1 above, the Project will result in an interaction with the following VCs (*i.e.*, a ranking of 1), during one or more phases of the Project:

- Groundwater Resources;
- Human Health and Wellbeing
- Land Use and Infrastructure;
- Transportation; and
- Labour and Economy.

Further discussion is provided below.

Groundwater Resources

Groundwater is the water held beneath the earth's surface in the pores, fractures, crevasses, and seams of bedrock and surficial geology. Groundwater Resources refer specifically to the value and function of groundwater in maintaining stream flow for ecological habitat and in supplying fresh water for human use. Groundwater availability for ecological and human uses and its susceptibility to chemical degradation or physical depletion by human activities is determined by the natural chemical and physical properties of the surficial and bedrock geology in which it is found.

Interactions between the Project and Water Resources have been ranked as 1 in Table 5.1.1 because the Project will not substantively alter the water requirements during any phase, and the existing water supply will continue to be used throughout the Operation of the Project. The maximum conceivable water consumption of this Project is estimated at 3.2 m^3/day or less depending on the vendor selected.

Water resources in Yukon are regulated at the federal and territorial level under a number of Acts and regulations.

Relevant acts, policies and guidelines related to the protection of water quality include the following:

- Yukon *Environmental and Socio-economic Assessment Act*;
- Yukon *Waters Act* and *Regulations*; and
- water quality guidelines (Canadian Council of Ministers of the Environment).

Groundwater resources are included as a VC because they provide potable, commercial, and industrial water supply to the population of Haines Junction. The potential for the disruption or contamination of the groundwater drinking supply for nearby residents therefore requires assessment.

Possible effects to Groundwater Resources include a change in groundwater quantity and a change in groundwater quality. It is unlikely that there will be effects to the quantity of groundwater in Haines Junction resulting from the Project as the village's water treatment system was recently upgraded. In addition, due to mitigation included Section 6.0 (Accidents, Malfunctions, and Unplanned Events), a contingency plan will be in place during operation for accidental spills at the plant. At this time the location of feedstock harvesting is unknown, however, vibration from large machinery may affect the water quality of any drinking water wells in the vicinity of harvesting operations.

In the event that the feedstock harvesting site is located near drinking water wells the potential effects will be evaluated. Mitigation measures may include baseline sampling and monitoring of the well(s) during operation to confirm that the water quality is not affected.

Follow-up may include monitoring of any drinking water wells in the vicinity of feedstock harvest operations. Additionally, investigation of any residential well owner complaints may be conducted, with application of industry standard remedial measures to rectify an effect.

In consideration of the nature of the interactions and relation to existing legislation and environmental policy in respect of Groundwater Resources, significant adverse environmental effects of the Project on Water Resources during all phases of the Project are not anticipated. Groundwater Resources are not considered further in this document.

Human Health and Wellbeing

Interactions between the Project and Human Health and Wellbeing have been ranked as 1 because Project activities, if not carried out in a careful and safe manner, could result in risks to the public or workers. Occupational exposure of Project workers to an industrial site carries with it a number of health and safety concerns, which are subject to territorial occupational health and safety legislation.

Yukon Energy has, and will continue to have, many measures in place to protect safety, including worker health and safety policies, and limited access to the facility. The Project would comply with emissions limits, which are established to be protective of health.

The Project will necessarily comply with all requirements of the Yukon Occupational Health and Safety Act and Regulations; thus, the environmental effects of the Project on Health and Safety will not be significant from the perspective of worker safety and occupational exposure. There are no features of the Project that would result in a higher potential for Accidents, Malfunctions, or Unplanned Events to occur as compared to similar industrial projects. Prior to commissioning of the plant, an emergency response plan would be developed to handle potential accidents, malfunctions and unplanned events that may occur in a safe manner. Employees hired to work at the plant or in harvesting activities would be provided with all required health and safety training prior to beginning work.

Procedures would be developed for the safe operation of the plant to minimize the likelihood of a work place accident or unplanned event that could affect the public.

As the Project involves consumption of spruce bark beetle-killed wood that is very dry and is suspected to be creating increased potential of forest fires surrounding Haines Junction, there could be a reduced likelihood of health and safety issues associated with implementation of the Project.

Based on the above, no substantive interactions between the Project and Health and Safety are anticipated. Therefore, significant adverse environmental of the Project on Health and Safety during all phases of the Project are not anticipated, and are not considered further.

Land Use and Infrastructure

As the location of the Project is not currently known, the extent of potential effects on land Use and Infrastructure cannot be fully assessed at this time. Land use by First Nations communities is considered as part of the Traditional Activities and Culture section.

Transportation

Interactions between the Project and Transportation have been ranked as 1 in Table 5.1.1 because of Project-related traffic to and from the plant site and forest harvesting areas during Construction and Operation. Materials will be delivered to, and transported away from, the Project site by truck. During

Construction, Project components and other materials will be required. During Operation, biomass will be transported to the site and small shipments of ash will be transported away from the site.

Road Transportation is governed by the Yukon *Highways Act* and the Yukon *Motor Vehicle Act* and associated regulations. The Project will adhere to the restrictions and limitations included in these and applicable federal acts and regulations.

Traffic during Construction for materials and equipment deliveries is expected to be very low and is estimated at several trucks per week as well as several passenger vehicles. The estimated traffic is a total of 3 to 15 trucks per week during Operation depending on the size of plant installed. This increased traffic can easily be accommodated by existing truck routes.

There may be a requirement to dispose of some general construction wastes during Construction, which will be transported to existing recycling operations or to an approved sanitary landfill for disposal. However, the volumes of waste materials to be managed and transported from the site during Construction are expected to be very low, as most or all of the infrastructure would be fabricated offsite.

Ash generated during Operation will be trucked off-site to the landfill, composting facilities or other approved locations. Based on the quantities of ash generated at the site, it is expected that less than 1 shipment per week would be required.

During Operation of the Project, a reduction in the number of fuel oil trucks travelling to Haines Junction may occur as less diesel would be required in the buildings using the plant's waste heat.

Based on the above, no substantive interactions between the Project and Road Transportation are anticipated. The Project-related traffic is expected to be confined to existing truck routes and the addition of 15 trucks per day is not expected to result in a noticeable change in traffic volumes on these routes for the purposes of efficient and safe road transportation. Therefore, the potential environmental effects on Road Transportation during all phases of the Project are rated not significant, and are not considered further.

Labour and Economy

Interactions between the Project and Labour and Economy have been ranked as 1 in Table 5.1.1 because activities and physical works associated with all phases of the Project will result in job creation and business expenditure. Labour and Economy refers to the importance of employment opportunities and economic growth on a local and regional scale within the Yukon. The Proponent is committed to hiring CAFN citizens and other local and Yukon residents, where available.

During Construction, the Project is expected to create direct construction labour employment for construction contractors for site clearing and preparation as well as infrastructure work over the 8 month Construction period. The extent of job creation is dependent on whether the plant is located in a building and if so, what type of building is chosen. The total capital investment of the Project is estimated at approximately C$7 to $45 million dollars (depending on the option chosen).

The Project will generate additional employment during Operation; through employment at the plant site as well as in forest harvesting. The extent of employment is dependent on the plant technology and

size chosen as well as the methods used for harvesting. Regardless of the methods employed, several new jobs will be created in Haines Junction in both technical trades and forest resource management.

Employment opportunities will also occur during Decommissioning and Abandonment of the Project, at the appropriate time, although not currently contemplated.

Employment in the Yukon is regulated at the territorial level under the Employment Standards Act and Regulations.

The potential effects on labour and economy could also extend beyond the Project to • outfitters and tourism, commercial trapping and fishing and other forestry and agriculture. To reduce land use conflicts and any potential negative effects on others in relation to proposed activities on-site or along the access route, the Proponent will continue to consult with other users and communicate its plans and the timing of proposed activities to other resource users (*e.g.*, trappers, outfitters, and known subsistence harvesters) who may be affected by the Project, as soon as practicable and prior to commencement of the activity.

Given the lifespan of the Project and the potential for other future development activity in the area, it is a challenge to predict with certainty the full range of socio-economic effects that will occur. However, as the Project will only require a small fraction of available feedstock for Operation and will be planned to proceed in harmony with existing land use, negative effects are expected to be very small if they do occur.

Key socio-economic indicators for the Project will be monitored by the Proponent (*e.g.*, number of local, Yukon, other employees and value of local, Yukon goods and services). This will provide for an understanding of the Project‘s socio-economic effects, identification of any emerging or unanticipated effects, and the opportunity for the Proponent or other parties to respond as appropriate.

The effects monitoring and adaptive management related to Terrestrial Environment (Section 5.4) and Freshwater Resources (Section 5.5) may also be relevant in terms of potential effects on other local or regional economic activities, such as outfitting, tourism, and trapping. More information on proposed mitigation and adaptive management measures can be found in the sections referenced.

Overall, the increased demand for labour and anticipated employment opportunities and related economic spin-offs of the Project are expected to result in positive environmental effects on Labour and Economy. As such, positive environmental effects on Labour and Economy as a result of the Project are anticipated and are not discussed further.

VCs Ranked as 2

Based on the rankings provided in Table 5.1.1 above, the Project may result in a significant interaction with Atmospheric Environment (ranking of 2 during Plant Operation), Freshwater Environment (ranking of 2 for Feedstock Harvesting), Vegetation Environment (ranking of 2 during Feedstock Harvesting, Wildlife Resources (ranking of 2 for Feedstock Harvesting), Heritage Resources (ranking of 2 during Plant Operation and Feedstock Harvesting), Traditional Activities and Culture (ranking of 2 during Feedstock Harvesting) and Effects of the Environment on the Project (ranking of 2 during Feedstock Harvesting). These VCs are thus assessed in greater detail in the detail VC sections of this chapter.

The scope of this assessment is focused on components that could be linked to the Project; as set out in the YESAB Guide to Assessment, both Project-specific issues and regional issues that are relevant to the Project need to be considered in the establishment of VCs. Therefore, VCs have potential to be modified throughout the next stage of assessment (revisions based on decisions made following the FEED Study review). Similarly, determination of VCs and environmental and socio-economic scoping requires input from local communities and interested parties; in this case, that may involve field studies and consultation that have not been completed in this Project phase. Therefore, VCs and rankings will be revisited during the completion of the final Project Proposal for the Feedstock and Facility components.

5.1.2 Project Interactions with the Bio-Physical and Human Environment

The Project activities that may interact with the bio-physical and human environments are identified and described for each VC.

5.1.3 Description of Effects Mechanisms

For each VC, one or more measurable parameters will be identified for the potential Project-related and cumulative environmental effects. The magnitude of the change in these measurable parameters will be used to characterize the Project environmental effects and to evaluate the significance of the potential environmental effects.

5.1.4 Temporal and Spatial Boundaries

The temporal boundaries for the assessment will be defined based on the timing and duration of Project activities and the nature of the interactions with each VC. The purpose of a temporal boundary is to identify when an environmental effect may occur in relation to specific Project phases and activities.

The spatial boundaries for the assessment will be defined based on the geographical extent of the environmental effects (*i.e.,* the zone of influence) for each VC. Generally, the spatial boundaries will be referred to as the Assessment Area.

At this time, both of these boundaries have yet to be determined. However, YESAB Guides provide definitions which will be adhered to when they are finalized. The preliminary phases and footprints and defined in Section 3 (Project Description) and provided here for ease of review.

Construction Phase: This phase generally consists of the estimated time required to complete the construction of the Project, including commissioning of the facilities.

Construction Footprint Area: Construction Footprint Area is the geographic area needed for construction and operation of the physical infrastructure associated with Power facility (*i.e.,* power access, access road, the plant, office, maintenance building, log storage yard, chipping plant, chip storage, conveyor, hopper, *etc*.)

Operation Phase: The time period following construction, through the life of the relevant components of the Project, during which time the Project will be used for its primary purpose of power generation.

Decommissioning Phase: The time period following operation when the Facility is no longer being used for its primary purpose; this may include transitioning the facility to another use or closure and abandonment.

Project Study Region: A broader Project Study Region for examining potential environmental and socio-economic effects has yet to be defined.

5.1.5 Mitigation of Project Effects

Standard mitigation measures that have been developed by the "Ex Comm" under Section 37 of the *YESAA* will be included in the design and operation of the Project. Further, any additional mitigation required to reduce potential environmental effects to acceptable levels (below the threshold of significance, see Section 5.1.7) will be proposed and included in the assessment.

5.1.6 Characterization of Residual Effects

Residual environmental effects are those that remain after mitigation has been applied. Each residual environmental effect will be described for each VC and each Project phase. Residual effects will be assessed for significance.

Environmental effects for each VC will be characterized for each applicable Project phase and presented in an environmental effects summary table. The following criteria will be used to characterize potential residual environmental effects:

- **Direction –** the ultimate long-term trend of the environmental effect (*i.e.,* positive or adverse);
- **Magnitude –** the amount of change in a measurable parameter or variable relative to existing (baseline) conditions;
- **Geographic Extent –** the area where an environmental effect of a defined magnitude occurs (*e.g.,* site-specific, local, regional);
- **Duration –** the period of time required until the VC returns to its baseline condition or the environmental effect can no longer be measured or otherwise perceived (*e.g.,* short-term, medium-term, long-term, or in some cases permanent);
- **Frequency –** the number of times during the Project or a specific Project phase or activity that an environmental effect might occur (*e.g.,* one time or multiple times) in a specified time period;
- **Reversibility –** the likelihood that a measurable parameter will recover from an environmental effect, including through active management techniques (*e.g.,* habitat restoration); and
- **Ecological or Socio-economic Context –** the general characteristics of an area in which the Project is located, as indicated by past and existing levels of human activity.

A key for each environmental effects summary table will provide summary criteria that will be modified as necessary for each VC based on the specific boundaries (temporal, spatial) and significance criteria selected for each VC.

5.1.7 Determination of Significance of Residual Effects

The criteria or standards for determining the significance of environmental effects will be identified for each measurable parameter in each VC, beyond which a residual environmental effect would be considered significant. These will be generally selected in consideration of provincial and federal regulatory requirements, standards, objectives, or guidelines that are applicable to the VC. In the absence of standards or criteria, significance criteria will be suggested by the Study Team for consideration by the decision making regulatory authorities.

5.1.8 Project Interactions with Other Projects (Cumulative Effects)

A cumulative environmental effects assessment will be conducted for those Project-related environmental effects that may overlap (spatially or temporally) with other projects and activities that have been or will be carried out.

The environmental effects of other past and existing projects are generally reflected in the existing baseline environment and will therefore be considered in the Project-related environmental effects assessment for each VC.

Other projects that may overlap spatially or temporally with the Project will be identified.

5.1.9 Cumulative Effects Assessment Methods

The assessment of each cumulative environmental effect will begin with a description of the environmental effect and the mechanisms whereby the Project environmental effects may interact with other projects and activities in the Assessment Area. Where possible, the cumulative environmental effects will be quantified in terms of the degree of change in the appropriate measurable parameter(s).

5.1.10 Mitigation of Cumulative Effects

Similar to Project-related environmental effects, mitigation measures that would reduce the cumulative environmental effects will be described.

5.1.11 Characterization of Residual Cumulative Effects

Residual cumulative environmental effects will be described and assessed, taking the proposed mitigation into account. The cumulative environmental effects will be characterized where applicable and appropriate in terms of the direction, magnitude, geographic extent, frequency, duration, reversibility, and ecological or social-economic context.

5.1.12 Effects Monitoring and Adaptive Management

Follow-up programs are used, where applicable, to verify environmental effects predictions and effectiveness of mitigation measures. Monitoring programs are compliance programs used to verify that mitigation has been applied. Appropriate follow-up and/or monitoring programs are proposed where a need has been identified or where the scientific certainty of the environmental effects predictions or the effectiveness of the mitigation warrants the need for such programs.

5.2 ATMOSPHERIC ENVIRONMENT

The Atmospheric Environment is considered a VC as the atmosphere is a pathway for transport of air contaminants to humans, wildlife and vegetation as well as the built environment. If not properly managed, releases of air contaminants to the atmosphere may cause adverse environmental effects on the air, the land and the waterways in the vicinity of the Project.

Greenhouse gas (GHG) emissions are considered a major factor in climate change and are thus also assessed in relation to changes in GHG emissions from the Project.

Changes to air quality during Construction are expected to be limited to potential fugitive dust during ground preparation. Changes to air quality during Operation of the Project are possible due to emissions from the combustion of gasified biomass and from trucks used to deliver feedstock and/or materials to the site and move feedstock onsite.

Changes to sound quality during Construction and Operation of the Project are possible due to sound emissions from mobile and stationary equipment.

Measurable parameters and significance criteria for air quality are defined based on regulatory ground-level concentration standards and objectives, while for GHG emissions these are based on current best practice guidance from the CEA Agency. For sound quality, measureable parameters and significance criteria are defined based on sound pressure level guidelines.

The assessment of the Atmospheric Environment was centered on a 10 km x 10 km area centred near the Project site.

Existing conditions are defined based on published data from Environment Canada and Yukon Environment. An air contaminant and GHG emissions inventory was developed for Operation of the Project, as this is likely to generate the highest emissions of air contaminants and GHGs emissions during the Project life. Dispersion modelling of specific contaminants, selected due to substantive emissions, was performed for Operation to predict the ground-level concentrations of those contaminants. The results of the modelling were compared to ambient air quality standards and objectives.

The dispersion modelling results showed that during Operation the ambient concentrations are likely to be well below the ambient standards and objectives for the operational scenarios considered.

The estimated GHG emissions from Operation are considered to be low (less than 50,000 tonnes of carbon dioxide equivalent (CO_2e)).

Sound pressure levels during Construction are anticipated to attenuate to 55 dB_A within 600 to 1,500 m of the site (depending on activity). Construction activities are transient and will not take place during nighttime to help reduce annoyance and avoid sleep disturbance. Therefore, although Construction within 600 to 1,500 metres will generate perceivable noise, annoyance will be limited in duration and extent and occur during daytime hours only.

Sound pressure levels during Operation of the plant (excluding the chipper) are anticipated to attenuate to a nighttime background level (assumed at approximately 40 dB_A) within 600 metres of the site,

considering the 2 MW_e case and as a conservative estimate. However, wood chipping activities may be noticeably noisy and may cause widespread annoyance within 1,000 m. It is thus recommended that annoyance be mitigated by procuring the lowest noise generating chipper feasible, locating the chipper at least 1,000 m from the nearest permanent resident and/or installing noise mitigation such as a barrier between the chipper and the nearest residences to reduce noise transmission.

Thus, as will be demonstrated by the analyses that follow, with the proposed mitigation and environmental protection measures, the residual environmental effects on the Atmospheric Environment during all phases of the Project are rated not significant.

5.2.1 Scope of the Assessment

The scope of the environmental assessment of Atmospheric Environment is defined in consideration of the nature of the regulatory setting, the issues identified during public and First Nations engagement activities, potential Project-VEC interactions, and existing knowledge.

The Atmospheric Environment is considered a Valued Component (VC) for a number of reasons, as follows.

- The atmosphere and its constituents are needed to sustain life and maintain the health and well-being of humans, wildlife, vegetation and other biota.
- The atmosphere is a pathway for the transport of air contaminants to the freshwater, marine, terrestrial and human environments, presenting the contaminants in the form of varying atmospheric concentrations or in particle phase or gas phase deposition.
- If not properly managed, releases of air contaminants to the atmosphere from the Project may cause adverse environmental effects on the air, the land, and the waterways in the vicinity of the Project.
- GHG emissions accumulate in the atmosphere and are believed to be a major factor in producing the greenhouse effect which is believed to influence climate.
- If not properly managed, sound emissions in the form of noise (unwanted sound) from the Project may cause adverse environmental effects on the sound quality in the vicinity of the Project.

The Atmospheric Environment has therefore been selected as a VC due to the potential for Project-related activities to cause adverse environmental effects through processes that occur in the atmosphere.

In this assessment, the approach is to select the environmental effects, select the associated measurable parameters (concentrations, emissions rates of GHG or air contaminants) to be considered, establish boundaries for the assessment, characterize the environmental effects, establish the significance criteria, assess the residual environmental effects (with mitigation such as emission control equipment), determine significance, and prepare a follow-up or monitoring program as applicable.

5.2.1.1 Key Issues and Identification of Potential Effects

Potential interactions between the Project and the Atmospheric Environment are highlighted and those aspects of the Project that may cause environmental effects, either positive or adverse, are identified. The Project may interact with the Atmospheric Environment in the following ways:

- combustion of gasified biomass will generate air contaminant emissions in the form of particulate matter and combustion gases;
- construction and operation of the Project will result in sound emissions;
- equipment movement on-site, trucks used to deliver feedstock, equipment and/or materials to the site, and passenger vehicles will generate combustion gases and greenhouse gases as well as sound emissions during construction and operation;
- earthworks and on-site earth moving activities during construction will generate particulate matter in the form of fugitive dust; and
- removal of vegetation from forested areas to be used as fuel for the Project will result in combustion emissions from harvesting equipment, fugitive dust and a reduction in the availability of carbon dioxide sinks currently associated with the forested areas.

The potential environmental effects to be assessed are associated with Project-related releases of air contaminants and GHGs to the atmosphere during Construction, Operation, and Decommissioning of the Project.

5.2.1.2 Regulatory/Policy Setting

The regulatory requirements for assessing environmental effects on Atmospheric Environment in environmental assessments are prescribed by both the federal and territorial governments.

Air quality is regulated in the Yukon pursuant to the *Air Emissions Regulation* under the *Environment Act* (Government of Yukon 1998). The requirements for facilities that are sources of air contaminants are described in the Regulation and as part of the permitting process (Part V of the Air Emissions Regulation). Ambient air quality standards for Criteria Air Contaminants (CACs) are presented in the Yukon Ambient Air Quality Standards document. The releases of GHGs are not currently regulated in the Yukon.

Federally, the main instrument for managing air quality is via the *Canadian Environmental Protection Act* (*CEPA*) as well as from Canada-Wide Standards that have been developed under the CCME Canada-Wide Accord on Environmental Harmonization. The standards may include qualitative or quantitative standards, guidelines or objectives for protecting the environment and human health. A number of these exist to protect air quality, including those for benzene (not an ambient standard); dioxins and furans for specific industries, mercury for specific industries, and ambient air quality objectives for $PM_{2.5}$ and O_3.

The emissions of air contaminants from the Project and the predicted downwind ground-level concentrations (GLC) are compared to applicable Yukon Environment ambient air standards or

emissions limits, as well as to Canada-Wide Standards (CWS), where they exist. The ambient standards are developed by the regulatory agencies, including Yukon Environment and Environment Canada, and others such as the British Columbia Ministry of Environment (BCMOE), to provide threshold values for assessing the extent of the potential environmental effects on air quality, human health and the environment.

The ambient air quality standards and objectives used in the assessment are presented in Table 5.2.1. These thresholds are a combination of the territorial, provincial and federal values from the Yukon, British Columbia and Environment Canada, respectively.

Table 5.2.1 Ambient Air Quality Standards and Objectives

Compound	Averaging Period	Yukon Ambient Air Quality Standards* (µg/m³)	Other Ambient Air Quality Standards or Criteria (µg/m³)
Total Suspended Particulate Matter (TSP)	24-hour Annual	120 60 (geometric mean)	-- --
Particulate Matter Less than 10 microns (PM_{10})	24-hour	--	50 [2]
Particulate Matter Less than 2.5 microns ($PM_{2.5}$)	24-hour	30	30 [1]
Sulphur Dioxide (SO_2)	1-hour 24-hour Annual	450 (172 ppbv) 150 (57 ppbv) 30 (11 ppbv)	-- -- --
Nitrogen Oxides (NO_X) as Nitrogen Dioxide (NO_2)	1-hour 24-hour Annual	400 (213 ppbv) 200 (106 ppbv) 60 (32 ppbv)	-- -- --
Carbon Monoxide (CO)	1-hour 8-hour	14,885 (13 ppmv) 5,725 (5 ppmv)	-- --

Notes:
* Yukon Environment Ambient Air Quality Standards.
[1] CCME (2000), Canada-wide Standards for Particulate Matter (Based on 98th percentile of 3 year rolling average).
[2] BCMOE (2009), British Columbia Ministry of Environment Ambient Air Quality Objective for PM_{10}.

For GHG emissions and climate, the federal government recently released the latest version of *A Climate Change Plan for the Purposes of the Kyoto Protocol Implementation Act* in May 2012 (Environment Canada 2012a). Canada officially withdrew its participation in the Kyoto Protocol in December 2011; however, the federal government is still committed to addressing climate change. In October 2010, the final *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* established fleet average GHG emission standards for new vehicles in model years 2011 through 2016. Standards for the 2017 to 2025 model years are in development. In August 2011, the federal government proposed regulations to apply a GHG performance standard to new coal-fired electricity generation plants for the purpose of encouraging a phase-out of traditional coal-fired electricity generation. Proposed regulations for the reduction of GHG emissions from new on-road heavy-duty vehicles were announced in April 2012.

With respect to federal guidance on assessing GHG emissions and climate change, the Canadian Environmental Assessment Agency (“CEA Agency”) has not updated its 2003 guidance (CEA Agency 2003). This EIA Report includes an assessment of emissions from the Project and from the related industrial sector. Further, where Project emissions are medium or high, preparation of a GHG Management Plan is required.

In relation to sound quality, there are no overarching noise guideline levels, regulations, or standards currently established in the Yukon Territory for limiting acceptable noise levels from industrial facilities. The Yukon Government generally requires that sound emissions from any activity not disturb the peace and quiet of persons outside the premises or vehicle (Government of Yukon 2002a).

Under Health Canada's *Useful Information for Environmental Assessments* (Health Canada 2010), construction activities that last for less than 2 months may be considered temporary and do have any sound pressure level guidance. For construction phases less than one year in duration, Health Canada recommends using the US EPA method from their 1974 document on noise (US EPA 1974), where an equivalent day-night average ("L_{DN}") of 55 dB_A outdoors is considered the threshold for widespread complaints. For construction phases greater than one year in duration and during operation the Health Canada guidance is based on the change in percentage of highly annoyed due to the noise. L_{DN} is an energy-weighted average, similar to the equivalent sound pressure level, L_{eq}, for a full day, except that the night time hour (22:00 to 07:00) levels are artificially weighted by an additional 10 dB_A to reflect increased sensitivity of the community to sound levels during those hours. The percentage highly annoyed is estimated for the baseline condition and for the baseline plus the construction condition. The guideline indicates that the increase from the estimated percent highly annoyed of the baseline condition to the construction of a project should not be greater than 6.5%. The algorithm to calculate the percent highly annoyed is defined by ISO 1996-1:2003 (Canadian Standards Association 2003).

As the Haines Junction School is the nearest sensitive receptor to the preliminary Project site, guideline levels from the World Health Organization (WHO) for schools are also considered. The sound pressure level in an outdoor playground area should not exceed 55 dB_A or 35 dB_A indoors (WHO 1999).

With respect to perception of noise, a 3 dB change in sound pressure level is considered to be the threshold of which a change in sound pressure level is noticeable (Hoover & Keith Inc. 1981). A change of 10 dB_A gives a perception that the sound is twice as loud (Hoover & Keith Inc. 1981).

These regulatory requirements form the basis for the assessment of the potential environmental effects on Atmospheric Environment and are discussed in more detail in the following sections.

5.2.1.3 Selection of Measureable Parameters

The environmental assessment of the Atmospheric Environment is focused on the following aspects:

- Change in Air Quality;
- Change in GHG Emissions; and
- Change in Sound Quality.

The Atmospheric Environment has been divided into three key factors for consideration in the EIA, reflecting key Project-atmospheric interactions: Air Quality, Climate Change and Sound Quality.

- Air Quality is defined as a measure of the constituents of ambient air, and includes the presence and the quantity of these constituents including air contaminants in the atmosphere. The aspect of concern is defined as a Change in Air Quality, reflecting potential changes resulting from emissions from the Project.

- GHG Emissions and Climate, for the purpose of this assessment, are defined as the presence and quantity of GHGs in the atmosphere. The aspect related to climate change to be assessed is the net emissions of greenhouse gases (GHG) as a result of the Project.

- Sound Quality in the outdoor environment may be adversely affected by the Project. Noise is defined as unwanted sound and is usually present through a range of frequencies. The audible frequencies for humans are in the range of 20-20,000 Hertz (Hz). In this assessment, the environmental effects of sound emissions from the Project on Sound Quality in the area surrounding the Project are assessed.

The assessment of Changes in Air Quality, GHG Emissions and Sound Quality in the atmosphere requires knowledge of the constituents making up and present in the atmosphere, both in magnitudes and as trends. This knowledge is established by measuring concentrations of air contaminants and GHG as well as sound pressure levels in the atmosphere at strategic locations for extended or representative periods of time.

The measurable parameters used for the assessment of the environmental effect presented above and the rationale for their selection are provided in Table 5.2.2.

Table 5.2.2 Measurable Parameters for Atmospheric Environment

Environmental Effect	Measurable Parameter	Rationale for Selection of the Measurable Parameter
Change in Air Quality	Ambient ground-level concentrations of Criteria Air Contaminants	• Regulatory objectives, guidelines and/or standards exist provincially and federally for SO_2, NO_X, CO, TSP, PM_{10} and $PM_{2.5}$, as well as specific hydrocarbon compounds.
Change in GHG Emissions	GHG emissions - CO_2, CH_4 and N_2O (in units of CO_2 equivalents or CO_2e)	• Greenhouse gases have been identified as a major contributor to climate change worldwide, thus management of GHG emissions has become a concern for the general public, industry and government.
Change in Sound Quality	Sound Pressure Levels, A-weighted scale (dB_A)	• Ambient sound pressure levels are characterized using a logarithmic decibel (dB) scale, with the A-weighted (dB_A) scale being the most commonly used for environmental sound assessments. Measured parameters for environmental sound or noise (defined as unwanted sound) are often expressed as an "equivalent sound level" (L_{eq}) which represents an equivalent energy level over a specified period of time (*e.g.*, 1-hour or 24-hours).

The magnitude of GHG emissions is expressed in units of CO_2e. The term "greenhouse effect" is commonly used to describe the earth's heat balance that maintains temperature, humidity and precipitation regimes and makes the earth habitable for humans and other forms of life. Increases in the ambient concentrations of CO_2 and other GHGs such as CH_4 and N_2O, over recent decades are believed by many to have changed the heat balance resulting in a warming of the planet. The ability to trap heat in the atmosphere varies with each GHG. This difference is expressed in terms of global warming potential (GWP). The GWP is established relative to CO_2 (*e.g.,* CH_4 has approximately 21 times the warming ability as CO_2). The relative contribution to the greenhouse effect, and both the emissions and concentrations of each GHG in the atmosphere, are commonly expressed in terms of its carbon dioxide equivalent, or CO_2e, by accounting for the GWP of each GHG.

5.2.1.4 Spatial Boundaries

The spatial boundaries for the environmental effects assessment of the Atmospheric Environment are defined below.

Project Development Area (PDA): The PDA is the most basic and immediate area of the Project. The PDA is limited to the area of physical ground disturbance associated with the Project, and consists of an area that includes the area of physical disturbance associated with the biomass plant. It will be revised following final site selection and detailed design and ultimately include the plant site and the area associated with biomass feedstock harvesting (including forest roads). The PDA is the area represented by the physical Project footprint as defined in Chapter 3.1.2 above.

Local Assessment Area (LAA): The LAA includes a 10 km x 10 km area centred on the plant site. The LAA is the maximum area within which Project-related environmental effects are likely to occur. The LAA includes the PDA and any adjacent areas where Project-related environmental effects may reasonably be expected to occur.

Regional Assessment Area (RAA): The RAA is limited to and includes the Yukon Territory for air quality, and extends nationally and globally for greenhouse gas emissions. For sound quality, the RAA is considered to extend 2 km from the PDA as no measurable cumulative effects related to sound quality would occur beyond this area. The RAA is the area within which the Project's environmental effects may overlap or accumulate with the environmental effects of other projects or activities that have been or will be carried out. The extent to which cumulative environmental effects for Atmospheric Environment may occur depend on physical and biological conditions and the type and location of other past, present, and reasonably foreseeable future projects or activities that have been or will be carried out, as defined within the RAA.

5.2.1.5 Temporal Boundaries

The temporal boundaries for the assessment of the potential environmental effects of the Project on the Atmospheric Environment include the phases of Construction, Operation, and Decommissioning.

5.2.1.6 Residual Effects Significance Criteria

For a Change in Air Quality, a significant adverse residual environmental effect is one that degrades the quality of the ambient air such that the maximum Project-related ground-level concentration plus the conservative background level of the air contaminant being assessed frequently exceeds the respective ambient air quality objective, guideline or standard. "Frequently" is defined as once per week for 1 hour objectives, once per month for 24 hour objectives or any exceedance of annual average objectives.

For a Change in GHG Emissions (related to climate change), following guidance from the CEA Agency, "the environmental assessment process cannot consider the bulk of GHG emitted from already existing developments. Furthermore, unlike most project-related environmental effects, the contribution of an individual project to climate change cannot be measured" (CEA Agency 2003). It is, therefore, recognized that it is not possible to assess significance related to a measured environmental effect on climate change on a project-specific basis. At the same time, it is recognized that a scientific consensus is emerging in respect of global emissions of GHG and consequent changes to global

climate as generally representing a significant cumulative environmental effect. Project emissions of GHG will contribute to these cumulative environmental effects, but the contribution, although measurable and potentially important in comparison to local and territorial levels, will be very small in a global context. Policies and regulations are being developed by the Government of Canada for regulating GHG emissions for specific sources or industry sectors.

Thus, instead of setting a specific significance criterion for environmental effects on GHG emissions or climate change and determining whether and how it can be met, the assessment involves estimating Project-related GHG emissions and considering the magnitude, intensity, and duration of Project emissions as directed by the CEA Agency guidance (CEA Agency 2003). Three categories are described in the CEA Agency guidance: low, medium and high. In this EIA, these are attributed quantitatively based on evaluation of GHG emissions from other industrial facilities and regulatory thresholds (such as reporting thresholds for GHG emissions to provincial and federal programs). For the purpose of assessment of magnitude of the Project GHG emissions, (on a tonnes CO_2e per annum basis), the following criteria have been developed.

- Less than 50,000 tonnes is considered low (as below this reporting to the federal program is not required).
- Between 50,000 and 500,000 tonnes is considered medium.
- Greater than 1 million tonnes is considered high.

Where the GHG emissions are considered to be either medium or high, a GHG Management Plan must be prepared.

For a Change in Sound Quality with respect to sound pressure levels, a significant adverse residual environmental effect on the Acoustic Environment is one where Project-related sound emissions during Construction cause the sound pressure levels at the nearest noise sensitive area or receptor (NSA) to frequently exceed the US EPA guidance of 55 dB_A (L_{DN}) and during Operation cause the percent of highly annoyed receptors to increase by 6.5%. “Frequently” is defined as twice (*i.e.*, two days) per week.

5.2.2 VC Existing Conditions

5.2.2.1 Air Quality

As noted earlier, the Project is located in an area that is primarily rural, in the community of Haines Junction. There are no other substantive sources located nearby. Existing emissions of air contaminants are limited to household and institutional (school, other smaller community buildings) heating appliances burning wood or oil and motor vehicle fuel combustion.

There are no ambient air quality monitoring stations in the area of the Project. The nearest air quality monitoring station is located in Whitehorse, approximately 130 km to the east of the Project site. In the absence of any other ambient air quality monitoring information near the Project site, existing conditions in the Project area are based on the most recent monitoring data from the Whitehorse station. Ambient concentrations of particulate matter < 2.5 microns ($PM_{2.5}$), nitrogen dioxide (NO_2), carbon monoxide

(CO), and ozone (O_3) are measured at the station. The most recently available monitoring data were obtained from Yukon Environment and Environment Canada. Ambient air quality data is collected at Whitehorse by Environment Canada as part of the National Air Pollution Surveillance Program (NAPS) (Environment Canada 2012b).

Based on the information provided by Environment Canada, there have been equipment operational issues over the last few years; therefore, there are some gaps in the data. Thus, data from 2008-2010 were used to establish the existing conditions with respect to ambient air quality in the area.

The publication from Yukon Environment, entitled *Yukon State of the Environment Interim Report – An Update from Environmental Indicators 2012* provides an additional description of existing and historical ambient air quality conditions in the Whitehorse Area (Yukon Environment 2012a).

Based on the information provided in the environment report, there were 15 days with exceedances of the $PM_{2.5}$ ambient standard in 2009. As noted above, there are some gaps in the data; in 2009 the months of January and February are missing due to equipment operational issues. The average concentration of $PM_{2.5}$ in 2009 is also higher than in recent years. This is likely attributed to a substantive increase in wildfires in the summer of 2009. There were no measured concentrations exceeding the 24-hour $PM_{2.5}$ Yukon Standard in 2008 or in 2010.

For NO_2 and CO, no exceedances of the Yukon ambient air quality standards were measured in 2008, 2009 or 2010 at the Whitehorse station. Further, based on the monthly average data from Environment Canada the NO_2 and CO concentrations are relatively low, most of the time.

For O_3, there were no exceedances of the 8-hour average Canada-wide Standard for the period of 2008 to 2010.

The 2010 annual average NO_2, CO, and O_3 concentrations measured at the Whitehorse station are 5.5 $\mu g/m^3$, 0.4 $\mu g/m^3$, and 32 $\mu g/m^3$, respectively. The 2010 annual average $PM_{2.5}$ concentration measured at Whitehorse is 1.9 $\mu g/m^3$. The 2010 annual average concentrations are based on data from the beginning of January to the end of May, as data from June to December were unavailable for 2010 due to station operational issues, as noted above.

The measured air contaminant concentrations at Whitehorse are likely to be higher than ambient concentrations in Haines Junction, given Haines Junction is a smaller, more rural community and Whitehorse is a larger centre with more sources of emissions, specifically vehicle traffic and increased stationary combustion related to heating. However, due to the regional nature of ambient ozone concentrations, the concentrations measured at Whitehorse would likely be similar to what would be observed in Haines Junction.

In summary, as there are no substantive sources of emissions in the in the vicinity of the Project or in region, the air quality in the Project area is considered to be good, as the rate of compliance with the ambient standards is greater than 95% for the period of 2008 to 2010. Occasionally during winter under certain meteorological conditions (calm winds, atmospheric temperature inversion), smoke from home heating has been observed at ground level.

5.2.2.2 Air Contaminant and GHG Emissions

The existing air contaminant and GHG emissions sources in the Haines Junction area consist mainly of combustion emissions associated with space heating of public buildings and houses located in the community, power generation in small diesel generators (very infrequent) and vehicle emissions. Emissions also result from natural events/releases such as forest fires (during the summer months).

Air contaminant and GHG emissions from institutional sources related to space heating requirements in the Haines Junction area are provided in Table 5.2.3. The emission rates are estimated using US EPA emission factors for diesel combustion (US EPA 2010) and the estimated diesel fuel offset volumes from the *Haines Junction Bioenergy Project – Evaluation of Waste Heat Potential Final Report* dated December 10, 2012, prepared by Clean Technology Community Gateway (CTCG 2012).

Table 5.2.3 Estimated Existing Space Heating Emissions – Haines Junction

Building	Emission Rate (t/a)						
	NO_X	CO	SO_2	TSP	PM_{10}	$PM_{2.5}$	CO_2
School	0.082	0.021	0.88	8.2E-03	4.5E-03	3.4E-03	91.9
Convention Centre	0.019	4.8E-03	0.20	1.9E-03	1.0E-03	8.0E-04	21.4
Arena & Pool Complex	0.13	0.033	1.4	0.013	7.1E-03	5.5E-03	147
Fire Hall and Yukon Government Building	0.085	0.021	0.91	8.5E-03	4.6E-03	3.5E-03	95.2
Total	**0.32**	**0.080**	**3.4**	**0.032**	**0.017**	**0.013**	**356**

Greenhouse gases (GHG) of primary concern include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), among others. Territorial GHG emissions in 2010, including industrial facilities, vehicles and natural sources, were 340 kilotonnes of carbon dioxide equivalent (CO_2e) (Environment Canada 2012c). No facilities in the Yukon Territory reported GHG emissions to Environment Canada in 2010, indicating none are over 50,000 t CO_2e (Environment Canada 2011).

Canada's GHG emissions in 2010 were 692,000 kilotonnes CO_2e (Environment Canada 2012c). Yukon's contribution to national GHG emissions is <1%. GHG emissions due to stationary combustion account for 324 kilotonnes CO_2e in 2010 (Environment Canada 2012c), which represents approximately 0.05% of Canada's 2010 emissions.

Carbon dioxide emissions globally are estimated to be 34 Gt per year (Climate Analysis Indicator Tool (CAIT 2012). Canada's contribution to global GHG emissions is approximately 2%.

5.2.2.3 Sound Quality

Sound Quality in the outdoor environment can be influenced by a variety of natural and anthropogenic sources. These may include unwanted sounds (noise) from stationary and mobile sources, noise from industrial equipment, vehicle traffic, and the operation of heavy equipment such as bulldozers, trucks, or diesel generators. It is also well known that sound propagation and the potential environmental effects of noise on nearby receptors is heavily influenced by weather conditions such as temperature, humidity, wind direction and wind speed. Local topographical features such as hills or wooded areas may serve to attenuate sound levels. Also, large reflective surfaces such as water bodies may serve to reflect sound to more distant locations than would occur in their absence. There may also be sound reflections if the atmospheric mixing height is low (a few hundred metres), or if solid structures are located close to sources of noise emissions.

Existing sound levels in the immediate vicinity of the proposed Project have not been documented in this or any previous work. Local traffic is expected to be the main contributor. However, given the nature of the area within the community of Haines Junction, existing sound levels are expected to be typical of a small rural community with higher sound pressure levels near the main throughways. According to the ERCB (2007), a typical sound level on a quiet street during daytime hours is 50 dB_A. Based on the experience of the Study Team, sound pressure levels at night in a quiet rural community may be between 30 and 40 dB_A.

5.2.3 Potential Project VC Interactions

5.2.3.1 Project Effects Mechanisms

Each Project activity and physical work for the Project is listed in Table 5.2.4. The activities are ranked as 0, 1, or 2 based on the level of interaction each activity or physical work will have with the Atmospheric Environment.

Table 5.2.4 Potential Project Environmental Effects to the Atmospheric Environment

Project Activities and Physical Works	Potential Environmental Effects		
	Change in Air Quality	Change in GHG Emissions	Change in Sound Quality
Construction			
Site preparation	1	1	2
Physical construction of the facility structures and installation of equipment	1	1	2
Commissioning	1	1	1
Construction of infrastructure for feedstock harvesting	1	1	1
Operation			
Operation and Maintenance of Plant Site	2	2	2
Feedstock Harvesting	1	1	1
Decommissioning, Reclamation and Closure			
Plant Site	1	1	1
Harvested Areas	1	1	1

Project-Related Environmental Effects
Notes:
Project-Related Environmental Effects were ranked as follows:
0 = No interaction. The environmental effects are rated not significant and are not considered further in this report.
1 = Interaction will occur. However, based on past experience and professional judgment, the interaction would not result in a significant environmental effect, even without mitigation, or the interaction would clearly not be significant due to application of codified practices and/or permit conditions.. The environmental effects are rated not significant and are not considered further in this report.
2 = Interaction may, even with codified mitigation and/or permit conditions, result in a potentially significant environmental effect and/or is important to regulatory and/or public interest. Potential environmental effects are considered further and in more detail in the EA.

The Project activities during Construction, Operation and Decommissioning may result in emissions of sound, air contaminants and GHGs to the atmosphere. These emissions may cause adverse environmental effects on the Atmospheric Environment, specifically a Change in Air Quality, Change in GHG Emissions and Change in Sound Quality during Operation.

During Construction, air contaminant and GHG emissions and noise are likely to occur; however, given the relatively small scale of the Project, emissions of air contaminants, GHGs and noise are not likely to be substantive. Fugitive dust is expected to be the largest potential concern during Construction and can be mitigated using water application if needed (during windy, dry periods). Effort to re-vegetate the surrounding area as soon as possible during Construction will also limit the potential for dust generation. Based on the small site footprint and scope of Construction required, these activities are not evaluated in detail and are considered a 1.

During Operation, feedstock harvesting activities may result in air contaminant, GHG and sound emissions to the atmosphere. However, these emissions are expected to be in remote locations, periodic and are not likely to be substantive, given that a large portion or all of the feedstock required for the Project can be sourced from existing forestry operations in the area, depending on the scale of the Project. These activities are therefore not evaluated in detail and are ranked as 1. Once the Project scale has been confirmed, the assessment of feedstock harvesting activities may need to be re-visited, as required.

Project activities during Decommissioning are expected to result in sound emissions and releases of air contaminants and GHGs in magnitude that are similar to or less than those associated with Construction and Operation activities; thus these are not evaluated in detail and are considered a 1.

Thus, in consideration of the nature of the interactions and the planned implementation of known and proven mitigation, the potential environmental effects of all Project activities and physical works that were ranked as 0 or 1 in Table 5.5, including cumulative environmental effects, on the Atmospheric Environment during any phase of the Project are rated not significant, and are not considered further in the assessment.

5.2.3.2 Assessment of Environmental Effects

A summary of the environmental effects assessment and prediction of residual environmental effects resulting from interaction ranked as 2 on the Atmospheric Environment (Operation of plant site for air quality and Construction and Operation for Sound Quality) is provided in Table 5.2.5.

Table 5.2.5 Summary of Residual Project-Related Environmental Effects on the Atmospheric Environment

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics						Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context					
Change in Air Quality • Combustion gases. • Particulate matter (dust).	Operation	• Implement idling reduction program. • Implement equipment maintenance program. • Continuous emissions monitors (specifically O_2) in exhaust stack to optimize combustion. • Process closely monitored and controlled for optimum operation. • Syngas cleaned and filtered prior to combustion in engines. • Biomass stored inside to minimize potential dust emissions and help control moisture content to maximize gasification and combustion efficiency.	A	L	L	LT/ C	R	D	N	M	L	Y	One source emissions testing campaign is recommended to confirm vendor emission guarantees.
	Residual Environmental Effects for all Phases								N	M	L	Y	

Table 5.2.5 Summary of Residual Project-Related Environmental Effects on the Atmospheric Environment

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics						Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context					
Change in GHG Emissions • Fuel combustion. • Feedstock harvesting.	Operation	• Implement equipment maintenance program. • Implement idling reduction program.	A	L	L	LT/ C	R	D	N	M	L	Y	Estimate direct GHG emissions for comparison with reporting threshold.
	Residual Environmental Effects for all Phases								N	M	L	Y	
Change in Sound Quality • Equipment operation.	Construction	• Construction and trucking of material during daytime hours only. • Use of mufflers. • Maintenance for equipment.	A	L	L	MT/ R	R	D	N	H	L	Y	If noise complaints are received, sound monitoring may be conducted and activities modified to reduce noise.
	Operation	• Maintenance of equipment. • Gasifier and engines in enclosed in containers/buildings. • Trucking and chipper operation during daytime hours only. • Locate chipper 500 to 1,000 m from nearest resident or other mitigation (depending on sound power level of chosen technology.	A	L	L	LT/ C	R	D	N	H	L	Y	If noise complaints are received, sound monitoring may be conducted and activities modified to reduce noise.
	Residual Environmental Effects for all Phases								N	H	L	Y	

Table 5.2.5 Summary of Residual Project-Related Environmental Effects on the Atmospheric Environment

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics										Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context	Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	

KEY

Direction
- P Positive.
- A Adverse.

Magnitude
- L Low: (Air Quality is not affected or slightly affected but is well below objectives, guidelines, or standards; GHG Emissions < 10,000 t CO_2e/a; sound pressure levels at or below background)
- M Medium: (Air Quality is affected to values that are near but largely below the objectives, guidelines, or standards; GHG Emissions < 50,000 and > 10,000 t CO_2e/a; sound pressure levels above background and below limits)
- H High: (Air Quality is degraded to values that may substantially exceed objectives, guidelines, or standards; GHG Emissions > 50,000 t CO_2e/a; sound pressure levels exceed limits)

Geographic Extent
- S Site-specific: Within the PDA.
- L Local: Within the LAA.
- R Regional: Within the RAA.

Duration
- ST Short term: Occurs and lasts for short periods (*e.g.,* days/weeks).
- MT Medium term: Occurs and lasts for extended periods of time (*e.g.,* years).
- LT Long term: Occurs during Construction and/or Operation and lasts for the life of Project.
- P Permanent: Occurs during Construction and Operation and beyond.

Frequency
- O Occurs once.
- S Occurs sporadically at irregular intervals.
- R Occurs on a regular basis and at regular intervals.
- C Continuous.

Reversibility
- R Reversible.
- I Irreversible.

Ecological/Socio-economic Context
- U Undisturbed: Area relatively or not adversely affected by human activity.
- D Developed: Area has been substantially previously disturbed by human development or human development is still present.
- N/A Not Applicable.

Significance
- S Significant.
- N Not Significant.

Prediction Confidence

Confidence in the significance prediction, based on scientific information and statistical analysis, professional judgment and known effectiveness of mitigation:
- L Low level of confidence.
- M Moderate level of confidence.
- H High level of confidence.

Likelihood

Likelihood of a significant environmental effect occurring, based on professional judgment:
- L Low probability of occurrence.
- M Medium probability of occurrence.
- H High probability of occurrence.

Cumulative Environmental Effects?
- Y Potential for environmental effect to interact with the environmental effects of other past, present or foreseeable projects or activities in RAA.
- N Environmental effect will not or is not likely to interact with the environmental effects of other past, present or foreseeable projects or activities in RAA.

5.2.3.3 Mitigation Measures

The following mitigation measures, through careful design and planning, will be employed to avoid or reduce the environmental effects of the Project on the Atmospheric Environment potentially resulting from the environmental effects mechanisms described above.

- Continuous emissions monitors (specifically O_2) of exhaust gases to control combustion and minimize emissions;
- Gasification and combustion processes closely monitored and controlled for optimum operation to reduce air contaminant emissions;
- Filtration of syngas prior to combustion to remove any tar formation from the gasification process;
- Biomass stored inside to minimize potential dust emissions and help control moisture content to maximize gasification and combustion efficiency;
- Construction and Decommissioning activities and trucking to and from the site (feedstock transport) limited to daytime hours only to minimize sound pressure levels at night;
- Use of mufflers on heavy equipment and vehicles to reduce sound emissions;
- Equipment enclosed in buildings where feasible or located to minimize sound pressure levels at off-site sensitive receptors; and
- Location of the chipper at least 1,000 m from nearest permanent residence or further review of noise generation of specific chipper required for a low noise model or incorporation of mitigation such as a barrier to attenuate noise.

5.2.3.4 Characterization of Residual Effects

As described in the text below, the results of the dispersion modelling indicate that for the three Project configuration scenarios considered for Operation, exceedances of the applicable ambient air quality standards, objectives and criteria are unlikely to occur. In most cases the predicted ground-level concentrations were well below the ambient standards and objectives.

During Operation, with respect to air contaminant emissions, it is expected that emissions of NO_2 and CO are likely to increase slightly over the existing conditions following implementation of the Project, due to the combustion of gasified biomass. However, a decrease in SO_2 emissions over the existing condition is also expected, as biomass contains less sulphur than fossil fuels. The reduction in SO_2 emissions is expected due to a reduction in fossil fuel consumption for space heating requirements of public buildings in the community. The magnitude of the increases and reductions in air contaminant emissions are dependent on the size selected for the Project as well as the final stack design, as this will dictate how many individual heating systems in community buildings are decommissioned and how emissions from the Project are dispersed.

GHG emissions are likely to range from 6,700 to 26,780 t/a of CO_2 due to biomass combustion, depending on the ultimate scale of the Project. Emissions of CO_2 account for the majority of the total GHG emissions. However, CO_2 emissions from biomass combustion are reported separately under the Environment Canada reporting system, since carbon dioxide emissions from biomass are considered carbon neutral as the emissions are part of the global carbon cycle. Emissions of other GHGs including CH_4 and N_2O are expected to be nominal, given the relatively low volumes of fuel consumed during Operation. Therefore, given the Project is to replace existing fossil fuel fired heating systems in the community; a small offset of GHG emissions is expected following implementation of the Project, ranging from 90 to 350 t/a CO_2.

To estimate sound pressure levels at distances from sources, the Study Team used the inverse square law which indicates that sound energy dissipates approximately 6 dB for a doubling of distance (ERCB 2007). This calculation does not account for attenuation from atmospheric or ground absorption (terrain effects) and hence is considered conservative.

The Study Team estimated the sound pressure levels of heavy equipment used for tree clearing, site preparation, and facility installation using typical equipment types and engine horsepower. The Construction phase is anticipated to take less than one year. Tree cutting can be a noisy activity and may cause sound pressure levels to exceed 55 dB_A within 1,500 metres. Noise from earth moving activities may exceed 55 dB_A on occasion within approximately 600 m from the activity. These are conservative estimates as the effects of terrain, treed areas, and buildings were not taken into account. Construction activities are transient and will not take place during nighttime to help reduce annoyance and avoid sleep disturbance. Therefore, although Construction within 600 to 1,500 metres will generate perceivable noise, annoyance will be limited in duration and extent and occur during daytime hours only. The L_{DN} criterion of 55 dB_A will likely be exceeded within 1,500 m of tree cutting, and may be exceeded on occasion within 600 m of earth moving activities. As the Project site is relatively small, Construction is expected to cause a short term disturbance. A 8-month period is anticipated for Construction.

The estimated sound pressure level from Operation of a 2 MW_e gasification plant is 87 dB_A at 4.5 m (10 feet), based on the maximum sound pressure level provided by CPC (CPC 2012). The sound from the facility would attenuate from 87 dB_A to 55 dB_A approximately 120 m from the site, as a conservative estimate. Based on the expected baseline noise levels in the village, it is estimated that the 2 MW_e facility would not be highly audible during daytime beyond 120 m. At night, the plant may be audible up to 325 m from the site; however at that level would not be highly audible and would not be expected to cause sleep disturbance (may be perceived as a dull hum on very quiet evenings outdoors).

The nearest sensitive receptor (the school building) is approximately 160 m from the proposed site in the FEED study. WHO indicates that the sound pressure level in an outdoor playground area should not exceed 55 dB_A and also indicate an indoor level of 35 dB_A for schools (WHO 1998). Since building walls are capable of decreasing sound levels by 10-20 dB_A (no windows open) (WHO 1998), meeting the outdoor limit of 55 dB_A results in meeting the indoor limit of 35 dB_A. Therefore as long as the plant is located greater than 120 m away from the school, noise from Operation of the facility is not expected to exceed WHO guidelines.

The percentage highly annoyed (% HA) by noise in the existing case was estimated to be approximately 2.2%, based on an assumed daytime sound pressure level of 50 dB_A and a nighttime sound pressure level of 40 dB_A. A 10 dB_A penalty was added to the nighttime sound pressure level, as per guidance from US EPA and Health Canada. For Project Operation, the % HA at a location 120 m away (where the Project contribution to sound pressure level is 55 dB_A during day and night), in addition to the existing case, was estimated to be 4.8%. Therefore the change in % HA is 2.6%, which is below the 6.5% significance criterion. The significance criterion would be exceeded if the Project contribution to sound pressure levels exceeds 60 dB_A (approximately 75 m or closer for the 2 MW_e case) at a sensitive receptor.

The location of the wood chipping operation is not currently known. Based on the reference wood chipping sound pressure level information (Health and Safety Laboratory 2008), noise from the chipper would be noticeable over background within approximately 500 to 1,000 m from the wood chipper (depending on technology of wood chipper used). At closer than 200 to 400 m, the noise would be highly audible (perceived as a doubling of background noise). As stated above, these are conservative estimates as screening effects were not taken into account. Therefore the noise from the wood chipping operations during daytime hours is not expected to be noticeable beyond 1,000 m. Wood chipping is only expected to be required for several hours per day and not every day. Wood chipping would be scheduled to avoid evening, nighttime and early morning hours as well as weekends. If the chipper is to be located within 1 km of permanent residents, the school or other areas considered noise sensitive, further assessment would be completed to establish background sound pressure levels at the location as well as the actual sound levels for the required chipper. Effort would be made in selection of the chipping equipment as well as through noise mitigation (such as barriers) as required to reduce the noise at the nearest sensitive receptor to 3 dB or less above background levels (where the noise would be just perceivable).

Dispersion Modelling

Dispersion modelling of air contaminant emissions resulting from Operation of the Project was conducted to predict resulting ground-level concentrations downwind. This technical evaluation was used to inform the assessment of environmental effects on Air Quality. Emissions during construction activities were not modelled as the releases will be short-term in duration (during the construction period) and the air contaminant emissions are likely to be less than those during Operation.

As noted above, since the Project is in the early design stages, the scale and configuration of the Project operation is not yet confirmed. Therefore, three scenarios currently being considered for the Project were modelled as follows:

- **Scenario 1:** 0.5 MW biomass gasifier and engines with two 8 metre exhaust stacks;
- **Scenario 2:** 2 MW biomass gasifier and engines with eight 8 metre exhaust stacks; and
- **Scenario 3:** 2 MW biomass gasifier and engines with one 20 metre exhaust stack.

These scenarios are expected to conservatively evaluate the range of potential technology configurations that could be chosen. The maximum short term and long term (annual) average ground-level concentrations are predicted with the most recent version of the AERMOD dispersion model.

The inputs required for the dispersion modelling consist of three components: meteorological data; receptor grid and terrain data; and point source characteristics and emissions data.

Hourly meteorological data (*e.g.*, wind speed and direction, temperature) from the beginning of January 2006 to the end of December 2011 were obtained from the National Climatic Data Centre (NCDC 2012) for the Whitehorse Airport, the nearest representative surface station to the Project site. Twice daily, upper air sounding data were also obtained for the Whitehorse weather station, the nearest representative upper air station to the Project site (NOAA 2012). The raw data for the area were used to calculate stability parameters and mixing layer depths (mixing heights) with AERMET, the AERMOD meteorological pre-processor.

A receptor grid covering the LAA was established for the dispersion modelling, consisting of a 10 km x 10 km Cartesian receptor grid with the Project site near the center of the grid. The receptor grid spacing was 100 m apart for the 6 km by 6 km grid centered near the Project and 500 m apart for the remainder of the 10 km x 10 km domain. Terrain elevation data used in the development of the receptor grid were obtained from the Yukon Environment GIS Data (Yukon Environment 2012b).

The source data required to run the AERMOD model includes the following:

- Physical location of the point sources;
- Emission rate of the selected air contaminant;
- Physical height of the emission source (stack height);
- Diameter of the stack at its exit (stack exit diameter);
- Average stack exhaust gas exit velocity; and
- Average stack exhaust gas temperature.

The source parameters and emission rates required for the dispersion modelling were obtained from emissions data provided by equipment vendors (CPC 2012).

The model input parameters and emission rates included in the modelling for Operation of the Project are provided in Tables 5.2.6 and 5.2.7, below.

Table 5.2.6 Model Inputs – Source Parameters

Source	Location (m)		Stack Height (m)	Stack Diameter (m)	Average Stack Gas Exit Temperature (K)	Average Stack Gas Exit Velocity (m/s)
	UTM X	UTM Y				
Scenario 1						
Engine Stack 1	363,155	6,738,485	7.6	0.2	647	10.0
Engine Stack 2	363,162	6,738,479	7.6	0.2	647	10.0
Scenario 2						
Engine Stack 1	363,125	6,738,503	7.6	0.2	647	10.0
Engine Stack 2	363,139	6,738,503	7.6	0.2	647	10.0
Engine Stack 3	363,174	6,738,489	7.6	0.2	647	10.0

Table 5.2.6 Model Inputs – Source Parameters

Source	Location (m)		Stack Height (m)	Stack Diameter (m)	Average Stack Gas Exit Temperature (K)	Average Stack Gas Exit Velocity (m/s)
	UTM X	UTM Y				
Engine Stack 4	363,160	6,738,489	7.6	0.2	647	10.0
Engine Stack 5	363,173	6,738,503	7.6	0.2	647	10.0
Engine Stack 6	363,158	6,738,503	7.6	0.2	647	10.0
Engine Stack 7	363,139	6,738,488	7.6	0.2	647	10.0
Engine Stack 8	363,124	6,738,488	7.6	0.2	647	10.0
Scenario 3						
Engine Stack	363,125	6,738,503	20.0	0.3	647	10.0

Table 5.2.7 Model Inputs – Air Contaminant Emission Rates

Source	Emission Rate (g/s)					
	NO_X	CO	SO_2	TSP	PM_{10}	$PM_{2.5}$
Scenario 1						
Engine Stack 1	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 2	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Scenario 2						
Engine Stack 1	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 2	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 3	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 4	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 5	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 6	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 7	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Engine Stack 8	0.045	0.018	5.7E-03	1.9E-04	1.9E-04	1.9E-04
Scenario 3						
Engine Stack	0.36	0.15	0.045	1.5E-03	1.5E-03	1.5E-03

Additional details on the source parameters and emissions rates used in the modelling are provided in the Emission and Wastes section in the Project Description (Section 3.3).

The effects of downwash due to wind flow over and around the surrounding buildings are considered in the modeling. Since building wake effects may influence the predictions, building heights and widths were included in the input file using the US EPA Building Profile Input Program (BPIP-PRIME) so those effects would be considered in the analysis (US EPA 1997).

After running AERMOD, output files were generated for the maximum 1-hour, 8-hour and 24-hour predicted concentrations and annual average concentrations at each receptor for the complete 6-year time period spanned by the meteorological input file.

Measured ambient air quality data were used to characterize the baseline and establish background concentrations used in the modelling. The incremental changes related to Project activities during Operation were considered in the context of these baseline values by adding maximum model-predicted values to measured ambient (*i.e.*, background) values.

To conservatively estimate baseline ambient air concentrations for relevant averaging periods in the Study Area, monitoring data from the nearest ambient station to the Project site were considered. The nearest ambient air quality monitoring station to the Project site is located in Whitehorse, approximately 130 km to the east. For averaging periods of 24 h or less, the maximum of the monthly hourly averages from 2008-2010 were used in conjunction with the OMOE relation for determination of alternate averaging periods. For annual averaging periods, the average of the monthly concentrations was used.

The background concentrations of the Criteria Air Contaminants (CAC) used in the modelling analysis are presented in Table 5.2.8. Ambient baseline values were estimated wherever data were available for all relevant averaging periods. For certain air contaminants, limited or no ambient data were available. For the cases where no data are available, the background concentrations are assumed to be negligible. Where limited data are available, details of the specific data treatment are specified in the table below.

Table 5.2.8 Ambient Background CAC Concentrations Used for Modelling

Criteria Air Contaminant	Averaging Period	Background Concentration Used ($\mu g/m^3$)	Additional Notes
SO^2	1-hour	--	No data available, SO_2 not monitored at Whitehorse station.
	24-hour	--	
	Annual	--	
NO_2	1-hour	19.9	Estimated using maximum of monthly hourly average concentrations measured at the Whitehorse station in 2008. 24-hour average background concentration estimated using OMOE relation. Annual background concentration based on the average of the 2008 monthly average values.
	24-hour [1]	8.2	
	Annual	7.1	
CO	1-hour	1.1	Estimated using maximum of the monthly hourly average concentrations measured at the Whitehorse station from 2008-2010 and OMOE relation.
	8-hour [1]	0.61	
TSP	24-hour[1]	4.3	No data available, TSP not monitored at Whitehorse station. In absence of ambient data for TSP, $PM_{2.5}$ background concentration used for 24-hour averaging period. For annual average, the average of the monthly $PM_{2.5}$ concentrations from 2008-2010 was used.
	Annual	2.5	
PM_{10}	24-hour[1]	4.3	No data available, PM_{10} not monitored at Whitehorse station. In absence of ambient data for PM_{10}, $PM_{2.5}$ background concentration was used.
$PM_{2.5}$	24-hour[1]	4.3	Estimated using maximum of the monthly hourly average concentrations measured at the Whitehorse station from 2008-2010 and OMOE relation.

Notes:
[1] Ambient background concentrations (24 h or weekly) were converted to an alternate averaging period using the following equation described in Table 7-1 in the OMOE's document "Procedure for Preparing an Emission Summary and Dispersion Modelling Report", dated July 2009: $C_0 = C_1 \times (t_1/t_0)^n$ where C_0 = the concentration at the averaging period t_0, C_1 = the concentration at the averaging period t_1, and n = 0.28.

Although no SO_2 data are available for the Yukon, as the Project will result in decreased SO_2 emissions in Haines Junction, this is not considered a technical limitation.

Dispersion Modelling Results

The maximum predicted ground-level air contaminant concentrations (including background) for each operational scenario modelled are provided in Table 5.2.9, 5.2.10 and 5.2.11.

Table 5.2.9 Maximum Predicted Ground-level Concentrations – Scenario 1

CAC	Averaging Period	Background ($\mu g/m^3$)	Location		Maximum Predicted Concentration ($\mu g/m^3$)	Maximum Predicted Concentration Plus Background ($\mu g/m^3$)	Objective/ Guideline or Standard ($\mu g/m^3$)	Percentage of Objective/ Guideline or Standard
			UTM X (m)	UTM Y (m)				
SO_2	1-hour	-	363,200	6,738,600	7.78	7.78	450	2%
	24-hour	-	363,200	6,738,400	2.80	2.80	150	2%
	Annual	-	363,100	6,738,600	0.52	0.52	30	2%
NO_2	1-hour	20	363,200	6,738,600	42.8	62.8	400	16%
	24-hour	8.2	363,200	6,738,400	15.4	23.6	200	12%
	Annual	7.1	363,100	6,738,600	3.82	10.9	60	18%
CO	1-hour	1.1	363,200	6,738,600	23.0	24	14,885	<1%
	8-hour	0.61	363,200	6,738,400	13.1	13.8	5,725	<1%
TSP	24-hour	4.3	363,200	6,738,400	0.09	4.39	120	4%
	Annual	2.5	363,100	6,738,600	0.02	2.52	60	4%
PM_{10}	24-hour	4.3	363,200	6,738,400	0.09	4.39	50	9%
$PM_{2.5}$	24-hour	4.3	363,200	6,738,400	0.09	4.39	30	15%
C_6H_6	24-hour	-	363,200	6,738,400	0.65	0.65	2.3	28%
HCHO	24-hour	-	363,200	6,738,400	0.68	0.68	65	1%

Table 5.2.10 Maximum Predicted Ground-level Concentrations – Scenario 2

CAC	Averaging Period	Background ($\mu g/m^3$)	Location		Maximum Predicted Concentration ($\mu g/m^3$)	Maximum Predicted Concentration Plus Background ($\mu g/m^3$)	Objective/ Guideline or Standard ($\mu g/m^3$)	Percentage of Objective/ Guideline or Standard
			UTM X (m)	UTM Y (m)				
SO_2	1-hour	-	363,300	6,738,500	24.1	24.1	450	5%
	24-hour	-	363,200	6,738,400	9.55	9.55	150	6%
	Annual	-	363,100	6,738,600	2.25	2.25	30	8%
NO_2	1-hour	20	363,300	6,738,500	133	153	400	38%
	24-hour	8.2	363,200	6,738,400	52.5	60.7	200	30%
	Annual	7.1	363,100	6,738,600	12.4	19.5	60	32%
CO	1-hour	1.1	363,300	6,738,500	72.4	73.5	14,885	<1%
	8-hour	0.61	363,200	6,738,400	42.2	42.8	5,725	<1%
TSP	24-hour	4.3	363,200	6,738,400	0.32	4.62	120	4%
	Annual	2.5	363,100	6,738,600	0.08	2.58	60	4%
PM_{10}	24-hour	4.3	363,200	6,738,400	0.32	4.62	50	9%
$PM_{2.5}$	24-hour	4.3	363,200	6,738,400	0.32	4.62	30	15%
C_6H_6	24-hour	-	363,200	6,738,400	2.21	2.21	2.3	96%
HCHO	24-hour	-	363,200	6,738,400	2.31	2.31	65	4%

Table 5.2.11 Maximum Predicted Ground-level Concentrations – Scenario 3

CAC	Averaging Period	Background ($\mu g/m^3$)	Location		Maximum Predicted Concentration ($\mu g/m^3$)	Maximum Predicted Concentration Plus Background ($\mu g/m^3$)	Objective/ Guideline or Standard ($\mu g/m^3$)	Percentage of Objective/ Guideline or Standard
			UTM X (m)	UTM Y (m)				
SO_2	1-hour	-	363,200	6,738,600	6.73	6.73	450	1%
	24-hour	-	363,200	6,738,400	2.34	2.34	150	2%
	Annual	-	363,100	6,738,600	0.68	0.68	30	2%
NO_2	1-hour	20	363,200	6,738,600	39.5	59.5	400	15%
	24-hour	8.2	363,200	6,738,400	13.7	21.9	200	11%
	Annual	7.1	363,100	6,738,600	3.99	11.1	60	18%
CO	1-hour	1.1	363,200	6,738,600	21.8	22.9	14,885	<1%
	8-hour	0.61	363,200	6,738,600	15.2	15.8	5,725	<1%
TSP	24-hour	4.3	363,200	6,738,400	0.10	4.40	120	4%
	Annual	2.5	363,100	6,738,600	0.03	2.53	60	4%
PM_{10}	24-hour	4.3	363,200	6,738,400	0.10	4.40	50	9%
$PM_{2.5}$	24-hour	4.3	363,200	6,738,400	0.10	4.40	30	15%
C_6H_6	24-hour	-	363,200	6,738,400	0.58	0.58	2.3	25%
HCHO	24-hour	-	363,200	6,738,400	0.60	0.60	65	1%

The maximum predicted concentrations of the modelled air contaminants, including background, were well below the ambient air quality standards and objectives for the three scenarios modelled. The operational configuration for Scenario 3 results in the lowest downwind concentrations; this is due to better dispersion of the stack exhaust plume which results from having a higher stack (20 m in height). Although the emission rates are lower for Scenario 1, the shorter stack (approximately 8 m in height) results in less dispersion downwind which in turn causes higher ground-level concentrations.

Concentration contour plots of the 1-hour maximum predicted ground-level NO_2 concentrations are provided below in Figures 5.2.1, 5.2.2 and 5.2.3, for each scenario. The highest predicted concentrations generally occur in the immediate vicinity of the Project site.

Ground-level concentrations of selected hazardous air contaminants were also modelled for each scenario. The estimated 24-hour ground-level concentrations were predicted for the air contaminants expected to be released in the largest quantities (benzene and formaldehyde), as noted above in Section 3.3. The estimated 24-hour benzene and formaldehyde concentrations were compared with Ontario Ministry of the Environment Ambient Air Quality Criteria (OMOE 2012). The estimated 24-hour benzene and formaldehyde ground-level concentrations were below the OMOE ambient criteria of 2.3 $\mu g/m^3$ and 65 $\mu g/m^3$, respectively, for each modelled scenario.

Figure 5.2.1 Maximum Predicted 1-hour Nitrogen Dioxide Ground-level Concentrations – Scenario 1

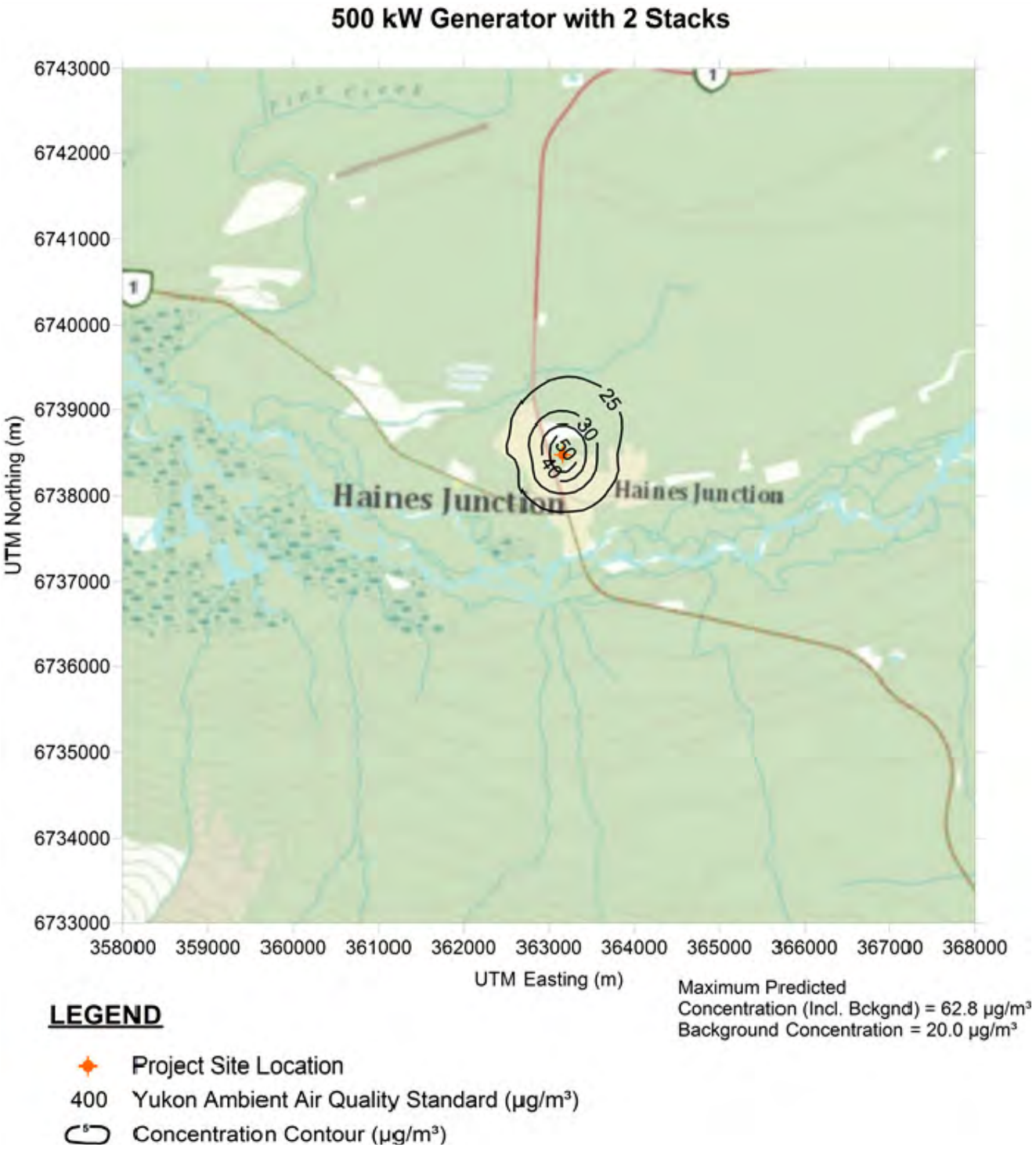


Figure 5.2.2 Maximum Predicted 1-hour Nitrogen Dioxide Ground-level Concentrations – Scenario 2

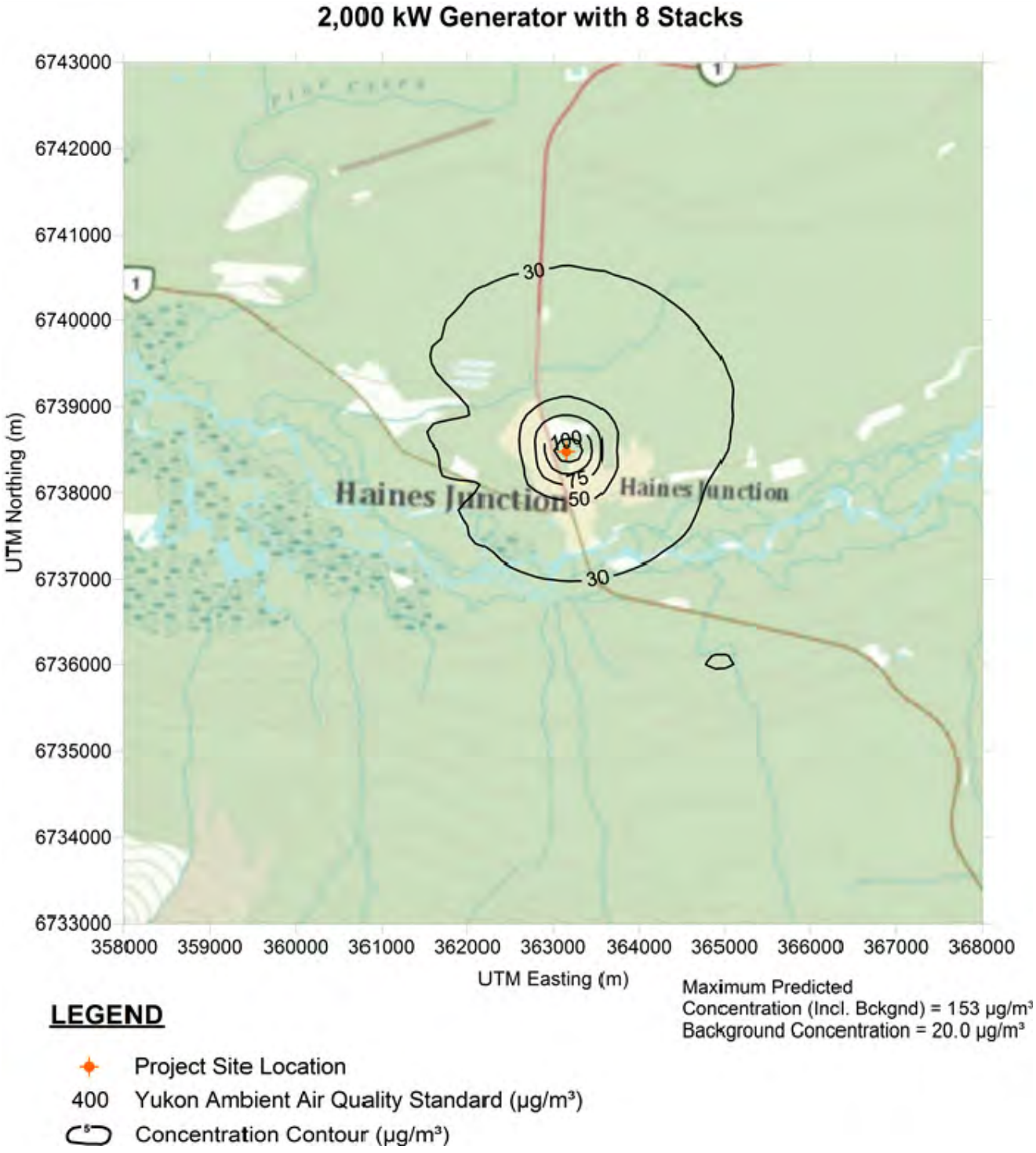
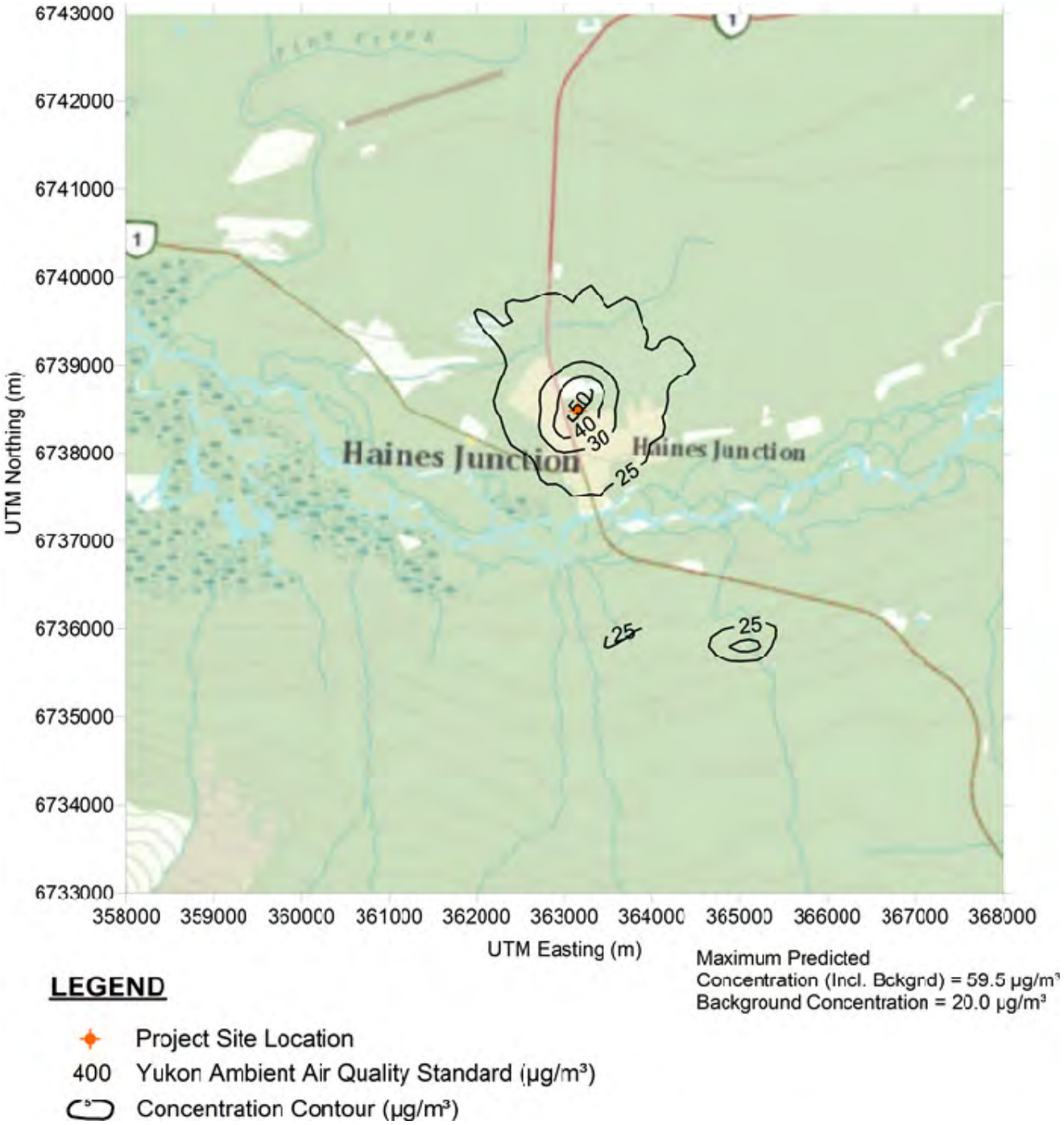


Figure 5.2.3 Maximum Predicted 1-hour Nitrogen Dioxide Ground-level Concentrations – Scenario 3



5.2.4 Assessment of Cumulative Effects

In addition to the Project environmental effects discussed above, an assessment of the potential cumulative environmental effects was conducted for other projects and activities that have potential to cause environmental effects that overlap with those of the Project, as identified in Table 5.2.5. The potential cumulative environmental effects to the Atmospheric Environment are presented in Table 5.2.12. In the table each interaction with other projects is ranked as 0, 1, or 2 with respect to the nature and degree to which important Project-related environmental effects overlap with those of other projects and activities.

Table 5.2.12 Potential Cumulative Environmental Effects to the Atmospheric Environment

Other Projects and Activities With Potential for Cumulative Environmental Effects	Potential Cumulative Environmental Effects		
	Change in Air Quality	Change in GHG Emissions	Change in Sound Quality
Industrial Land Use (Past or Present)	1	1	1
Forestry and Agricultural Land Use (Past or Present)	1	1	1
Current Use of Land and Resources for Traditional Purposes by Aboriginal Persons (Past or Present)	1	1	1
Recreational Land Use (Past or Present)	1	1	1
Residential Land Use (Past or Present)	1	1	1
Industrial Land Use (Future)	1	1	1
Forestry and Agricultural Land Use (Future)	1	1	1
Current Use of Land and Resources for Traditional Purposes by Aboriginal Persons (Future)	1	1	1
Recreational Land Use (Future)	1	1	1
Planned Residential Development (Future)	1	1	1

Cumulative Environmental Effects

Notes:

Cumulative environmental effects were ranked as follows:

0 = Project environmental effects do not act cumulatively with those of other Projects and Activities.

1 = Project environmental effects act cumulatively with those of other Project and Activities, but are unlikely to result in significant cumulative environmental effects OR Project environmental effects act cumulatively with existing significant levels of cumulative environmental effects but will not measurably change the state of the VC.

2 = Project environmental effects act cumulatively with those of other project and activities, and may result in significant cumulative environmental effects OR Project environmental effects act cumulatively with existing significant levels of cumulative environmental effects and may measurably change the state of the VC.

With respect to Forestry and Land Use, logging equipment and trucks release combustion gases, GHGs, and sound emissions and may cause fugitive road dust emissions during Operation in the areas harvested for Project feedstock. These emissions are transient as the logging operations move from site to site, and are limited to emissions from the operation of heavy equipment. As such, cumulative environmental effects from the Project and Forestry and Land Use are not expected to be substantive most of the time.

Existing Industrial Land Use near the Project includes the Yukon Electrical Company Diesel Plant in Haines Junction. The operation of the diesel plant is infrequent, typically during periods of electrical grid outages. Given there are no substantive industrial sources with frequent emissions in the area of the Project, the interactions between the other sources and the Project with respect to a Change in the Air Quality, a Change in GHG Emissions, and a Change in Sound Quality are likely to be minimal.

At this time, no future Industrial Land Use projects are known. The interaction between any future projects and the Project would be addressed by the EA for a future project.

With respect to Residential Land Use, air contaminant and GHG emissions from space heating requirements could combine with Project emissions at the ground-level on occasion, specifically during times with poor dispersion. However, given the small magnitude of the emissions due to residential space heating, cumulative environmental effects from the Project and Residential Land Use are not expected to be substantive most of the time.

It is not expected that Current Use of Land and Resources for Traditional Purposes by Aboriginal Persons will be substantively affected by the Operation of the Project as air contaminant emissions released from the Project will disperse from the site and ground-level concentrations will return to background levels.

The Project has the potential to interact with the recreational areas near the Project with respect to a Change in Air Quality and a Change in GHG Emissions during Operation. However, given the emissions from the Project are relatively low, negligible cumulative effects are expected with respect to Recreational Land Use.

Sound emissions from Current Use of Land and Resources by Aboriginal Persons for Traditional Purposes, Recreational Land Use and Residential Land Use are generally minimal and close to background sound levels. As such, substantive interactions between their environmental effects and those of the Project are not anticipated.

At this time, there are no known planned or future residential developments considered near the Project. The interaction between any future projects and the Project would be addressed by the EA for a future project.

5.2.4.1 Mitigation of Cumulative Environmental Effects

Mitigation measures for the Project Case were discussed previously for Project-related environmental effects (Section 5.2.3.3). The mitigation measures proposed for the Project-related environmental effects are also anticipated to be effective in mitigating any cumulative environmental effects, as would the mitigation associated with other past and future projects and activities.

5.2.5 Determination of Significance

5.2.5.1 Residual Project Environmental Effects

With the proposed mitigation and environmental protection measures, the residual environmental effect of a Change in Air Quality during all phases of the Project is rated not significant. This conclusion has been determined with a high level of confidence based on the conservative assumptions and emission factors used to estimate air contaminant emissions.

With the proposed mitigation and environmental protection measures, the residual environmental effect of a Change in GHG Emissions during all phases of the Project is rated not significant. This conclusion has been determined with a high level of confidence based on the conservative assumptions and emission factors used to estimate GHG emissions.

With the proposed mitigation and environmental protection measures, the residual environmental effect of a Change in Sound Quality during all phases of the Project is rated not significant. This conclusion has been determined with a high level of confidence based on the conservative assumptions used to estimate sound pressure levels.

5.2.5.2 Residual Cumulative Environmental Effects

The characterization of the potential cumulative environmental effects and associated mechanisms, combined with the proposed mitigation measures proposed in Section 5.2.4.2 demonstrate that the residual cumulative environmental effect of a Change in Air Quality is rated not significant. This determination has been made with a moderate level of confidence due to the preliminary nature of data available for the Project activities and the site location.

The characterization of the potential cumulative environmental effects and associated mechanisms, combined with the proposed mitigation measures proposed in Section 5.2.4.2 demonstrate that the residual cumulative environmental effect of a Change in GHG Emissions is rated not significant. This determination has been made with a moderate level of confidence due to the preliminary nature of data available for the Project activities.

The characterization of the potential cumulative environmental effects and associated mechanisms, combined with the proposed mitigation measures proposed in Section 5.2.4.2 demonstrate that the residual cumulative environmental effect of a Change in Sound Quality is rated not significant. This determination has been made with a moderate level of confidence due to the preliminary nature of data available for the Project activities, including Project location.

The proposed mitigation measures demonstrate that the Project contribution to the cumulative environmental effects on a Change in Air Quality, a Change in GHG Emissions, and a Change in Sound Quality is rated not significant. This determination has been made with a moderate level of confidence.

5.2.6 Summary Consultation Influence on the Assessment

At the time of writing, consultations in the community are on-going. A summary of the consultations as they apply to Atmospheric Environment will be provided following the completion of the consultations for the Project.

5.2.7 Effects Monitoring and Adaptive Management

During Operation, it is recommended that one stack testing campaign be conducted following commissioning of the Project to confirm vendor emissions guarantees. Given the current uncertainty of the scale and operational configuration of the Project, some parts of the assessment of Atmospheric Environment may need to be updated, specifically with respect to feedstock harvesting.

Ambient air quality monitoring is not warranted, given relatively small scale of the Project with relatively low emissions and the absence of substantive existing emission sources. There are no other warranted follow-up programs for air quality.

If sound complaints are received during Construction and/or Operation, monitoring may be implemented to confirm that sound pressure levels are within acceptable levels.

5.3 TERRESTRIAL ENVIRONMENT

5.3.1 Scope of the Assessment

This section defines the scope of the environmental assessment of the Terrestrial Environment in consideration of the nature of the regulatory setting, issues identified during public and First Nations engagement activities, potential Project-VC interactions, and existing knowledge.

5.3.1.1 Key Issues and Identification of Potential Effects

5.3.1.2 Regulatory/Policy Setting

The assessment of the Terrestrial Environment for the Project has been completed in accordance with the requirements of the *Yukon Environmental and Socio-Economic Assessment Act* (*YESAA*). The *YESAA* is not specific with respect to which aspects of vegetation and wildlife are to be assessed. However, the Yukon Environmental and Socio-economic Assessment Board (YESAB) does provide guidance in the Proponent‘s Guide to Information Requirements for Executive Committee Project Proposal Submissions (YESAB 2005).

The Project has the potential to interact with the Terrestrial Environment by changing terrestrial habitats, including wetlands, and/or populations of vascular plants and/or wildlife species that are important in a socio-economic or environmental context, including species at risk (SAR), as defined federally by the *Species at Risk Act* (*SARA*), or species of conservation concern (SOCC), defined here as species ranked S1, S2, or S3 by the Yukon Conservation Data Centre (YCDC), with a general status rank of May Be At Risk, or Sensitive as determined by the Canadian Endangered Species Conservation Council (CESCC), and/or that have undergone an assessment by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC), but not yet included on Schedule 1 of *SARA*. Additional species considered in this assessment as SOCC include species that will be assessed by COSEWIC. SOCC are species that, unlike SAR, are not afforded direct protection by legislation. SOCC are placed on lists as a precautionary measure that reflects an observed trend in their provincial population status.

Additional guidance for the feedstock component of the Project can be found in the “Strategic Forest Management Plan (SFMP)”, the “Integrated Landscape Plan (ILP) for the Champagne and Aishihik Traditional Territory”, and the YESAB “Proponent’s Guide: Completing a Forestry Project Proposal”. The SFMP was developed to provide direction for sustainable forest management in the CATT. The ILP was developed to provide guidance for projects involving forestry harvest and site planning. The SFMP directs the ILP to identify areas where forest harvesting should or should not take place. At a broad scale the ILP has identified these areas based on a number of factors, including:

- cultural;
- traditional;

- tourism;
- viewscapes;
- wilderness;
- wildlife;
- biological diversity;
- connectivity;
- community safety from wildfire risk;
- timber; and
- economy.

The Forestry Project Proposal Guide is a document designed to accompany the Project Proposal Form for Forestry. The completed form contains information that the YESAB requires to conduct an environmental and socio-economic assessment.

5.3.1.3 Selection of Measureable Parameters

The environmental assessment of the Terrestrial Environment is focused on the following environmental effects:

- Change in Terrestrial Populations; and
- Change in Wetlands.

The Project has the potential to affect the Terrestrial Environment through changes in abundance of wildlife and wildlife habitat, and degradation in habitat quality, all of which influence terrestrial populations of wildlife and plants. These potential changes could possibly influence the loss, or sustained presence of terrestrial populations and the maintenance of biodiversity in the region. In light of the value placed on terrestrial populations and wetlands by regulatory agencies, stakeholders, and the public, the environmental assessment of the Terrestrial Environment is focused on these environmental consequences which encompass the critical aspects of the VC.

The measurable parameters used for the assessment of the environmental effect presented above and the rationale for their selection is provided in Table 5.3.1.

Table 5.3.1 Measurable Parameters for Terrestrial Environment

Environmental Effect	Measurable Parameter	Rationale for Selection of the Measurable Parameter
Change in Terrestrial Populations	Loss of Vascular Plant SAR or SOCC (number of individuals)	• Addresses loss of known locations of rare vascular plants within the territory that are disturbed as a result of the Project.
	Loss of Wildlife SAR or SOCC (number of individuals)	• Loss of Wildlife SAR or SOCC (number of individuals)
	Changes to community structure or composition	• Addresses changes to the community structure and/or composition at a temporal scale.
	Loss of Migratory Birds (number of individuals)	• Addresses the concern of loss of individuals of migratory birds, including their nests, eggs, and young.
	Direct Habitat Loss (ha)	• This includes habitats for many wildlife and vascular plant species (such as old growth forests) and will also include an evaluation of the rarity of habitats affected.
	Loss of Old Growth Forest	• Old growth forests are important to biodiversity as well as regulators, First Nations, and other residents of Yukon Territory.
Change in Wetlands	Loss of wetland area (ha)	• Wetlands provide habitat for many wildlife and vascular plant species and will also include an evaluation of the rarity and proportion of wetlands affected.
	Loss of wetland function	• Wetlands can provide a number of functions, including hydrological, socio-economic, and ecological.

The measurable parameters in Table 5.4.1 were based on the professional judgment of the Study Team. Measurable parameters have clear units of measurement and are indicative of change in the Terrestrial Environment.

5.3.1.4 Spatial Boundaries

The spatial boundaries for the environmental effects assessment of the Terrestrial Environment are defined below.

Project Development Area (PDA): The PDA is the most basic and immediate area of the Project. The PDA is limited to the area of physical ground disturbance associated with the Project, and consists of an area that includes the area of physical disturbance associated with the biomass plant and associated facilities as well as the area associated with biomass feedstock harvesting (including forest roads, to be defined in detail upon further study). The PDA is the area represented by the physical Project footprint as defined in Chapter 3.1.2 above.

Local Assessment Area (LAA): The LAA includes a 10 x 10 km centred on the PDA. At present, the feesdstock harvesting area has not been identified; however a qualitative assessment of the harvesting area has been undertaken. The LAA is the maximum area within which Project-related environmental effects can be predicted or measured with a reasonable degree of accuracy and confidence. The LAA includes the PDA and any adjacent areas where Project-related environmental effects may reasonably be expected to occur. The LAA will be redefined to include areas of forest harvesting activities once the forest harvesting activities associated with the Project have been defined.

Regional Assessment Area (RAA): The RAA is limited to and includes the Yukon Territory. The RAA is the area within which the Project's environmental effects may overlap or accumulate with the environmental effects of other projects or activities that have been or will be carried out. The extent to which cumulative environmental effects for Vegetation and Wetland Resources may occur depend on physical and biological conditions and the type and location of other past, present, and reasonably foreseeable future projects or activities that have been or will be carried out, as defined within the RAA.

5.3.1.5 Temporal Boundaries

The temporal boundaries for the assessment of the potential environmental effects of the Project on the Terrestrial Environment include the phases of Construction, Operation, and Decommissioning. The preliminary Project schedule is provided in Section 3.4.

5.3.1.6 Administrative and Technical Boundaries

The assessment of the potential environmental effects of this Project on the Terrestrial Environment includes a consideration of populations of species that are listed under various federal and territorial acts and regulations. Existing habitat information used for the EA includes YCDC occurrences for species of special status in the vicinity of the Project, and information on Environmentally Significant Areas (ESAs). Information used for the assessment of potential environmental effects on the Terrestrial Environment was obtained from the *SARA*, the *MBCA*, 1994, the *Federal Policy on Wetland Conservation*, the *YESAA*, YCDC, the *Yukon Forest Protection Act*, the *Yukon Forest Resources Act*, the *Territorial Lands Act* (Yukon), and Yukon *Wildlife Act*, and the *Yukon Act* . Additional knowledge of vegetation and wetlands potentially affected by the Project is based on other information provided by the above sources, and the professional judgment of the Study Team.

Canada's indigenous species, subspecies, and distinct populations that are considered "At Risk" are protected under the *SARA*. The *SARA* provides legal protection to species and the conservation of their biological diversity. The purposes of the Act are to prevent species from becoming extirpated or extinct, to provide for the recovery of endangered or threatened species, and encourage the management of other species to prevent them from becoming at risk. Designation under the Act follows recommendation and advice provided by COSEWIC to the Government of Canada. The COSEWIC is responsible under the *SARA* for assessing the biological status of each rare species in Canada. Under the *SARA*, the Governor in Council may accept the assessment and add the species to Schedule 1 of the *SARA*, decide not to add the species to Schedule 1, or may refer the assessment back to COSEWIC for further information or consideration.

Subsection 79(1) of the *SARA* stipulates that every person who is required by or under an Act of Parliament to ensure that an assessment of the environmental effects of a project is conducted must, without delay, notify the competent minister or ministers in writing of the project if it is likely to affect a listed wildlife species or its critical habitat. Additionally, *SARA* Subsection 79(2) states that where a federal environmental assessment is being carried out in relation to a project that may affect a listed wildlife species or its critical habitat, the person responsible for ensuring the assessment is conducted must:

- identify potential adverse effects on the listed wildlife species and its critical habitat;

- if the project is carried out:
    - ensure that measures are taken to avoid or lessen those adverse effects and to monitor them; and
    - ensure that such measures are consistent with any applicable recovery strategy and action plans.

Under the *SARA*, there are three schedules; species officially protected are listed under Schedule 1 of the *SARA* and designated as "Extinct, Extirpated, Endangered, Threatened, and Special Concern" by COSEWIC are protected by that Act. Species listed as "Special concern" are not protected by the prohibitions of Sections 32-36 of the *SARA*; however, they do not require that provincial or regional management plans are development to protect the species. Species of special concern are considered species at risk as Section 79 requirements of the Act apply to these species. "Listed Species" refer to species listed in Schedule 1 of the *SARA* and includes species designated as extirpated, endangered, threatened, or of special concern. Listed species are identified on the Species at Risk Public Registry.

Schedule 1 of the *SARA* is the official list of wildlife species at risk. Once a species is "listed", the measures to protect and recover a listed wildlife species are implemented. Species that were designated at risk by the COSEWIC prior to the existence of the *SARA* require reassessment before being placed on Schedule 1. These species are listed on Schedule 2 if they were previously assessed by COSEWIC as endangered or threatened, and on Schedule 3 if they were previously assessed by COSEWIC as special concern. Both Schedules 2 and 3 are not provided with legal protection under the *SARA*.

Migratory birds are protected federally under the *Migratory Birds Convention Act* (*MBCA*) (1994), which states that "...no person shall disturb, destroy or take a nest, egg, nest shelter, eider duck shelter, or duck box of a migratory bird…" without a permit. The Act includes prohibition of "incidental take" of migratory birds or their nests as a result of activities such as those required for the Project.

Wildlife species are protected in the territory under the Yukon *Wildlife Act*. The Act reserves the right to place prohibitions, restrictions, or measures to be observed or implemented for the protection or survival of a population or species designated as "specially protected". Section 5 of the regulations lists several specially protected species, including:

- Cougar (*Puma concolor*);
- Gyrfalcon (*Falco rusticolus*);
- Peregrine Falcon (*Falco peregrinus*);
- Trumpeter Swan (*Cygnus buccinators*); and
- Chisana Caribou Herd.

The *Yukon Act* also offers protection from being hunted to wildlife species declared by order of the Governor in Council to be in danger of becoming extinct.

Forests are protected in the territory under the *Forest Protection Act*, the *Forest Resources Act*, and the *Territorial Lands Act*. These acts regulate the harvesting of forestry resources (through a permitting process), construction of forestry roads, and activities surround fires in forested areas, as well as many other activities.

Wetlands are protected federally under the *Federal Policy on Wetland Conservation.* The objective of this policy is to *"…promote the conservation of Canada's wetlands to sustain their ecological and socio-economic function now, and in the future*…" Coordination of implementation of the policy is the responsibility of Environment Canada, specifically the Canadian Wildlife Service and the Environmental Conservation Branch. Although there is no specific federal legislation regarding wetlands, they may be protected federally under the *SARA*, if they contain critical species habitat for Species At Risk, the *MBCA*, 1994, if they contain nests of migratory birds, and/or the *Fisheries Act*, if the wetland contributes to existing or potential fish habitat.

5.3.1.7 Residual Effects Significance Criteria

Residual environmental effects rating criteria for the potential environmental effects of the Project on the Terrestrial Environment are applied to the evaluation of a loss of plant populations, SAR, or SOCC.

A *significant residual adverse environmental effect* on the Terrestrial Environment is defined as a Project-related environmental effect that results in any of the following:

- On secure species, one that affects terrestrial populations or habitat in such a way as to cause a decline in abundance or change in distribution of common and secure population(s) such that populations will not be sustainable within the RAA.

- On any Endangered or Threatened Species at Risk, one that results in a non-permitted contravention of any of the prohibitions stated in Sections 32-36 of *SARA*. Sections 32-36 stipulate that it is an offence to capture, take, possess, collect, and sell endangered or threatened species. It is also illegal to damage or destroy the residence, for example the nest or den, of an endangered or threatened species.

- On any species of special status (SAR or SOCC), one that alters the terrestrial habitat within the spatial boundaries physically, chemically, or biologically, in quality or extent, in such a way as to cause a change or decline in the distribution or abundance of a viable plant or wildlife population that is dependent upon that habitat such that the likelihood of the long-term survival of these populations within the RAA is substantially reduced as a result.

- On any species of special status (SAR or SOCC), one that results in the direct mortality of individuals or communities such that the likelihood of the long-term survival of these rare, uncommon and/or non-secure population(s) within the RAA is substantially reduced as a result.

- For wetland environments, one that results in a non-compensated net loss of wetland area and function.

5.3.2 VC Existing Conditions

The Terrestrial Environment includes vascular plant and wildlife (including birds) species and communities, and their habitats, including both upland and wetland habitats. The assessment focuses on important habitats and vascular plant and wildlife species at risk (SAR), as defined by the federal *Species at Risk Act* (*SARA*), or species of conservation concern (SOCC), defined here as species ranked S1, S2, or S3 by the YCDC, and with a status rank of At Risk, May Be At Risk, or Sensitive as determined by the CESCC. Additional species considered in this assessment as SOCC at the request of Environment Canada include species that will be assessed by COSEWIC in the coming year. Other species, communities, and habitats in the Yukon are secure, and although they may be affected by the Project, are not of particular sensitivity to the potential environmental effects.

5.3.2.1 Vegetation

Haines Junction is located in the Ruby Ranges ecoregion of the Boreal Cordillera ecozone. Vegetation in the lower boreal forest areas of the ecoregion include white spruce (*Picea glauca*), black spruce (*Picea mariana*), dwarf willow (*Salix herbacea*), birch (*Betula* sp.), ericaceous shrubs, and to a lesser extent, lodgepole pine (*Pinus contorta*). In poorly draining areas black spruce, scrub willow, birch, and various mosses can be found. Subalpine areas include alpine fir (*Abies lasiocarpa*) and lodgepole pine, while the highest elevated alpine areas of the ecoregion have plant communities that consist of mountain avens (*Dryas octopetala*), dwarf willow, birch, ericaceous shrubs, graminoid species, and mosses (The Ecological Framework of Canada n.d.).

Haines Junction has three species of trees; white spruce, trembling aspen (*Populous temuloides*), and balsam poplar (*Populous balsamifera*). The Project site is classified as a white spruce forest. A search of the YCDC did not indicate that there are any plant SAR or SOCC that have been identified in the vicinity of the site (B. Bennett pers. comm. 2012). There is currently only one plant listed by the *SARA* in the Yukon. The Baikal sedge (*Carex sabulosa*) is listed on Schedule 1 as Threatened, S2 by the YCDC, and as At Risk in the territory by the CESCC). The Baikal sedge can be found in sand dune habitats; the habitat at the Project site is not suitable for the sedge (B. Bennett, pers. comm. 2012). There are three additional plant SOCC found in the Yukon; the Yukon draba (*Draba yukonensis*, listed as endangered by COSEWIC, S1 by YCDC, and May be at Risk by CESCC), spiked saxifrage (*Saxifraga spicata*, awaiting review by COSEWIC in 2013, listed at May be at Risk by CESCC, and S1S2 by YCDC), and Yukon podistera (*Podistera yukonensis*, awaiting review by COSEWIC in 2013, listed at May be at Risk by CESCC, and S2 by YCDC). No suitable habitat is found at the Project site for these plants SOCC (B. Bennett pers. comm. 2013).

There are 170 recorded invasive plant species in the Yukon, each with its own invasiveness rank and general abundance with Yukon Environment. The spread of invasive species threatens biodiversity and is of concern to native species and habitats. Nineteen of these species are considered highly invasive and are listed below in Table 4.1.1.

Table 5.3.2 Highly Invasive Plant Species in Yukon Territory

Common Name	Scientific Name	Invasiveness Rank	Abundance	Persistence
Crested Wheat Grass	*Agropyron cristatum*	1	C	1
Smooth Brome	*Bromus inermis*	1	C	1
Spotted Knapweed	*Centaurea maculosa*	1	X	3
Creeping (Canada) Thistle	*Cirsium arvense*	1	R	2
Narrow-leaved Hawksbeard	*Crepis tectorum*	1	C	1
Leafy Spurge	*Euphorbia esula*	1	R	2
Field Hawkweed	*Hieracium caespitosum*	1	R	2
Oxeye Daisy	*Leucanthemum vulgare*	1	R	1
Narrow-leaved (Altai) Lyme Grass	*Leymus angustus*	1	R	2
Dalmatian Toadflax	*Linaria dalmatica*	1	X	3
Butter-and-eggs	*Linaria vulgaris*	1	C	1
Lucerne	*Medicago falcata*	1	C	1
White Sweetclover	*Melilotus alba*	1	C	1
Yellow Sweetclover	*Melilotus officinalis*	1	C	1
Reed Canary Grass	*Phalaris arundinacea*	1	?	1
Field Snow-thistle	*Sonchus arvensis ssp. uliginosus*	1	C	1
Common Tansy	*Tanacetum vulgare*	1	U	2
Scentless Chamomile	*Tripleurospermum inodoratum*	1	R	1
Tufted Vetch	*Vicia cracca*	1	C	2

Notes:
Invasiveness Rank
1 - Highly invasive - may displace or replace native ecosystems.

General Abundance
C = Common – widespread, established.
R = Rare, known from only one or two localities.
U = Unknown.
X = Possibly not persistent.
? = Possibly native.

Persistence
1 = Widespread.
2 = Local.
3 = Not persistent.

Source: Government of Yukon 2012a, Yukon Introduced Plants, January 2012 accessed at: http://www.env.gov.yk.ca/animals-habitat/invasiveplants.php.

Spruce bark beetle (*Dendroctonus rufipennis*) infestation in the region has had an impact on the age class and stand height of forests in the region (CAFN 2005). Large stands of dead wood are now found in many areas throughout the CAFN region. The beetle attacks semi-mature and mature white spruce, boring into the tree to create a cavity for eggs. Once hatched, larvae bore into the phloem. The beetles are carriers of a fungus that affects the phloem tubes of the trees and helps the beetles weaken the trees. Stands of dead trees are wildfire hazards and are of concern, especially near residential areas.

The closest wetlands to Haines Junction are located adjacent to the southern municipal boundaries of the village and are associated with Dezadeash River (see Figure 5.3.1).

Figure 5.3.1 Terrestrial Environment

The location of the source feedstock has not been identified at the time of writing. Once selected, information regarding vegetation (including invasive species) and wetlands at the sites will be included in this report.

5.3.2.2 Wildlife

Wildlife typically encountered in the Ruby Ranges ecoregion include caribou (*Rangifer tarandus*), grizzly bears (*Ursus arctos horribilis*), black bears (*Ursus americanus*), Dall sheep (*Ovis dalli*), moose (*Alces alces*), foxes (*Vulpes* sp.), wolves (*Canis* sp.), hares (*Lepus* sp.), ravens (*Corvus corax*), rock ptarmigan (*Lagopus muta*), willow ptarmigan (*Lagopus lagopus*), and golden eagles (*Aquila chrysaetos*) (The Ecological Framework of Canada n.d.).

A search of the YCDC did not indicate that there are any wildlife SAR or SOCC that have been identified in the vicinity of Haines Junction (B. Bennett, pers. comm. 2012). While no SAR or SOCC have been identified, it is always possible to encounter Barn Swallows (*Hirundo rustica*, designated as Threatened by COSEWIC and Sensitive by CESCC) nesting in old buildings. It has also been suggested that there is potential nesting habitat for Olive-sided Flycatcher (*Contopus cooperi*, listed in Schedule 1 of the *SARA* as Threatened and ranked At Risk by CESCC) and Common Nighthawk (*Chordeiles minor*, listed in Schedule 1 of the *SARA* as Threatened and ranked At Risk by CESCC) in the village (B. Bennett pers. comm. 2012). The possibility of encountering grizzly bears (designated as Special Concern by COSEWIC and Sensitive by CESCC) also exists (B. Bennett pers. comm. 2012). Additional SAR and SOCC in the Yukon are listed in Table 4.2, below.

Table 5.3.3 Additional Wildlife Species at Risk and Species of Conservation Concern in Yukon Territory

Common Name	Scientific Name	*SARA* Schedule and Status	COSEWIC Rank	CESCC Rank (2010)	YCDC S-Rank
Northern Long-eared Bat	*Myotis septentrionalis*	No schedule, no status	Endangered	Sensitive	S3
Little Brown Bat	*Myotis lucifugus*	No schedule, no status	Endangered	Secure	S1S3
Canada Warbler	*Wilsonia canadensis*	Schedule 1, Threatened	Threatened	At Risk	S1B
Red Knot	*Calidris canutus roselaari*	Schedule 1, Threatened	Threatened	-	-
Wood Bison	*Bison bison athabascae*	Schedule 1, Threatened	Threatened	At Risk	S2S3
Woodland Caribou (boreal population)	*Rangifer tarandus caribou*	Schedule 1, Threatened	Threatened	-	S1
Western Toad	*Anaxyrus boreas*	No schedule, no status	Special Concern	Sensitive	S3
Horned Grebe	*Podiceps auritus*	No schedule, no status	Special Concern	Sensitive	S3B
Peregrine Falcon	*Falco peregrinus anatum/tundrius*	Schedule 1, Special Concern	Special Concern	Sensitive	S3B
Rusty Blackbird	*Euphagus carolinus*	Schedule 1, Special Concern	Special Concern	Sensitive	S3B
Short-eared Owl	*Asio flammeus*	Schedule 1, Special Concern	Special Concern	Sensitive	S3B
Buff-breasted Sandpiper	*Tryngites subruficollis*	No schedule, no status	Special Concern	May be at Risk	S1B

Common Name	Scientific Name	*SARA* Schedule and Status	COSEWIC Rank	CESCC Rank (2010)	YCDC S-Rank
Collared Pika	*Ochotona collaris*	No schedule, no status	Special Concern	Sensitive	S3
Polar Bear	*Ursus maritimus*	Schedule 1, Special Concern	Special Concern	May be at Risk	S1
Wolverine (western population)	*Gulo gulo*	No schedule, no status	Special Concern	Sensitive	S3
Woodland Caribou (northern mountain population)	*Rangifer tarandus caribou*	Schedule 1, Special Concern	Special Concern	-	S3
Bank Swallow	*Riparia riparia*	No schedule, no status	Upcoming assessment in 2013	Secure	S5B
Red-necked Phalarope	*Phalaropus lobatus*	No schedule, no status	Upcoming assessment in 2014	Sensitive	S3B
Evening Grosbeak	*Coccothraustes vespertinus*	No schedule, no status	To be determined	Sensitive	S3B

Notes:

S1 = Critically Imperiled—Critically imperiled in the jurisdiction because of extreme rarity or because of some factor(s) such as very steep declines making it especially vulnerable to extirpation from the jurisdiction.

S2 = Imperiled—Imperiled in the jurisdiction because of rarity due to very restricted range, very few populations, steep declines, or other factors making it very vulnerable to extirpation from jurisdiction.

S3 = Vulnerable—Vulnerable in the jurisdiction due to a restricted range, relatively few populations, recent and widespread declines, or other factors making it vulnerable to extirpation.

S4 = Apparently Secure—Uncommon but not rare; some cause for long-term concern due to declines or other factors.

S5 = Secure—Common, widespread, and abundant in the jurisdiction.

S#S# = Range Rank — A numeric range rank (*e.g.*, S2S3 or S1S3) is used to indicate any range of uncertainty about the status of the species or ecosystem. Ranges cannot skip more than two ranks (*e.g.*, SU is used rather than S1S4).

B = Breeding—Conservation status refers to the breeding population of the species in the nation or state/province.

Wild Species: The General Status of Wild Species in Canada

At Risk: Species for which a formal, detailed risk assessment (COSEWIC status assessment or provincial or territorial equivalent) has been completed and that have been determined to be at risk of extirpation or extinction (*i.e*. Endangered or Threatened). A COSEWIC designation of Endangered or Threatened automatically results in a Canada General Status Rank (Canada rank) of At Risk. Where a provincial or territorial formal risk assessment finds a species to be Endangered or Threatened in that particular region, then, under the general status program, the species automatically receives a provincial or territorial general status rank of At Risk.

May Be At Risk: Species that may be at risk of extirpation or extinction and are therefore candidates for a detailed risk assessment by COSEWIC, or provincial or territorial equivalents.

Sensitive: Species that are not believed to be at risk of immediate extirpation or extinction but may require special attention or protection to prevent them from becoming at risk.

Secure: Species that are not believed to belong in the categories Extinct, Extirpated, At Risk, May Be At Risk, Sensitive, Accidental or Exotic. This category includes some species that show a trend of decline in numbers in Canada but remain relatively widespread or abundant.

Source Wild Species: The General Status of Wild Species in Canada' website Available at: http://www.wildspecies.ca/ranks.cfm?lang=e (CESCC 2012).

The Fish and Wildlife Branch of Yukon Environment maintains data on key areas where wildlife are found during important stages of their life cycle. Key Wildlife Areas (see Figure 5.3.1) located within the Village of Haines Junction municipal boundary include those for Sharp-tailed Grouse (*Tympanuchus phasianellus*) at the northern boundary and moose at the southeastern boundary. Just outside the municipal boundary there are key areas for grizzly bear (east of the village) and an additional area for moose (southwest of the village). An additional search using the Yukon Energy, Mines, and Resources lands viewer mapping application also displayed a spring staging area for geese east of the village.

The location of the biomass plant and the areas for feedstock harvesting have not been identified at this time. Once selected, targeted field surveys will be conducted at the sites and will be included in this report.

5.3.3 Potential Project VC Interactions

Table 5.4.2 below lists each Project activity and physical work for the Project, and ranks each interaction as 0, 1, or 2 based on the level of interaction each activity or physical work will have with the Terrestrial Environment.

Table 5.3.4 Potential Project Environmental Effects to the Terrestrial Environment

Project Activities and Physical Works	Potential Environmental Effects	
	Change in Terrestrial Populations	Change in Wetlands
Construction		
Site Preparation	2	0
Physical Construction of the Facility Structures And Installation of Equipment	2	0
Commissioning of the plant	1	0
Construction of Infrastructure for Feedstock Harvesting	2	1
Operation		
Operation and Maintenance of Plant site	1	0
Feedstock Harvesting	2	1
Decommissioning, reclamation, and closure		
Plant Site	1	0
Harvested Areas	1	1

Notes:
Project-Related Environmental Effects were ranked as follows:
0 No interaction. The environmental effects are rated not significant and are not considered further in this report.
1 Interaction will occur. However, based on past experience and professional judgment, the interaction would not result in a significant environmental effect, even without mitigation, or the interaction would clearly not be significant due to application of codified practices and/or permit conditions. The environmental effects are rated not significant and are not considered further in this report.
2 Interaction may, even with codified mitigation and/or permit conditions, result in a potentially significant environmental effect and/or is important to regulatory and/or public interest. Potential environmental effects are considered further and in more detail in the EA.

Construction

VCs With No Interaction With the Project (Ranking of 0)

During Construction, site preparation, construction of the facility structures and installation of equipment, and commissioning of the plant have been ranked as 0 for potential change in wetlands. There are no wetlands in the vicinity of the proposed biomass plant site (based on FEED site selection), and as such, no potential for the Project to directly impact wetland habitat. Therefore, a change in wetlands resulting from these Project activities is rated not significant.

VCs With Interactions That Would Not Result in Significant Environmental Effects (Ranking of 1)

During Construction, commissioning of the plant has been ranked as 1 for potential change in terrestrial populations. Once site preparation and construction of the building are complete, there are no further

disturbances expected on the site. If present, the locations any sensitive habitats, SAR, or SOCC within the PDA will have been identified during field surveys and as such, all commissioning activities will be conducted away from these areas.

Construction of infrastructure for feedstock harvesting has been ranked as 1 for potential changes in wetlands. At this time, information surrounding the harvesting of feedstock is not known. Table 5.4.2 will be revised once the forest harvesting activities associated with the Project have been defined and field surveys have been conducted.

Operation

VCs With No Interaction With the Project (Ranking of 0)

During Operation, operation and maintenance of the plant site has been ranked as 0 for potential change in wetlands. There are no wetlands present at the proposed plant site and therefore, there is no potential for operation and maintenance activities at the site to directly impact wetland habitat. As a result, a change in wetlands resulting from these Project activities is rated not significant.

VCs With Interactions That Would Not Result in Significant Environmental Effects (Ranking of 1)

During Operation, operation and maintenance of the plant site has been ranked 1 for potential change in terrestrial populations. In the event sensitive habitats, SAR, or SOCC are discovered on the site during field surveys, it would be ensured that operation and maintenance activities would be conducted away from these areas. Indirect environmental effects could also be associated with Accidents, Malfunctions, and Unplanned Events; however, contingency plans will be put in place during Operation to address such events.

Feedstock harvesting has been ranked as 1 for potential change in wetlands. At this time the source of feedstock is unknown. If feedstock is to be collected in the vicinity of wetland habitat, there could be potential for erosion and sedimentation, as well as changes in hydrology in wetlands due to the removal of the trees. Implementation of established and effective erosion and sedimentation controls will be used during all harvesting activities, limiting the magnitude of any potential interactions. Any hydrological changes in wetlands will be compensated for, and thus are rated not significant. The assessment of feedstock harvesting in relation to wetlands will be revised once the forest harvesting activities associated with the Project have been defined and field surveys have been conducted.

Decommissioning, Reclamation, and Closure

VCs With No Interaction With the Project (Ranking of 0)

During decommissioning, reclamation, and closure of the Project activities at the plant site have been ranked as 0 for potential change in wetlands. There are no wetlands present at the proposed plant site and therefore, there is no potential for decommissioning activities at the site to directly impact wetland habitat. As a result, a change in wetlands resulting from these activities is rated not significant.

VCs With Interactions That Would Not Result in Significant Environmental Effects (Ranking of 1)

Decommissioning, reclamation, and closure activities at the plant have been ranked as 1 for potential change in terrestrial populations. Decommissioning activities would be governed by regulations current at the time of the activities and reclamation plan would be developed at that time. The site would likely be redeveloped for other purposes or left to re-vegetate naturally.

The decommissioning, reclamation, and closure of harvested areas has been ranked as 1 for both potential environmental effects. While the activities and location of feedstock harvesting have yet to be determined, it is likely that these activities would include the removal of access roads. If access roads were being removed in areas in the vicinity of wetlands erosion and sedimentation controls would be in place prior to work being conducted. Reclamation efforts would likely involve re-forestation efforts in the previously harvested areas.

Thus, in consideration of the nature of the interactions and the planned implementation of mitigation, the potential environmental effects of all Project activities and physical works that were ranked as 0 or 1 in Table 5.4.2, including cumulative environmental effects, on the Terrestrial Environment during any phase of the Project are rated not significant, and are not considered further in the assessment.

5.3.3.1 Assessment of Project-Related Environmental Effects

A summary of the environmental effects assessment and prediction of residual environmental effects resulting from interactions ranked as 2 on the Terrestrial Environment is provided in Table 5.4.3.

Table 5.3.5 Summary of Residual Project-Related Environmental Effects on the Vegetation and Wetland Resources

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics						Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context					
Change in Terrestrial Populations	Construction: • Site preparation; • Physical construction of the facility structures and installation of equipment; and • Construction of infrastructure for feedstock harvesting	• Avoid known locations of plant and wildlife SAR and SOCC, where feasible. • Include any SAR or SOCC found within or adjacent to the PDA in post-construction monitoring and follow-up plans. • Conduct clearing activities at the plant location in fall and/or winter, outside the breeding season of migratory birds and calving season. • If active nests are discovered during tree clearing at the plant site, a vegetated buffer zone around the nest will be established and activities will be minimized in the immediate area until nesting is complete and chicks have fledged and left the area. • Flag any vascular plant SAR or SOCC found within 30 m of the PDA, and minimize Construction adjacent to the plants whenever feasible. • Keep litter and garbage contained to limit wildlife encounters. • Use designated roadways and access roads.	A	L	S	ST/ O	R	U/D	N	M	L	N	Follow-up to include field study of the selected plant site and potentially feedstock harvesting infrastructure areas (if not previously evaluated).

Table 5.3.5 Summary of Residual Project-Related Environmental Effects on the Vegetation and Wetland Resources

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics						Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context					
		• Flag off environmentally sensitive areas prior to site clearing and construction. • Limit Project-related activity outside of the PDA. • Clean construction machinery prior to entering and leaving areas known to contain invasive species to reduce their spread. • Native species will be used, where possible, for re-vegetation efforts. Where not possible, species used will be non-invasive.											
	Operation: • Feedstock harvesting	• Clean construction machinery prior to entering and leaving areas known to contain invasive species to reduce their spread. • Conduct tree clearing activities at the plant location in fall and/or winter, outside the breeding season of migratory birds and calving season. • Avoid known locations of plant SAR and SOCC, where feasible. • Use designated roadways and access roads. • Limit Project-related activity outside of the PDA. • Keep litter and garbage	x	x	x	x/x	x	x	x	x	x	x	Follow-up to include field surveys once location of feedstock harvesting is determined.

Table 5.3.5 Summary of Residual Project-Related Environmental Effects on the Vegetation and Wetland Resources

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics						Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context					
		contained to limit wildlife encounters. • Field engineering, design, and construction of new roads will follow the Timber Harvest Planning and Operating Guidebook.											

KEY

Direction:
- P Positive.
- A Adverse.

Magnitude:
- L Low: Change of plant populations that do not affect the sustainability or biodiversity of populations within the RAA; no change in wetland function.
- M Moderate: Change in populations that affect the sustainability of populations or biodiversity within the RAA; change in wetland function after the application of mitigation and compensation.
- H High: Change in populations that affect the sustainability of populations or biodiversity within the region; non-compensated loss of wetland function.

Geographic Extent:
- S Site-specific: Within the PDA.
- L Local: Within the region.

Duration:
- ST Short term: Occurs and lasts for short periods (*e.g.,* days/weeks/months).
- MT Medium term: Occurs and lasts for extended periods of time (*e.g.*, years).
- LT Long term: Occurs during Construction and/or Operation and lasts for the life of Project.
- P Permanent: Occurs during Construction and Operation and beyond.

Frequency:
- O Occurs once.
- S Occurs sporadically at irregular intervals.
- R Occurs on a regular basis and at regular intervals.
- C Continuous.

Reversibility:
- R Reversible.
- I Irreversible.

Ecological/Socio-economic Context:
- U Undisturbed: Area relatively or not adversely affected by human activity.
- D Developed: Area has been substantially previously disturbed by human development or human development is still present.
- N/A Not Applicable.

Significance:
- S Significant.
- N Not Significant.

Prediction Confidence:
Based on scientific information, statistical analysis, professional judgment, and/or effectiveness of mitigation.
- L Low level of confidence.
- M Moderate level of confidence.
- H High level of confidence.

Likelihood:
Based on professional judgment:
- L Low probability of occurrence.
- M Medium probability of occurrence.
- H High probability of occurrence.

5.3.3.2 Potential Project Environmental Effect Mechanisms

The following Project activities and physical works associated with Construction and Operation that were ranked as 2 will interact with the Terrestrial Environment and have potential to result in significant adverse residual environmental effects, and will thus be considered in more detail in this EA:

- site preparation (change in terrestrial populations only);
- physical construction of the facility structures and installation of equipment (change in terrestrial populations only);
- construction of infrastructure for feedstock harvesting (change in terrestrial populations only); and
- feedstock harvesting (change in terrestrial populations only).

The interactions between these Project activities and the Terrestrial Environment are discussed in the context of the measurable parameters for the potential environmental effects.

The activities associated with Construction (*i.e*., site preparation and installation of structures) have potential to result in a change in terrestrial populations through habitat loss and degradation, loss of individuals of plant and wildlife SAR and SOCC, and mortality to migratory birds. Field studies will be conducted once the plant site is selected to determine the potential for changes in terrestrial populations.

Construction activities within the PDA will result in the permanent loss of habitat for some plant and wildlife species, and the creation of edge habitat along the PDA, through vegetation removal and grubbing of the site. Clearing of the PDA will result in the direct habitat loss of forest. At this time the amount of clearing required for the plant site has not been determined. Only three species of trees grown in the village of Haines Junction, including, white spruce, trembling aspen, and balsam poplar. These species are typically found in previously disturbed sites such as roadsides and forest edges, and are commonly found in the Yukon.

Further discussion will be included regarding the feedstock harvesting site once details are available. When available the following details will be included, where applicable:

- habitat types within the LAA;
- discussion of old growth forest;
- loss and degradation of habitat;
- habitat fragmentation;
- discussion of plant SAR and/or SOCC;
- migration routes;

- trapping activities in the vicinity of the PDA;
- identification of forest resource management zones (*i.e.*, high wildlife value areas and fuel abatement areas) in the vicinity of the PDA;
- identification of traditional use plants;
- loss of wetland area and the resultant loss of wetland function (including hydrological function).

5.3.3.3 Mitigation Measures

The mitigation measures that will be implemented during the Project are listed in Table 5.4.3. The key mitigation measures to reduce environmental effects of the Project on the Terrestrial Environment are listed below. These mitigation measures will be implemented wherever technically and economically feasible to minimize potential environmental effects of the Project on the Terrestrial Environment:

- avoid known locations of plant and wildlife SAR and SOCC, and established nest sites of migratory birds;
- limit Project-related activity outside of the PDA;
- clean construction machinery prior to entering and leaving the worksite to reduce the spread of potential invasive species from one area to another;
- flag off environmentally sensitive areas prior to Construction;
- conduct clearing activities in fall and/or winter, outside the breeding season of migratory birds (May 1 to August 31). If any clearing during migratory bird breeding season is required, surveys will be conducted to determine if migratory bird nesting activity is taking place. If nesting activity is taking place that clearing will be delayed until bird young of the year have fledged and left the nest;
- conduct clearing activities in fall and/or winter, outside of calving season;
- establish buffers and protect active migratory bird nests until fledging, upon their discovery in work areas;
- keep litter and garbage contained to reduce wildlife encounters;
- use designated roadways and access roads;
- follow conditions of any Project environmental permits; and
- field engineering, design, and construction of new roads will follow the Timber Harvest Planning and Operating Guidebook.

Due to the unknown location of feedstock harvesting, additional mitigation may be required, including but not limited to:

- Employ standard erosion and sediment control measures, including:
  - erosion control fencing;
  - check dams;
  - sedimentation control ponds where appropriate;
  - construction sequencing to minimize soil exposure;
  - retaining existing vegetation as long as possible;
  - re-vegetating and mulching of denuded areas;
  - diverting run-off away from denuded areas;
  - optimizing length and steepness of slope;
  - keeping surface water run-off velocities low;
  - proper sizing and protecting of drainage ways and outlets;
  - intercepting of sediments on site; and
  - inspecting and maintaining the above-mentioned control measures.
- Minimize channeling near wetlands.
- Clean construction machinery prior to entering and leaving wetlands to reduce the spread of potential invasive species from one wetland to another.

The mitigation sequence of avoidance, minimization, and compensation, as applied to the Project, are presented here in the form of mitigation to avoid wetlands where possible, minimize the loss and potential environmental effects, and ultimately compensate for any residual losses.

5.3.3.4 Characterization of Residual Effects

If not carefully carried out or suitably mitigated, the Project could affect the Terrestrial Environment due to a change in terrestrial populations. The loss of individuals of SAR or SOCC would constitute a residual environmental effect. At the plant site there are no anticipated occurrences of SAR or SOCC, however, if they were present it is anticipated that the individuals of each species outside of the PDA will ensure that the local populations persist. Effective Project planning, design, avoidance, and the application of known and proven mitigation measures will reduce the environmental effects of the Project on changes to Terrestrial Populations so that they are not significant. The application of the same standard mitigation to avoid or reduce potential environmental effects on migratory birds will be

implemented. This includes clearing outside the breeding season when nests and/or nestlings are not present.

Residual effects related to feedstock harvesting will be evaluated once the harvesting area has been selected. If the selected areas are in the vicinity of a wetland, effective Project planning, design, avoidance, and the application of known and proven mitigation measures will reduce the environmental effects of the Project on changes to wetlands so that they are not significant. Where avoidance is not possible, mitigation measures that will be established for work with regard to wetlands will include implementation of well-established and proven erosion and sedimentation control measures. With mitigation, potentially including compensation, the Project will result in no net loss of wetland function and area.

With the proposed mitigation (*e.g.*, no loss of protected or rare species, mitigation for protection of migratory birds) the residual environmental effects of a change in terrestrial populations during all phases of the Project are rated not significant. This conclusion has been determined with a moderate level of confidence in consideration of the planned implementation of proposed proven mitigation measures described above and current lack of site specific data.

5.3.4 Assessment of Cumulative Effects

In addition to the Project environmental effects discussed above, an assessment of the potential cumulative environmental effects was conducted for other projects and activities that have potential to cause environmental effects that overlap with those of the Project, as identified in Table 1.2.3. Table 5.4.4 below presents the potential cumulative environmental effects to the Terrestrial Environment, and ranks each interaction with other projects as 0, 1, or 2 with respect to the nature and degree to which important Project-related environmental effects overlap with those of other projects and activities.

Table 5.3.6 Potential Cumulative Environmental Effects to the Terrestrial Environment

Other Projects and Activities With Potential for Cumulative Environmental Effects	Potential Cumulative Environmental Effects	
	Change in Terrestrial Populations	Change in Wetlands
Upgrades to Municipal Water Treatment System	0	0
Land Use	1	1

Notes:
Cumulative environmental effects were ranked as follows:
0 = Project environmental effects do not act cumulatively with those of other Projects and Activities.
1 = Project environmental effects act cumulatively with those of other Project and Activities, but are unlikely to result in significant cumulative environmental effects OR Project environmental effects act cumulatively with existing significant levels of cumulative environmental effects but will not measurably change the state of the VEC.
2 = Project environmental effects act cumulatively with those of other project and activities, and may result in significant cumulative environmental effects OR Project environmental effects act cumulatively with existing significant levels of cumulative environmental effects and may measurably change the state of the VEC.

Interactions between the Project and upgrades to the municipal water treatment system in Haines Junction have ranked as a 0 in Table 5.23. The upgrades are currently complete and increased the villages capacity for municipal water use, including that for industry. Any additional future upgrades to the water treatment system would only serve to further improve water quality and quantity in Haines Junction and would not result in adverse cumulative environmental effects.

Potential Project-related effects on terrestrial populations and wetlands could overlap with current land use within the RAA and therefore result in a cumulative change in terrestrial populations and change in wetlands. Historical and current use of land for recreational purposes includes recreational hunting, fishing, trail development, and use of land for hiking, all-terrain vehicles, or snowmobiling as well as industrial and forest resource harvesting activities. Past and present terrestrial population effects and change in wetlands associated with land use in the RAA have potential to interact cumulatively with the Project to adversely affect terrestrial populations and wetlands.

Existing recreational land use in the RAA has potential to encroach on lands and waters that support terrestrial populations, and result in changes in wetland area and function. These potential effects could be amplified due to overlap with similar effects associated with Project-related activities and infrastructure. Trails intended for recreational land use support ATV and other traffic that can also disturb wetlands, and other wildlife habitat important to terrestrial populations and can overlap cumulatively with other projects affecting these habitats.

Resource land use in the RAA, including forestry and mining activities, has potential to interact cumulatively with the Project to affect terrestrial populations and wetlands through removal, destruction, or disturbance of SOCC individuals and habitats, including wetlands. Potential forestry-related cumulative effects on SOCC will be mitigated by the compliance with territorial forestry guidelines, where applicable and by the natural regeneration of forestry resources.

The contribution of the Project to cumulative environmental effects is not expected to be substantive in the LAA, and likely not in the RAA.

Cumulative effects will be re-evaluated once the location of feedstock harvesting is determined and final plant siting has been completed.

5.3.5 Determination of Significance

5.3.5.1 Residual Cumulative Environmental Effects

The potential environmental effects of the Project on a Change in Terrestrial Populations and Change in Wetlands are not significant, but will overlap with the environmental effects of other projects and activities that have been or will be carried out. The principal activities of concern are forest resource harvesting, mining, and recreational land use resulting in the loss of terrestrial habitat, including wetlands. The residual cumulative environmental effects of a Change in Terrestrial Populations and Change in Wetlands, as a result of past, present, and reasonably foreseeable projects or activities that have been or will be carried out, in combination with the environmental effects of the Project, during all phases are rated not significant. This determination has been made with a moderate level of confidence as the specific areas are currently undefined.

5.3.6 Summary Consultation Influence on the Assessment

At the time of writing, consultations in the community are on-going. A summary of the consultations as they apply to Terrestrial Environment will be provided following the completion of the consultations for the Project.

5.3.7 Effects Monitoring and Adaptive Management

Baseline terrestrial field studies of the PDA will be completed prior to Construction. Studies typically include breeding bird surveys and rare plant surveys, with incidental occurrences of other wildlife species being recorded in conjunction with these activities. Studies are developed in consultation with regulatory authorities (*e.g.*, Yukon Environment, Environment Canada, *etc*.)

In the event that the feedstock harvesting areas are located in the vicinity of a wetland, wetland monitoring is recommended for any wetlands (mapped or unmapped) within the PDA or a 15 m buffer, in order to assess potential change in function. A wetland monitoring plan will be developed prior to construction. Monitoring (as per Section 79 of the *SARA*) may be warranted if SAR are likely to be affected by the Project (to be determined by targeted field studies). No other follow-up or monitoring is required to verify the predictions of the environmental effects assessment on the Terrestrial Environment, or to verify the effectiveness of mitigation.

5.4 FRESHWATER RESOURCES

Freshwater Resources consists of watercourses (rivers and streams) that provide habitat for fish and other freshwater aquatic species. The Freshwater Resources VC includes fish and fish habitat and surface water quality as indicators of the overall health of the ecosystem. Fish habitat includes physical (*e.g.*, substrate, temperature, flow velocity and volumes, water depth), chemical (*e.g.*, dissolved oxygen, pH, nutrients), and biological (*e.g.*, fish, benthic invertebrates, aquatic plants) attributes of the environment that are required by fish to carry out life cycles processes (*e.g.*, spawning, rearing, feeding, overwintering, migration). Biomass plant activities are not anticipated to have significant environmental effects on the Freshwater Environment as the plant is not located in the immediate vicinity of any freshwater source. Once the locations of feedstock harvesting have been selected, further information will be included with respect to the selected areas and the VC scope of assessment would be revised as required.

5.4.1 Scope of the Assessment

This section defines the scope of the environmental assessment of Freshwater Resources in consideration of the nature of the regulatory setting, issues identified during public and First Nations engagement activities, potential Project-VEC interactions, and existing knowledge.

5.4.2 Existing Conditions

The Yukon Territory is drained by three major river systems. The Yukon drainage basin, the Alsek/Tatshenshini drainage basin, and the Peel and Liard sub-basins of MacKenzie River (Fisheries and Oceans Canada 2011). These rivers and streams have 38 recorded species of freshwater fishes. A list of these species and their status ranks can be found in Table 4.1.3. Please note that the last CESCC assessment that included an assessment for fish was in 2005 report; no current fish ranking data is available in the 2010 report.

Table 5.4.1 Freshwater Fish Species in Yukon Territory

Common Name	Scientific Name	*SARA* Schedule and Status	COSEWIC Rank	CESCC Rank (2005)	YCDC S-Rank
Artic Lamprey	*Lethenteron*	No schedule,	No status	Undetermined	S2S4B

Table 5.4.1 Freshwater Fish Species in Yukon Territory

Common Name	Scientific Name	*SARA* Schedule and Status	COSEWIC Rank	CESCC Rank (2005)	YCDC S-Rank
	camtschaticum	no status			
Lake Chub	*Couesius plumbeus*	No schedule, no status	No status	Secure	S5
Northern Pearl Dace	*Semotilus margarita*	No schedule, no status	No status	-	-
Flathead Chub	*Platygobio gracilis*	No schedule, no status	No status	Undetermined	SU
Longnose Dace	*Rhinichthys cataractae*	No schedule, no status	No status	Undetermined	SNA
Northern Redbelly Dace	*Chrosomus eos*	No schedule, no status	No status	-	-
Finescale Dace	*Phoxinus neogaeus*	No schedule, no status	No status	-	-
Goldfish	*Carassius auratus auratus*	No schedule, no status	No status	Exotic	Exotic/SNA
Longnose Sucker	*Catostomus catostomus*	No schedule, no status	No status	Secure	S5
White Sucker	*Catostomus commersonii*	No schedule, no status	No status	Secure	S2S3
Northern Pike	*Esox lucius*	No schedule, no status	No status	Secure	S5
Pond Smelt	*Hypomesus olidus*	No schedule, no status	No status	-	-
(Arctic) Rainbow Smelt	*Osmerus mordax*	No schedule, no status	No status	Undetermined	SU
Rainbow Trout/Steelhead	*Oncorhynchus mykiss*	No schedule, no status	No status	Secure	S3
Lake Trout	*Salvelinus namaycush*	No schedule, no status	No status	Secure	S3S4
Dolly Varden	*Salvelinus malma malma*	No schedule, no status	Special Concern	Secure	S3S4
Bull Trout	*Salvelinus confluentus*	No schedule, no status	Special Concern	Sensitive	S3
Arctic Char	*Salvelinus alpinus*	No schedule, no status	No status	Undetermined	S1
Chum Salmon	*Oncorhynchus keta*	No schedule, no status	No status	Secure	S4
Kokanee/Sockeye Salmon	*Oncorhynchus nerka*	No schedule, no status	Upcoming assessment in 2014	Sensitive	S3
Chinook Salmon	*Oncorhynchus tshawytscha*	No schedule, no status	No status	Secure	S2S3B
Coho Salmon	*Oncorhynchus kisutch*	No schedule, no status	No status	Secure	S3
Least Cisco	*Coregonus sardinella*	No schedule, no status	No status	Secure	S4
Bering Cisco	*Coregonus laurettae*	No schedule, no status	Special Concern	Undetermined	S3
Arctic Cisco	*Coregonus autumnalis*	No schedule, no status	No status	Undetermined	S2S3
Lake Whitefish	*Coregonus clupeaformis*	No schedule, no status	No status	Secure	S4

Table 5.4.1 Freshwater Fish Species in Yukon Territory

Common Name	Scientific Name	*SARA* Schedule and Status	COSEWIC Rank	CESCC Rank (2005)	YCDC S-Rank
Squanga Whitefish	*Coregonus sp.*	Schedule 3, Special Concern	Special Concern	-	S3
Broad Whitefish	*Coregonus nasus*	No schedule, no status	No status	Secure	S4
Pygmy Whitefish	*Prosopium coulterii*	No schedule, no status	No status	Sensitive	S4
Round Whitefish	*Prosopium cylindraceum*	No schedule, no status	No status	Secure	S5
Mountain Whitefish	*Prosopium williamsoni*	No schedule, no status	No status	Undetermined	SU
Inconnu	*Stenodus leucichthys*	No schedule, no status	No status	Secure	S4
Arctic Grayling	*Thymallus arcticus*	No schedule, no status	No status	Secure	S5
Trout-perch	*Percopsis omiscomaycus*	No schedule, no status	No status	Undetermined	SU
Burbot	*Lota lota*	No schedule, no status	No status	Secure	S5
Threespine Stickleback	*Gasterosteus aculeatus*	No schedule, no status	No status	Exotic	SNA
Ninespine Stickleback	*Pungitius pungitius*	No schedule, no status	No status	Undetermined	S2S3
Slimy Sculpin	*Cottus cognatus*	No schedule, no status	No status	Secure	S5
Spoonhead Sculpin	*Cottus ricei*	No schedule, no status	Not at Risk	Undetermined	SU

Notes:

S1 = Critically Imperiled—Critically imperiled in the jurisdiction because of extreme rarity or because of some factor(s) such as very steep declines making it especially vulnerable to extirpation from the jurisdiction.

S2 = Imperiled—Imperiled in the jurisdiction because of rarity due to very restricted range, very few populations, steep declines, or other factors making it very vulnerable to extirpation from jurisdiction.

S3 = Vulnerable—Vulnerable in the jurisdiction due to a restricted range, relatively few populations, recent and widespread declines, or other factors making it vulnerable to extirpation.

S4 = Apparently Secure—Uncommon but not rare; some cause for long-term concern due to declines or other factors.

S5 = Secure—Common, widespread, and abundant in the jurisdiction.

S#S# = Range Rank — A numeric range rank (*e.g.*, S2S3 or S1S3) is used to indicate any range of uncertainty about the status of the species or ecosystem. Ranges cannot skip more than two ranks (*e.g.*, SU is used rather than S1S4).

B = Breeding—Conservation status refers to the breeding population of the species in the nation or state/province.

SU = Unrankable—Currently unrankable due to lack of information or due to substantially conflicting information about status or trends.

SNA = Not Applicable —A conservation status rank is not applicable because the species or ecosystem is not a suitable target for conservation activities.

Wild Species: The General Status of Wild Species in Canada

At Risk: Species for which a formal, detailed risk assessment (COSEWIC status assessment or provincial or territorial equivalent) has been completed and that have been determined to be at risk of extirpation or extinction (*i.e.* Endangered or Threatened). A COSEWIC designation of Endangered or Threatened automatically results in a Canada General Status Rank (Canada rank) of At Risk. Where a provincial or territorial formal risk assessment finds a species to be Endangered or Threatened in that particular region, then, under the general status program, the species automatically receives a provincial or territorial general status rank of At Risk.

May Be At Risk: Species that may be at risk of extirpation or extinction and are therefore candidates for a detailed risk assessment by COSEWIC, or provincial or territorial equivalents.

Sensitive: Species that are not believed to be at risk of immediate extirpation or extinction but may require special attention or protection to prevent them from becoming at risk

Secure: Species that are not believed to belong in the categories Extinct, Extirpated, At Risk, May Be At Risk, Sensitive, Accidental or Exotic. This category includes some species that show a trend of decline in numbers in Canada but remain relatively widespread or abundant.

Exotic: Species that have been moved beyond their natural range as a result of human activity. In this report, Exotic species have been purposefully excluded from all other categories.

Table 5.4.1 Freshwater Fish Species in Yukon Territory

Common Name	Scientific Name	*SARA* Schedule and Status	COSEWIC Rank	CESCC Rank (2005)	YCDC S-Rank

Source Wild Species: The General Status of Wild Species in Canada' website Available at: http://www.wildspecies.ca/ranks.cfm?lang=e (CESCC 2006)

The closest river to the anticipated Project site is an unnamed tributary of the Dezadeash River. The tributary flows west and is located approximately 800 m to the north of the village, within the municipal boundary. The main branch of Dezadeash River flows west and is located adjacent to the south of the village. Dezadeash River empties into Alsek River and is located within the boundaries of the Alsek River watershed. Fish species found within the Alsek River basin are listed in Table 4.1.5 below.

Table 5.4.2 Fish Species Found within the Alsek River Basin, Yukon Territory

Common Name	Scientific Name
Sockeye Salmon	*Oncorhynchus nerka*
Rainbow Trout	*Oncorhynchus mykiss*
Dolly Varden	*Salvelinus malma malma*
Lake Trout	*Salvelinus namaycush*
Humpback (Lake) Whitefish	*Coregonus clupeaformis*
Pygmy Whitefish	*Prosopium coulterii*
Round Whitefish	*Prosopium cylindraceum*
Arctic Grayling	*Thymallus arcticus*
Northern Pike	*Esox lucius*
Longnose Sucker	*Catostomus catostomus*
Burbot	*Lota lota*
Slimy Sculpin	*Cottus cognatus*
Source: Fisheries and Oceans Canada 2011	

The location of feedstock harvesting has not yet been determined. Once the location is selected information on freshwater resources in these areas will be included in this report.

5.4.3 Regulatory/Policy Setting

For the purposes of this report, the current interpretation of the federal *Fisheries Act* has been applied. Changes to the Act will come into effect in 2013. Planned mitigation with respect to Freshwater Resources will not be affected by any changes to the Act. The federal *Fisheries Act* defines "fish" to mean all fish, shellfish, crustaceans, marine animals and any parts of shellfish, crustaceans, or marine animals, and the eggs, sperm, spawn, larvae, spat, and juvenile stages of fish, shellfish, crustaceans, and marine animals. The federal *Fisheries Act* defines "fish habitat" as spawning grounds and any other areas including, nursery, rearing, food supply, and migration areas on which fish directly or indirectly depend on. Fish habitat includes physical (*e.g.*, substrate, temperature, flow velocity and volumes, water depth), chemical (*e.g.*, dissolved oxygen, pH, nutrients), and biological (*e.g.*, fish, benthic invertebrates, plankton, aquatic plants) attributes of the environment that are required by fish to carry out life cycles processes (*e.g.*, spawning, rearing, feeding, overwintering, migration).

Fish and fish habitat are protected through federal and provincial legislation. Currently, fish habitat is protected under the *Fisheries Act*, as per the DFO's Policy for the Management of Fish Habitat (DFO 1986). This policy applies to all projects and activities in or near water. The guiding principle of this

policy is to achieve no-net-loss of the productive capacity of fish habitats. Fish and fish habitat are regulated by Sections 20, 21, 22, 30, 32, 35, 36, 37, 40, and 43 of the *Fisheries Act* which is administered by DFO, as follows.

- Sections 20, 21, and 22 relate to the obstruction of fish passage, and state that where fish passage is obstructed, a fish pass or passage must be provided, and sufficient water must flow to allow for fish migration and movement past the obstruction.
- Section 30 requires that if deemed necessary by the Minister of Fisheries, screens will be placed on artificially created ditches to prevent fish from entering.
- Section 32 prohibits the killing of fish from means other than fishing.
- Section 35 prohibits the harmful alteration, disruption or destruction (HADD) of fish habitat by any persons unless authorized by the Minister of Fisheries.
- Section 36 prohibits the release of deleterious substances into any river or harbour or in any water where fishing is carried on.
- Section 37 states that anyone undertaking work that may cause HADD must submit their works for review by the Minister. The Minister can then refuse the works, grant permission for the works providing changes are made, or grant permission for the works to take place.
- Section 40 outlines the consequences of contravening section 35 of the *Fisheries Act*.
- Section 43 outlines the regulations for carrying out the purposes and provisions of the *Fisheries Act*.

A number of Boards and Councils have been established under the Umbrella Final Agreement (UFA) and Yukon First Nation Final Agreements which have advisory and management responsibilities related to fish and fish habitat Yukon-wide, and within specific First Nation Traditional Territories. These include the Yukon Fish and Wildlife Management Board which make recommendations to the Yukon and First Nation governments on issues related to fisheries management, legislation, research, policies and programs; and the Mayo District Renewable Resource Council (MDRRC), which is responsible for making recommendations on fish and wildlife management; policies and proposed development activities in the Na-cho Nyäk Dun Traditional Territory. The Salmon Sub-Committee, also established under the UFA, is mandated with providing advice and recommendations to governments specific to the management of salmon and salmon habitat in the territory.

Surface water quality is managed through federal guidelines. The CCME maintains guidelines for the protection of aquatic life for many water quality parameters. These guidelines are generally accepted as best practice in environmental assessment to mitigate Project activities such that the CCME guidelines are not exceeded, where it is considered technically and economically feasible to do so.

Aquatic SAR are protected federally under *SARA*. While there are no current publicly available provincial ranks for fish species of special concern, fish are included in the 2005 CESCC ranking list and they have a YCDC rank within the province.

5.4.4 Key Issues and Identification of Effects

Freshwater Resources has been selected as a VC due to its importance in supporting aquatic life. Freshwater Resources are valued as biological and natural resources by the public and by federal and territorial regulatory authorities.

There have been no interactions identified between Freshwater Resources and the proposed plant site (FEED site location) or throughout the majority of Haines Junction (with the exception of the southern part of the village). At this time the location of feedstock harvesting is unknown and could potentially be in the vicinity of a river, lake, pond, or stream.

Potential effects to Freshwater Resources resulting from harvesting activities could include effects to freshwater resulting in changes to fish populations, disruption, destruction or alteration to fish habitat, and/or impacts to water quality.

5.4.5 Mitigation Measures

The application of known and proven mitigation measures will be implemented as part of the Project to avoid or minimize the environmental effects on Freshwater Resources, in the event any part of the Project will be conducted in the vicinity of a freshwater source. The following mitigation measures will be employed along with other mitigation, as appropriate.

- implementation of well-established and proven erosion and sedimentation control measures, including silt fences, mulching, and hydroseeding;
- all barren soil will be stabilized for over-wintering;
- proper storage and use of hazardous materials;
- The Proponent will consult with DFO to ensure that Project activities (if determined to interact with freshwater resources) will be conducted, where possible, outside of biologically sensitive life stages of resident fish species. If activities are required in waters during these periods, DFO may require additional mitigation;
- visual monitoring in the vicinity of the Project to ensure that turbidity in waterways is limited;
- removal of any construction debris or other material that enters the freshwater environment; and
- compensation for HADD in accordance with the DFO Policy for the Management of Fish Habitat, if required.

5.4.6 Summary Consultation Influence on the Assessment

This section will be completed following planned consultations.

5.4.7 Effects Monitoring and Adaptive Management

Depending on the harvesting areas, baseline field surveys may be required, and would include fish and fish habitat studies.

Continued monitoring of sediment controls is suggested during all Project activities that have potential to affect freshwater resources. Water quality monitoring may be conducted if determined necessary during Project planning. The Canadian Water Quality Guidelines for Protection of Aquatic Life (for TSS) should be consulted for guidance in this event. If required, monitoring of the HADD compensation project will be conducted after the Project is implemented.

5.5 HERITAGE RESOURCES

The proposed biomass gasification power plant (the Project) by the Champagne and Aishihik First Nations (CAFN) and the Yukon Energy Corporation (YEC) will be located within the village of Haines Junction, Yukon, on Settlement Lands belonging to the CAFN. The Project is comprised of two parts:

- the biomass energy plant (the Plant); and
- biomass feedstock timber harvesting (Feedstock).

The Plant will operate as a power and heat source for buildings within Haines Junction and the Feedstock will be the fuel source for the Plant. At the time of the writing of this document, the areas to be harvested for Feedstock are unknown; however, future development of Feedstock is anticipated to take place on Settlement and non-Settlement Lands within the Champagne and Aishihik Traditional Territory (CATT).

5.5.1 Scope of the Assessment

This section defines the scope of the environmental assessment for Heritage Resources valued component in consideration of the nature of the regulatory setting, issues identified during public and First Nations engagement activities, potential Project-VC interactions, and existing knowledge.

At the time of the writing of this document, public and First Nations engagement activities have not all taken place. An introductory open house was held in Haines Junction and input from that engagement is included in Section 2.0 (Consultation). This assessment will be updated prior to submission to YESAA to incorporate engagement issues as warranted.

5.5.1.1 Key Issues and Identification of Potential Effects

Potential interactions between the Project and Heritage Resources are presented below and those aspects of the Project that may cause environmental effects, either positive or adverse, are identified. The Project may interact with Heritage Resources in the following ways:

- the Construction and Operation phases of the Plant will result in ground disturbing operations, potentially impacting unidentified subsurface heritage resources; and

- the Construction and Operation phases of the Feedstock will result in site-alteration (removal of vegetation from forested areas), potentially affecting built or subsurface heritage resources.

The potential environmental effects to be assessed are associated with Project-related ground disturbing or site-altering activities that may have an effect on Heritage Resources.

5.5.1.2 Regulatory/Policy Setting

Heritage Resources in the Yukon Territory are protected and managed under multiple sets of legislation; the *Historic Resources Act*, the *Umbrella Final Agreement,* the Champagne and *Aishihik First Nations Final* Agreement, and the Yukon *Environmental and Socio-Economic Assessment Act* (*YESAA*).

5.5.1.2.1 Definition of Heritage Resources

Heritage Resources, as defined in the *Historic Resources Act* include *"…(a) a historic site, (b) a historic object, and (c) any work or assembly of works of nature or of human endeavour that is of value for its archaeological, palaeontological, pre-historic, historic, scientific, or aesthetic features*…" (Government of Yukon 2002b:5).

Heritage Resources, as defined in the *Umbrella Final Agreement* (Government of Canada 1993a:4–5), include:

- **Moveable Heritage Resources:** Moveable non-documentary works or assemblies of works of people or of nature that are of scientific or cultural value for their archaeological, palaeontological, ethnological, prehistoric, historic or aesthetic features, including moveable structures and objects;

- **Heritage Sites:** An area of land which contains Moveable Heritage Resources, or which is of value for aesthetic or cultural reasons;

- **Documentary Heritage Resources**: Public Records or Non- Public Records, regardless of physical form or characteristics, that are of heritage significance, including correspondence, memoranda, books, plans, maps, drawings, diagrams, pictorial or graphic works, photographs, films, microforms, sound recordings, videotapes, machine-readable records, and any copy thereof.

The definition of a Heritage Resource under *YESAA* mirrors the definition outlined in the *Umbrella Final Agreement*, but also includes "…*an area of land that contains a work or assembly of works…or an area that is of aesthetic or cultural value, including a human burial site outside a recognized cemetery…*" (YESAB 2011).

Any object, whether archaeological, historic, ethnographic or palaeontological in nature, abandoned, and more than 45 years old can be deemed a historic object by the Government of Yukon's Minister of Tourism and Culture (the Minister). The Minister may, with appropriate criteria, designate a site as a historic site, whether or not historic objects are associated with it. The only exception is when the site in question is located on Yukon First Nation settlement land. In this case, the Minister may designate a

site with consent from the Yukon First Nation which governs the settlement land, in this case, CAFN (Government of Yukon 2002b).

Historic sites are generally classified as being associated with the historic period, and are typically associated with built heritage structures (Gotthardt and Thomas 2007). It should be noted that while the historic period is, by convention, associated with appearance of documentary written records, within CATT the historic period commences in the early-mid 19th century, and coincides with the arrival of the Hudson's Bay Company in the Yukon Territory (Thomas 2006:13). Archaeological sites are generally associated with human evidence pre-dating European contact, or, the prehistoric period and are usually associated with sub-surface deposits or remains (Gotthardt and Thomas 2007).

5.5.1.2.2 Legislation

The *Historic Resources Act* (Government of Yukon 2002b), is administered by representatives in the Historic Sites Unit and Heritage Resources Unit (HRU) (Archaeology, Palaeontology, and Geographic Place Names Programs), Cultural Services Branch, in the Yukon Department of Tourism and Culture.

- The Historic Sites Unit "provides for the research, preservation, management, development and interpretation of Yukon's historic sites and routes" (Government of Yukon 2012b). This includes the administration of the *Historic Resources Act* and meeting the Government of Yukon heritage obligations under the *Umbrella Final Agreement* and individual First Nation final agreements.

- The Heritage Resources Unit "is responsible for the management, conservation, research and interpretation of land-based heritage resources" (Government of Yukon 2012c). This includes licencing for scientific research under the *Scientists and Explorers Act* (Government of Yukon 2002c) and permitting for archaeological research under a Yukon Archaeological Sites Regulation Permit.

The *Umbrella Final Agreement* (Government of Canada 1993a) signed between the Government of the Yukon, The Government of Canada, and The Council for Yukon Indians, allows for self-governance and management of all aspects of heritage pertaining to individual Yukon First Nations traditional territories and Settlement Lands, in this case the CAFN. CAFN has developed a framework for Heritage Resources, outlined in *Chapter 13 – Heritage of the Champagne and Aishihik First Nations Final Agreement* (Government of Canada 1993b).

YESAA guidelines state that socio-economic effects include that any effects on Heritage Resources must be taken into consideration by all parties involved in a proposed development.

5.5.1.2.3 Heritage Resources Assessments

The implementation of a Heritage Resource Assessment (HRA) in the Yukon Territory is dependent on two factors:

- the level of impact a development may have; and,

- the type of lands on which the proposed development is taking place (*i.e.,* Settlement vs. non-Settlement lands).

As a result of the need for disposition of lands for the Project, an HRA, mandated under *Operational Policy 2011-01 – Heritage Resources Information Requirements for Land Application Proposals Policy* (YESAB 2011) of *YESAA* is required. HRAs are comprised of two stages. The first stage, the "overview assessment", includes a description of known heritage resources in the Project area, an evaluation of potential to encounter unknown heritage resources, the effects the Project may have on existing or unidentified/potential heritage resources, and, if necessary, appropriate mitigation measures. The overview assessment takes place at a desktop level, and provides baseline information. Following the "overview assessment", if it is determined that further investigation of potential effects of the Project on existing or unidentified/potential Heritage Resources is warranted, then the second stage, a "site assessment" must take place within the Project Development Area (PDA).

Known heritage resources may be identified prior to design and construction of a project. Archaeologists use these known resources, along with generalisations about the movement of past humans across the landscape and environmental factors (*e.g.,* distance to water, slope of terrain) to suggest the potential for encountering previously unrecorded heritage resources. This is not an exact process, and the factors that archaeologists consider when determining the "heritage resource potential" of an area can vary significantly depending on the region or sub-region. Furthermore, the criteria employed by archaeologists for assessing heritage resource potential often do not include consideration for intangible heritage resources. The cultural, ethnographic, or spiritual connection and the special relationship between First Nations and their environments is not an easily quantified value. Documentary and ethnographic accounts, oral histories, community consultation, and traditional use studies are all essential elements for understanding this relationship.

As this Project will have the potential to interact with Heritage Resources due to ground disturbing activities, both for the Plant and Feedstock elements, an HRA is required.

On non-Settlement lands, or lands administered by the Government of Yukon, an HRA follows policies and guidelines established by the Cultural Services Branch. The *Position Statement – Historic Resources Impact Assessment and Mitigation Requirements Related to Land Altering Developments* (the Position Statement) (Government of Yukon 2003) and processes outlined in the *British Columbia Archaeological Impact Assessment Guidelines* (the Guidelines) (Government of British Columbia 1998) provide guidance and methodology for conducting an HRA.

Particularly relevant for the Feedstock component of the Project is the implementation plan for forestry-related HRAs conducted within CATT (Section 3.8 of the *Integrated Landscape Plan for the Champagne and Aishihik Traditional Territory* (the ILP)) (EMR 2006). The ILP was developed by CAFN and the Yukon Department of Energy, Mines and Resources as a means to address concerns about management of Heritage Resources with the development of a forestry industry in the Yukon. Furthermore, Energy, Mines and Resources has developed *Forest Resources Regulation – Historic and Archaeological Resources Standards and Guidelines* (EMR 2011) to assist with the protection and management of Heritage Resources.

As outlined in *Chapter 13 – Heritage* of the *Champagne and Aishihik First Nations Final Agreement*, CAFN will develop independent heritage management policies for Settlement Lands. *CAFN Heritage Resources specialists are currently developing an assessment process to ensure the protection of Heritage Resources. In consultation with Stantec, CAFN have indicated they envisage this process as operating independent of, but parallel to, territorial impact assessments.*

5.5.1.3 Selection of Measureable Parameters

The environmental assessment of Heritage Resources is focused on the following environmental effect:

- Change in Heritage Resources within the PDA.

The environmental effect has been selected as a result of the need for disposition of lands for the Project and the requirement to conduct an HRA. The requirement to protect any known or unknown/undocumented heritage resources is also outlined under the *Historic Resources Act* and Chapter 13 of the *Champagne and Aishihik First Nations Final Agreement*. The manner in which these effects are mitigated is described in the Guidelines and appropriate mitigation to be developed in consultation with CAFN.

The measurable parameters used for the assessment of potential environmental effects presented above and the rationale for their selection is provided in Table 5.7.1.

Table 5.5.1 Measurable Parameters for Heritage Resources, Traditional Activities and Culture

Environmental Effect	Measurable Parameter	Rationale for Selection of the Measurable Parameter
Change in Heritage Resources	Presence/absence of a heritage resource	• The Position Statement (Government of Yukon 2003) and the Guidelines (Government of British Columbia 1998) establish the process for determining presence/absence of heritage resources (*e.g.,* overview assessment (documentary research, direct consultation and preliminary field reconnaissance), and archaeological impact assessment (survey, evaluative testing, assessment, impact management)) on non-Settlement Lands. Presence confirms an environmental effect; absence indicates that any discovery (unplanned) of a Heritage Resource would be an Accident. • *CAFN Heritage Resources specialists are currently developing an assessment process to ensure the protection of Heritage Resources. In consultation with Stantec, CAFN have indicated they envisage this process as operating independent of, but parallel to, territorial impact assessments.* • The *Historic Resources Act* and *Chapter 13 – Champagne and Aishihik First Nations Final Agreement* protect all Heritage Resources, including built heritage, prehistoric and historic sites and objects, archaeological, palaeontological, ethnological, or aesthetic features, moveable structures and objects, documentary resources and human burial sites.

5.5.1.4 Spatial Boundaries

The spatial boundaries for the environmental effects assessment of the Heritage Resources, Traditional Activities and Culture are defined below.

Project Development Area (PDA): The PDA is the most basic and immediate area of the Project. The PDA is limited to the area of physical ground disturbance associated with the Project, and consists of an area that includes the area of physical disturbance associated with the biomass plant and associated facilities as well as the area associated with biomass feedstock harvesting (including forest roads). The PDA is the area represented by the physical Project footprint as defined in Chapter 3.1.2 above.

Local Assessment Area (LAA): The LAA is the maximum area within which Project-related environmental effects can be predicted or measured with a reasonable degree of accuracy and confidence. The LAA includes the PDA, Haines Junction, and any adjacent areas where Project-related environmental effects may reasonably be expected to occur. Since the potential environmental effects on Heritage Resources are limited to the area where ground disturbing or site-altering activities will take place, for this VC, the LAA is essentially the same as the PDA. At this time, there are no anticipated environmental effects that will occur outside of the PDA for Heritage Resources.

Regional Assessment Area (RAA): The RAA is limited to and includes the Yukon Territory. The RAA is the area within which the Project's environmental effects may overlap or accumulate with the environmental effects of other projects or activities that have been or will be carried out. The extent to which cumulative environmental effects for Heritage Resources may occur depend on physical and biological conditions and the type and location of other past, present, and reasonably foreseeable future projects or activities that have been or will be carried out, as defined within the RAA. For Heritage Resources, the RAA may be considered lands within the Champagne and Aishihik Traditional Territory (CATT), and the southwest region of the Yukon Territory.

5.5.1.5 Temporal Boundaries

The temporal boundaries for the assessment of the potential environmental effects of the Project on Heritage Resources include the phases of Construction, Operation, and Decommissioning.

5.5.1.6 Residual Effects Significance Criteria

A *significant adverse residual environmental effect* on Heritage Resources is defined as one that results in a permanent Project-related disturbance to, or destruction of, all or part of a Heritage Resource (including Historic sites and objects, and all moveable and documentary Heritage Resources) considered by CAFN and the Government of Yukon to be of major importance due to factors such as rarity, undisturbed condition, spiritual or cultural importance, or research importance, and that cannot be mitigated or remedied by way of compensation.

5.5.2 VC Existing Conditions

The Project PDA will be located within the limits of the village of Haines Junction, in southwest Yukon. The preliminary PDA of the proposed biomass plant is located just east of the intersection between Willow Acres Road and the Alaska Highway (to be confirmed prior to detailed design). As the site location has not been finalized, the greater area of the village of Haines Junction was included in the evaluation of existing information.

At the time of the writing of this report, specific Feedstock areas are undefined. It is anticipated that feedstock timber harvesting will take place within the CATT, which encompasses an estimated 1,959,000 HA of southwest Yukon, according to the ILP (EMR 2006) (Figure 5.5.1). However, planning and development for the forest industry will occur only in the Forest Resource Management Zone (93,700 HA in the ILP) (EMR 2006). The areas that would potentially be harvested for Feedstock are likely to be predominantly located within 50-70 km of Haines Junction over the life of the Project, delimited by the boundaries of the Forest Resource Management Zone (Damecour, pers. comm. 2012).

Typically, there are two methods for determining the existing conditions of Heritage Resources within the PDA. These include:

- **evaluation of existing information,** gathering data of known heritage resources provided by documented archaeological and historic sites, territorial and museum records, First Nations (*i.e.*, CAFN), local historical societies, community historians; and

- **field investigation,** consists of a field assessment for those resources that might exist within the PDA but of which we currently do not have knowledge.

5.5.2.1 Evaluation of Existing Information – Heritage Resources

Representatives from CAFN and the Cultural Services Branch, Government of Yukon, provided information on known or recorded heritage resources for Haines Junction. Various documentary resources were consulted for background information and history of the PDA and the general Project area. The results are presented below.

Haines Junction is a small village located along the Alaska Highway, and named after the point where the Alaska and Haines Highways meet. The village was established in the 1940s during construction of the Alaska Highway, but has been home to the Southern Tutchone people and their ancestors for over 5,000 years. Prior to its 1940's naming, Haines Junction was known as "Dakwakada", or "high cache" for the type of food caches used in that area throughout the year (VOHJ 2012). The region surrounding Haines Junction is well known for its dynamic landscape; located in the foothills of the St. Elias Mountains, close to glaciers, and immediately east of the boundary of Kluane National Park and Reserve. Kluane Park, along with adjoining parks in British Columbia and Alaska are designated as a UNESCO World Heritage Site (Figure 5.5.1).

Human History and Prehistory

The known period of human occupation in the southwest Yukon extends back over 12,000 years since the receding of the Cordilleran Glaciers and has been well documented relative to other regions even within the Yukon (Clark 1991; Thomas 2006). The prehistory of this region is generally divided up chronologically into five periods based on technological changes visible in the archaeological record and known assemblages (Thomas 2006). This sequence begins with the Palaeo-Indian period (ca. 12,000–8000 BP) and the Northern Cordilleran tradition (ca. 8000–7000 BP) (Clark 1991), followed by the Little Arm Phase (ca. 7000-5000 BP), Taye Lake Phase (ca. 5000-1250 BP) and culminates in the Aishihik Phase (ca. 1250-200 BP) (Workman 1978; Thomas 2006).

Stratigraphic dating of late prehistoric sites (associated with the Aishihik Phase) in the southwest of Yukon and eastern Alaska is made easier by the presence of the White River Ash layer, or White River tephra. This pale-coloured ash layer is the result of a volcanic eruption originating at Mount Bona, Alaska just over 1200 years ago in AD 803 (Clague et al. 1995). Although its thickness and coverage depends on distance from the original eruption, the tephra can be 20 cm thick almost 300 km from the source (Clark 1991), and covers an area of approximately 540,000 km^2 (Robinson 2001). It is speculated that while this eruption certainly caused immediate disruption and displacement of the Southern Tutchone people living there at the time, they returned to the area shortly after the eruption event (Clark 1991).

Figure 5.5.1 Champagne and Aishihik First Nations Traditional Territory

The Southern Tutchone are a group of peoples linked by a common language family, Athabaskan (McClellan 1975), or Athapaskan (Clark 1991; Workman 1978). The six regional groups that constitute the Southern Tutchone occupy an area including most of the southwest Yukon Territory and into northern British Columbia and parts of Alaska (McClellan 1975; Thomas 2006). Four of these groups occupy the Alsek River drainage system, and comprise the modern-day Champagne and Aishihik First Nations (CAFN 2012b; Thomas 2006). These groups are:

- the Champagne Band, formerly centred at the village of Champagne (approximately 65 km east of Haines Junction) and originally lived near *Shäwshe*-Dalton Post;
- the Hutshi Band, previously located east of Hutshi Lake (northeast of Haines Junction) and exploited territory in the headwaters of the Nordenskiold River;
- the Aishihik Band and village were in the past situated at the head of Aishihik Lake (north-northeast of Haines Junction); they shared common territory with Champagne and exploited territory as far east as Kluane Lake; and
- the Kloo Lake Band resided near a trading post located on Kloo Lake, northwest of Haines Junction (McClellan 1975; Thomas 2006:11).

Up until the early 1900s the most recent ancestors of modern-day Champagne and Aishihik First Nations were subsistence hunter-fisher-gatherers, exploiting the land and resources surrounding them. Summers were usually spent gathering berries and fishing salmon, including Sockeye, coho and chinook on the Tatshenshini River although fish resources in the lakes and rivers within traditionally exploited territories were year-round food sources (CAFN 2013; Thomas 2006). Late summer hunting of moose, caribou, Dall's sheep, mountain goat, gophers and other small mammals was essential both for food and for trade with other groups in the region, particularly the Pacific Coast Tlingit groups (CAFN 2013; McClellan 1975; Thomas 2006). During the winter, the Southern Tutchone would use caches of dried fish and meat for subsistence (McClellan 1975; Thomas 2006). Winter was also the period of time when trapping was most prevalent, a practice that took place primarily in and around the lakes where much of the population lived (McClellan 1975; Thomas 2006).

Trapping and trade of furs was always an essential part of the CAFN economy, and after the arrival of the Europeans this practice intensified and increased in importance (Thomas 2006). The Chilkat people, a sub-group of the Pacific Coast Tlingit and neighbours of the Southern Tutchone, moved inland to southwest Yukon during the early European Contact period (Thomas 2006). This migration lead to an increase in trapping and trade with Europeans, but also allowed for greater trade, exchange and sharing of culture between the Chilkat and Southern Tutchone peoples (CAFN 2013; McClellan 1975). Trapping continues to be actively pursued in modern times by members of CAFN on both a full- and part-time basis (CAFN 2013).

Prior to the arrival of European goods and technology (*e.g.*, steel implements, outboard motors for boats), the Southern Tutchone employed resources readily available to them from the land for crafting tools. Implements made of bone, antler and stone were used for cutting down trees, preparing hides, and processing meat (McClellan 1975). Native copper was a resource available to the Southern Tutchone due to its availability in nugget form. It is speculated that prior to European contact, native

copper have been sourced at the upper White River/Klutlan glacier area approximately 185 km west-northwest of Haines Junction (Workman 1978).

The first Europeans explored southwest Yukon in the late 1800s, entering over the Chilkat Pass, a boundary between the Coast and St. Elias mountain ranges southwest of Haines Junction, following the Chilkat (now Dalton) Trail (Thomas 2006; VHJ 2012). European-led expeditions to the area occurred from 1882-1896; however, it was the Klondike gold rush that brought the Canadian Government to the region. The Northwest Mounted Police established Dalton Post in 1898, and legal surveys demarcating the national and territorial boundaries along the Tatshenshini-Alsek drainage were established the same year (Thomas 2006). The discovery of gold in the creeks east of Kluane Lake in 1903 created an influx of over a thousand miners to the area, a rush that continued sporadically in the region until the late 1920s (Thomas 2006; VHJ 2012). The completion of the Haines Road/Alaska Highway in 1942 saw the establishment of Village of Haines Junction at this crossroads, Historic Mile 1016 on the Alaska Highway (Government of Yukon 2012d).

Environment

The Champagne and Aishihik Traditional Territory (CATT) encompasses six ecoregions including the Klondike Plateau, Ruby Ranges, Saint Elias Mountains, Yukon Plateau-Central, Yukon Southern Lakes and the Yukon-Stikine Highlands (EMR 2006). The only two ecoregions within the CATT that may be affected by the Project are the Ruby Ranges Ecoregion and a small portion of the Yukon Southern Lakes Ecoregion (EMR 2006; Smith et al. 2007). However, of equal importance is the Yukon Stikine Highlands Ecoregion, due to the presence of the Tatshenshini River which lies within its boundaries. The Tatshenshini River is a traditionally significant river for CAFN peoples, as described in *Chapter 13 – Schedule B* of the CAFNFA and a designated Canadian Heritage River (CHRS 2013; Government of Canada 1993b).

Major waterbodies and watercourses in the Ruby Ranges are located in the Aishihik Basin east of the St. Elias Mountains where Haines Junction and the CATT are situated. These include the Dezadeash, Aishihik, Kathleen, Donjek and Kluane Rivers. The Alsek and Kaskawulsh Rivers form the south boundary of the Ruby Ranges Ecoregion, and Nisling River the north (YEWG 2004). The largest lake entirely within the Yukon, Kluane Lake, is also located in the Ruby Ranges (YEWG 2004). Significant watercourses in the Yukon Southern Lakes include the Teslin, upper Yukon, and Takhini Rivers, and smaller rivers including Nisutlin, Wolf and M'Clintock Rivers. Major waterbodies include Teslin, Wolf, Marsh and Laberge Lakes, and the Nisultin River Delta wetland complex (YEWG 2004).

The glacial history of the valley where Haines Junction is located, created by the Shakwak Trench, is fairly complex. Margins of three Pleistocene glaciers, all originating in the St. Elias Mountains to the west, are visible in various places in the Ruby Ranges ecoregion (YEWG 2004). Approximately 90% of this ecoregion was glaciated during the pre-Reid glaciation (2.9 million years ago to ca. 400,000 years ago), 60% during the Reid glaciation (ca. 300,000 to 230,000 years ago) and 50% during the McConnell glaciation (ca. 28,000 to 15,000 years ago) (YEWG 2004). The Yukon Southern Lakes ecoregion was covered in glacial ice between ca. 26,000 and 9000 years ago (YEWG 2004).

The close proximity of existing glaciers to the Haines Junction area, and the advance and retreat of various ice-sheets has resulted in an area that has been flooded repeatedly over the last 12,000 years. Glacial- and Neoglacial Lake Alsek formed as a result of the built-up of water from glacial ice blocking

the Alsek River drainage, southwest of Haines Junction (Duk-Rodkin 2004; YEWG 2004). Most recently, the Shakwak valley was submerged under Neoglacial Lake Alsek from 1725–1850, caused by the advance of the Lowell Glacier (YGS 2012). While the period between 1725–1850 is the most recent, Neoglacial Lake Alsek had formed three times in the period known as the "Little Ice Age", a global cooling period extending for approximately 500 years between the years 1350–1850 (YGS 2012).

Champagne and Aishihik Heritage Routes

The Champagne and Aishihik Heritage Routes were identified in the *Champagne and Aishihik First Nations Final Agreement* as having a particular cultural and heritage significance to CAFN and consist of:

- The Shakat Trail that follows from Aishihik Village to Nisling River, Onion Creek, Tincup Lake, Talbot Creek, Albert Creek and back to Aishihik Village;
- The Isaac Creek Trail that follows from Aishihik Village to Tetchal Mun (Sekulmun Lake), Isaac Creek, Gladstone Creek, Kluane Lake, Talbot Arm (Kluane Lake), Talbot Creek, and then meets with the Shakat Trail;
- The Hutshi Trail that follows from Hutshi to Giltana Lake, Tetchal Mun (Sekulmun Lake), Aishihik Village, Nisling River and Carmacks;
- The Kloo Lake to Aishihik Village Trail that follows from Kloo Lake to Dry Pass, Bear Lakes, Tetchal Mun (Sekulmun Lake) and Aishihik Village; and
- The Selkirk Trail that follows from Kusawa Lake (west side) to Takhini River, Klusha Creek, Nordenskiold River, Yukon River and Fort Selkirk, with a branch west from Kusawa Lake to Klukshu.

These routes are outlined in *Chapter 13 – Schedule A* and depicted in *Appendix B – Maps* in the *Champagne and Aishihik First Nations Final Agreement*.

The PDA of the Plant will not impact any of the recorded Champagne and Aishihik Heritage Routes. At the time that this report was written, Feedstock areas were undefined. It is recommended that prior to development of Feedstock areas, Champagne and Aishihik Heritage Routes be taken into consideration as areas of avoidance and special concern to ensure the protection of these heritage resources.

Recorded Archaeological Sites in the Yukon Archaeological Sites Data Base

<u>Pre-Contact Resources</u>

Biomass Energy Plant

A review of the general Project boundaries for the preliminary Plant PDA, which included all CAFN Settlement Lands and all non-Settlement Lands located within the community of Haines Junction, was conducted by HRU, Cultural Services Branch of the Government of Yukon. This review found that no

documented archaeological sites are located inside the preliminary PDA of the Plant or within the limits of the village of Haines Junction (Gotthardt, pers. comm. 2012).

Feedstock Harvesting

At the time that this report was written, feedstock areas were undefined and no formal review was conducted. Upon receiving Feedstock PDAs, the HRU and Heritage Resources specialists with CAFN will be contacted and consulted prior to any ground disturbing or site-altering activities to determine presence/absence of recorded Pre-Contact archaeological sites in the Yukon Archaeological Sites Data Base.

Historic Resources

Biomass Plant

Upon reviewing the Yukon Register of Historic Places and the Canadian Register of Historic Places, there were no identified Historic Places located in the preliminary Plant PDA, or within the limits of the village of Haines Junction (CRHP 2012; YRHP 2012). The Yukon Sites Inventory Program provided information on six documented Historic Sites/Structures within the LAA for the Plant (*i.e.,* Haines Junction). Exact locations were provided for all six structures (Figure 5.5.2) and after reviewing, no Historic Sites/Structures will be impacted by the Plant component of the Project.

Feedstock Harvesting

At the time that this report was written, Feedstock areas were undefined and no formal review was conducted. Upon receiving Feedstock PDAs, the Government of Yukon Historic Sites Registrar, the Yukon Register of Historic Places and the Canadian Register of Historic Places will be contacted and consulted prior to any ground disturbing or site-altering activities to determine presence/absence of known Historic Resources.

Palaeontological Resources

Biomass Energy Plant

Representatives from HRU, Palaeontology Program, were contacted regarding the potential to encounter palaeontological resources within the Plant PDA. The area in and around Haines Junction was completely glaciated during the late Wisconsinan period (13,000–14,000 years before present), thus the preservation of Pleistocene-aged fossils is unlikely (Hare pers. comm. 2012; Smith et al. 2007). Holocene-aged fossils have been recovered from the mountainous areas surrounding Haines Junction; however, none within the Plant PDA or LAA (Farnell et al. 2004; Hare pers. comm. 2012).

The closest recorded palaeontological resource was found at Pine Lake, approximately 10 km northeast of Haines Junction (Figure 5.5.1), and was a Pleistocene elk (*Cervus elaphus*) mandible collected from glacial outwash deposits located near the lake. The discovery of this fossil suggests that other late Pleistocene vertebrate remains may be located in glacial sediments (glaciofluvial outwash) in the areas surrounding Haines Junction (Zazula pers. comm. 2013).

Figure 5.5.2 Historic Sites and Structures

Feedstock Harvesting

At the time that this report was written, Feedstock areas were undefined and no formal review was conducted. Upon receiving Feedstock PDAs, the HRU, Palaeontology Program will be contacted prior to any ground disturbing or site-altering activities to determine the potential for encountering palaeontological resources. However, due to the level of ground-disturbance involved in forest harvesting, the likelihood for interaction with palaeontological resources is not high.

5.5.2.2 Field Investigation

Field investigation was not completed at the time of the writing of this report. This section will be updated upon completion of a Heritage Resource Assessment for the Project.

5.5.3 Potential Project VC Interactions

5.5.3.1 Project Effects Mechanisms

Table 5.7.2 below lists each activity and physical work for the Project, and ranks each interaction as 0, 1, or 2 based on the level of interaction each activity or physical work will have with the Heritage Resources.

Table 5.5.2 Potential Project Environmental Effects to the Heritage Resources

Project Activities and Physical Works	Potential Environmental Effects Change in Heritage Resources
Construction	
Site preparation	2
Physical construction of the Facility Structures	2
Installation of Equipment	0
Commissioning	0
Construction of Infrastructure for Feedstock Harvesting	2
Operation	
Operation and Maintenance of Plant Site	0
Feedstock Harvesting	2
Decommissioning, Reclamation and Closure	
Plant Site	0
Harvested Areas	1

Project-Related Environmental Effects

Notes:

Project-Related Environmental Effects were ranked as follows:

0 = No interaction. The environmental effects are rated not significant and are not considered further in this report.

1 = Interaction will occur. However, based on past experience and professional judgment, the interaction would not result in a significant environmental effect, even without mitigation, or the interaction would clearly not be significant due to application of codified practices and/or permit conditions. The environmental effects are rated not significant and are not considered further in this report.

2 = Interaction may, even with codified mitigation and/or permit conditions, result in a potentially significant environmental effect and/or is important to regulatory and/or public interest. Potential environmental effects are considered further and in more detail in the EA.

5.5.3.2 Construction

Activities ranked as 0 for the Construction Phase in Table 5.7.2 include: Installation of Equipment and Commissioning. Installation of the Equipment and Commissioning does not involve ground disturbance and therefore there will be no interaction with these activities and Heritage Resources. As a result, the potential environmental effects of Installation of the Equipment and Commissioning activities on a change in Heritage Resources are ranked as 0.

There are no Construction activities ranked as 1 in Table 5.7.2.

5.5.3.3 Operation

Activities ranked as 0 for the Operation Phase in Table 5.7.2 include: Operation and Maintenance of Plant Site. Operation and Maintenance of the Plant Site does not involve ground disturbance and therefore there will be no interaction with these activities and Heritage Resources. As a result, the potential environmental effects of Operation and Maintenance of Plant Site on a change in Heritage Resources are ranked as 0.

There are no activities ranked as 1 in Table 5.7.2.

5.5.3.4 Decommissioning, Reclamation and Closure

Activities ranked as 0 for the Decommissioning, Reclamation and Closure Phase in Table 5.7.2 include: Plant Site. No ground disturbance beyond that already completed during the Construction is anticipated for this phase of the Project. As a result, the potential environmental effects of Plant Site activities on a change in Heritage Resources are ranked as 0.

Activities ranked as 1 in Table 5.7.2 include: Harvested Areas. Ground disturbance is not expected to take place at this stage, in which case the result will be no further environmental effects to Heritage Resources during the Decommissioning, Reclamation and Closure – Harvested Areas activity. However, in the event that post-harvest scarification or mechanical ground preparation activities take place during the Decommissioning, Reclamation and Closure – Harvested Areas activity, the implementation of a Heritage Resource Assessment (HRA) (described below in Section 5.5.3.6), protection of sites, and establishment of buffer zones prior to the Construction and Operation phases will prevent any significant environmental effect to Heritage Resources.

Thus, in consideration of the nature of the interactions and the planned implementation of known and proven mitigation, the potential environmental effects of all Project activities and physical works that were ranked as 0 or 1 in Table 5.7.2 on Heritage Resources during any phase of the Project are rated not significant, and are not considered further in the assessment.

5.5.3.5 Assessment of Environmental Effects

A summary of the environmental effects assessment and prediction of residual environmental effects resulting from interactions ranked as 2 on Heritage Resources is provided in Table 5.7.3.

Table 5.5.3 Summary of Residual Project-Related Environmental Effects on the Heritage Resources, Traditional Activities and Culture

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics						Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context					
Change in Heritage Resources • Unauthorized disturbance or destruction of Heritage Resources of significance.	Construction (includes: Site Preparation, Physical Construction of the Facility Structure, and Construction of Infrastructure for Feedstock Harvesting)	• Complete a confirmatory Heritage Resource Assessment within the PDA. • Report results of HRA to the Government of Yukon Heritage Resources Unit and CAFN. • If approved, implement mitigation for any heritage resources encountered during field investigation. • Development of an archaeological response protocol should there be any accidental discovery of heritage resources during Project activities.	A	L	S	P/O	I	U/D	N	H	L	N	To be determined following completion of Heritage Resource Assessment.
	Operation (Feedstock Harvesting)	• Development of a strategic plan for the assessment, inventory, mitigation and/or protection of heritage resources in Feedstock areas. • Complete a confirmatory Heritage Resource Assessment within the PDA(s) for Feedstock. • Report results of HRA to the Government of Yukon Heritage Resources Unit and CAFN. • If approved, implement mitigation for any heritage resources encountered during field investigation.	A	L	S	P/O	I	U/D	N	H	L	N	To be determined following determination of potential Feedstock harvesting areas and completion of subsequent Heritage Resource Assessment.

Table 5.5.3 Summary of Residual Project-Related Environmental Effects on the Heritage Resources, Traditional Activities and Culture

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics						Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring
			Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context					
		• Minimize the impact area or propose buffering zones, flagging and/or fencing. • Winter logging on snow-covered ground. • Post-harvest Heritage Resource Assessments may be recommended											
	Residual Environmental Effects for all Phases								N	H	L	N	

Table 5.5.3 Summary of Residual Project-Related Environmental Effects on the Heritage Resources, Traditional Activities and Culture

Potential Residual Project-Related Environmental Effects	Project Phases, Activities, and Physical Works	Proposed Mitigation / Compensation Measures	Residual Environmental Effects Characteristics: Direction	Magnitude	Geographic Extent	Duration and Frequency	Reversibility	Ecological/Socio-economic Context	Significance	Prediction Confidence	Likelihood	Cumulative Environmental Effects?	Recommended Follow-up or Monitoring

KEY

Direction
- P Positive.
- A Adverse.

Magnitude
- L Low: Minor impairments to heritage resources or recent built feature (*e.g.*, loss of individual artifact, movement of hunting blind, trap line)
- M Medium: Loss of heritage resources in a previously disturbed context (*e.g.*, some artifacts disturbed/lost, features remain intact), or in a deteriorated state (*e.g.*, wooden structures such as an abandoned cabin, brush camp or cache)
- H High: Destruction or loss of a significant portion of intact heritage resources, including sites, structures, and subsurface heritage resources in a stable and undisturbed condition.

Geographic Extent
- S Site-specific: Within the PDA.
- L Local: Within the LAA.
- R Regional: Within the RAA.

Duration
- ST Short term: Occurs and lasts for short periods (*e.g.,* days/weeks).
- MT Medium term: Occurs and lasts for extended periods of time (*e.g.,* years).
- LT Long term: Occurs during Construction and/or Operation and lasts for the life of Project.
- P Permanent: Occurs during Construction and Operation and beyond.

Frequency
- O Occurs once.
- S Occurs sporadically at irregular intervals.
- R Occurs on a regular basis and at regular intervals.
- C Continuous.

Reversibility
- R Reversible.
- I Irreversible.

Ecological/Socio-economic Context
- U Undisturbed: Area relatively or not adversely affected by human activity.
- D Developed: Area has been substantially previously disturbed by human development or human development is still present.
- N/A Not Applicable.

Significance
- S Significant.
- N Not Significant.

Prediction Confidence

Confidence in the significance prediction, based on scientific information and statistical analysis, professional judgment and known effectiveness of mitigation:
- L Low level of confidence.
- M Moderate level of confidence.
- H High level of confidence.

Likelihood

Likelihood of a significant environmental effect occurring, based on professional judgment:
- L Low probability of occurrence.
- M Medium probability of occurrence.
- H High probability of occurrence.

Cumulative Environmental Effects?
- Y Potential for environmental effect to interact with the environmental effects of other past, present or foreseeable projects or activities in RAA.
- N Environmental effect will not or is not likely to interact with the environmental effects of other past, present or foreseeable projects or activities in RAA.

5.5.3.6 Mitigation Measures

The following mitigation measures, through careful design and planning, will be employed to avoid or reduce the environmental effects of the Project on Heritage Resources potentially resulting from the environmental effects mechanisms described above:

Construction Phase

The HRA will include a visual assessment of the PDA for the Plant and infrastructure for Feedstock where ground disturbing activities are planned. This HRA will seek to confirm presence/absence of heritage resources within those PDAs. The methodology for the HRA will be developed as part of a strategic Heritage Resources management plan in consultation with the Government of Yukon Heritage Resources Unit and Forest Management Branch and representatives from CAFN.

Results of the HRA will be reported to Government of Yukon Heritage Resources Unit and CAFN. Following consultation with HRU and CAFN, additional investigation and/or mitigation of any identified heritage resources discovered in the PDAs may be necessary.

In the event that heritage resources not identified during the HRA are encountered, an archaeological response protocol will be developed. This will include, at a minimum, the immediate cessation of all ground-disturbing activities and require contacting representatives with CAFN or the HRU.

Operation Phase (in relation to Feedstock only)

The following mitigating measures have been defined to avoid significant effects on Heritage Resources, in general consideration of the Feedstock activities and will be refined as the extent of the activities become known.

A strategic plan for the assessment, inventory, mitigation and/or protection of Heritage Resources will be developed in consultation with CAFN and the Government of Yukon Heritage Resources Unit and Forest Management Branch. This plan will be implemented prior to any ground disturbance and/or site-altering activities where appropriate.

The HRA will include a visual assessment of the PDAs for Feedstock harvesting where ground disturbing and/or site-altering activities are planned. This HRA will seek to confirm presence/absence of heritage resources within the PDA(s). The methodology for the HRA will be developed as part of a strategic Heritage Resources management plan in consultation with the Government of Yukon Heritage Resources Unit and Forest Management Branch and representatives from CAFN. Areas will be assessed on a case by case basis as Feedstock areas are developed.

Results of the HRA will be reported to Government of Yukon Heritage Resources Unit and CAFN. Following consultation with HRU and CAFN, additional investigation and/or mitigation of any identified heritage resources discovered in the PDAs may be necessary.

In the event that heritage resources not identified during the HRA are encountered, an archaeological response protocol will be developed. This will include, at a minimum, the immediate cessation of all ground-disturbing activities and require contacting representatives with CAFN or the HRU.

Should heritage resources, including places of cultural or spiritual importance to CAFN citizens, be identified in Feedstock areas, buffer zones using flagging and/or fencing will be established to minimize the potentially affected area. Forest Resource Regulations, for example, stipulate that 100 m "no disturbance" buffer zones may be established in areas with known heritage resources. Furthermore, if following the HRA it is determined that heritage resources are solely subsurface deposits, winter logging on snow-covered ground is recommended. Forest harvesting on snow covered grounds can minimize ground disturbance and any potential effects to Heritage Resources.

Post-harvest HRAs may be recommended as a research and monitoring requirement, as outlined in Section 3.8 of the ILP.

Field investigations have not been completed at the time of the writing of this report. Information pertaining to the results of the HRA, including the identification of heritage resources and any required mitigation, will be discussed in detail here when complete.

5.5.3.7 Characterization of Residual Effects

At this time, no field investigation or HRA has been conducted for the Plant or Feedstock. It is recommended that the Characterization of Residual Effects be revised following the completion of the field investigation and HRA.

The potential for an adverse environmental effect on Heritage Resources present in the PDA has the highest probability of occurring during Construction (Site Preparation, Physical Construction of the Facility Structures) of the Plant component and Construction and Operation of the Feedstock component of the Project when ground breaking activities will take place. The majority of ground disturbing, earth moving, and site-altering (*e.g.*, tree-felling) activities will take place during these phases. With appropriate mitigation measures in place, the potential destruction or alteration of all or part of a Heritage Resource, including those Heritage Resources identified by CAFN as pertaining to a special relationship their people have with the natural environment, should be avoidable.

The Plant component is located within Haines Junction village limits, is a small footprint, and while it will most likely be located in an undeveloped block (preliminary PDA is undeveloped), the area surrounding the Plant PDA has witnessed development extending back to the original development of the Alaska Highway. Background research and consultation with the Government of Yukon HRU and Palaeontology Program (Gotthardt pers. comm. 2013; Hare pers. comm. 2012; Zazula pers. comm. 2013) and representatives with CAFN (Brown pers. comm. 2013) indicate that the potential for encountering heritage resources in the immediate preliminary Plant PDA or within the village of Haines Junction is considered low.

Many of the proposed Feedstock harvesting areas within the CATT are undeveloped and located in areas where past overland travel routes, past and present hunting, trapping and fishing, and short-term habitation may have taken place. Some of the most sensitive areas, *Conservation Forest Management Zones,* have been previously accounted for and protected from future timber harvesting under the ILP (EMR 2006). The potential for encountering heritage resources within Feedstock harvesting areas could range from low to high, depending on the locations. However, the implementation of mitigation measures, including Heritage Resource Assessments, "no disturbance" buffer zones, and winter

logging where warranted will reduce the likelihood of a significant adverse effect on Heritage Resources.

Consultation with regulatory bodies (*i.e.*, the Government of Yukon HRU and CAFN) will take place following the determination of Feedstock harvesting areas. No ground disturbing or site-altering activities will proceed prior to this consultation and/or the implementation of an HRA for the Feedstock PDAs.

Potential adverse environmental effects are anticipated to be low in magnitude for all phases of the Plant component as the likelihood of encountering heritage resources is low within the village of Haines Junction. Potential for adverse environmental effects are anticipated to be low in magnitude for all phases of the Feedstock as the assessment and mitigation measures in place will allow for the protection and/or avoidance and/or excavation of heritage resources identified in the PDAs. The geographic extent of the environmental effect is limited to the specific area within the PDA where potential heritage resources are located and thus mitigation measures are achievable. The duration of any potential adverse environmental effects on Heritage Resources for the Project would be permanent and irreversible. Heritage Resources are non-renewable, and cannot be reclaimed or reconstituted. Disturbance of an intact Heritage Resource occurs only once, either through mitigation or accident, and is permanently altered thereafter. Mitigation would be conducted in a controlled, professional, and sensitive manner with the input and participation of CAFN, regulatory bodies and all Project stakeholders. Due to these measures, the potential adverse environmental effects to Heritage Resources are not anticipated. The ecological context of the preliminary Plant PDA is relatively undisturbed, but the LAA (the village of Haines Junction) is a developed area. Potential Feedstock PDAs will be located in an area within the CATT that is both undeveloped and undisturbed apart from low-level forest operations.

An HRA will be conducted, including a visual assessment of areas within the Plant PDA. At the time that this report was written, Feedstock areas were undefined; however, it is anticipated that an HRA will be conducted on a case by case basis as areas are defined. Implementation of mitigation measures established in consultation between CAFN, the Government of Yukon HRU and Forest Management Branch and any party involved in conducting the HRA will also take place at this time. Procedures and protocols outlined in the Position Statement and the Guidelines will be followed. CAFN is currently developing a process to ensure the protection of Heritage Resources. This process will act as an independent and parallel assessment to those outlined in the Position Statement and Guidelines.

A significant adverse environmental effect on Heritage Resources during the Construction and Operation of the Plant and Feedstock components of the Project is not anticipated. A significant adverse environmental effect may be avoided through the implementation of mitigation where by all areas with known heritage resources, or the potential to encounter heritage resources, including areas of cultural or spiritual importance, are investigated prior to any ground disturbing or site-altering activities.

5.5.4 Assessment of Cumulative Effects

At the time of the writing of this report, there is insufficient information to conduct an assessment of Cumulative Effects or Statement of Significance for Heritage Resources. This will be revised upon the determination of final Plant and Feedstock PDA locations.

5.6 TRADITIONAL ACTIVITIES AND CULTURE

The proposed biomass gasification power plant (the Project) by the Champagne and Aishihik First Nations (CAFN) and the Yukon Energy Corporation (YEC) will be located within the village of Haines Junction, Yukon on Settlement Lands belonging to the CAFN. The Project is comprised of two parts:

- the biomass plant (the Plant); and
- biomass feedstock timber harvesting (Feedstock).

The Plant will operate as a power and heat source for buildings within Haines Junction and the Feedstock will be the fuel source for the Plant. At the time of the writing of this document, the PDA(s) of the Feedstock are unknown; however, future development of Feedstock is anticipated to take place on non-Settlement Lands within the Champagne and Aishihik Traditional Territory (CATT).

Traditional Activities and Culture is recognized as a VC for this EIA due to the potential impacts with those activities identified in consultation with CAFN as being of traditional or cultural importance to the community and citizens at large. These activities may include hunting, fishing, or trapping but may also include social and community gatherings, cultural or spiritual ceremonies. This assessment of Traditional Activities and Culture is preliminary and will be further refined through consultation with the CAFN community members as details of feedstock harvesting are defined.

5.6.1 Scope of the Assessment

This section defines the scope of the environmental assessment of Traditional Activities and Culture in consideration of the nature of the regulatory setting, issues identified during public and First Nations engagement activities, potential Project-VEC interactions, and existing knowledge.

At the time of the writing of this document, public and First Nations engagement activities have not all taken place. An introductory open house was held in Haines Junction and input from that engagement is included in Section 2.0 (Consultation). This assessment will be updated prior to submission to YESAA to incorporate engagement issues as warranted.

5.6.1.1 Key Issues and Identification of Potential Effects

Potential interactions between the Project and Traditional Activities and Culture are highlighted and those aspects of the Project that may cause environmental effects, either positive or adverse, are identified. The Project may interact with Traditional Activities and Culture in the following ways:

- Construction and Operation of the Plant will result in ground disturbing and site-altering activities (alternative use of the land during Operation), potentially impacting the ability to conduct Traditional or Cultural Activities within the Plant PDA and on adjacent lands; and
- Construction and Operation of the Feedstock will result in site-alteration (removal of vegetation from forested areas), potentially impacting the ability to conduct Traditional or Cultural Activities taking place within the greater CATT.

5.6.1.2 Regulatory/Policy Setting

The *Traditional Activities and Protection Act* (the Act) (CAFN 1998) was established:

> *"(a) to ensure the wise management of Settlement Land and resources of Champagne and Aishihik people on behalf of present and future generations; (b) to ensure comprehensive and integrated decision making respecting the use and management of Settlement Land and resources, including the full consideration of environmental, cultural, historic and socio-economic factors in that decision making; and (c) to protect the culture, traditions, health and lifestyle of Champagne and Aishihik people and to ensure that information pertaining to these things is used respectfully and wisely in decisions made by the Champagne and Aishihik First Nations."* (CAFN 1998:3)

Any development project taking place on CAFN Settlement Lands is required to obtain a permit for, and is responsible for protection of, those Settlement Lands under the Act. The Act and permits issued under it are enforced by the administrator of the act (the Director) and officers appointed by the CAFN Council.

The protection of Traditional Activities and Culture on non-Settlement Lands in the CATT is afforded through *Section 3.8 – Heritage and Culture Guidelines* of the *Integrated Landscape Plan for the Champagne and Aishihik Traditional Territory* (the ILP) (EMR 2006). Section 3.8 of the ILP outlines a process by which qualified representatives on behalf of CAFN and the Government of Yukon Heritage Resources will assess the cultural and heritage values of each proposed forest development on a site by site basis.

5.6.1.3 Selection of Measureable Parameters

The environmental assessment of Traditional Activities and Culture is focused on the following environmental effect:

- Change in Traditional Activities and Culture within the PDA

This environmental effect has been selected as a result of the need for disposition of lands for the Project and protection afforded to Traditional Activities and Culture under *YESAA* and the Act.

The measurable parameters used for the assessment of the environmental effect presented above and the rationale for their selection is provided in Table 5.8.1.

Table 5.6.1 Measurable Parameters for Traditional Activities and Culture

Environmental Effect	Measurable Parameter	Rationale for Selection of the Measurable Parameter
Change in Traditional Activities and Culture	Ability to conduct Traditional or Cultural Activities within the PDA	• Traditional Activities and Culture are afforded protection under CAFN legislation, the *Traditional Activities Protection Act.* • Land- and Site-altering (*e.g.*, tree-felling) activities, and noise and dust during construction, within the PDA has the potential to impact traditional and/ or cultural activities that may take place within the PDA (*e.g.*, subsistence harvesting, cultural or spiritual ceremonies, social gatherings)

5.6.1.4 Spatial Boundaries

The spatial boundaries for the environmental effects assessment of Traditional Activities and Culture are defined below.

Project Development Area (PDA): The PDA is the most basic and immediate area of the Project. The PDA is limited to the area of physical ground disturbance associated with the Project, and consists of an area that includes the area of physical disturbance associated with the biomass plant and associated facilities as well as the area associated with biomass feedstock harvesting (including forest roads). The PDA is the area represented by the physical Project footprint as defined in Chapter 3.1.2 above.

Local Assessment Area (LAA): The LAA is the maximum area within which Project-related environmental effects can be predicted or measured with a reasonable degree of accuracy and confidence. The LAA includes the PDA, Haines Junction, and any adjacent areas where Project-related environmental effects may reasonably be expected to occur. Since the potential environmental effects on Traditional Activities and Culture may extend beyond the PDA (*e.g.*, the disruption of key migration routes for hunting, trap-line concessions), the LAA must include

Regional Assessment Area (RAA): The RAA is limited to and includes the Yukon Territory. The RAA is the area within which the Project's environmental effects may overlap or accumulate with the environmental effects of other projects or activities that have been or will be carried out. The extent to which cumulative environmental effects for Traditional Activities and Culture may occur depend on physical and biological conditions and the type and location of other past, present, and reasonably foreseeable future projects or activities that have been or will be carried out, as defined within the RAA. For Traditional Activities and Culture, the RAA may be considered lands within the CATT, and the southwest region of the Yukon Territory.

5.6.1.5 Temporal Boundaries

The temporal boundaries for the assessment of the potential environmental effects of the Project on Traditional Activities and Culture include the phases of Construction, Operation, and Decommissioning.

5.6.1.6 Residual Effects Significance Criteria

A *significant adverse residual environmental effect* on Traditional Activities and Culture is defined as one that results in a permanent Project-related change in ability to conduct a Traditional or Cultural Activity including, but not limited to, those activities conducted by CAFN citizens and outlined as "traditional activities" in the Act *"…for food, subsistence or ceremonial purposes to strengthen and enhance social, spiritual and cultural relationships and values…*" (CAFN 1998:2) and that cannot be mitigated or compensated for.

5.6.2 VC Existing Conditions

The Project PDA will be located within the limits of the village of Haines Junction, in southwest Yukon. The preliminary PDA of the biomass energy plant is located just east of the intersection between Willow Acres Road and the Alaska Highway. This assessment will be updated as required following final siting.

At the time of the writing of this report, specific Feedstock areas are undefined. It is anticipated that feedstock timber harvesting will take place within the CATT, which encompasses an estimated 1,959,000 HA of southwest Yukon, according to the ILP (EMR 2006) (Figure 5.5.1). However, planning and development for the forest industry will occur only in the Forest Resource Management Zone (93,700 HA in the ILP) (EMR 2006). The areas that would potentially be harvested for Feedstock are likely to be predominantly located within 50-70 km of Haines Junction over the life of the project, delimited by the boundaries of the Forest Resource Management Zone (Damecour, pers. comm. 2012).

Methods for determining the existing conditions of Traditional Activities and Culture within the Project PDA rely on communication with the population who currently occupy that land, or have knowledge of recent use and activities conducted therein. At the time of the writing of this report, documentary sources remain the primary resource for Traditional Activities and Culture. Consultation with CAFN citizens, non-aboriginal Yukon citizens living in the area, and traditional use studies for the Project, including the Plant and Feedstock PDAs will be conducted and/or consulted prior to any Project-related ground disturbance or site-altering activities.

5.6.2.1 Evaluation of Existing Information

Information contained in the Heritage Resources VC (Section 5.5) describes the general human setting of the recent past with a particular focus on the Southern Tutchone people, direct ancestors to the modern-day Champagne and Aishihik First Nations. Section 5.5 discusses traditional hunting-fishing-gathering practices and a brief overview of the Southern Tutchone seasonal round based on information available in documentary sources. Further descriptions of more recent (*i.e*., present-day) use of the land and resources, community, spiritual, and cultural activities practiced by CAFN and non-aboriginal Yukon citizens in the Project area will be gathered through consultation during the detailed Feedstock assessment.

5.6.3 Potential Project VC Interactions

5.6.3.1 Project Effects Mechanisms

Table 5.8.2 below lists each Project activity and physical work for the Project, and ranks each interaction as 0, 1, or 2 based on the level of interaction each activity or physical work will have with the Traditional Activities and Culture.

Table 5.6.2 Potential Project Environmental Effects to Traditional Activities and Culture

Project Activities and Physical Works	Potential Environmental Effects
	Change in Traditional Activities and Culture
Construction	
Site preparation	1
Physical construction of the Facility Structures	1
Installation of Equipment	0
Commissioning	0
Construction of infrastructure for Feedstock Harvesting	2
Operation	
Operation and Maintenance of Plant Site	0
Feedstock Harvesting	2
Decommissioning, Reclamation and Closure	

Table 5.6.2 Potential Project Environmental Effects to Traditional Activities and Culture

Project Activities and Physical Works	Potential Environmental Effects
	Change in Traditional Activities and Culture
Plant Site	0
Harvested Areas	0

Project-Related Environmental Effects
Notes:
Project-Related Environmental Effects were ranked as follows:
0 = No interaction. The environmental effects are rated not significant and are not considered further in this report.
1 = Interaction will occur. However, based on past experience and professional judgment, the interaction would not result in a significant environmental effect, even without mitigation, or the interaction would clearly not be significant due to application of codified practices and/or permit conditions. The environmental effects are rated not significant and are not considered further in this report.
2 = Interaction may, even with codified mitigation and/or permit conditions, result in a potentially significant environmental effect and/or is important to regulatory and/or public interest. Potential environmental effects are considered further and in more detail in the EA.

5.6.3.2 Construction

Activities ranked as 0 for the Construction Phase in Table 5.8.2 include: Installation of Equipment and Commissioning. Final Plant site selection will take into account key areas for Traditional Activities and Culture, and Installation of the Equipment and Commissioning does not involve land- or site-altering activities, therefore will not interact with any Traditional or Cultural Activities. As a result, the potential environmental effects of Installation of the Equipment and Commissioning activities on a change in Traditional Activities and Culture are ranked as 0.

Activities ranked as 1 for the Construction Phase in Table 5.8.2 include: Site Preparation and Physical Construction of the Facility Structures. While both activities ranked as 1 in the table will result in land- or site-altering activities, site selection of the Plant will take into consideration, and be located to minimize, interaction with Traditional Activities and Culture. As a result, it is anticipated that no significant environmental effect, due to the application of codified practices and permit conditions, would occur to Traditional Activities and Culture.

Operation

Activities ranked as 0 for the Operation Phase in Table 5.8.2 include: Operation and Maintenance of Plant Site. The biomass energy Plant will be located to avoid key areas for Traditional Activities and Culture, and the Operation and Maintenance of Plant Site activity does not involve land- or site-altering activities, therefore will not interact with any Traditional or Cultural Activities. As a result, the potential environmental effects of Operation and Maintenance of Plant Site activities on a change in Traditional Activities and Culture are ranked as 0.

There are no activities ranked as 1 during the Operation phase in Table 5.8.2.

5.6.3.3 Decommissioning, Reclamation and Closure

Activities ranked as 0 for the Decommissioning, Reclamation and Closure Phase in Table 5.8.2 include: Plant Site and Harvested Areas. No land- or site-alteration beyond that already completed during the Construction and Operation Phases are anticipated for this phase of the Project. As a result, the potential environmental effects of Plant Site and Harvested Areas activities on a change in Traditional Activities and Culture are ranked as 0. The ranking of 0 for Plant Site and Harvested Areas activities

assumes that the Plant PDA will remain unchanged and that the Feedstock PDA(s) will be re-forested and returned to natural growth.

There are no activities ranked as 2 for Traditional Activities and Culture in the Decommissioning, Reclamation and Closure phase.

Thus, in consideration of the nature of the interactions and the planned implementation of known and proven mitigation, the potential environmental effects of all Project activities and physical works that were ranked as 0 or 1 in Table 5.8.2, including cumulative environmental effects, on Traditional Activities and Culture during any phase of the Project are rated not significant, and are not considered further in the assessment.

5.6.3.4 Assessment of Environmental Effects

The only interactions ranked as a 2 and thus requiring further assessment are related to Feedstock harvesting which is not being assessed in detail in this draft assessment. At the time of the writing of this report, there is insufficient information to conduct a further assessment of Environmental Effects on Traditional Activities and Culture. Mitigation measures, Residual and/or Cumulative effects will be revised upon the determination of final Plant and Feedstock PDA locations. No land- or site-altering activities or disruption of Traditional or Cultural Activities (*e.g.*, subsistence hunting, trapping, spiritual or cultural ceremonies, social and community gatherings) will take place for the Project prior to consultation with CAFN citizens and non-aboriginal Yukon citizens living on and/or using lands that may potentially be impacted by the Project.

6.0 ASSESSMENT OF EFFECTS OF ACCIDENTS AND MALFUNCTIONS

Accidents and malfunctions are unplanned, adverse events affecting the Project during Construction and Operation. Three potential sources of accidents and malfunctions are considered in this assessment: process upsets, fires, and vehicle collisions.

Process upsets will be minimized to the extent possible by conducting the appropriate preventative and routine maintenance of mechanical components of the Project, as well as the control of the process operation by an installed system. In the event of a process upset, operators would respond to the event by manually adjusting the relevant process parameters to resolve the issue as quickly as possible. For mechanical breakdowns, operators would be dispatched as soon as possible to conduct the required maintenance or repairs of the affected equipment. In the case of major process upsets, if the issue cannot be resolved internally in a timely fashion, the process would be shut down in a controlled manner to conduct the required repairs.

Fires at the Project site could result from an accident, from spontaneous combustion of biomass, or from potential fires within the equipment (*e.g.*, gas cleaning). The immediate concern for a fire would be for human health and safety. Local air quality conditions may be influenced by emissions from a fire and other adjacent infrastructure could be at risk of damage or loss as well.

The emissions from a fire would likely consist mainly of smoke (particulate matter) and CO_2 but could also include CO, NO_X, SO_2, VOCs, and other products of incomplete combustion. A large fire could create particulate matter levels greater than the ambient air quality standard over distances of several kilometres, but such situations would be of short duration and are not expected to occur.

The facility will be equipped with several fire hydrants, and personnel will be adequately trained in fire-fighting procedures, to respond to any fire that may result from spontaneous combustion of biomass or other means. However, since limited quantities of biomass will be stored on-site, and since their storage will be for a relatively short period of time, the risk of spontaneous combustion is low.

The potential for vehicle accidents exists for all phases of the Project. In addition to the employee-related traffic to and from the site, the operation of heavy equipment on-site during Construction as well as the operation of heavy trucks for equipment and biomass deliveries has the potential to result in vehicle accidents during Operation.

The Project is anticipated to be located near the Alaska Highway, which is a main roadway. The Project will result in an increase of 3 to 15 trucks per week in during Operation. This increased truck traffic associated with Operation of the Project equates to a small increase in overall traffic volumes in the area. Further to this, the Project-related traffic is expected to be confined to existing truck routes. Therefore, the increase in traffic is not expected to result in a substantive increase in the potential for vehicles accidents.

7.0 EFFECTS OF THE ENVIRONMENT ON THE PROJECT

The effects of the environment on the Project are associated with risks of natural hazards and influences of nature on the Project, during all phases. These environmental effects are defined in Section 2(1) of the *Canadian Environmental Assessment Act* as *"…any change to the project that may be caused by the environment…whether any such change or effect occurs within or outside Canada*." Typically, potential effects of the environment on any project are a function of project or infrastructure design and how these may be affected by nature. These effects may arise from physical conditions, land forms, and site characteristics which may act on the Project such that the Project components, schedule and/or costs could be substantively and adversely changed.

Good engineering design involves the consideration of environmental effects and loadings or stresses (from the environment) on the Project. The planning and engineering design for this Project are no exception. Equipment and materials will be used that are able to withstand severe weather, and other influences. Environmental stressors, such as those that could arise as a result of climate change, severe weather, and other factors, would be addressed by engineering design, materials selection, and best practices.

Mitigation strategies for minimizing the likelihood of a significant effect of the environment on the Project are inherent in the planning process, the engineering design codes and standards, and the construction practices. As such, and in consideration of the best management practices that will be applied throughout the design, Construction and Operation of the Project, as demonstrated in the following sections, the effects of the environment on the Project during all phases of the Project will be managed through responsible design and thus have been rated not significant.

7.1.1 Influence of Consultation on the Assessment

At the time of writing, consultations in the community are on-going. A summary of the consultations as they apply to effects of the environment on the Project will be provided following the completion of the consultations.

7.1.2 Potential Effects on the Project

The environmental attributes that were considered to have a potential effect on the Project were based on a review of the known past and existing conditions, and knowledge gained through projections of potential future conditions (*e.g.*, potential effects of climate change). Based on the issues and concerns identified, the environmental attributes selected for consideration include:

Severe weather, including:

- wind;
- precipitation; and
- electrical storms.

Climate change, including:

- changes in mean temperature; and
- changes in precipitation amounts, frequency, and type (rain).

As a result of climate change, the Haines Junction area may be subject to melting permafrost and increased risk of forest fires resulting from causes other than the Project.

Climate conditions and climate change are presently the focus of much concern globally. "*With global attention now focused on climate change, government agencies, non-profit organizations, the private sector, and individual citizens are gearing up to face climate-related challenges*" (NOAA 2010). The people of the Yukon have already begun addressing climate change by holding two conferences, titled *Climate Change in Our Backyard*, in 2006 and 2009. The conferences brought together local experts in the Champagne and Aishihik First Nations Traditional Territory (CATT) and researchers to discuss the observed changes in the CATT, what changes might be expected, and what adaptive strategies may be employed.

7.1.3 Extreme Weather Events

Extreme weather events may be characterized as events of heavy precipitation or strong winds.

There are climate normals data available from the Whitehorse meteorological station (Environment Canada 2012d) . The most extreme daily rainfall event in Whitehorse was recorded on June 27, 1985 to be 44.9 mm, and the most extreme daily snowfall event was recorded on March 8, 1967 to be 27.2 cm. The maximum hourly wind speed was recorded on January 9, 1962 to be 72 km/hour, and a maximum gust speed of 106 km/hour was recorded on February 19, 1964.

With respect to effects on the Project, extreme weather events may affect the harvesting and transportation of wood through temporarily reduced access to wood and transportation infrastructure. In addition, the storage of wood chips on site may be compromised if the biomass storage building fails. These effects may be mitigated by considering extreme weather events in the design and operation of the Project activities and infrastructure.

7.1.4 Forest Fire

Between 1950 and 2006, a total of 6,294 fires have occurred in the Yukon. Forest fires may be caused by lightning strikes or human activities. The average annual area burned is 1,495 km^2 (149,515 hectares) (Government of Yukon 2011b). Haines Junction has a volunteer fire department.

In the event that Haines Junction is evacuated due to a forest fire, the Project can be safely and quickly shut down. The immediate area surrounding the site will be cleared of vegetation. No other effects on the Project due to forest fires are anticipated.

7.1.5 Climate Change

"Climate" is defined as the statistical average (mean and variability) of weather conditions over a substantial period of time (typically 30 years), accounting for the variability of weather during that period (Catto 2006). The relevant parameters used to characterize climate are most often surface variables such as temperature, precipitation, and wind, among others.

"Climate change" is an acknowledged change in climate that has been documented over two or more periods, each with a minimum of 30 years (Catto 2006). The Intergovernmental Panel on Climate Change (IPCC) defines climate change as a change in the state of the climate that can be identified (*e.g.*, by using statistical tests) by changes in the mean and/or the variability of its properties and that persists for an extended period, typically decades or longer. Climate change may be due to natural internal processes or external forcings, or to persistent anthropogenic changes in the composition of the atmosphere or in land use (IPCC 2007). The United Nations Framework Convention on Climate Change (UNFCCC) makes a distinction between climate change attributed to human activities and climate variability attributable to natural causes, by defining climate change as a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods (IPCC 2007).

The definition of climate change dictates the context in which the effects of those changes are discussed. While it is appropriate to examine the effects of projected climate change on Operation over the next 50 to 100 years, it is not fitting to consider the effects of climate change projections on Construction which will take place over a relatively short period of time (6 to 8 years) in the near future. Construction will occur over the first year of the Project, and as such it is more appropriate to consider the effects of recent climatological conditions, especially the potential adverse effects of weather variability and weather extremes (*e.g.*, change in precipitation) on Construction.

To assess the environmental effects of climate on the Project, current climate and climate change must both be considered. Current climate conditions are established by compiling relevant historical data and establishing a climatological background for the Haines Junction area. Climate change effects projected over the life of the Project (approximately 20 years) are determined through a review of the two Climate Change in Our Backyard conference reports (CAFN 2006; CAFN 2009b). The 2009 report indicates that the annual mean temperature of southern Yukon is projected to be 2.6°C warmer and that precipitation is projected to increase by 10 to 45% in the next 50 years. As a result, changes to water resources, biodiversity, transportation infrastructure, health, and local economies are anticipated. Nevertheless, given the lifetime of the Project (approximately 20 years), the effects of Climate Change are not likely to cause adverse effects on the Operation of the Project.

8.0 SUMMARY OF SIGNIFICANCE

The assessment of potential effects provided in the sections above has been completed based on desktop literature and information review and in consideration of initial consultation with First Nations and the public on their interests and values. Preliminary findings for each VC have been developed in consideration of the Project activities as understood from the FEED study and may require updates once the Project location and infrastructure are finalized. Updates may also include a more detailed assessment of feedstock harvesting activities.

In consideration of existing ambient air quality conditions and estimated Project emissions of air contaminants, ambient air quality is expected to remain well below regulatory objectives during operation of the plant. Annoyance from noise is not expected to be caused by the plant if it is located at least 500 m from residences (to avoid sleep disturbance). If the plant is located in a building this distance could be less. The chipping operation will likely need to be located 500 to 1,000 m from residences and sensitive receptors (such as the school or other areas of frequent land use) to avoid annoyance.

Minimal influence on water resources is expected as the plant will use little to no water (depending on vendor) and should be located at least 30 m away from surface water sources. Feedstock (in chip form) will be stored indoors to avoid siltation to surface water run-off.

Significant environmental effects on vegetation and wildlife are not expected based on the species documented in Haines Junction.

Additional consultation is required in relation to traditional ecological knowledge and traditional activities and culture to confirm any constraints that should be considered. Based on the consultation conducted to date, no concerns have been raised that are expected to hinder development of the Project in a way that will not significantly effect these values.

Known and documented heritage resources have been confirmed and will be avoided in locating the plant.

Transportation infrastructure is not expected to be noticeably influenced as a result of the Project. Truck traffic is estimated at 3 to 15 trucks per week to supply feedstock during Operation. Similar or less traffic is expected during Construction.

The Project will require resources for construction and operation, therefore a positive effect on labour and economy is expected. Planning of forest harvesting will include consideration of existing land users to ensure that other land users such as existing harvesters, trappers, outfitters and wilderness tourism are not negatively affected.

Human health and well-being should not be affected by the Project. The plant would be operated within applicable regulations which have been developed to protect human health and well-being.

The risk of accidents related to the Project will be minimized through the design and procedures during Operation.

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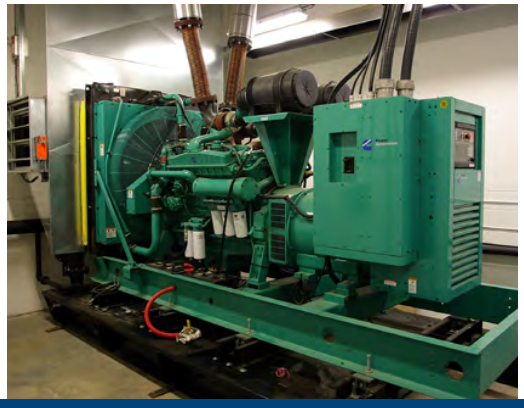

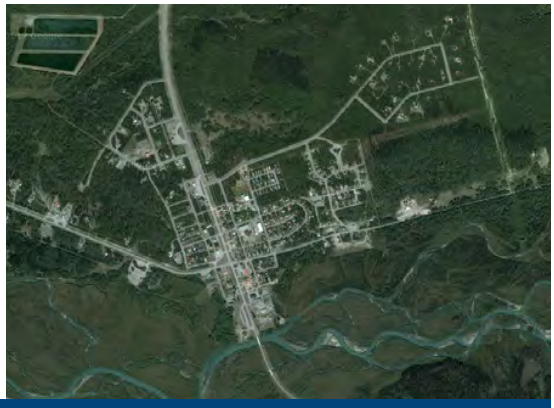

APPENDIX I

Engagement Plan

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

Stantec

This document has been prepared exclusively for the client and the project identified herein.
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.

DRAFT YUKON BIOMASS FEED STUDY - PUBLIC AND FIRST NATIONS ENGAGEMENT PLAN

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TABLE OF CONTENTS

1 Background 1
1.1 Introduction 1
1.2 Communications Approach 2
1.3 Public Engagement Principles 2
1.4 Communications Aim 2
1.5 Key Messages 3
1.6 Communications Goals and Objectives 4

2 Project Team 5
2.1 Structure 5
2.2 Roles and Responsibilties 6

3 Communication Protocols 8
3.1 Confidentiality 8
3.2 Communications With Regulators 8
3.3 Media Relations 8
3.4 Communications with Steering Committee 9
3.5 Monitoring 9

4 Engagement with Stakeholders 10
4.1 Project Stakeholders 10
4.2 YESAA Stakeholder Consultation Requirements and Processes 11

5 Engagement with First Nations 12
5.1 YESAA First Nations Consultation Requirements 12

6 Level of Engagement and Participation 13

7 Engagement Processes and Timelines 15

8 Engagement Methods 18
8.1 Recording Communications 18
8.2 Documenting Issues and Concerns 19
8.3 Scheduled Meetings 19
8.4 Open Houses 20
8.4.1 Timing 20
8.4.2 Format and Materials 20
8.4.3 Recording Attendance 21

9 Engagement Performance Measures..... 22

List of Tables

Table 1.1: Key Messages 3
Table 2.1: Communications Roles and Responsibilities..... 7
Table 3.1: Project Media Contacts..... 9
Table 4.1: Stakeholder List 10
Table 6.1: Audiences and Engagement Levels 14
Table 7.1: Key Dates, Events and Audiences 15
Table 8.1: Example Issue Log 19
Table 8.2: Meetings 19
Table 8.3: Open Houses..... 20

List of Figures

Figure 2.1: Project Team 6
Figure 6.1: Engagement and Participation Levels..... 13
Figure 7.1: Engagement Timelines..... 17

List of Appendices

Appendix A: .....Communication Log Template
Appendix B: …… Record of Contact Form (Example)

1 BACKGROUND

1.1 Introduction

The primary objective of this Front End Engineering Design (FEED) Study is to confirm the viability of electricity generation in Yukon using small-scale gasification technology fuelled from local forest biomass feedstock. The project will require either a Yukon Environmental and Socio-economic Assessment Board (YESAB) District Office or Executive Office level effects assessment for the biomass facility. Baseline work on feedstock harvesting is outside the scope of this project.

Also outside of the scope of this project is the waste heat study that will be led by Champagne and Aishihik First Nations' Renewable Energy Committee. The waste heat study will identify possible uses of the waste heat from the biomass plant, will be carried out at the same time as the FEED study, and will be completed by Clean Technology Community Gateway (CTCG).

This engagement plan sets out how the project team will meaningfully engage with First Nations, stakeholders, regulators, decision-makers and the general public. It provides a working list of stakeholders and potentially interested First Nations, a description of communication timelines, and describes how engagement will be carried out. It is based, in part, on information provided in the draft communications plan provided to Stantec by the project team.

For the purposes of this document, the Project Partners/Project Sponsors are the following:

- Yukon Energy (YEC)
- Champagne Aishihik First Nations (CAFN)
- Dakwakada Development Corporation (DDC)
- Cold Climate Innovation (CCI)
- Village of Haines Junction (VHJ)

The Project Steering Committee is made up of the following individuals:

- Michael Brandt, YEC – Co-Chair
- Ray Wells, YEC – Co-Chair
- Roger Brown, CAFN
- Hector Campbell, YEC
- Stephen Mooney, CCI

The Project Management Team and Project Contributors are those individuals shown in Figure 2.1.

1.2 Communications Approach

Strong stakeholder engagement is required to build community support for the use of biomass energy generation in Haines Junction. As several organizations are sponsoring the project, the project team will ensure the views of each Project Partner are contained in engagement and communication materials, as appropriate. The outputs from project engagement will be shared with the Project Partners and Steering Committee members at key decision points and at the end of the project.

1.3 Public Engagement Principles

The project will involve stakeholder and relationship-building over a number of different phases and possibly over a number of years. The following principles will guide this engagement:

Communication

- Communicate regularly on the project's progress
- Wherever practical, maximise opportunities for stakeholders to provide feedback
- Clearly communicate feedback mechanisms to foster two-way communication

Transparency

- Clearly explain the decision-making process and define the intended outcomes of any engagement activities
- Where and as appropriate, communicate to stakeholders what they can and cannot influence in the consultation process
- Inform stakeholders about how their input will be used
- Where appropriate, document decisions or outcomes of meetings with stakeholders

Inclusiveness

- Identify stakeholders and, wherever possible, involve them in any consultation at an early stage
- Seek to understand stakeholder issues or concerns
- Facilitate stakeholder engagement as appropriate

1.4 Communications Aim

The overarching communications aim for the project is to generate stakeholder awareness, understanding and support and to communicate the following to project audiences:

- CAFN, DDC, YEC, CCIC, and VHJ are working together to investigate the possibility of locating a biomass electricity generation plant in the Haines Junction area

- If the project proceeds, it could mean additional renewable energy and, potentially, a source of district heat, creation of local jobs, and economic opportunities/growth for local businesses and corporations
- The project may serve as a demonstration project for biomass power generation in other similar northern and rural communities in Canada

1.5 Key Messages

The steering committee and project team have worked to develop the following key messages. These key messages will be used when communicating with stakeholders, regulators and the general public. These messages may be amended and added to as the project progresses.

Table 1.1: Key Messages

Question	Detailed Key Messages
Who are the Project Partners?	▪ The Champagne and Aishihik First Nations, the Dakwakada Development Corporation, Yukon Energy, Cold Climate Innovation at the Yukon Research Centre, and the Village of Haines Junction
What's the project all about?	▪ The partners are exploring a potential opportunity to produce renewable energy in the Haines Junction area using biomass gasification technology ▪ The plant concept envisions the building of a small scale gasification plant that will generate between 0.5 and 2 megawatts of renewable electricity, helping to develop a sustainable and secure energy future for the Haines Junction community and the Yukon. ▪ The partners are looking at producing electricity using a power plant fueled by beetle-killed trees, sawmill waste, and other sources of renewable wood fiber harvested from the Haines Junction area. The partners are also exploring whether heat energy produced by the power plant could potentially be provided to local facilities.
What stage is the project at?	▪ We are in the early stages of exploring this opportunity and we are investigating different technologies and project scales. ▪ Our initial work includes informing and discussing the concept with First Nations, stakeholders and the public while conducting a detailed feasibility study to see if operating a biomass gasification power plant in Haines Junction is technologically, environmentally and financially a good choice. ▪ Based on preliminary work that demonstrated the possible viability of a biomass gasification facility in Haines Junction, Stantec has been engaged to conduct a detailed feasibility study funded by each of the project partners and Natural Resources Canada, Canadian Northern Economic Development Agency and the Government of Yukon. The results of that technology study are expected in 2013. ▪ Once the results of Stantec's feasibility study are known, the project partners will share that information and seek feedback. They will then decide whether to continue with further studies and how best to move forward. Future work will involve exploring in greater detail the source and sustainable supply of wood fiber fuel for the proposed biomass facility. If the overall concept is feasible, the biomass project will then undergo community, environmental, socio-economic, and regulatory reviews before a decision is finally made to proceed with construction and operations.
Why is the project unique?	▪ This is the first time that the project partners have combined forces to collaborate on a potential renewable energy project. The technology is innovative and has been successfully used in other parts of Canada, in the United States, and in Europe and

Question	Detailed Key Messages
	Asia. If built, the power plant would be the first biomass electricity production facility in the Yukon and has the potential to act as a demonstration project for other small rural and northern communities.
What are the potential benefits of the project?	▪ A biomass power plant could generate at least 0.5 megawatts of much-needed renewable electricity, contributing to a sustainable and secure energy future for the Haines Junction community and the Yukon. ▪ The project could create local jobs and offer long-term economic opportunities for local businesses to grow. ▪ Waste heat from the facility could potentially be used to heat existing or new facilities (such as a community greenhouse).
What are the potential challenges?	▪ Cost ▪ Wood fiber availability ▪ Ensuring sustainable wood fiber harvesting and sustainable operation of the power plant ▪ Potential noise and other effects from increased traffic, construction, and industrial activity ▪ Possible air emissions
What are key questions that the Project Partners still need to answer?	▪ Given existing technology and potential fuel sources, is a biomass power project in the Haines Junction area technically and economically feasible? ▪ Is there an acceptable location for the biomass power plant? ▪ Can a biomass power plant be developed and operated in an environmentally and socially responsible way? ▪ Is there enough renewable wood fiber available to fuel the proposed power plant for the long-term? ▪ Where would the wood fiber be harvested and can it be sustainably harvested? ▪ What are the likely positive and negative effects on the environment and on local residents? ▪ Would there be any significant negative effects? ▪ Could any significant negative effects be satisfactorily avoided or mitigated?

1.6 Communications Goals and Objectives

- Create and maintain awareness and understanding of the project among the general public, decision-makers, key stakeholders, and interested First Nations, including its potential costs and benefits, and proposed engagement processes
- Identify stakeholders and potentially interested First Nations, build and maintain strong relationships, ensure that engagement occurs at the right level, at the right time, in the right way
- Identify, document and monitor issues and concerns that arise during the engagement process
- Identify needed planning, design and management measures to avoid, mitigate or resolve issues

- Encourage the sharing of traditional land use and traditional knowledge information by interested and potentially affected First Nations
- Provide early notification of the project and adequate opportunities for public input
- Ensure the steering committee, project partners and the project team communicate with 'one voice' to the public, stakeholders and regulators
- Identify and manage communications issues to minimize their potential adverse impact on the project

2 PROJECT TEAM

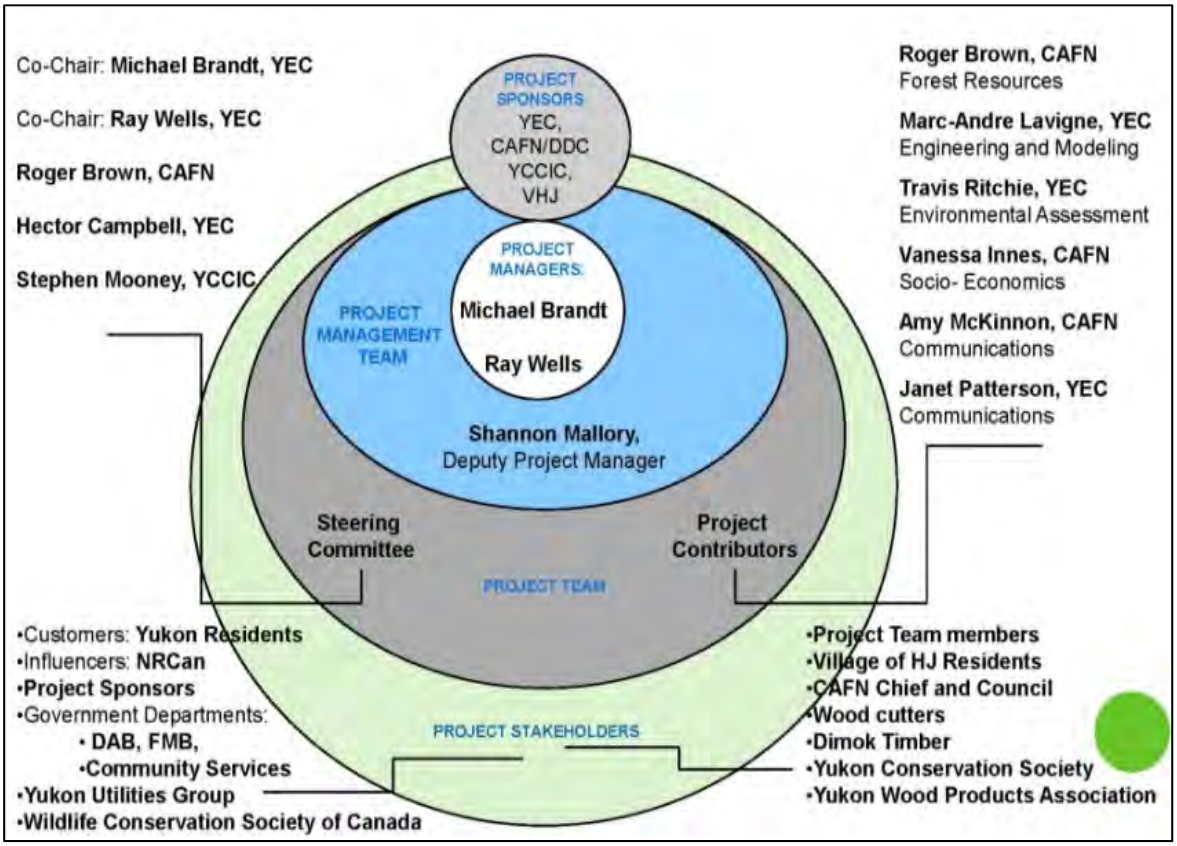
2.1 Structure

The project team is shown in Figure 1.1 below. The project team is comprised of technical staff from YEC, DDC and CAFN. Team members will be given tasks that are relevant to their knowledge area by the steering committee, co-project managers or deputy project manager.

To support the project management team and project consultants, the Steering Committee has been established that has technical representation from at least two of the Project Partners. A number of sub-committees may be formed to deal with specific issues throughout the project. The Steering Committee will:

- Have overall guidance and direction of the Project
- Direct actions to the deputy project manager and the co-project managers as well as the project team

Figure 2.1: Project Team



2.2 Roles and Responsibilties

To ensure that project communications are clear, consistent and coordinated, the roles and responsibilities of the Project Partners, Steering Committee, project management team, and Project Contributors must be clearly described. The following roles and responsibilities have been recommended by the Steering Committee:

Table 2.1: Communications Roles and Responsibilities

Partner	Role/Responsibility
Project Sponsors/Project Partners	The Project Sponsors will: • Defer all public/media communications regarding the project to their Communications representatives
Project Steering Committee	The Steering Committee will: ▪ Have overall guidance and direction of the Project ▪ Direct actions to the deputy project manager and the co-project managers as well as to the project team ▪ Act as project points of contact and decision makers for their organizations as members of the Project Steering Committee ▪ Approve the communications and stakeholder engagement strategy ▪ Approve all media releases and media interviews ▪ Approve all engagements and communications with assessment, resource management and regulatory agencies (e.g., YG Forest Management Branch, YESAB), beyond sharing information that is already in the public domain ▪ The Project Steering Committee with the Project Sponsors, Project Management Team and Project Contributors will be involved in the the development of the key messages to ensure consistency and content accuracy of communication
Project Management Team	The Project Management Team will: ▪ Defer all public communications regarding the project to communications representatives ▪ Act as a key contact point for stakeholders in cooperation with the deputy project manager ▪ Have overarching responsibility for preparation of communications and engagement materials and events ▪ Have overarching responsibility for assessment and regulatory agency communications and engagement ▪ Identify and manage issues ▪ Approve all communications as authority may be designated to it in writing by the steering committee
Deputy Project Manager / Designate (e.g. Project Consultants)	The Deputy Project Manager/Designate will: ▪ develop draft materials for Project Sponsor, Project Steering Committee, Project Management Team and Project Contributor review ▪ provide information to Communications Representatives for website materials ▪ maintain the contact database ▪ prepare papers and advice to the Project Management Team, the Steering Committee, and Project Contributors ▪ communicate with Stantec regarding Steering Committee direction on engagement and communications activities
Project Contributors	The Project Contributors will play a supporting role in communications and stakeholder engagement for the project. Working with the Steering Committee, the Project Contributors may assist with: • managing communications and engagement activities

Partner	Role/Responsibility
	• identifying and managing issues • assisting with media activities as required • monitoring media coverage and the external environment for impacts on the project • providing strategic communications advice to the Project Management Team and Steering Committee as needed
Communications Representatives	Will draft the following: • summaries of media coverage and external opinion/discussions relating to the Project • communication responses to manage reactive media activities • information for newsletters The Communications Representatives will update the engagement plan as needed

3 COMMUNICATION PROTOCOLS

3.1 Confidentiality

Project-related documents are considered confidential and are only to be shared with the internal project team unless specific approval is given for their release by the steering committee.

3.2 Communications With Regulators

Any communications and engagement regarding the project with assessment and regulatory agencies/personnel requires prior notification and approval by the steering committee. Improptu conversations may occur, but shall not go beyond sharing information currently available to the public and hearing what the other party may want to share.

3.3 Media Relations

The following rules should govern all project-related communications with the media:

- Media releases are to be signed off by the Steering Committee before being sent out
- All planned contact with media will be coordinated through the project management team
- All media releases and media engagements (e.g., interviews) will be pre-approved by the Steering Committee
- *** NRCan requires three weeks notice of any news releases

- Before doing media interviews, the spokesperson should notify all project parties by email. Following the interview, the spokesperson should send another email to the Project parties providing a summary of the conversation
- Communications representatives will be the initial point of contact for all reactive media enquiries (see table below for details)

Table 3.1: Project Media Contacts

Project Partner	Communications Representatives
Yukon Energy	David Morrison / Janet Patterson
CAFN	Chief James Allen
DDC	Murray Arsenault
Village of Haines Junction	Mayor George Nassiopoulos
Cold Climate Innovation Research Centre	Tanis Davey

3.4 Communications with Steering Committee

Project communications with the Steering Committee will be governed by the following rules:

- Steering Committee meetings will be sent out with an outlook meeting request with a link and phone number for GoTo Meeting
- Project status reports will be sent to the Steering Committee by email as they are received from the consultant

3.5 Monitoring

The project management team will continuously identify emerging issues by monitoring the following:

- Media coverage
- Blogs and other social media (Facebook/Twitter/Google +)
- Policy environment
- Stakeholder feedback (formal and informal)

4 ENGAGEMENT WITH STAKEHOLDERS

4.1 Project Stakeholders

Potential project stakeholders are listed below (this list will be added to and amended over time):

Table 4.1: Stakeholder List

Industry and Industry Associations Arctic Inland Building Products Dimok Timber Ltd. Tourism Industry Association Yukon Wilderness Tourism Association Yukon Outfitters Association Yukon Wood Products Association	**Project Team, Sponsors and Contributors** CAFN Dakwakada Development Corporation Yukon Energy Centre Cold Climate Innovation Village of Haines Junction
Research and Academic Yukon College, Northern Research Institute	**Regulators and Decisionmakers** YESAB YUB Yukon Executive Council Office
Local Government and Local Government Associations Village of Haines Junction (Mayor and Council) Association of Yukon Communities	**Potentially affected land users and representative organizations** Trappers Guide Outfitters Hunters Recreational/Commercial Fishermen
Nongovernmental Organizations Wildlife Conservation Society of Canada Council of Canadians Yukon Conservation Society Canadian Parks and Wilderness Society	**Yukon Government** Environment Yukon Yukon Highways and Public Works Yukon Economic Development Yukon Energy, Mines and Resources Yukon Government Climate Change Secretariat Yukon Health and Social Services Yukon Land Use Planning Council
Government of Canada Environment Canada Canadian Northern Economic Development Agency (CanNor) Natural Resources Canada	**Other Interested or Influential Groups** Local Residents of Village of Haines Junction and surrounding area Alsek Renewable Resource Council General Public Media MLAs MPs

4.2 YESAA Stakeholder Consultation Requirements and Processes

Section 50(3) of the *Yukon Environmental and Socio-Economic Assessment Act* ("YESAA") states the following with respect to both First Nations and stakeholder consultation requirements:

> Before submitting a proposal to the Executive Committee, the proponent of a project shall consult any first nation in whose territory, or the residents of any community in which, the project will be located or might have significant environmental or social economic effects.

Section 3 of YESAA states:

> Where, in relation to any matter, a reference is made in this Act to consultation, the duty to consult shall be exercised
>
> (a) by providing, to the party to be consulted,
>
> (i) notice of the matter in sufficient form and detail to allow the party to prepare its views on the matter,
>
> (ii) a reasonable period for the party to prepare its views, and
>
> (iii) an opportunity to present its views to the party having the duty to consult; and
>
> (b) by considering, fully and fairly, any views so presented.

Under YESAA, the amount of public participation and engagement required varies significantly depending on the type of assessment. Public participation is significantly greater in an Executive Committee screening scenario when compared to the level of participation required for a Designated Office evaluation. Scale of the project, the environmental sensitivity to the type of development, and level of public concerns also may dictate the degree of public participation required.

When reviewing the project proposal, the Yukon Environmental and Socio-economic Assessment Board (YESAB), will be most concerned that :

- Adequate consultation was conducted with all stakeholders
- The project team listened, fully and fairly considered, and responded to the issues raised during the consultation
- The project team made adjustments to the planning process or the project proposal as a result of the consultation where appropriate

Following submission of the Project Proposal, YESAB will conduct their formal First Nation and public consultation review process. During that process, the project team may be asked to respond to queries or concerns. The project team will continue meetings with all stakeholders and First Nation groups on ongoing issues as appropriate and public meetings may be held to provide further opportunities for participation.

5 ENGAGEMENT WITH FIRST NATIONS

The project will be located entirely within the traditional territory of the CAFN and they are the primary First Nations that will be engaged with regard to the Project. As they are a project partner it is likely that engagement with the CAFN community and leadership will take place in an ongoing fashion, with regular meetings and information updates to assess ongoing CAFN community support and to deepen the understanding of potential CAFN concerns. Dedicated presentations for CAFN members only (possibly in the various CAFN communities outside of Haines Junction) may also be held to encourage feedback and to ensure support.

While it is unlikely that the project will have an effect on the traditional territories of other First Nations, there is potential that the following First Nations and First Nations associations may express some interest in the Project and may request information:

- Carcross/Tagish First Nation
- Council of Yukon First Nations – Natural Resources and Environment
- Kluane First Nation
- Kwanlin Dun First Nation
- Little Salmon Carmacks First Nation
- Ta'an Kwäch'än Council
- White River First Nation

Letters introducing the project and project partners may be sent to those First Nations that express interest (or are likely to have an interest) in the Project. Meetings and/or follow-up phone calls may be necessary. A record of all communications and communication attempts will be maintained. The majority of communication with interested First Nations groups should be by letter or, alternatively, the details of verbal communications should be confirmed by letter to maintain an accurate record.

5.1 YESAA First Nations Consultation Requirements

YESAA, Section 50(3) states the following with respect to First Nations consultation:

> Before submitting a proposal to the Executive Committee, the proponent of a project shall consult any first nation in whose territory, or the residents of any community in which, the project will be located or might have significant environmental or social economic effects.

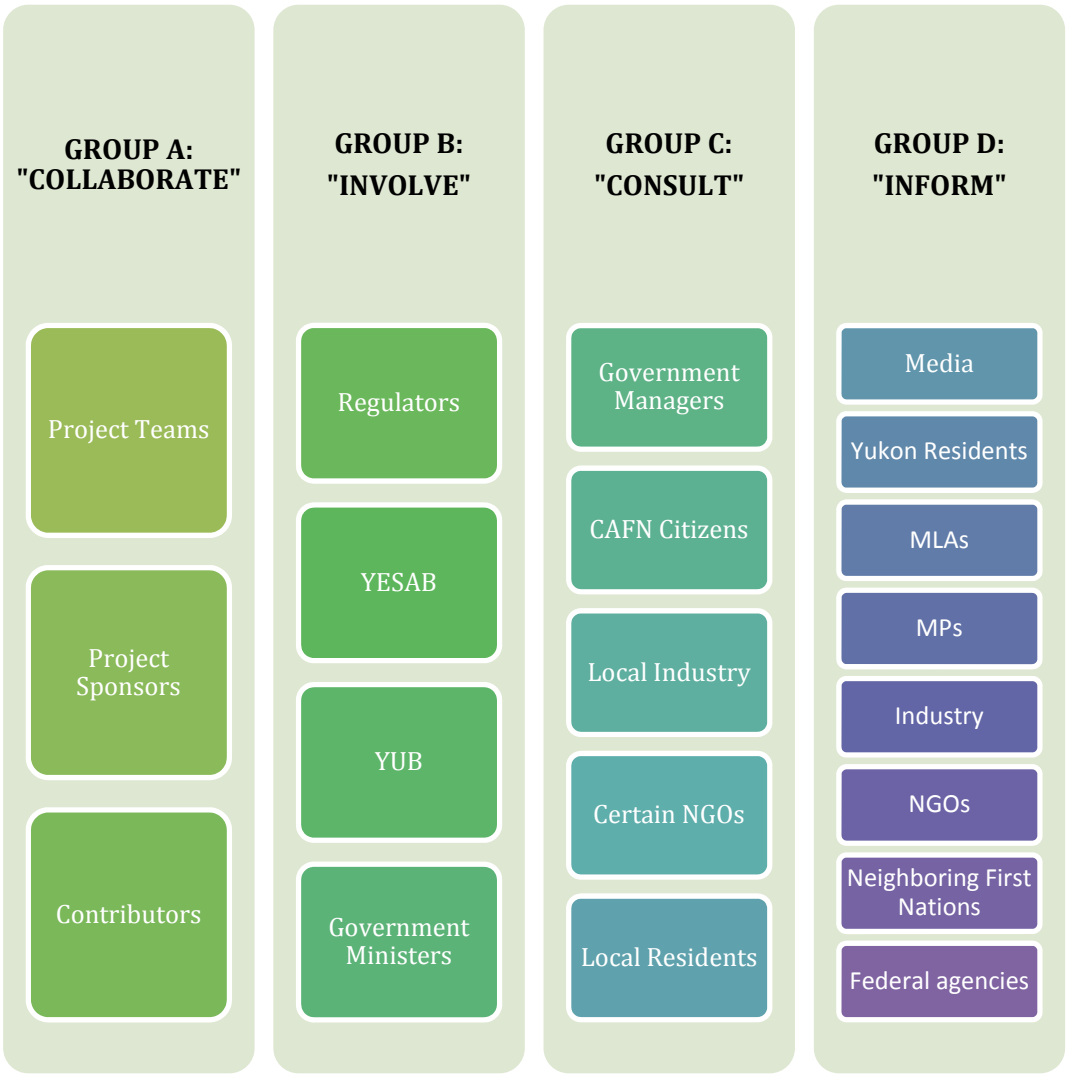
Under YESAA the knowledge and views of Yukon First Nations and their citizens will be sought out by regulators. Notification will be sent to all First Nations whose territory the project may be located on or where the project might have significant environmental or socio-economic effects. Renewable Resource Councils, Yukon Fish and Wildife Management Board and Salmon Sub-Committee will be notified if the Project may have environmental or socio-economic effects on areas or wildlife within their mandate. First Nations will have the opportunity to participate and share their views and information during the comment period for the assessment. YESAA also provides opportunities for

incorporation of traditional knowledge into the assessment of the Project and that traditional knowledge is a factor that must be considered and incorporated into the assessment.

6 LEVEL OF ENGAGEMENT AND PARTICIPATION

The level of engagement and participation in the Project by First Nations communities and stakeholders can be grouped as follows:

Figure 6.1: Engagement and Participation Levels



The following table describes the different stakeholder audiences, their projected engagement level, potential methods of engagement (this table will be updated and amended as needed)

Table 6.1: Audiences and Engagement Levels

Group	Engagement Level	Description	Audiences				
A	COLLABORATE	Stakeholders that are responsible for driving the Project (e.g. Project Sponsors, Project Management, Deputy Project Manager, Project Steering Committee, Project Contributors)	CAFN Dakwakada Development Corporation Yukon Energy Yukon Research Centre Cold Climate Innovation Village of Haines Junction				
B	INVOLVE	Stakeholders who have a high-level of engagement with the Project and are involved in the decision-making process	YESAB YUB Yukon Executive Council Office First Nation regulatory agencies(?) Government Ministers? Natural Resources Canada				
C	CONSULT	Stakeholders who need to have a good understanding of the Project and will be invited to provide input at critical points (e.g. Federal, Territorial, and FN Resource Management Agencies, FN citizens and local residents, industry, land users and owners, planning groups and committees, NGOs, ENGO)	CAFN citizens CAFN Resource Management Agencies Local Residents of Village of Haines Junction and surrounding area Potentially affected local land users and representative organizations Trappers Guide Outfitters Hunters (?) Nongovernmental Organizations Yukon Conservation Society		Territorial Government Resource Management Agencies Environment Yukon Yukon Highways and Public Works Yukon Energy, Mines and Resources Government of Canada Resource Management Agencies Canadian Northern Economic Development Agency (CanNor) Alsek Renewable Resource Council		
D	INFORM	Stakeholders who require a broad level of awareness of the project Stakeholders who may be influential or important	Yukon Residents Media MLAs MPs Research and Academic Yukon College, Northern Research Institute	Industry and Industry Associations Arctic Inland Building Products Dimok Timber Ltd. Tourism Industry Association Yukon Wilderness Tourism Association Yukon Outfitters Association Yukon Wood Products Association Whitehorse Chamber of Commerce Yukon Chamber of Commerce Oil and Gas interests Mining interests – Yukon Chamber of Mines Other Logging interests	First Nations (FN citizens, resource management agencies and leadership) Carcross/Tagish First Nation Council of Yukon First Nations – Natural Resources and Environment Kluane First Nation Kwanlin Dun First Nation Little Salmon Carmacks First Nation Ta'an Kwäch'än Council White River First Nation Nongovernmental Organizations Wildlife Conservation Society of Canada Council of Canadians Yukon Conservation Society Canadian Parks and Wilderness Society	Local Government and Local Government Associations City of Whitehorse (Mayor and Council) Village of Carmacks (Mayor and Council) Association of Yukon Communities Territorial Government Resource Management Agencies Yukon Government Climate Change Secretariat Yukon Health and Social Services Yukon Housing Corporation Yukon Land Use Planning Council Yukon Water Board Yukon Surface Rights Board Yukon Fish and Wildlife Management Board Porcupine Caribou Management Board Yukon Community Services Yukon Economic Development Government of Canada Resource Management Agencies Environment Canada	Nongovernmental Organizations Wildlife Conservation Society of Canada Council of Canadians Canadian Parks and Wilderness Society

7 ENGAGEMENT PROCESSES AND TIMELINES

The following table provides a list of key dates, events, techniques and audiences:

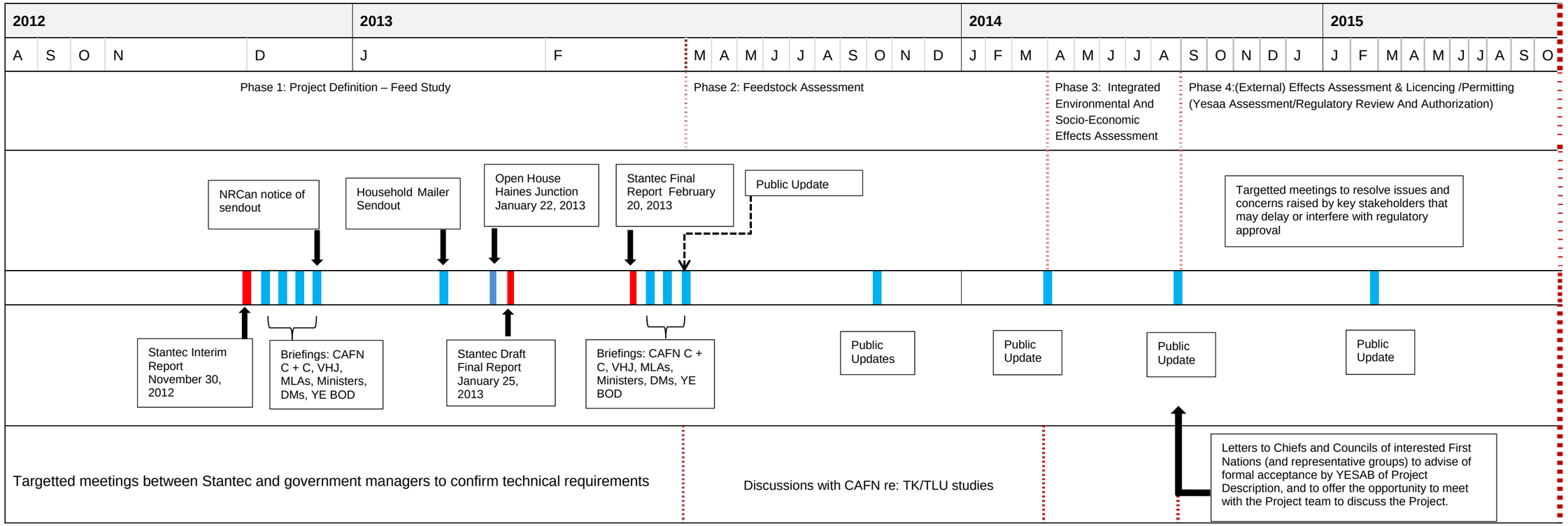
Table 7.1: Key Dates, Events and Audiences

Phase	Date	Event and Techniques	Key Audiences
PHASE 1	**AUGUST 2012 – MARCH 2013 BIOMASS TECHNOLOGY RESEARCH AND FEASIBILITY STUDY**		
	November 30, 2012 Stantec - Final Interim Report		
	Late November – December 2012	Briefings on Project Progress • Face to face meetings and targetted correspondence • Targetted meetings between government managers and Stantec to confirm technical requirements such as code requirements	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors Government managers
	November 30, 2012	• Newsletter Complete	All
	December 13, 2012	• Final proofs to Aasman for design and printing	n/a
	Mid-January 2013	• Newsletter mailout sent to Haines Junction area residents. Information also posted on various websites. Key Messages: • Project is in early stages – here's what is happening • Build awareness of Project and progress • Project Team is looking for input on how stakeholders want to be consulted moving forward and their issues and concerns	CAFN citizens, Haines Junction area residents, Stakeholders, General public
	January 25, 2013 Stantec Submits Draft of Final Report		
	January 22, 2013 5:30 p.m Da Ku Cultural Centre Haines Junction	Open House in Haines Junction • Build awareness and support for Project • Confirm/add to list of those interested in participating in engagement opportunities and receiving information • Confirm location preferences among stakeholders and community	CAFN citizens, Haines Junction area residents, Interested stakeholders, General public Key regulatory agencies should also be notified of the open houses via email, and invited to attend.
	February 20, 2013 ***** Stantec Submits Final Report *********		
	Late February 2013	Briefings on Project Progress and Final Report results • Face to face meetings and targetted correspondence	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors
**** DECISION POINT ****			
	Spring 2013	Communication update to key stakeholders and the public • Email/targeted correspondence Provide updated information on Project progress (on website etc.) • Methods of communication and messages can be determined based on final report (i.e. is this project a go or no go at this point).	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
PHASE 2	**2013/2014 FEEDSTOCK ASSESSMENT**		
	Fall 2013	Communication update to key stakeholders and the public • Email/targeted correspondence Provide updated information on Project progress (on website etc.)	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public

Section 7: Engagement Processes and Timelines

**** DECISION POINT ****			
PHASE 3	**2014 INTEGRATED ENVIRONMENTAL AND SOCIO-ECONOMIC EFFECTS ASSESSMENT**		
	Spring 2014	Communication with CAFN regarding traditional knowledge and traditional land use studies + capacity support. Communication update to key stakeholders and the public (email/targeted correspondence, provide updated information on Project progress (on website etc.)	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
**** DECISION POINT ****			
PHASE 4	**2014 – 2016 (EXTERNAL) EFFECTS ASSESSMENT & LICENCING /PERMITTING (YESAA ASSESSMENT/REGULATORY REVIEW AND AUTHORIZATION)**		
	Fall 2014	Communication update to key stakeholders and the public. • email/targeted correspondence and provide updated information on Project progress (on website etc.)	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
	Spring 2015	Communication update to key stakeholders and the public • email/targeted correspondence and provide updated information on Project progress (on website etc.)	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
	Fall 2015	• Communication update to key stakeholders and the public • Email/targeted correspondence • Face to face meetings or written correspondence to address specific issues and respond to queries and concerns that resut from the formal review process • Public meetings as required • Updated information on Project progress on website etc.	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
PHASE 5	**2016 DETAILED DESIGN AND TENDERING**		
	Spring 2016	Communication update to key stakeholders and the public • Email/targeted correspondence • Provide updated information on Project progress (on website etc.)	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
**** DECISION POINT ****			
PHASE 6	**2016+ CONSTRUCTION**		
	Fall 2016	Communication update to key stakeholders and public • email/targeted correspondence, provide updated information on Project progress	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
	Spring 2017	Communication update to key stakeholders and public • email/targeted correspondence and provide updated information on Project progress (on website etc.)	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
PHASE 7	**2016 + OPERATIONS**		
	Fall 2017	Communication update to key stakeholders and public • email/targeted correspondence and provide updated information on Project progress (on website etc.)	CAFN Chief and Council, Village of Haines Junction Mayor and Council, Kluane MLA, Ministers and DMs of Energy, Mines & Resources and Economic Development, Yukon Energy Board of Directors, CAFN citizens, Haines Junction area residents, General public
PHASE 8	**DECOMMISSIONING**		

Figure 7.1: Engagement Timelines



8 ENGAGEMENT METHODS

The following are techniques that may be used by the Project team to engage First Nations, stakeholders and the general public:

- Letters and email correspondence
- Face to face meetings
- Workshops and open houses
- Project information sheets and posters (distribute to local government offices, libraries, local recreational centres, community bulletin boards, schools, First Nation band offices
- Radio and television advertisements
- Media interviews
- Website and social media
- Advertisements in community newspapers

To cultivate relationships with First Nations and key stakeholders that have an active interest in the Project, meetings will be held to provide updates on the Project, discuss planned work, listen to concerns and assess areas of interest. The Project Team may also choose, where appropriate, to engage with particular First Nations and stakeholder groups in planning and conducting specific Project tasks.

8.1 Recording Communications

All feedback from First Nations and stakeholders will be tracked in a shared information management system (“Smartsheet”). Where follow-up communication is required, the responsibility for that communication will be clearly assigned to an individual and the name of the person who followed up will be recorded, along with when the communication happened, how it happened (e.g. email, telephone), and a brief description of the content of conversation/communication. Speeches and presentations will be documented in a similar manner; the identities of those who attended the event and the nature of feedback received will be documented. Where follow-up communication is required after the presentation or speech then the details of that communication will be documented and tracked.

Information on communications activities will be available on demand and the data will be regularly updated. Stantec recommendeds that a communications log modelled on the template found in Appendix B be used when documenting communications with First Nations, key stakeholders and the general public. The communications log should be accessible either by all members of the Project team so they are able to add their own data as they carry out engagement activities, or alternatively, by selected team members with responsibility for adding the information. Note that regular backing up and protection of engagement log contents from accidental deletion is essential. Stantec has agreed that it will be responsible for maintaining the log until January 30, 2013.

A “Record of Contact” form may also be used by team members to standardize recording of communications. A template for that form is attached as Appendix B.

8.2 Documenting Issues and Concerns

Issues may be recorded using a table similar to the following (new columns can be added where appropriate):

Table 8.1: Example Issue Log

Primary Issue	Potential Responses/Mitigations

8.3 Scheduled Meetings

Scheduled/completed meetings for the project are as follows (to be completed as dates are known):

Table 8.2: Meetings

Location	Date	Venue	Address

DRAFT

8.4 Open Houses

8.4.1 Timing

An introductory open house will be held in Haines Junction on January30, 2013 to introduce the Project, generate interest and inform First Nations citizens (particularly CAFN citizens), stakeholders and the general public. The following table will be revised as venues and dates are confirmed:

Table 8.3: Open Houses

Location	Date	Venue	Address
Haines Junction	January 22, 2013 (date moved to January 23, 2012 due to death of CAFN elder)	Da Ku Cultural Centre	280 Alaska Highway Haines Junction

8.4.2 Format and Materials

Project open houses will be staffed by members of the Project team, and potentially by representatives of the Project partners and Project consultants. Project representatives will be on hand to speak with attendees, present information, and answer questions from attendees.

Team members staffing the open house should discretely record comments, questions, and concerns from those in attendance on simple notepads when it is convenient. That information can then be transcribed into a more standardized record of contact form (see Appendix B for a record of contact form template) at a later date. We recommend that Team members not fill out forms while actually speaking to attendees.

Poster boards laid out within the venue can provide key information on aspects of the Project and Project Partners, preferred locations, preliminary designs, regulatory processes, potential interactions with the environment, key studies to be carried out and next steps.

The structure of the open houses should allow members of the public in attendance to speak with project representatives with expertise in particular subject areas of interest. Attending project team members should represent a wide range of technical expertise so that detailed and/or technical questions can be answered in person, wherever possible. This will reduce the need for follow-up communications and increase the likelihood that the open house will lead to greater understanding of the Project and spread of reliable and correct information throughout the community by attendees.

Materials required will include:

- Project information sheets
- Sign-up sheets
- Comments cards

Stantec recommends the use of draw prizes or other incentives at open houses. Prizes can enhance interest, boost attendance, encourage attendees to provide contact information, and increase the likelihood that attendees will stay longer and provide more comments and questions.

8.4.3 Recording Attendance

A “welcome” table will be placed inside the entrance of each open house and will be staffed by Project team members who are responsible for tracking attendance. Attendees will be asked to sign in and provide email addresses or other contact information (so that they can be added to Project newsletter, information mailing list etc.). Signing in should not be required, however. Project team members should also maintain an overall head count of all attendees and keep a record of total attendance.

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9 ENGAGEMENT PERFORMANCE MEASURES

The Project's engagement processes should be evaluated using both objective and subjective measures. Relevant measures include the following:

- Number of specific meetings, open houses and other engagement sessions with interested First Nations, key stakeholders and representative local organizations (e.g. non-profit organizations, advocacy groups)
- Website traffic statistics (e.g. number of visits, frequency, duration, etc.)
- Quantity and quality of dialogue generated (letters, comments, discussion on project website and external discussions)
- Number of public events held and attendance level at those events, presentations or workshops provided, inquiries received concerning the Project, brochures/flyers distributed, subscribers to website and/or newsletter, articles or columns in local newspapers, radio/tv spots, and radio/tv interviews

These statistics should be tabulated and included in the Project reporting, along with other indicators as part of the summary of engagement necessary for any future project proposal for assessment pursuant to YESAA

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APPENDIX A

Communication Log Template

DRAFT Yukon BioMass FEED Study - Public and First Nations Engagement Plan

Communication Number	Confidential (Yes/No)	Communication Date	Communication Location	Project Team Member Contact	Communication Method	Individual Contact Name/Contact Information	Aboriginal Group or Stakeholder Group Name	Group Type	Project Phase	Issues	Communication Summary	Outcomes (e.g. information exchange, engagement discussions,	Documents Distributed	Follow Up Action? (Action/Lead/Deadline/ Completed?)	Add to Mailing List?

DRAFT

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APPENDIX B

Record of Contact Form (Example)

YUKON BIOMASS FEED STUDY PROJECT

Record of Contact Form (Confidential? ☐ Yes ☐ No)

Date: Pick from Calendar **Location:** Enter Location of contact

PROJECT TEAM CONTACT

Name: **Organization:** Enter Project Team Organization

COMMUNICATION METHOD

☐ Telephone – incoming ☐ Telephone – outgoing ☐ Group Meeting/Event[1]

☐ E-Mail Received ☐ E-mail Sent ☐ In-Person Conversation

☐ Letter/Fax Received ☐ Letter/Fax Sent

☐ Other (specify): Specify contact method

EXTERNAL CONTACT INFORMATION

First Name: Enter First Name Last Name: Enter Last Name

Role/Position: Enter Role/Position if applicable Organization: Enter Organization if applicable

Address:
Enter Address Here

City / Town: Enter City / Town | Province: Pick from List | Postal Code: Enter Postal Code

Business No: Enter Business Phone No. Cell No: Enter Cellphone No. Home No Enter Home Phone No.:

Fax: Enter Fax Number E-mail: Enter E-mail Address

Add to Project Mailing List:
☐ Yes ☐ No

Contact information for other external contacts: *(list any other participants & information here)*
Enter other external contacts information

[1] A separate meeting note / event record template can be created for documenting events other than individual communications. Copies of completed forms should be retained in the files of the responsible organization.

Group Type (*Please check all that apply):*

☐ First Nation	☐ Business	☐ Research and Academic
☐ Federal Government/Agency	☐ Industry Association	☐ Media
☐ Territorial Government/Agency	☐ Citizen/Resident Association	☐ General Public
☐ Local Government/Agency	☐ Non-Government Organization	☐ Other (specify):
☐ Local Authority	☐ Environmental NGO	Specify other group type
	☐ Special Interest	

PROJECT COMPONENT / PHASE

Project Phase or Component:

☐ Pre-Application ☐ Application Review ☐ Regulatory Approvals (if applicable)

ISSUES (*IMPORTANT: Please check all that apply)*

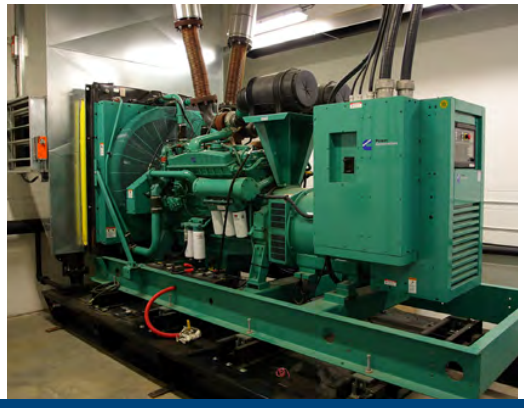
Issues Categories

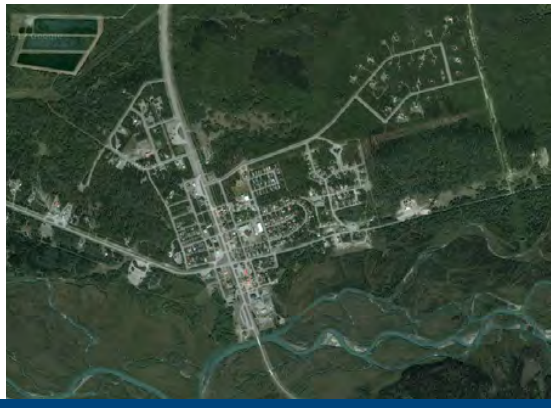
☐ Aboriginal Engagement	☐ Human Health/Risk Management
☐ Public/Stakeholder Engagement	☐ Land Use
☐ Water Resources	☐ Traditional Land Use
☐ Forestry	☐ Traditional Knowledge
☐ Vegetation	☐ Environmental Assessment Methodology
☐ Terrestrial Wildlife	☐ Environmental Assessment Process/Products
☐ Surface Geology, Soils and Terrain	☐ Documentation
☐ Reclamation	☐ Regulatory
☐ Air Quality	☐ Project Components
☐ Meteorology and Climate	☐ Project Phases/Schedule
☐ Noise and Vibration	☐ Legacy Issues
☐ Archaeological Resources	☐ Project Benefits
☐ Heritage Resources	☐ Negotiated Agreements/Commitments
☐ Socio-Cultural	
☐ Employment and Economic Opportunities	

DRAFT Yukon BioMass FEED Study - Public and First Nations Engagement Plan

Appendix B – Communication Log Template

Contact Notes / Staff Response *Summary of the discussion/specific issues* Enter Contact Notes / Staff Response				
Documents Distributed *List the documents (title, date, author)* Enter Documents Distributed				
Follow-up Action Required *IMPORTANT: Please list date of action to be completed and party responsible for follow-up action*	Follow-up action required? ☐ Yes ☐ No			
	Action	**Lead**	**Deadline**	**Complete?**
Form Completed by*:* May be same as "Project Team Contact"			Date Form Completed: Pick from Calendar	
Distribution / Copies To: Enter text here		Input to Communications Log: ☐ Yes ☐ No Date Entered to Communications Log: Pick from Calendar		





APPENDIX J

Financials

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

This document has been prepared exclusively for the client and the project identified herein.
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.

ASSUMPTIONS - OPTION 1 (0.5 MW)

INPUT IN SHADED CELLS ONLY yellow cells indicate awaiting final numbers from engineering

CAPITAL:

District heating, installed cost		*not included*
Biomass plant, installed cost	$6,307,949	
Total plant etc.	$6,307,949	*see 'Capital Costs' worksheet*
ORC	$194,235	
Feedstock yard		
Land	$0	*see 'Capital Costs' worksheet*
Buildings	$2,983,204	*see 'Capital Costs' worksheet*
Equipment	$2,278,988	*see 'Capital Costs' worksheet*
Total capital requirement	$11,764,376	
Capital renewal - annual rate		
Plant	4.0%	*% of original capex, starting in year 4 - assume 25 year life*
Buildings	2.0%	*% of original capex, starting in year 4 - assume 50 year life*
Equipment	6.0%	*% of original capex, starting in year 4 - assume 15 year life*

OPERATING:

Revenues

Total annual sales - kWh	3,504,000	*500kWe, 80% availability*
Electricity selling price - $/kWh	$0.200	per CAFN (Ray)
ORC Electricity sales - kWh	258361	*@ 8% of remaining heat*
District heat annual sales - kWh	1,283,645	*Revised DE Network*
Heat selling price - $/kWh	$0.185	*per CTCG*
Government subsidies - $/kWh	$0.00	

Expenses

O&M expenses - plant - $ / kWh		
O&M expenses - yard - $ / kWh		
O&M expenses - district heat - $	$37,000	*per CTCG*
O&M ORC	$5,938	*per CTCG*
O&M Plant	$242,000	*per FEED report*
Feedstock - $/tonne	$50.40	*per FEED report*

Production factor - tonnes/kWh	0.00086		*1 kg (.001 tonne) per hour = 1 kWh*
Fuel cost per kWh	$0.04		
Amortization (CCA) - annual rate			
Plant	50.0%		*Accelerated CCA class 43.2, see below*
Buildings	4.0%		*CCA class 1*
Equipment	30.0%		*CCA class 43*
Income tax - combined rate	35.0%		
FINANCIAL:			
Grant money	67%	$7,882,132	
Capitalization			
Debt %	70%	$2,717,571	per CAFN (Ray)
Equity %	30%	$1,164,673	per CAFN (Ray)
Total capital funding		$11,764,376	ok
Ownership			
CAFN	60%	$698,804	per CAFN (Ray)
Yukon Energy	30%	$349,402	per CAFN (Ray)
Village of Haines Junction	10%	$116,467	per CAFN (Ray)
	100%	$1,164,673	
Long term debt			
Interest rate	5.0%		
Debt term, in years	20		
ROI requirements - after tax			
CAFN	15%		per CAFN (Ray)
Yukon Energy	15%		per CAFN (Ray)
Village of Haines Junction	15%		per CAFN (Ray)
WACC - after tax	8.00%		
Annual inflation rate	3.0%		*assumes same rate for both operating and capital expenditures*
Terminal (perpetuity) value multiple	20.0		*Terminal Value = FCF (yr 20)/(WACC – growth rate) : assumes growth rate = inflation rate*
Feedstock inflation rate	1%		

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Yukon

Corporate income tax rates (for December 31, 2012 year ends)

General (non M&P)	M&P	CCPC		Investment income
		Active business income to $500,000		
		Non-M&P	M&P	
15 **30**	2.5 **17.5**	4 **15**	2.5 **13.5**	15 **49.67**

Figures in **bold** are combined federal/territorial rates.

Other 2012 rates

Capital tax	None
Payroll tax	
Sales tax	

Additional highlights

No additional significant corporate tax changes were announced.

http://www.budget.gc.ca/2010/plan/anx5-eng.html#a27

Accelerated CCA for Clean Energy Generation

Class 43.2 was introduced in 2005 and is currently available for assets acquired on or after February 23, 2005 and before 2020. For assets acquired before February 23, 2005, accelerated CCA is provided under Class 43.1 (30 per cent). The eligibility criteria for these two classes are generally the same, except that cogeneration systems that use fossil fuels must meet a higher efficiency standard for Class 43.2 than for Class 43.1. Systems that only meet the lower efficiency standard are eligible for Class 43.1.

Class 43.2 includes a variety of stationary clean energy generation or conservation equipment that is used to produce electricity or thermal energy, or used to produce certain fuels from waste that are in turn used to produce electricity or thermal energy. Subject to detailed rules in the regulations, eligible equipment includes:

ELECTRICITY

- High efficiency cogeneration equipment;
- Wind turbines;
- Small hydroelectric facilities;
- Fuel cells;
- Photovoltaic equipment;
- Wave and tidal power equipment;
- Equipment that generates electricity using geothermal energy; and
- Equipment that generates electricity using an eligible waste fuel.

THERMAL ENERGY

- Active solar equipment;
- Ground source heat pump equipment;
- District energy equipment that distributes thermal energy from cogeneration;
- Equipment that generates heat for an industrial process or a greenhouse using an eligible waste fuel; and
- Heat recovery equipment used in electricity generation and industrial processes.

FUELS FROM WASTE

- Equipment that recovers landfill gas or digester gas;
- Equipment used to convert biomass into bio-oil; and
- Equipment used to produce biogas through anaerobic digestion.

If the majority of tangible property in a project is eligible for inclusion in Class 43.2, then certain intangible project start-up expenses (for example, engineering and design work and feasibility studies) are treated as Canadian Renewable and Conservation Expenses. These expenses may be deducted in full in the year incurred, carried forward indefinitely for use in future years, or transferred to investors using flow-through shares.

Budget 2010 proposes to expand Class 43.2 to include: (a) heat recovery equipment used i a broader range of applications; and (b) distribution equipment used in district energy systems that rely primarily on ground source heat pumps, active solar systems or heat recovery equipment.

NEWCO CASH FLOW PROJECTION OPTION 1 - 0.5 MW PLANT (NEWCO OWNED / ISP OPERATED)	TOTAL NPV	CONSTRUCTION Year 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
REVENUE																							
Electricity sales	$8,187,383		$721,824	$743,479	$765,783	$788,757	$812,419	$836,792	$861,896	$887,752	$914,385	$941,817	$970,071	$999,173	$1,029,148	$1,060,023	$1,091,824	$1,124,578	$1,158,316	$1,193,065	$1,228,857	$1,265,723	
ORC Electricity	$651,975		$53,222	$54,819	$56,464	$58,157	$59,902	$61,699	$63,550	$65,457	$67,420	$69,443	$71,526	$73,672	$75,882	$78,159	$80,503	$82,919	$85,406	$87,968	$90,607	$93,326	
District heat sales	$2,774,391		$244,599	$251,937	$259,495	$267,279	$275,298	$283,557	$292,063	$300,825	$309,850	$319,146	$328,720	$338,582	$348,739	$359,201	$369,977	$381,077	$392,509	$404,284	$416,413	$428,905	
Total revenue	**$11,613,749**	**$0**	**$1,019,645**	**$1,050,234**	**$1,081,741**	**$1,114,193**	**$1,147,619**	**$1,182,048**	**$1,217,509**	**$1,254,035**	**$1,291,656**	**$1,330,405**	**$1,370,317**	**$1,411,427**	**$1,453,770**	**$1,497,383**	**$1,542,304**	**$1,588,573**	**$1,636,231**	**$1,685,318**	**$1,735,877**	**$1,787,953**	
EXPENSE																							
Operations & maintenance - biomass	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Operations & maintenance - district heat	($432,268)		($38,110)	($39,253)	($40,431)	($41,644)	($42,893)	($44,180)	($45,505)	($46,870)	($48,277)	($49,725)	($51,217)	($52,753)	($54,336)	($55,966)	($57,645)	($59,374)	($61,155)	($62,990)	($64,880)	($66,826)	
Operations & maintenance - ORC	($74,919)		($6,116)	($6,299)	($6,488)	($6,683)	($6,883)	($7,090)	($7,303)	($7,522)	($7,747)	($7,980)	($8,219)	($8,466)	($8,720)	($8,981)	($9,251)	($9,528)	($9,814)	($10,109)	($10,412)	($10,724)	
Administration expense	($2,827,264)		($249,260)	($256,738)	($264,440)	($272,373)	($280,544)	($288,961)	($297,629)	($306,558)	($315,755)	($325,228)	($334,985)	($345,034)	($355,385)	($366,047)	($377,028)	($388,339)	($399,989)	($411,989)	($424,348)	($437,079)	
Fuel (feedstock)	($1,492,889)		($152,887)	($154,415)	($155,960)	($157,519)	($159,094)	($160,685)	($162,292)	($163,915)	($165,554)	($167,210)	($168,882)	($170,571)	($172,276)	($173,999)	($175,739)	($177,497)	($179,271)	($181,064)	($182,875)	($184,704)	
Amortization	($10,433,788)		($1,978,500)	($3,063,564)	($1,701,804)	($1,174,753)	($900,949)	($758,839)	($686,212)	($650,955)	($636,312)	($633,415)	($637,489)	($645,911)	($657,206)	($670,522)	($685,358)	($701,412)	($718,499)	($736,507)	($755,365)	($775,034)	
Total expense	**($15,261,129)**		**($2,424,872)**	**($3,520,270)**	**($2,169,122)**	**($1,652,972)**	**($1,390,364)**	**($1,259,755)**	**($1,198,941)**	**($1,175,821)**	**($1,173,645)**	**($1,183,557)**	**($1,200,792)**	**($1,222,735)**	**($1,247,923)**	**($1,275,515)**	**($1,305,021)**	**($1,336,150)**	**($1,368,730)**	**($1,402,658)**	**($1,437,880)**	**($1,474,367)**	
EARNINGS BEFORE INTEREST & TAXES	**($3,647,379)**		**($1,405,227)**	**($2,470,036)**	**($1,087,381)**	**($538,778)**	**($242,745)**	**($77,707)**	**$18,568**	**$78,214**	**$118,010**	**$146,848**	**$169,526**	**$188,692**	**$205,847**	**$221,868**	**$237,284**	**$252,424**	**$267,501**	**$282,659**	**$297,997**	**$313,586**	
Less: Income taxes	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Add: Amortization	$10,433,788		$1,978,500	$3,063,564	$1,701,804	$1,174,753	$900,949	$758,839	$686,212	$650,955	$636,312	$633,415	$637,489	$645,911	$657,206	$670,522	$685,358	$701,412	$718,499	$736,507	$755,365	$775,034	
Add: Government (NRCan) capital funding	$7,298,271	**$7,882,132**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Capital expenditures	($10,892,941)	**($11,764,376)**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Annual capital renewal	($4,107,814)		$0	$0	$0	($505,040)	($520,191)	($535,797)	($551,871)	($568,427)	($585,480)	($603,044)	($621,135)	($639,769)	($658,962)	($678,731)	($699,093)	($720,066)	($741,668)	($763,918)	($786,836)	($810,441)	
Add: Terminal value of free cash flow at year 20	$1,023,371		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,563,599
Add: PV of unused tax losses at year 20	$515,281		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,801,345
FREE CASH FLOW	**($916,075)**	**($3,882,244)**	**$573,272**	**$593,528**	**$614,423**	**$130,935**	**$138,013**	**$145,335**	**$152,909**	**$160,742**	**$168,843**	**$177,219**	**$185,880**	**$194,834**	**$204,090**	**$213,659**	**$223,548**	**$233,770**	**$244,333**	**$255,248**	**$266,527**	**$278,180**	
CUMULATIVE FREE CASH FLOW		**($3,882,244)**	**($3,308,972)**	**($2,715,443)**	**($2,101,021)**	**($1,970,086)**	**($1,832,073)**	**($1,686,738)**	**($1,533,829)**	**($1,373,087)**	**($1,204,244)**	**($1,027,025)**	**($841,145)**	**($646,311)**	**($442,221)**	**($228,562)**	**($5,014)**	**$228,756**	**$473,088**	**$728,336**	**$994,863**	**$1,273,043**	

	IRR	ROI
	3.4%	**-4.6%**
Simple Payback	**1600.0%**	**Years**

Income tax calculations:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Earnings before interest and taxes	($1,405,227)	($2,470,036)	($1,087,381)	($538,778)	($242,745)	($77,707)	$18,568	$78,214	$118,010	$146,848	$169,526	$188,692	$205,847	$221,868	$237,284	$252,424	$267,501	$282,659	$297,997	$313,586
Deduct: Interest expense on LTD	($411,753)	($399,301)	($386,226)	($372,497)	($358,081)	($342,945)	($327,052)	($310,365)	($292,843)	($274,445)	($255,127)	($234,843)	($213,545)	($191,183)	($167,702)	($143,047)	($117,159)	($89,976)	($61,435)	($31,467)
Net taxable income (loss)	($1,816,980)	($2,869,337)	($1,473,607)	($911,275)	($600,826)	($420,653)	($308,485)	($232,151)	($174,833)	($127,597)	($85,601)	($46,152)	($7,698)	$30,686	$69,582	$109,377	$150,342	$192,683	$236,562	$282,119
Income taxes payable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,740	$24,354	$38,282	$52,620	$67,439	$82,797	$98,742
Less: Prior year tax losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10,740)	($24,354)	($38,282)	($52,620)	($67,439)	($82,797)	($98,742)
Net tax payable	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unused tax losses, opening balance	$0	$635,943	$1,640,211	$2,155,973	$2,474,920	$2,685,209	$2,832,437	$2,940,407	$3,021,660	$3,082,851	$3,127,510	$3,157,470	$3,173,624	$3,176,318	$3,165,578	$3,141,224	$3,102,942	$3,050,323	$2,982,884	$2,900,087
Income tax losses - current year	$635,943	$1,004,268	$515,762	$318,946	$210,289	$147,228	$107,970	$81,253	$61,191	$44,659	$29,960	$16,153	$2,694	$0	$0	$0	$0	$0	$0	$0
Tax losses applied during the year	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10,740)	($24,354)	($38,282)	($52,620)	($67,439)	($82,797)	($98,742)
Unused tax losses - cumulative	**$635,943**	**$1,640,211**	**$2,155,973**	**$2,474,920**	**$2,685,209**	**$2,832,437**	**$2,940,407**	**$3,021,660**	**$3,082,851**	**$3,127,510**	**$3,157,470**	**$3,173,624**	**$3,176,318**	**$3,165,578**	**$3,141,224**	**$3,102,942**	**$3,050,323**	**$2,982,884**	**$2,900,087**	**$2,801,345**

ASSUMPTIONS - OPTION 2 (0.5 MW)

INPUT IN SHADED CELLS ONLY yellow cells indicate awaiting final numbers from engineering

CAPITAL:

District heating, installed cost		*not included*
Biomass plant, installed cost	$6,324,410	
Total plant etc.	$6,324,410	*see 'Capital Costs' worksheet*
ORC	$194,235	
Feedstock yard		
Land	$0	*see 'Capital Costs' worksheet*
Buildings	$3,658,073	*see 'Capital Costs' worksheet*
Equipment	$2,284,935	*see 'Capital Costs' worksheet*
Total capital requirement	$12,461,654	
Capital renewal - annual rate		
Plant	4.0%	*% of original capex, starting in year 4 - assume 25 year life*
Buildings	2.0%	*% of original capex, starting in year 4 - assume 50 year life*
Equipment	6.0%	*% of original capex, starting in year 4 - assume 15 year life*

OPERATING:

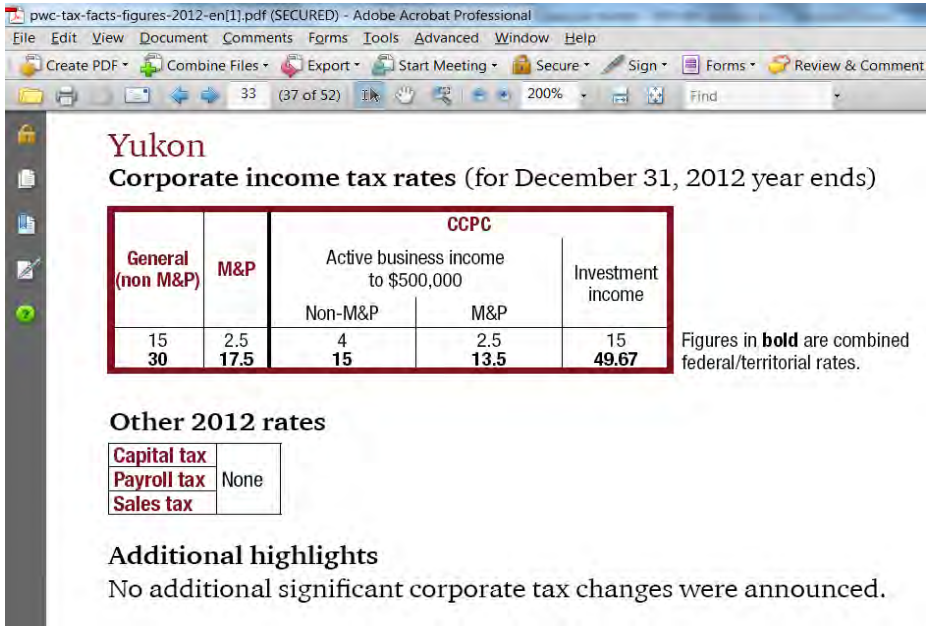
Revenues

Total annual sales - kWh	3,504,000	*500kWe, 80% availability*
Electricity selling price - $/kWh	$0.200	per CAFN (Ray)
ORC Electricity sales - kWH	258361	*@ 8% of remaining heat*
District heat annual sales - kWh	1,283,645	*Revised DE Network*
Heat selling price - $/kWh	$0.185	*per CTCG*
Government subsidies - $/kWh	$0.00	

Expenses

O&M expenses - plant - $ / kWh		
O&M expenses - yard - $ / kWh		
O&M expenses - district heat - $	$37,000	*per CTCG*
O&M ORC	$5,938	*per CTCG*
O&M Plant	$242,000	*per FEED report*
Feedstock - $/tonne	$50.40	*per FEED report*

Production factor - tonnes/kWh	0.00086		*1 kg (.001 tonne) per hour = 1 kWh*
Fuel cost per kWh	$0.04		
Amortization (CCA) - annual rate			
Plant	50.0%		*Accelerated CCA class 43.2, see below*
Buildings	4.0%		*CCA class 1*
Equipment	30.0%		*CCA class 43*
Income tax - combined rate	35.0%		
FINANCIAL:			
Grant money	67%	$8,349,308	
Capitalization			
Debt %	70%	$2,878,642	per CAFN (Ray)
Equity %	30%	$1,233,704	per CAFN (Ray)
Total capital funding		$12,461,654	ok
Ownership			
CAFN	60%	$740,222	per CAFN (Ray)
Yukon Energy	30%	$370,111	per CAFN (Ray)
Village of Haines Junction	10%	$123,370	per CAFN (Ray)
	100%	$1,233,704	
Long term debt			
Interest rate	5.0%		
Debt term, in years	20		
ROI requirements - after tax			
CAFN	15%		per CAFN (Ray)
Yukon Energy	15%		per CAFN (Ray)
Village of Haines Junction	15%		per CAFN (Ray)
WACC - after tax	8.00%		
Annual inflation rate	3.0%		*assumes same rate for both operating and capital expenditures*
Terminal (perpetuity) value multiple	20.0		*Terminal Value = FCF (yr 20)/(WACC – growth rate) : assumes growth rate = inflation rate*
Feedstock inflation rate	1%		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33 (37 of 52) 200% Find

Yukon

Corporate income tax rates (for December 31, 2012 year ends)

General (non M&P)	M&P	CCPC		
		Active business income to $500,000		Investment income
		Non-M&P	M&P	
15 **30**	2.5 **17.5**	4 **15**	2.5 **13.5**	15 **49.67**

Figures in **bold** are combined federal/territorial rates.

Other 2012 rates

Capital tax	None
Payroll tax	
Sales tax	

Additional highlights

No additional significant corporate tax changes were announced.

http://www.budget.gc.ca/2010/plan/anx5-eng.html#a27

Accelerated CCA for Clean Energy Generation

Class 43.2 was introduced in 2005 and is currently available for assets acquired on or after February 23, 2005 and before 2020. For assets acquired before February 23, 2005, accelerated CCA is provided under Class 43.1 (30 per cent). The eligibility criteria for these two classes are generally the same, except that cogeneration systems that use fossil fuels must meet a higher efficiency standard for Class 43.2 than for Class 43.1. Systems that only meet the lower efficiency standard are eligible for Class 43.1.

Class 43.2 includes a variety of stationary clean energy generation or conservation equipment that is used to produce electricity or thermal energy, or used to produce certain fuels from waste that are in turn used to produce electricity or thermal energy. Subject to detailed rules in the regulations, eligible equipment includes:

ELECTRICITY

- High efficiency cogeneration equipment;
- Wind turbines;
- Small hydroelectric facilities;
- Fuel cells;
- Photovoltaic equipment;
- Wave and tidal power equipment;
- Equipment that generates electricity using geothermal energy; and
- Equipment that generates electricity using an eligible waste fuel.

THERMAL ENERGY

- Active solar equipment;
- Ground source heat pump equipment;
- District energy equipment that distributes thermal energy from cogeneration;
- Equipment that generates heat for an industrial process or a greenhouse using an eligible waste fuel; and
- Heat recovery equipment used in electricity generation and industrial processes.

FUELS FROM WASTE

- Equipment that recovers landfill gas or digester gas;
- Equipment used to convert biomass into bio-oil; and
- Equipment used to produce biogas through anaerobic digestion.

If the majority of tangible property in a project is eligible for inclusion in Class 43.2, then certain intangible project start-up expenses (for example, engineering and design work and feasibility studies) are treated as Canadian Renewable and Conservation Expenses. These expenses may be deducted in full in the year incurred, carried forward indefinitely for use in future years, or transferred to investors using flow-through shares.

Budget 2010 proposes to expand Class 43.2 to include: (a) heat recovery equipment used i a broader range of applications; and (b) distribution equipment used in district energy systems that rely primarily on ground source heat pumps, active solar systems or heat recovery equipment.

NEWCO CASH FLOW PROJECTION
OPTION 2 - 0.5 MW PLANT
(NEWCO OWNED / ISP OPERATED)

	TOTAL NPV	CONSTRUCTION Year 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
REVENUE																							
Electricity sales	$8,187,383		$721,824	$743,479	$765,783	$788,757	$812,419	$836,792	$861,896	$887,752	$914,385	$941,817	$970,071	$999,173	$1,029,148	$1,060,023	$1,091,824	$1,124,578	$1,158,316	$1,193,065	$1,228,857	$1,265,723	
ORC Electricity	$651,975		$53,222	$54,819	$56,464	$58,157	$59,902	$61,699	$63,550	$65,457	$67,420	$69,443	$71,526	$73,672	$75,882	$78,159	$80,503	$82,919	$85,406	$87,968	$90,607	$93,326	
District heat sales	$2,774,391		$244,599	$251,937	$259,495	$267,279	$275,298	$283,557	$292,063	$300,825	$309,850	$319,146	$328,720	$338,582	$348,739	$359,201	$369,977	$381,077	$392,509	$404,284	$416,413	$428,905	
Total revenue	**$11,613,749**	**$0**	**$1,019,645**	**$1,050,234**	**$1,081,741**	**$1,114,193**	**$1,147,619**	**$1,182,048**	**$1,217,509**	**$1,254,035**	**$1,291,656**	**$1,330,405**	**$1,370,317**	**$1,411,427**	**$1,453,770**	**$1,497,383**	**$1,542,304**	**$1,588,573**	**$1,636,231**	**$1,685,318**	**$1,735,877**	**$1,787,953**	
EXPENSE																							
Operations & maintenance - biomass	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Operations & maintenance - district heat	($432,268)		($38,110)	($39,253)	($40,431)	($41,644)	($42,893)	($44,180)	($45,505)	($46,870)	($48,277)	($49,725)	($51,217)	($52,753)	($54,336)	($55,966)	($57,645)	($59,374)	($61,155)	($62,990)	($64,880)	($66,826)	
Operations & maintenance - ORC	($74,919)		($6,116)	($6,299)	($6,488)	($6,683)	($6,883)	($7,090)	($7,303)	($7,522)	($7,747)	($7,980)	($8,219)	($8,466)	($8,720)	($8,981)	($9,251)	($9,528)	($9,814)	($10,109)	($10,412)	($10,724)	
Administration expense	($2,827,264)		($249,260)	($256,738)	($264,440)	($272,373)	($280,544)	($288,961)	($297,629)	($306,558)	($315,755)	($325,228)	($334,985)	($345,034)	($355,385)	($366,047)	($377,028)	($388,339)	($399,989)	($411,989)	($424,348)	($437,079)	
Fuel (feedstock)	($1,492,889)		($152,887)	($154,415)	($155,960)	($157,519)	($159,094)	($160,685)	($162,292)	($163,915)	($165,554)	($167,210)	($168,882)	($170,571)	($172,276)	($173,999)	($175,739)	($177,497)	($179,271)	($181,064)	($182,875)	($184,704)	
Amortization	($10,667,591)		($1,997,004)	($3,097,709)	($1,731,348)	($1,202,519)	($927,631)	($784,815)	($711,694)	($676,073)	($661,152)	($658,037)	($661,942)	($670,236)	($681,437)	($694,695)	($709,504)	($725,562)	($742,684)	($760,754)	($779,704)	($799,494)	
Total expense	**($15,494,932)**		**($2,443,377)**	**($3,554,415)**	**($2,198,667)**	**($1,680,738)**	**($1,417,046)**	**($1,285,730)**	**($1,224,424)**	**($1,200,939)**	**($1,198,485)**	**($1,208,179)**	**($1,225,244)**	**($1,247,059)**	**($1,272,154)**	**($1,299,688)**	**($1,329,167)**	**($1,360,300)**	**($1,392,914)**	**($1,426,906)**	**($1,462,219)**	**($1,498,827)**	
EARNINGS BEFORE INTEREST & TAXES	**($3,881,182)**		**($1,423,732)**	**($2,504,180)**	**($1,116,926)**	**($566,544)**	**($269,427)**	**($103,683)**	**($6,914)**	**$53,095**	**$93,171**	**$122,226**	**$145,073**	**$164,368**	**$181,615**	**$197,695**	**$213,137**	**$228,273**	**$243,317**	**$258,412**	**$273,658**	**$289,127**	
Less: Income taxes	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Add: Amortization	$10,667,591		$1,997,004	$3,097,709	$1,731,348	$1,202,519	$927,631	$784,815	$711,694	$676,073	$661,152	$658,037	$661,942	$670,236	$681,437	$694,695	$709,504	$725,562	$742,684	$760,754	$779,704	$799,494	
Add: Government (NRCan) capital funding	$7,730,841	**$8,349,308**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Capital expenditures	($11,538,568)	**($12,461,654)**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Annual capital renewal	($4,240,670)		$0	$0	$0	($521,374)	($537,015)	($553,126)	($569,719)	($586,811)	($604,415)	($622,548)	($641,224)	($660,461)	($680,275)	($700,683)	($721,703)	($743,355)	($765,655)	($788,625)	($812,284)	($836,652)	
Add: Terminal value of free cash flow at yea	$926,944		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,039,370
Add: PV of unused tax losses at year 20	$566,824		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,081,560
FREE CASH FLOW	**($1,261,988)**	**($4,112,346)**	**$573,272**	**$593,528**	**$614,423**	**$114,600**	**$121,189**	**$128,006**	**$135,060**	**$142,358**	**$149,907**	**$157,715**	**$165,791**	**$174,142**	**$182,778**	**$191,707**	**$200,938**	**$210,481**	**$220,345**	**$230,541**	**$241,079**	**$251,969**	
CUMULATIVE FREE CASH FLOW		**($4,112,346)**	**($3,539,073)**	**($2,945,545)**	**($2,331,122)**	**($2,216,522)**	**($2,095,333)**	**($1,967,327)**	**($1,832,266)**	**($1,689,908)**	**($1,540,001)**	**($1,382,286)**	**($1,216,495)**	**($1,042,353)**	**($859,575)**	**($667,868)**	**($466,930)**	**($256,449)**	**($36,103)**	**$194,438**	**$435,516**	**$687,485**	

IRR	ROI
1.8%	**-6.2%**

Simple Payback **18** Years

Income tax calculations:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Earnings before interest and taxes	($1,423,732)	($2,504,180)	($1,116,926)	($566,544)	($269,427)	($103,683)	($6,914)	$53,095	$93,171	$122,226	$145,073	$164,368	$181,615	$197,695	$213,137	$228,273	$243,317	$258,412	$273,658	$289,127
Deduct: Interest expense on LTD	($436,158)	($422,967)	($409,117)	($394,575)	($379,305)	($363,272)	($346,437)	($328,760)	($310,200)	($290,712)	($270,249)	($248,763)	($226,202)	($202,514)	($177,641)	($151,525)	($124,103)	($95,309)	($65,076)	($33,332)
Net taxable income (loss)	($1,859,890)	($2,927,148)	($1,526,043)	($961,119)	($648,732)	($466,954)	($353,351)	($275,665)	($217,029)	($168,486)	($125,176)	($84,395)	($44,587)	($4,819)	$35,496	$76,748	$119,214	$163,102	$208,581	$255,795
Income taxes payable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,424	$26,862	$41,725	$57,086	$73,003	$89,528
Less: Prior year tax losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12,424)	($26,862)	($41,725)	($57,086)	($73,003)	($89,528)
Net tax payable	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unused tax losses, opening balance	$0	$650,961	$1,675,463	$2,209,578	$2,545,970	$2,773,026	$2,936,460	$3,060,133	$3,156,616	$3,232,576	$3,291,546	$3,335,357	$3,364,895	$3,380,501	$3,382,188	$3,369,764	$3,342,902	$3,301,177	$3,244,091	$3,171,088
Income tax losses - current year	$650,961	$1,024,502	$534,115	$336,392	$227,056	$163,434	$123,673	$96,483	$75,960	$58,970	$43,811	$29,538	$15,605	$1,687	$0	$0	$0	$0	$0	$0
Tax losses applied during the year	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12,424)	($26,862)	($41,725)	($57,086)	($73,003)	($89,528)
Unused tax losses - cumulative	**$650,961**	**$1,675,463**	**$2,209,578**	**$2,545,970**	**$2,773,026**	**$2,936,460**	**$3,060,133**	**$3,156,616**	**$3,232,576**	**$3,291,546**	**$3,335,357**	**$3,364,895**	**$3,380,501**	**$3,382,188**	**$3,369,764**	**$3,342,902**	**$3,301,177**	**$3,244,091**	**$3,171,088**	**$3,081,560**

ASSUMPTIONS - OPTION 3 (0.5 MW)

INPUT IN SHADED CELLS ONLY

yellow cells indicate awaiting final numbers from engineering

CAPITAL:

District heating, installed cost		*not included*
Biomass plant, installed cost	$6,271,314	
Total plant etc.	$6,271,314	*see 'Capital Costs' worksheet*
ORC	$194,235	
Feedstock yard		
Land	$0	*see 'Capital Costs' worksheet*
Buildings	$1,968,265	*see 'Capital Costs' worksheet*
Equipment	$2,126,588	*see 'Capital Costs' worksheet*
Total capital requirement	$10,560,401	
Capital renewal - annual rate		
Plant	4.0%	*% of original capex, starting in year 4 - assume 25 year life*
Buildings	2.0%	*% of original capex, starting in year 4 - assume 50 year life*
Equipment	6.0%	*% of original capex, starting in year 4 - assume 15 year life*

OPERATING:

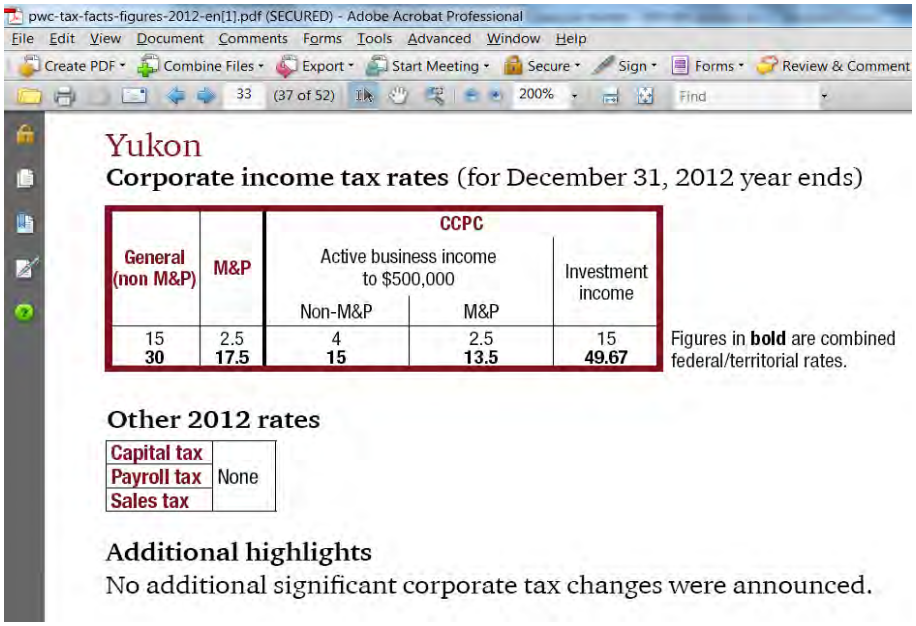
Revenues

Total annual sales - kWh	3,504,000	*500kWe, 80% availability*
Electricity selling price - $/kWh	$0.200	per CAFN (Ray)
ORC Electricity sales-kWh	258361	*@ 8% of remaining heat*
District heat annual sales - kWh	1,283,645	*Revised DE Network*
Heat selling price - $/kWh	$0.185	*per CTCG*
Government subsidies - $/kWh	$0.00	

Expenses

O&M expenses - plant - $ / kWh		
O&M expenses - yard - $ / kWh		
O&M expenses - district heat - $	$37,000	*per CTCG*
O&M ORC	$5,938	*per CTCG*
O&M Plant	$242,000	*per FEED report*
Feedstock - $/tonne	$50.40	*per FEED report*

Production factor - tonnes/kWh	0.00086		*1 kg (.001 tonne) per hour = 1 kWh*
Fuel cost per kWh	$0.04		
Amortization (CCA) - annual rate			
Plant	50.0%		*Accelerated CCA class 43.2, see below*
Buildings	4.0%		*CCA class 1*
Equipment	30.0%		*CCA class 43*
Income tax - combined rate	35.0%		
FINANCIAL:			
Grant money	67%	$7,075,469	
Capitalization			
Debt %	70%	$2,439,453	per CAFN (Ray)
Equity %	30%	$1,045,480	per CAFN (Ray)
Total capital funding		$10,560,401	ok
Ownership			
CAFN	60%	$627,288	per CAFN (Ray)
Yukon Energy	30%	$313,644	per CAFN (Ray)
Village of Haines Junction	10%	$104,548	per CAFN (Ray)
	100%	$1,045,480	
Long term debt			
Interest rate	5.0%		
Debt term, in years	20		
ROI requirements - after tax			
CAFN	15%		per CAFN (Ray)
Yukon Energy	15%		per CAFN (Ray)
Village of Haines Junction	15%		per CAFN (Ray)
WACC - after tax	8.00%		
Annual inflation rate	3.0%		*assumes same rate for both operating and capital expenditures*
Terminal (perpetuity) value multiple	20.0		*Terminal Value = FCF (yr 20)/(WACC – growth rate) : assumes growth rate = inflation rate*
Feedstock inflation rate	1%		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Yukon

Corporate income tax rates (for December 31, 2012 year ends)

General (non M&P)	M&P	CCPC		
		Active business income to $500,000		Investment income
		Non-M&P	M&P	
15 **30**	2.5 **17.5**	4 **15**	2.5 **13.5**	15 **49.67**

Figures in **bold** are combined federal/territorial rates.

Other 2012 rates

Capital tax	None
Payroll tax	
Sales tax	

Additional highlights

No additional significant corporate tax changes were announced.

http://www.budget.gc.ca/2010/plan/anx5-eng.html#a27

Accelerated CCA for Clean Energy Generation

Class 43.2 was introduced in 2005 and is currently available for assets acquired on or after February 23, 2005 and before 2020. For assets acquired before February 23, 2005, accelerated CCA is provided under Class 43.1 (30 per cent). The eligibility criteria for these two classes are generally the same, except that cogeneration systems that use fossil fuels must meet a higher efficiency standard for Class 43.2 than for Class 43.1. Systems that only meet the lower efficiency standard are eligible for Class 43.1.

Class 43.2 includes a variety of stationary clean energy generation or conservation equipment that is used to produce electricity or thermal energy, or used to produce certain fuels from waste that are in turn used to produce electricity or thermal energy. Subject to detailed rules in the regulations, eligible equipment includes:

ELECTRICITY

- High efficiency cogeneration equipment;
- Wind turbines;
- Small hydroelectric facilities;
- Fuel cells;
- Photovoltaic equipment;
- Wave and tidal power equipment;
- Equipment that generates electricity using geothermal energy; and
- Equipment that generates electricity using an eligible waste fuel.

THERMAL ENERGY

- Active solar equipment;
- Ground source heat pump equipment;
- District energy equipment that distributes thermal energy from cogeneration;
- Equipment that generates heat for an industrial process or a greenhouse using an eligible waste fuel; and
- Heat recovery equipment used in electricity generation and industrial processes.

FUELS FROM WASTE

- Equipment that recovers landfill gas or digester gas;
- Equipment used to convert biomass into bio-oil; and
- Equipment used to produce biogas through anaerobic digestion.

If the majority of tangible property in a project is eligible for inclusion in Class 43.2, then certain intangible project start-up expenses (for example, engineering and design work and feasibility studies) are treated as Canadian Renewable and Conservation Expenses. These expenses may be deducted in full in the year incurred, carried forward indefinitely for use in future years, or transferred to investors using flow-through shares.

Budget 2010 proposes to expand Class 43.2 to include: (a) heat recovery equipment used i a broader range of applications; and (b) distribution equipment used in district energy systems that rely primarily on ground source heat pumps, active solar systems or heat recovery equipment.

NEWCO CASH FLOW PROJECTION
OPTION 3 - 0.5 MW PLANT
(NEWCO OWNED / ISP OPERATED)

	TOTAL NPV	CONSTRUCTION Year 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
REVENUE																							
Electricity sales	$8,187,383		$721,824	$743,479	$765,783	$788,757	$812,419	$836,792	$861,896	$887,752	$914,385	$941,817	$970,071	$999,173	$1,029,148	$1,060,023	$1,091,824	$1,124,578	$1,158,316	$1,193,065	$1,228,857	$1,265,723	
ORC Electricity	$651,975		$53,222	$54,819	$56,464	$58,157	$59,902	$61,699	$63,550	$65,457	$67,420	$69,443	$71,526	$73,672	$75,882	$78,159	$80,503	$82,919	$85,406	$87,968	$90,607	$93,326	
District heat sales	$2,774,391		$244,599	$251,937	$259,495	$267,279	$275,298	$283,557	$292,063	$300,825	$309,850	$319,146	$328,720	$338,582	$348,739	$359,201	$369,977	$381,077	$392,509	$404,284	$416,413	$428,905	
Total revenue	**$11,613,749**	**$0**	**$1,019,645**	**$1,050,234**	**$1,081,741**	**$1,114,193**	**$1,147,619**	**$1,182,048**	**$1,217,509**	**$1,254,035**	**$1,291,656**	**$1,330,405**	**$1,370,317**	**$1,411,427**	**$1,453,770**	**$1,497,383**	**$1,542,304**	**$1,588,573**	**$1,636,231**	**$1,685,318**	**$1,735,877**	**$1,787,953**	
EXPENSE																							
Operations & maintenance - biomass	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Operations & maintenance - district heat	($432,268)		($38,110)	($39,253)	($40,431)	($41,644)	($42,893)	($44,180)	($45,505)	($46,870)	($48,277)	($49,725)	($51,217)	($52,753)	($54,336)	($55,966)	($57,645)	($59,374)	($61,155)	($62,990)	($64,880)	($66,826)	
Operations & maintenance - ORC	($74,919)		($6,116)	($6,299)	($6,488)	($6,683)	($6,883)	($7,090)	($7,303)	($7,522)	($7,747)	($7,980)	($8,219)	($8,466)	($8,720)	($8,981)	($9,251)	($9,528)	($9,814)	($10,109)	($10,412)	($10,724)	
Administration expense	($2,827,264)		($249,260)	($256,738)	($264,440)	($272,373)	($280,544)	($288,961)	($297,629)	($306,558)	($315,755)	($325,228)	($334,985)	($345,034)	($355,385)	($366,047)	($377,028)	($388,339)	($399,989)	($411,989)	($424,348)	($437,079)	
Fuel (feedstock)	($1,492,889)		($152,887)	($154,415)	($155,960)	($157,519)	($159,094)	($160,685)	($162,292)	($163,915)	($165,554)	($167,210)	($168,882)	($170,571)	($172,276)	($173,999)	($175,739)	($177,497)	($179,271)	($181,064)	($182,875)	($184,704)	
Amortization	($9,906,307)		($1,926,182)	($2,971,179)	($1,629,537)	($1,110,783)	($842,280)	($703,623)	($633,268)	($599,507)	($585,833)	($583,536)	($587,944)	($596,499)	($607,773)	($620,945)	($635,535)	($651,255)	($667,930)	($685,454)	($703,763)	($722,820)	
Total expense	**($14,733,648)**		**($2,372,554)**	**($3,427,884)**	**($2,096,856)**	**($1,589,002)**	**($1,331,695)**	**($1,204,538)**	**($1,145,997)**	**($1,124,373)**	**($1,123,166)**	**($1,133,678)**	**($1,151,246)**	**($1,173,323)**	**($1,198,490)**	**($1,225,938)**	**($1,255,198)**	**($1,285,993)**	**($1,318,160)**	**($1,351,606)**	**($1,386,278)**	**($1,422,152)**	
EARNINGS BEFORE INTEREST & TAXES	**($3,119,898)**		**($1,352,909)**	**($2,377,650)**	**($1,015,114)**	**($474,809)**	**($184,076)**	**($22,491)**	**$71,512**	**$129,662**	**$168,489**	**$196,727**	**$219,071**	**$238,104**	**$255,280**	**$271,445**	**$287,106**	**$302,581**	**$318,070**	**$333,712**	**$349,599**	**$365,801**	
Less: Income taxes	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Add: Amortization	$9,906,307		$1,926,182	$2,971,179	$1,629,537	$1,110,783	$842,280	$703,623	$633,268	$599,507	$585,833	$583,536	$587,944	$596,499	$607,773	$620,945	$635,535	$651,255	$667,930	$685,454	$703,763	$722,820	
Add: Government (NRCan) capital funding	$6,551,360	**$7,075,469**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Capital expenditures	($9,778,149)	**($10,560,401)**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Annual capital renewal	($3,824,865)		$0	$0	$0	($470,252)	($484,360)	($498,891)	($513,857)	($529,273)	($545,151)	($561,506)	($578,351)	($595,702)	($613,573)	($631,980)	($650,939)	($670,467)	($690,581)	($711,299)	($732,638)	($754,617)	
Add: Terminal value of free cash flow at yea	$1,228,736		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,680,073
Add: PV of unused tax losses at year 20	$411,455		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,236,894
FREE CASH FLOW	**($265,245)**	**($3,484,932)**	**$573,272**	**$593,528**	**$614,423**	**$165,722**	**$173,844**	**$182,241**	**$190,922**	**$199,896**	**$209,171**	**$218,757**	**$228,664**	**$238,902**	**$249,480**	**$260,410**	**$271,702**	**$283,368**	**$295,419**	**$307,867**	**$320,724**	**$334,004**	
CUMULATIVE FREE CASH FLOW		**($3,484,932)**	**($2,911,660)**	**($2,318,132)**	**($1,703,709)**	**($1,537,987)**	**($1,364,143)**	**($1,181,902)**	**($990,979)**	**($791,083)**	**($581,912)**	**($363,155)**	**($134,491)**	**$104,410**	**$353,890**	**$614,301**	**$886,003**	**$1,169,371**	**$1,464,790**	**$1,772,657**	**$2,093,382**	**$2,427,385**	

IRR	ROI
6.5%	-1.5%

Simple Payback: 12 Years

Income tax calculations:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Earnings before interest and taxes	($1,352,909)	($2,377,650)	($1,015,114)	($474,809)	($184,076)	($22,491)	$71,512	$129,662	$168,489	$196,727	$219,071	$238,104	$255,280	$271,445	$287,106	$302,581	$318,070	$333,712	$349,599	$365,801
Deduct: Interest expense on LTD	($369,614)	($358,436)	($346,699)	($334,375)	($321,435)	($307,848)	($293,582)	($278,602)	($262,873)	($246,358)	($229,017)	($210,809)	($191,691)	($171,617)	($150,539)	($128,407)	($105,169)	($80,768)	($55,148)	($28,246)
Net taxable income (loss)	($1,722,523)	($2,736,086)	($1,361,813)	($809,184)	($505,511)	($330,339)	($222,070)	($148,940)	($94,384)	($49,631)	($9,946)	$27,294	$63,589	$99,828	$136,568	$174,174	$212,902	$252,943	$294,451	$337,555
Income taxes payable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,553	$22,256	$34,940	$47,799	$60,961	$74,516	$88,530	$103,058	$118,144
Less: Prior year tax losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9,553)	($22,256)	($34,940)	($47,799)	($60,961)	($74,516)	($88,530)	($103,058)	($118,144)
Net tax payable	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unused tax losses, opening balance	$0	$602,883	$1,560,513	$2,037,148	$2,320,362	$2,497,291	$2,612,910	$2,690,634	$2,742,763	$2,775,798	$2,793,169	$2,796,650	$2,787,097	$2,764,841	$2,729,901	$2,682,102	$2,621,142	$2,546,626	$2,458,096	$2,355,038
Income tax losses - current year	$602,883	$957,630	$476,635	$283,214	$176,929	$115,619	$77,724	$52,129	$33,034	$17,371	$3,481	$0	$0	$0	$0	$0	$0	$0	$0	$0
Tax losses applied during the year	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9,553)	($22,256)	($34,940)	($47,799)	($60,961)	($74,516)	($88,530)	($103,058)	($118,144)
Unused tax losses - cumulative	**$602,883**	**$1,560,513**	**$2,037,148**	**$2,320,362**	**$2,497,291**	**$2,612,910**	**$2,690,634**	**$2,742,763**	**$2,775,798**	**$2,793,169**	**$2,796,650**	**$2,787,097**	**$2,764,841**	**$2,729,901**	**$2,682,102**	**$2,621,142**	**$2,546,626**	**$2,458,096**	**$2,355,038**	**$2,236,894**

ASSUMPTIONS - OPTION 4 (EXPANSION) (1.0 MW)

INPUT IN SHADED CELLS ONLY yellow cells indicate awaiting final numbers from engineering

CAPITAL:

District heating, installed cost		*not included*
Biomass plant, installed cost	$12,115,684	
Total plant etc.	$12,115,684	*see 'Capital Costs' worksheet*
ORC	$388,470	
Feedstock yard		
Land	$0	*see 'Capital Costs' worksheet*
Buildings	$3,909,184	*see 'Capital Costs' worksheet*
Equipment	$3,496,871	*see 'Capital Costs' worksheet*
Total capital requirement	$19,910,209	
Capital renewal - annual rate		
Plant	4.0%	*% of original capex, starting in year 4 - assume 25 year life*
Buildings	2.0%	*% of original capex, starting in year 4 - assume 50 year life*
Equipment	6.0%	*% of original capex, starting in year 4 - assume 15 year life*

OPERATING:

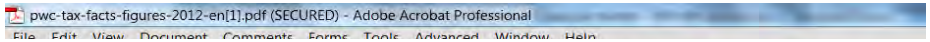
Revenues

Total annual sales - kWh	7,008,000	*500kWe, 80% availability*
Electricity selling price - $/kWh	$0.200	per CAFN (Ray)
ORC Electricity sales - kWh	516721	*@ 8% of remaining heat*
District heat annual sales - kWh	1,283,645	*Revised DE Network*
Heat selling price - $/kWh	$0.185	*per CTCG*
Government subsidies - $/kWh	$0.00	

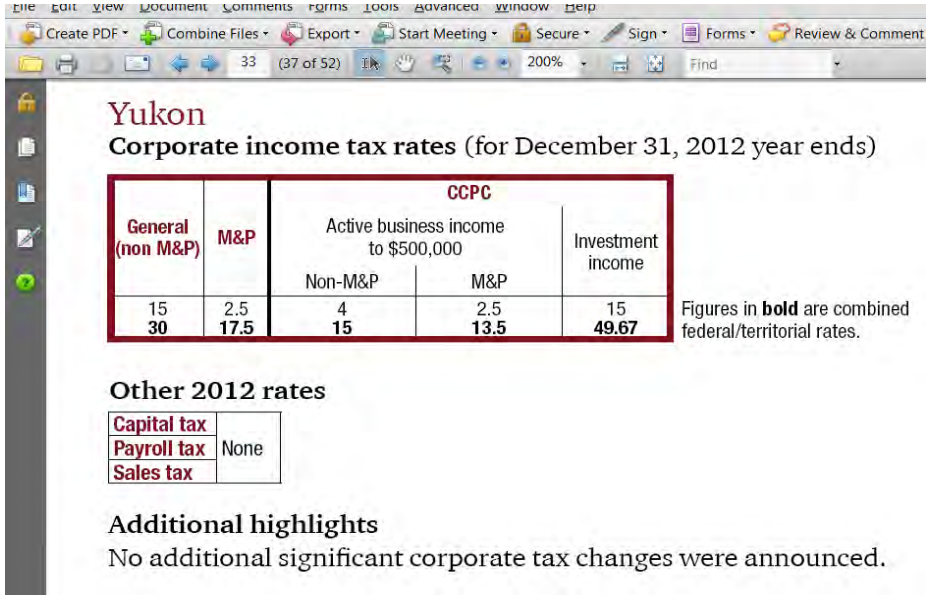
Expenses

O&M expenses - plant - $ / kWh		
O&M expenses - yard - $ / kWh		
O&M expenses - district heat - $	$37,000	*per CTCG*
O&M ORC	$11,875	*per CTCG*
O&M Plant	$351,125	*per FEED report*
Feedstock - $/tonne	$50.40	*per FEED report*

Production factor - tonnes/kWh	0.00086		*1 kg (.001 tonne) per hour = 1 kWh*
Fuel cost per kWh	$0.04		
Amortization (CCA) - annual rate			
Plant	50.0%		*Accelerated CCA class 43.2, see below*
Buildings	4.0%		*CCA class 1*
Equipment	30.0%		*CCA class 43*
Income tax - combined rate	35.0%		
FINANCIAL:			
Grant money	67%	$ 13,339,840	
Capitalization			
Debt %	70%	$4,599,258	per CAFN (Ray)
Equity %	30%	$1,971,111	per CAFN (Ray)
Total capital funding		$19,910,209	ok
Ownership			
CAFN	60%	$1,182,666	per CAFN (Ray)
Yukon Energy	30%	$591,333	per CAFN (Ray)
Village of Haines Junction	10%	$197,111	per CAFN (Ray)
	100%	$1,971,111	
Interest rate	5.0%		
Debt term, in years	20		
ROI requirements - after tax			
CAFN	15%	per CAFN (Ray)	
Yukon Energy	15%	per CAFN (Ray)	
Village of Haines Junction	15%	per CAFN (Ray)	
WACC - after tax	8.00%		
Annual inflation rate	3.0%		*assumes same rate for both operating and capital expenditures*
Terminal (perpetuity) value multiple	20.0		*Terminal Value = FCF (yr 20)/(WACC – growth rate) : assumes growth rate = inflation rate*
Feedstock inflation rate	1%		



http://www.budget.gc.ca/2010/plan/anx5-eng.html#a27



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33 (37 of 52) 200% Find

Yukon

Corporate income tax rates (for December 31, 2012 year ends)

General (non M&P)	M&P	CCPC		
		Active business income to $500,000		Investment income
		Non-M&P	M&P	
15 **30**	2.5 **17.5**	4 **15**	2.5 **13.5**	15 **49.67**

Figures in **bold** are combined federal/territorial rates.

Other 2012 rates

Capital tax	None
Payroll tax	
Sales tax	

Additional highlights

No additional significant corporate tax changes were announced.

Accelerated CCA for Clean Energy Generation

Class 43.2 was introduced in 2005 and is currently available for assets acquired on or after February 23, 2005 and before 2020. For assets acquired before February 23, 2005, accelerated CCA is provided under Class 43.1 (30 per cent). The eligibility criteria for these two classes are generally the same, except that cogeneration systems that use fossil fuels must meet a higher efficiency standard for Class 43.2 than for Class 43.1. Systems that only meet the lower efficiency standard are eligible for Class 43.1.

Class 43.2 includes a variety of stationary clean energy generation or conservation equipment that is used to produce electricity or thermal energy, or used to produce certain fuels from waste that are in turn used to produce electricity or thermal energy. Subject to detailed rules in the regulations, eligible equipment includes:

ELECTRICITY

- High efficiency cogeneration equipment;
- Wind turbines;
- Small hydroelectric facilities;
- Fuel cells;
- Photovoltaic equipment;
- Wave and tidal power equipment;
- Equipment that generates electricity using geothermal energy; and
- Equipment that generates electricity using an eligible waste fuel.

THERMAL ENERGY

- Active solar equipment;
- Ground source heat pump equipment;
- District energy equipment that distributes thermal energy from cogeneration;
- Equipment that generates heat for an industrial process or a greenhouse using an eligible waste fuel; and
- Heat recovery equipment used in electricity generation and industrial processes.

FUELS FROM WASTE

- Equipment that recovers landfill gas or digester gas;
- Equipment used to convert biomass into bio-oil; and
- Equipment used to produce biogas through anaerobic digestion.

If the majority of tangible property in a project is eligible for inclusion in Class 43.2, then certain intangible project start-up expenses (for example, engineering and design work and feasibility studies) are treated as Canadian Renewable and Conservation Expenses. These expenses may be deducted in full in the year incurred, carried forward indefinitely for use in future years, or transferred to investors using flow-through shares.

Budget 2010 proposes to expand Class 43.2 to include: (a) heat recovery equipment used i a broader range of applications; and (b) distribution equipment used in district energy systems that rely primarily on ground source heat pumps, active solar systems or heat recovery equipment.

NEWCO CASH FLOW PROJECTION
OPTION 4 (EXPANSION) - 1.0 MW PLANT
(NEWCO OWNED / ISP OPERATED)

	TOTAL NPV	CONSTRUCTION Year 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
REVENUE																							
Electricity sales	$16,374,767		$1,443,648	$1,486,957	$1,531,566	$1,577,513	$1,624,839	$1,673,584	$1,723,791	$1,775,505	$1,828,770	$1,883,633	$1,940,142	$1,998,346	$2,058,297	$2,120,046	$2,183,647	$2,249,157	$2,316,631	$2,386,130	$2,457,714	$2,531,446	
ORC Electricity	$1,303,950		$106,445	$109,638	$112,927	$116,315	$119,804	$123,398	$127,100	$130,913	$134,841	$138,886	$143,053	$147,344	$151,764	$156,317	$161,007	$165,837	$170,812	$175,937	$181,215	$186,651	
District heat sales	$2,774,391		$244,599	$251,937	$259,495	$267,279	$275,298	$283,557	$292,063	$300,825	$309,850	$319,146	$328,720	$338,582	$348,739	$359,201	$369,977	$381,077	$392,509	$404,284	$416,413	$428,905	
Total revenue	**$20,453,108**	**$0**	**$1,794,691**	**$1,848,532**	**$1,903,988**	**$1,961,107**	**$2,019,941**	**$2,080,539**	**$2,142,955**	**$2,207,244**	**$2,273,461**	**$2,341,665**	**$2,411,915**	**$2,484,272**	**$2,558,800**	**$2,635,564**	**$2,714,631**	**$2,796,070**	**$2,879,952**	**$2,966,351**	**$3,055,341**	**$3,147,002**	
EXPENSE																							
Operations & maintenance - biomass	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Operations & maintenance - district heat	($432,268)		($38,110)	($39,253)	($40,431)	($41,644)	($42,893)	($44,180)	($45,505)	($46,870)	($48,277)	($49,725)	($51,217)	($52,753)	($54,336)	($55,966)	($57,645)	($59,374)	($61,155)	($62,990)	($64,880)	($66,826)	
Operations & maintenance - ORC	($149,838)		($12,232)	($12,599)	($12,977)	($13,366)	($13,767)	($14,180)	($14,605)	($15,043)	($15,495)	($15,960)	($16,438)	($16,931)	($17,439)	($17,963)	($18,501)	($19,057)	($19,628)	($20,217)	($20,824)	($21,448)	
Administration expense	($4,102,162)		($361,659)	($372,509)	($383,684)	($395,194)	($407,050)	($419,262)	($431,839)	($444,795)	($458,138)	($471,883)	($486,039)	($500,620)	($515,639)	($531,108)	($547,041)	($563,453)	($580,356)	($597,767)	($615,700)	($634,171)	
Fuel (feedstock)	($2,985,778)		($305,773)	($308,831)	($311,919)	($315,038)	($318,189)	($321,371)	($324,584)	($327,830)	($331,108)	($334,419)	($337,764)	($341,141)	($344,553)	($347,998)	($351,478)	($354,993)	($358,543)	($362,128)	($365,750)	($369,407)	
Amortization	($18,477,139)		($3,631,635)	($5,588,324)	($3,042,993)	($2,061,095)	($1,556,189)	($1,297,592)	($1,167,761)	($1,106,386)	($1,082,236)	($1,078,948)	($1,087,818)	($1,104,135)	($1,125,293)	($1,149,819)	($1,176,860)	($1,205,915)	($1,236,683)	($1,268,983)	($1,302,708)	($1,337,799)	
Total expense	**($26,147,186)**		**($4,349,409)**	**($6,321,515)**	**($3,792,003)**	**($2,826,337)**	**($2,338,087)**	**($2,096,584)**	**($1,984,296)**	**($1,940,925)**	**($1,935,254)**	**($1,950,934)**	**($1,979,276)**	**($2,015,581)**	**($2,057,260)**	**($2,102,853)**	**($2,151,526)**	**($2,202,792)**	**($2,256,366)**	**($2,312,085)**	**($2,369,861)**	**($2,429,651)**	
EARNINGS BEFORE INTEREST & TAXES	**($5,694,078)**		**($2,554,718)**	**($4,472,983)**	**($1,888,015)**	**($865,230)**	**($318,147)**	**($16,045)**	**$158,659**	**$266,319**	**$338,207**	**$390,731**	**$432,639**	**$468,691**	**$501,541**	**$532,711**	**$563,105**	**$593,279**	**$623,587**	**$654,266**	**$685,481**	**$717,350**	
Less: Income taxes	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Add: Amortization	$18,477,139		$3,631,635	$5,588,324	$3,042,993	$2,061,095	$1,556,189	$1,297,592	$1,167,761	$1,106,386	$1,082,236	$1,078,948	$1,087,818	$1,104,135	$1,125,293	$1,149,819	$1,176,860	$1,205,915	$1,236,683	$1,268,983	$1,302,708	$1,337,799	
Add: Government (NRCan) capital funding	$12,351,704	**$13,339,840**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Capital expenditures	($18,435,379)	**($19,910,209)**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Annual capital renewal	($7,072,970)		$0	$0	$0	($869,594)	($895,682)	($922,553)	($950,229)	($978,736)	($1,008,098)	($1,038,341)	($1,069,491)	($1,101,576)	($1,134,623)	($1,168,662)	($1,203,722)	($1,239,834)	($1,277,029)	($1,315,339)	($1,354,800)	($1,395,444)	
Add: Terminal value of free cash flow at yea	$2,426,932		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,194,114
Add: PV of unused tax losses at year 20	$747,988		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,066,468
FREE CASH FLOW	**($373,584)**	**($6,570,369)**	**$1,076,918**	**$1,115,341**	**$1,154,977**	**$326,271**	**$342,360**	**$358,994**	**$376,192**	**$393,969**	**$412,345**	**$431,337**	**$450,966**	**$471,250**	**$492,210**	**$513,868**	**$536,244**	**$559,360**	**$583,241**	**$607,909**	**$633,389**	**$659,706**	
CUMULATIVE FREE CASH FLOW		**($6,570,369)**	**($5,493,451)**	**($4,378,111)**	**($3,223,133)**	**($2,896,863)**	**($2,554,503)**	**($2,195,509)**	**($1,819,317)**	**($1,425,348)**	**($1,013,003)**	**($581,666)**	**($130,701)**	**$340,549**	**$832,759**	**$1,346,627**	**$1,882,870**	**$2,442,231**	**$3,025,472**	**$3,633,381**	**$4,266,770**	**$4,926,476**	

IRR	ROI
6.8%	-1.2%

Simple Payback: 12 Years

Income tax calculations:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Earnings before interest and taxes	($2,554,718)	($4,472,983)	($1,888,015)	($865,230)	($318,147)	($16,045)	$158,659	$266,319	$338,207	$390,731	$432,639	$468,691	$501,541	$532,711	$563,105	$593,279	$623,587	$654,266	$685,481	$717,350
Deduct: Interest expense on LTD	($696,857)	($675,783)	($653,654)	($630,419)	($606,022)	($580,406)	($553,509)	($525,266)	($495,612)	($464,475)	($431,781)	($397,453)	($361,408)	($323,560)	($283,821)	($242,094)	($198,281)	($152,278)	($103,974)	($53,255)
Net taxable income (loss)	($3,251,575)	($5,148,766)	($2,541,669)	($1,495,649)	($924,169)	($596,451)	($394,849)	($258,948)	($157,405)	($73,744)	$858	$71,239	$140,133	$209,151	$279,284	$351,185	$425,305	$501,988	$581,507	$664,096
Income taxes payable	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$300	$24,934	$49,047	$73,203	$97,750	$122,915	$148,857	$175,696	$203,527	$232,433
Less: Prior year tax losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($300)	($24,934)	($49,047)	($73,203)	($97,750)	($122,915)	($148,857)	($175,696)	($203,527)	($232,433)
Net tax payable	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unused tax losses, opening balance	$0	$1,138,051	$2,940,119	$3,829,703	$4,353,181	$4,676,640	$4,885,398	$5,023,595	$5,114,227	$5,169,318	$5,195,129	$5,194,829	$5,169,895	$5,120,849	$5,047,646	$4,949,896	$4,826,982	$4,678,125	$4,502,429	$4,298,902
Income tax losses - current year	$1,138,051	$1,802,068	$889,584	$523,477	$323,459	$208,758	$138,197	$90,632	$55,092	$25,811	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Tax losses applied during the year	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($300)	($24,934)	($49,047)	($73,203)	($97,750)	($122,915)	($148,857)	($175,696)	($203,527)	($232,433)
Unused tax losses - cumulative	**$1,138,051**	**$2,940,119**	**$3,829,703**	**$4,353,181**	**$4,676,640**	**$4,885,398**	**$5,023,595**	**$5,114,227**	**$5,169,318**	**$5,195,129**	**$5,194,829**	**$5,169,895**	**$5,120,849**	**$5,047,646**	**$4,949,896**	**$4,826,982**	**$4,678,125**	**$4,502,429**	**$4,298,902**	**$4,066,468**

ASSUMPTIONS - OPTION 9 (0.5 MW)

INPUT IN SHADED CELLS ONLY yellow cells indicate awaiting final numbers from engineering

CAPITAL:

District heating, installed cost		*not included*
Biomass plant, installed cost	$2,836,094	
Total plant etc.	$2,836,094	*see 'Capital Costs' worksheet*
ORC	$194,235	
Feedstock yard		
Land	$0	*see 'Capital Costs' worksheet*
Buildings	$2,128,742	*see 'Capital Costs' worksheet*
Equipment	$2,299,974	*see 'Capital Costs' worksheet*
Total capital requirement	$7,459,045	
Capital renewal - annual rate		
Plant	4.0%	*% of original capex, starting in year 4 - assume 25 year life*
Buildings	2.0%	*% of original capex, starting in year 4 - assume 50 year life*
Equipment	6.0%	*% of original capex, starting in year 4 - assume 15 year life*

OPERATING:

Revenues

Total annual sales - kWh	4,051,500	*500kWe, 92.5% availability*
Electricity selling price - $/kWh	$0.200	*per CAFN (Ray)*
ORC Electricity sales - kWh	329036	*@ 8% of remaining heat*
District heat annual sales - kWh	1,283,645	*Revised DE Network*
Heat selling price - $/kWh	$0.185	*per CTCG*
Government subsidies - $/kWh	$0.00	

Expenses

O&M expenses - plant - $ / kWh		
O&M expenses - yard - $ / kWh		
O&M expenses - district heat - $	$37,000	*per CTCG*
O&M ORC	$6,468	*per CTCG*
O&M plant	$242,000	*per FEED report*
Feedstock - $/tonne	$50.40	*per FEED report*

Production factor - tonnes/kWh	0.00086		*1 kg (.001 tonne) per hour = 1 kWh*	
Fuel cost per kWh	$0.04			
Amortization (CCA) - annual rate				
Plant	50.0%		*Accelerated CCA class 43.2, see below*	
Buildings	4.0%		*CCA class 1*	
Equipment	30.0%		*CCA class 43*	
Income tax - combined rate	35.0%			
FINANCIAL:				
Grant money	67%	$4,997,560		
Capitalization				
Debt %	70%	$1,723,039	per CAFN (Ray)	
Equity %	30%	$738,445	per CAFN (Ray)	
Total capital funding		$7,459,045	ok	
Ownership				
CAFN	60%	$443,067	per CAFN (Ray)	
Yukon Energy	30%	$221,534	per CAFN (Ray)	
Village of Haines Junction	10%	$73,845	per CAFN (Ray)	
	100%	$738,445		
Long term debt				
Interest rate	5.0%			
Debt term, in years	20			
ROI requirements - after tax				
CAFN	15%		per CAFN (Ray)	
Yukon Energy	15%		per CAFN (Ray)	
Village of Haines Junction	15%		per CAFN (Ray)	
WACC - after tax	8.00%			
Annual inflation rate	3.0%		*assumes same rate for both operating and capital expenditures*	
Terminal (perpetuity) value multiple	20.0		*Terminal Value = FCF (yr 20)/(WACC – growth rate) : assumes growth rate = inflation rate*	
Feedstock inflation rate	1%			

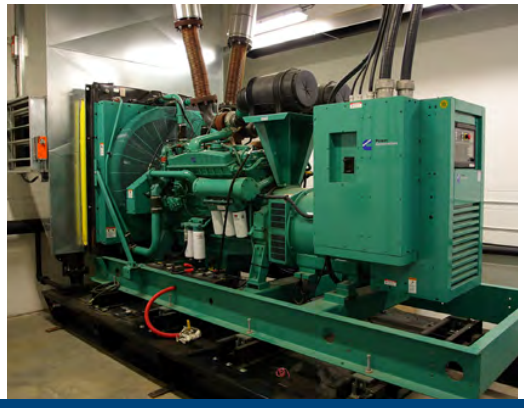
NEWCO CASH FLOW PROJECTION
OPTION 3 - 0.5 MW PLANT
(NEWCO OWNED / ISP OPERATED)

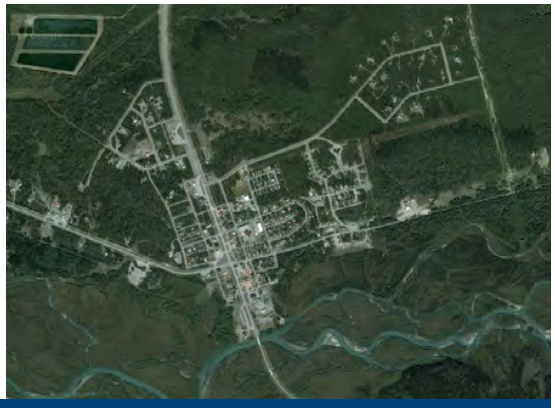
	TOTAL NPV	CONSTRUCTION Year 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
REVENUE																							
Electricity sales	$9,466,662		$834,609	$859,647	$885,437	$912,000	$939,360	$967,541	$996,567	$1,026,464	$1,057,258	$1,088,975	$1,121,645	$1,155,294	$1,189,953	$1,225,651	$1,262,421	$1,300,294	$1,339,302	$1,379,482	$1,420,866	$1,463,492	
ORC Electricity			$67,781	$69,815	$71,909	$74,067	$76,289	$78,577	$80,935	$83,363	$85,864	$88,439	$91,093	$93,825	$96,640	$99,539	$102,526	$105,601	$108,769	$112,032	$115,393	$118,855	
District heat sales	$2,774,391		$244,599	$251,937	$259,495	$267,279	$275,298	$283,557	$292,063	$300,825	$309,850	$319,146	$328,720	$338,582	$348,739	$359,201	$369,977	$381,077	$392,509	$404,284	$416,413	$428,905	
Total revenue	**$12,241,053**	**$0**	**$1,146,989**	**$1,181,399**	**$1,216,841**	**$1,253,346**	**$1,290,946**	**$1,329,675**	**$1,369,565**	**$1,410,652**	**$1,452,971**	**$1,496,561**	**$1,541,457**	**$1,587,701**	**$1,635,332**	**$1,684,392**	**$1,734,924**	**$1,786,972**	**$1,840,581**	**$1,895,798**	**$1,952,672**	**$2,011,252**	
EXPENSE																							
Operations & maintenance - biomass	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Operations & maintenance - district heat	($432,268)		($38,110)	($39,253)	($40,431)	($41,644)	($42,893)	($44,180)	($45,505)	($46,870)	($48,277)	($49,725)	($51,217)	($52,753)	($54,336)	($55,966)	($57,645)	($59,374)	($61,155)	($62,990)	($64,880)	($66,826)	
Operations & maintenance - ORC	($81,607)		($6,662)	($6,862)	($7,068)	($7,280)	($7,498)	($7,723)	($7,955)	($8,193)	($8,439)	($8,692)	($8,953)	($9,221)	($9,498)	($9,783)	($10,077)	($10,379)	($10,690)	($11,011)	($11,341)	($11,682)	
Administration expense	($2,827,264)		($249,260)	($256,738)	($264,440)	($272,373)	($280,544)	($288,961)	($297,629)	($306,558)	($315,755)	($325,228)	($334,985)	($345,034)	($355,385)	($366,047)	($377,028)	($388,339)	($399,989)	($411,989)	($424,348)	($437,079)	
Fuel (feedstock)	($1,726,153)		($176,775)	($178,543)	($180,328)	($182,132)	($183,953)	($185,792)	($187,650)	($189,527)	($191,422)	($193,336)	($195,270)	($197,222)	($199,195)	($201,186)	($203,198)	($205,230)	($207,283)	($209,355)	($211,449)	($213,564)	
Amortization	($6,382,465)		($1,096,594)	($1,733,475)	($1,022,422)	($742,523)	($590,039)	($506,286)	($460,472)	($436,186)	($424,511)	($420,494)	($421,312)	($425,313)	($431,504)	($439,271)	($448,230)	($458,132)	($468,817)	($480,181)	($492,157)	($504,702)	
Total expense	**($11,449,757)**		**($1,567,401)**	**($2,214,871)**	**($1,514,688)**	**($1,245,951)**	**($1,104,927)**	**($1,032,942)**	**($999,212)**	**($987,334)**	**($988,403)**	**($997,475)**	**($1,011,736)**	**($1,029,544)**	**($1,049,917)**	**($1,072,253)**	**($1,096,178)**	**($1,121,454)**	**($1,147,934)**	**($1,175,526)**	**($1,204,176)**	**($1,233,853)**	
EARNINGS BEFORE INTEREST & TAXES	**$791,296**		**($420,412)**	**($1,033,472)**	**($297,848)**	**$7,395**	**$186,019**	**$296,733**	**$370,353**	**$423,317**	**$464,568**	**$499,086**	**$529,722**	**$558,157**	**$585,415**	**$612,139**	**$638,746**	**$665,517**	**$692,646**	**$720,272**	**$748,496**	**$777,400**	
Less: Income taxes	($323,797)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,605)	($186,346)	($201,187)	($216,427)	($232,128)	($248,340)	($265,107)	
Add: Amortization	$6,382,465		$1,096,594	$1,733,475	$1,022,422	$742,523	$590,039	$506,286	$460,472	$436,186	$424,511	$420,494	$421,312	$425,313	$431,504	$439,271	$448,230	$458,132	$468,817	$480,181	$492,157	$504,702	
Add: Government (NRCan) capital funding	$4,627,370	**$4,997,560**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Capital expenditures	($6,906,523)	**($7,459,045)**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Less: Annual capital renewal	($2,691,575)		$0	$0	$0	($330,919)	($340,846)	($351,072)	($361,604)	($372,452)	($383,626)	($395,134)	($406,988)	($419,198)	($431,774)	($444,727)	($458,069)	($471,811)	($485,965)	($500,544)	($515,561)	($531,027)	
Add: Terminal value of free cash flow at yea	$1,787,783		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,719,354
Add: PV of unused tax losses at year 20	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FREE CASH FLOW	**$1,879,236**	**($2,461,485)**	**$676,182**	**$700,003**	**$724,574**	**$418,999**	**$435,212**	**$451,947**	**$469,221**	**$487,051**	**$505,453**	**$524,445**	**$544,045**	**$564,272**	**$585,145**	**$603,078**	**$442,561**	**$450,651**	**$459,071**	**$467,780**	**$476,752**	**$485,968**	
CUMULATIVE FREE CASH FLOW		**($2,461,485)**	**($1,785,303)**	**($1,085,300)**	**($360,725)**	**$58,274**	**$493,485**	**$945,433**	**$1,414,654**	**$1,901,705**	**$2,407,158**	**$2,931,603**	**$3,475,649**	**$4,039,920**	**$4,625,065**	**$5,228,143**	**$5,670,704**	**$6,121,355**	**$6,580,426**	**$7,048,206**	**$7,524,958**	**$8,010,926**	

IRR	ROI
23.1%	15.1%

Simple Payback: 4 Years

Income tax calculations:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Earnings before interest and taxes	($420,412)	($1,033,472)	($297,848)	$7,395	$186,019	$296,733	$370,353	$423,317	$464,568	$499,086	$529,722	$558,157	$585,415	$612,139	$638,746	$665,517	$692,646	$720,272	$748,496	$777,400
Deduct: Interest expense on LTD	($261,067)	($253,171)	($244,881)	($236,177)	($227,037)	($217,440)	($207,363)	($196,783)	($185,673)	($174,008)	($161,760)	($148,899)	($135,396)	($121,217)	($106,329)	($90,697)	($74,283)	($57,048)	($38,952)	($19,951)
Net taxable income (loss)	($681,479)	($1,286,643)	($542,729)	($228,782)	($41,017)	$79,293	$162,990	$226,535	$278,895	$325,078	$367,962	$409,258	$450,019	$490,922	$532,417	$574,821	$618,363	$663,223	$709,544	$757,449
Income taxes payable	$0	$0	$0	$0	$0	$27,753	$57,046	$79,287	$97,613	$113,777	$128,787	$143,240	$157,507	$171,823	$186,346	$201,187	$216,427	$232,128	$248,340	$265,107
Less: Prior year tax losses	$0	$0	$0	$0	$0	($27,753)	($57,046)	($79,287)	($97,613)	($113,777)	($128,787)	($143,240)	($157,507)	($168,218)	$0	$0	$0	$0	$0	$0
Net tax payable	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$3,605**	**$186,346**	**$201,187**	**$216,427**	**$232,128**	**$248,340**	**$265,107**
Unused tax losses, opening balance	$0	$238,518	$688,843	$878,798	$958,871	$973,228	$945,475	$888,429	$809,141	$711,528	$597,751	$468,964	$325,724	$168,218	$0	$0	$0	$0	$0	$0
Income tax losses - current year	$238,518	$450,325	$189,955	$80,074	$14,356	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Tax losses applied during the year	$0	$0	$0	$0	$0	($27,753)	($57,046)	($79,287)	($97,613)	($113,777)	($128,787)	($143,240)	($157,507)	($168,218)	$0	$0	$0	$0	$0	$0
Unused tax losses - cumulative	**$238,518**	**$688,843**	**$878,798**	**$958,871**	**$973,228**	**$945,475**	**$888,429**	**$809,141**	**$711,528**	**$597,751**	**$468,964**	**$325,724**	**$168,218**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**





APPENDIX K

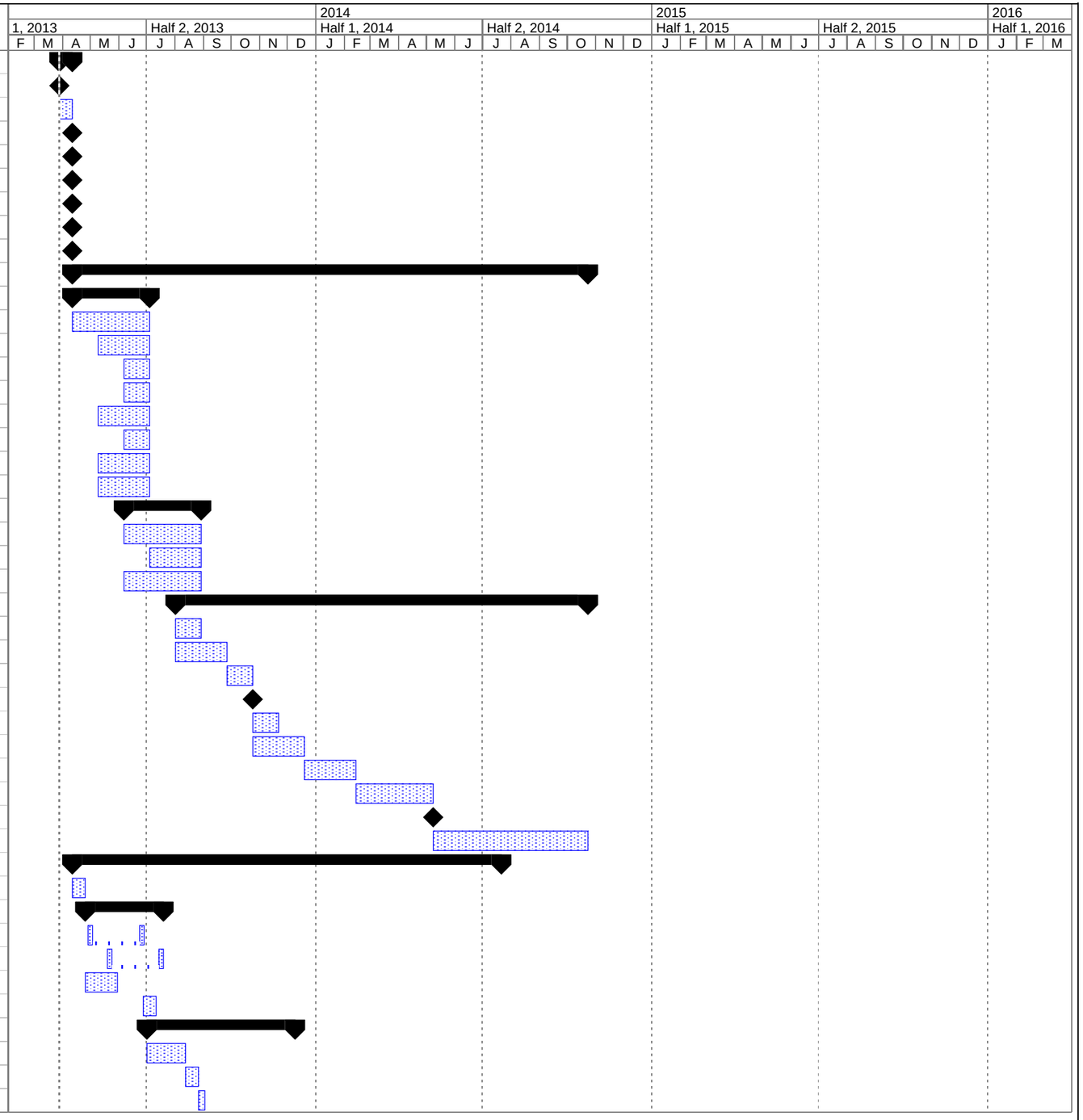
Implementation Schedule

Front End Engineering Design (FEED) Study
Yukon Bioenergy Demonstration Project
in Haines Junction, Yukon

Yukon Energy Corporation
2 Miles Canyon Road, Whitehorse, YT Y1A 6S7

This document has been prepared exclusively for the client and the project identified herein.
The material herein reflects Stantec's professional judgment given the information available to Stantec at the time of preparation.

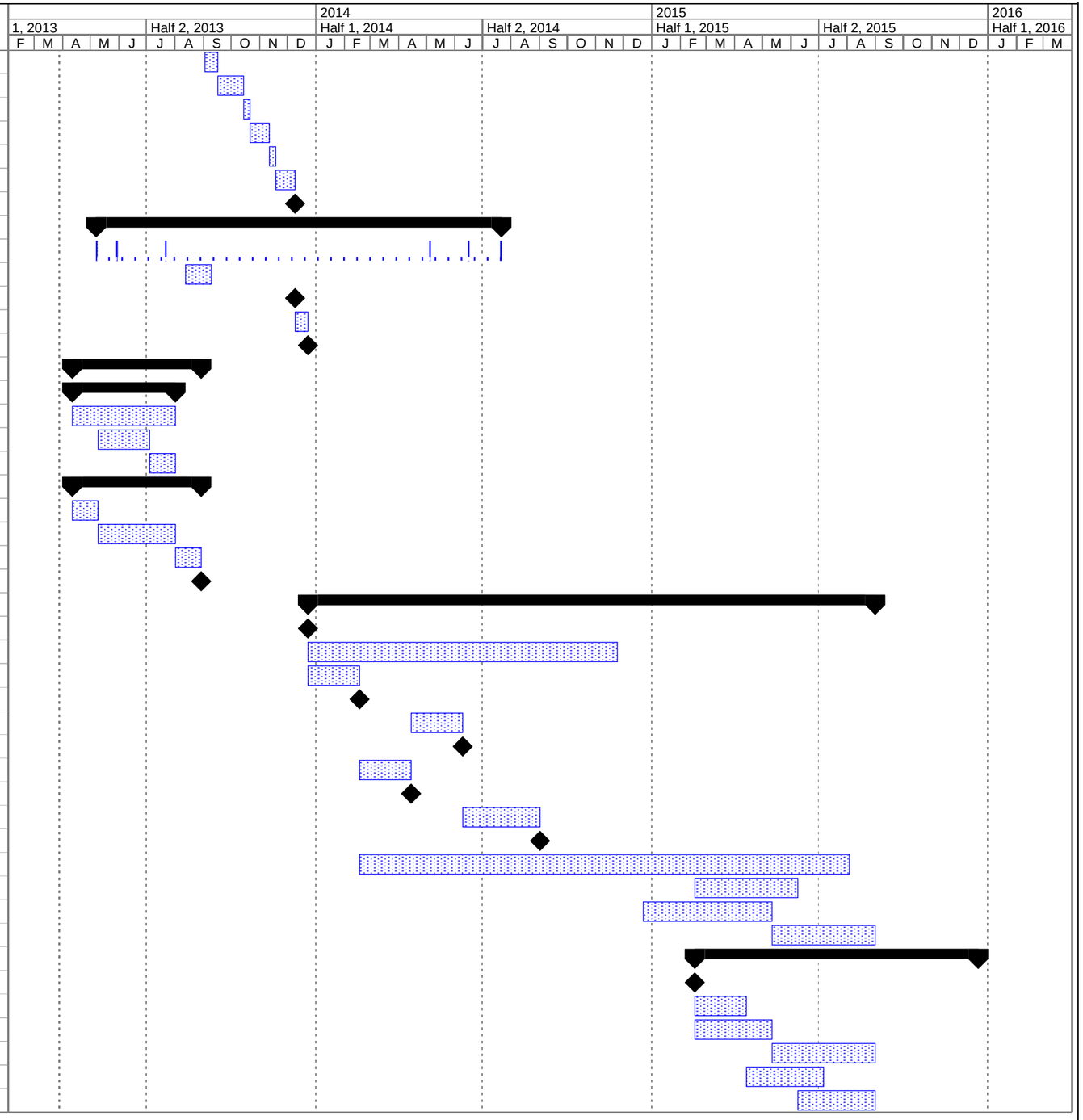
ID	Task Name	Duration	Start	Finish	Predecessors
1	**Phase 1 - FEED**	**10 days**	**Fri 03/29/13**	**Thu 04/11/13**	
2	Final Report Submission	0 days	Fri 03/29/13	Fri 03/29/13	
3	Final Report Review	10 days	Fri 03/29/13	Thu 04/11/13	2
4	**Approvals to Proceed**	**0 days**	**Thu 04/11/13**	**Thu 04/11/13**	**3**
5	CAFN (REC) Approval to Proceed	0 days	Thu 04/11/13	Thu 04/11/13	
6	YEC Board Approval to Proceed	0 days	Thu 04/11/13	Thu 04/11/13	
7	DDC Board Approval to Proceed	0 days	Thu 04/11/13	Thu 04/11/13	
8	VHJ Approval to Proceed	0 days	Thu 04/11/13	Thu 04/11/13	
9	YCCIC Approval to Proceed	0 days	Thu 04/11/13	Thu 04/11/13	
10	**Phase 2 - Feedstock**	**400 days**	**Fri 04/12/13**	**Thu 10/23/14**	**4**
11	**Procurement Logistics and Strategy (front end of**	**60 days**	**Fri 04/12/13**	**Thu 07/04/13**	
12	Procurement and Logistics Strategy	60 days	Fri 04/12/13	Thu 07/04/13	4
13	Supplier Business Model	40 days	Fri 05/10/13	Thu 07/04/13	12SS+20 days
14	Storage location options and retrieval*	20 days	Fri 06/07/13	Thu 07/04/13	13SS+20 days
15	Chipping options and locations*	20 days	Fri 06/07/13	Thu 07/04/13	14SS
16	Site Visits to Existing Operations	40 days	Fri 05/10/13	Thu 07/04/13	13SS
17	Input to design	20 days	Fri 06/07/13	Thu 07/04/13	14SS
18	Appreciate moisture content strategies	40 days	Fri 05/10/13	Thu 07/04/13	13SS
19	Alternative sources*	40 days	Fri 05/10/13	Thu 07/04/13	13SS
20	**Regulatory**	**60 days**	**Fri 06/07/13**	**Thu 08/29/13**	
21	Security of supply w FMB	60 days	Fri 06/07/13	Thu 08/29/13	14SS
22	Confirm Strategy (who needs to be up to speed)	40 days	Fri 07/05/13	Thu 08/29/13	21SS+20 days
23	Regulatory approvals before EOI	60 days	Fri 06/07/13	Thu 08/29/13	21SS
24	**Procurement**	**320 days**	**Fri 08/02/13**	**Thu 10/23/14**	
25	Expression of Interest (EOI) to Supply 500 kWe	20 days	Fri 08/02/13	Thu 08/29/13	22SS+20 days
26	EOI Preperation	40 days	Fri 08/02/13	Thu 09/26/13	25SS
27	EOI Issued	20 days	Fri 09/27/13	Thu 10/24/13	26
28	Letters of Interest (LOI) Returned	0 days	Thu 10/24/13	Thu 10/24/13	27
29	LOIs Reviewed	20 days	Fri 10/25/13	Thu 11/21/13	28
30	Feedstock Assessment & Costing	40 days	Fri 10/25/13	Thu 12/19/13	28
31	Procurement Plan	40 days	Fri 12/20/13	Thu 02/13/14	30
32	Private Shortlisted Request for Proposal	60 days	Fri 02/14/14	Thu 05/08/14	31
33	Formal Firm Proposals	0 days	Thu 05/08/14	Thu 05/08/14	32
34	Procurement Contracting	120 days	Fri 05/09/14	Thu 10/23/14	33
35	**Phase 3 - Environmental Permitting-DO Level Evaluati**	**332 days**	**Fri 04/12/13**	**Mon 07/21/14**	**4**
36	Scoping Meeting with YESAB	10 days	Fri 04/12/13	Thu 04/25/13	4
37	**Field Surveys and Technical Analyses**	**61 days**	**Fri 04/26/13**	**Fri 07/19/13**	
38	Wildlife and Wildlife Habitat (migratory birds, bat	10 days	Mon 04/29/13	Fri 06/28/13	36
39	Wetlands and Vegetation	10 days	Mon 05/20/13	Fri 07/19/13	36
40	Land Use/Traditional Use Consultation in Comm	25 days	Fri 04/26/13	Thu 05/30/13	36
41	Archaeological and Heritage Resources	10 days	Fri 06/28/13	Thu 07/11/13	40FS+20 days
42	**Impact Assessment Report**	**115 days**	**Tue 07/02/13**	**Mon 12/09/13**	
43	Prepare Draft DO Proposal for Internal Review	30 days	Tue 07/02/13	Mon 08/12/13	36FS+47 days
44	Client Review Period	10 days	Tue 08/13/13	Mon 08/26/13	43
45	Preparation of Regulatory Draft DO Proposal	5 days	Tue 08/27/13	Mon 09/02/13	44



Project: sch_cgv_20130301_project_ir
Date: Thu 03/28/13

Task | Milestone | Rolled Up Task | Rolled Up Progress | External Tasks | Group By Summary
Progress | Summary | Rolled Up Milestone | Split | Project Summary | Deadline

ID	Task Name	Duration	Start	Finish	Predecessors
46	Adequacy Review	10 days	Tue 09/03/13	Mon 09/16/13	45
47	Respond to Information Requests from Adequac	20 days	Tue 09/17/13	Mon 10/14/13	46
48	DO Reviews Responses	5 days	Tue 10/15/13	Mon 10/21/13	47
49	Seeking Views and Information (public consultat	15 days	Tue 10/22/13	Mon 11/11/13	48
50	DO Reviews input from SVI	5 days	Tue 11/12/13	Mon 11/18/13	49
51	Potential further Information Requests	15 days	Tue 11/19/13	Mon 12/09/13	50
52	DO Prepares/Issues Recommendation or Referr	0 days	Mon 12/09/13	Mon 12/09/13	51
53	**Permit Applications**	**314 days**	**Wed 05/08/13**	**Mon 07/21/14**	
54	Community and Stakeholder Engagement	6 days	Wed 05/08/13	Mon 07/21/14	36FS+8 days
55	Prepare other Applications and Submit to Decisi	20 days	Tue 08/13/13	Mon 09/09/13	43
56	Decision Bodies Receive Recommendation from	0 days	Mon 12/09/13	Mon 12/09/13	52
57	Review and Consideration by Decision Bodies	10 days	Tue 12/10/13	Mon 12/23/13	56
58	Decision Bodies Issue Permits	0 days	Mon 12/23/13	Mon 12/23/13	57
59	**Phase 4 - Bridging Engineering & Business Case**	**100 days**	**Fri 04/12/13**	**Thu 08/29/13**	
60	**AFE Study**	**80 days**	**Fri 04/12/13**	**Thu 08/01/13**	
61	Engineering	80 days	Fri 04/12/13	Thu 08/01/13	4
62	Firm Vendor Quotes	40 days	Fri 05/10/13	Thu 07/04/13	61SS+20 days
63	Class 3 Capital and Operating Cost	20 days	Fri 07/05/13	Thu 08/01/13	61FF
64	**Business Case**	**100 days**	**Fri 04/12/13**	**Thu 08/29/13**	
65	Funding Support	20 days	Fri 04/12/13	Thu 05/09/13	4
66	Heat and Electricity Sale Contact Support	60 days	Fri 05/10/13	Thu 08/01/13	65
67	Revised Business Case	20 days	Fri 08/02/13	Thu 08/29/13	66
68	AFE Report for Notice to Proceed	0 days	Thu 08/29/13	Thu 08/29/13	67
69	**Phase 5 - Detailed Engineering and Procurement**	**440 days**	**Mon 12/23/13**	**Tue 09/01/15**	
70	Engineering Notice to Proceed	0 days	Mon 12/23/13	Mon 12/23/13	68,58
71	Detailed Engineering	240 days	Tue 12/24/13	Mon 11/24/14	70
72	Finalize Performance, Agreements, T&Cs with Vendo	40 days	Tue 12/24/13	Mon 02/17/14	70
73	Award Gasification System	0 days	Mon 02/17/14	Mon 02/17/14	72
74	Spec/Bid Building	40 days	Tue 04/15/14	Tue 06/10/14	75SF
75	Award Building	0 days	Tue 06/10/14	Tue 06/10/14	81SF-180 days
76	Spec/Bid District Heating Network	40 days	Tue 02/18/14	Tue 04/15/14	77SF
77	Award District Heating Network	0 days	Tue 04/15/14	Tue 04/15/14	82SF-180 days
78	Spec/Bid BOP Equipment	60 days	Tue 06/10/14	Tue 09/02/14	79SF
79	Award BOP Equipment	0 days	Tue 09/02/14	Tue 09/02/14	83SF-180 days
80	Fabricate/Deliver Gasificaiton System	380 days	Tue 02/18/14	Mon 08/03/15	73
81	Fabricate/Deliver Building	80 days	Tue 02/17/15	Tue 06/09/15	90SF
82	Fabricate/Deliver District Heating Network	100 days	Tue 12/23/14	Tue 05/12/15	88SF
83	Fabricate/Deliver BOP Equipment	80 days	Tue 05/12/15	Tue 09/01/15	92SF
84	**Phase 6 - Construction**	**220 days**	**Tue 02/17/15**	**Mon 12/21/15**	
85	Construction Mobilization	0 days	Tue 02/17/15	Tue 02/17/15	86SS
86	Site Preparations	40 days	Tue 02/17/15	Mon 04/13/15	89SS-40 days
87	Heating Network Preparations	60 days	Tue 02/17/15	Mon 05/11/15	85
88	Install District Heating Network	80 days	Tue 05/12/15	Mon 08/31/15	87
89	Install Foundations	60 days	Tue 04/14/15	Mon 07/06/15	90SS-40 days
90	Install Building	60 days	Tue 06/09/15	Mon 08/31/15	91SS-40 days



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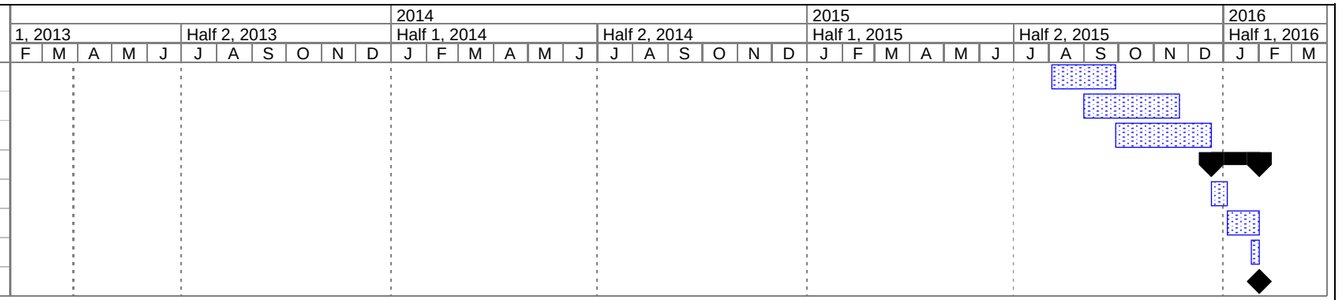
Date: Thu 03/28/13

Task | Milestone | Rolled Up Task | Rolled Up Progress | External Tasks | Group By Summary
Progress | Summary | Rolled Up Milestone | Split | Project Summary | Deadline

ID	Task Name	Duration	Start	Finish	Predecessors
91	Install Gasificaiton System	40 days	Tue 08/04/15	Mon 09/28/15	80
92	Install BOP Equipment	60 days	Tue 09/01/15	Mon 11/23/15	91FS-20 days
93	Install Mechanical / Piping / E,I&C	60 days	Tue 09/29/15	Mon 12/21/15	91
94	**Phase 7 - Start-up & Commissioning**	**30 days**	**Tue 12/22/15**	**Mon 02/01/16**	
95	System Turnover	10 days	Tue 12/22/15	Mon 01/04/16	93
96	Commissioning	20 days	Tue 01/05/16	Mon 02/01/16	95
97	Performance Testing	5 days	Tue 01/26/16	Mon 02/01/16	96FF
98	Commercial Operation	0 days	Mon 02/01/16	Mon 02/01/16	97



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ONE TEAM. INTEGRATED SOLUTIONS.

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Appendix 5.13
Biogas Feasibility Study (WSP 2016)

YUKON ENERGY CORPORATION

BIOGAS PLANT IN WHITEHORSE

FEASIBILITY STUDY

WHITEHORSE, YUKON

Project No: 151-06935-00

JANUARY 2016

BIOGAS PLANT IN WHITEHORSE

0BFEASIBILITY STUDY

WHITEHORSE, YUKON

Yukon Energy Corporation

Project No: 151-06935-00
January 2016

Report (Final version)

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PREPARED BY

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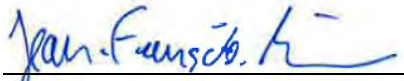
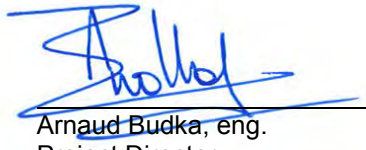


Jean-François Morin, Eng.
Project Engineer
WSP Group

Raphaël Duquette, Eng., MBA
Project Engineer
WSP Group



Arnaud Budka, eng.
Project Director
WSP Group

Reference:

WSP 2016. *Biogas Plant in Whitehorse | 0BFeasibility Study, Whitehorse, Yukon.* Report produced for Yukon Energy Corporation. Project No: 151-06935-00. 61 pages and appendices.

REVIEWED BY

Arnaud Budka, Eng.
Project Director
WSP Group

Éric Camirand, Eng.
Electrigaz Technologies Inc.

The original version of the electronic file we are submitting to you has been authenticated. WSP will keep it in record for a minimum period of 10 years. Given that the transmitted file is no further under the control of WSP and that its integrity cannot be ensured, no guarantee can be given to any subsequent modifications.

ACKNOWLEDGEMENTS

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City of Whitehorse

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Environmental Sustainability City of Whitehorse

Shannon Mallory
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SUBCONTRACTORS

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Project manager, Electrigaz	Eric Camirand
Engineer	Martin Tampier

EXECUTIVE SUMMARY

Yukon Energy Corporation (YEC) is studying the viability of developing a biogas plant to treat Whitehorse residential and commercial source separated organic (SSO) waste and utilize the biogas to produce power and/or heat. Biogas production is placed in the context of a large effort to expand electrical generation capacity in Yukon. Anaerobic digestion is a process to convert organic waste into a gas for the production of clean energy.

YEC hired Electrigaz/WSP to prepare a preliminary design of a biogas plant for Whitehorse organic waste and to assess its economic viability. The design is based on Whitehorse data and previous reports but also on analysis results that Electrigaz/WSP obtained from a sampling campaign conducted in May, September and October 2015.

Whitehorse residential organic waste has been collected and composted for several years. The following curve shows the seasonality of organic waste and municipal solid waste (MSW) being collected from 2000 to 2013.

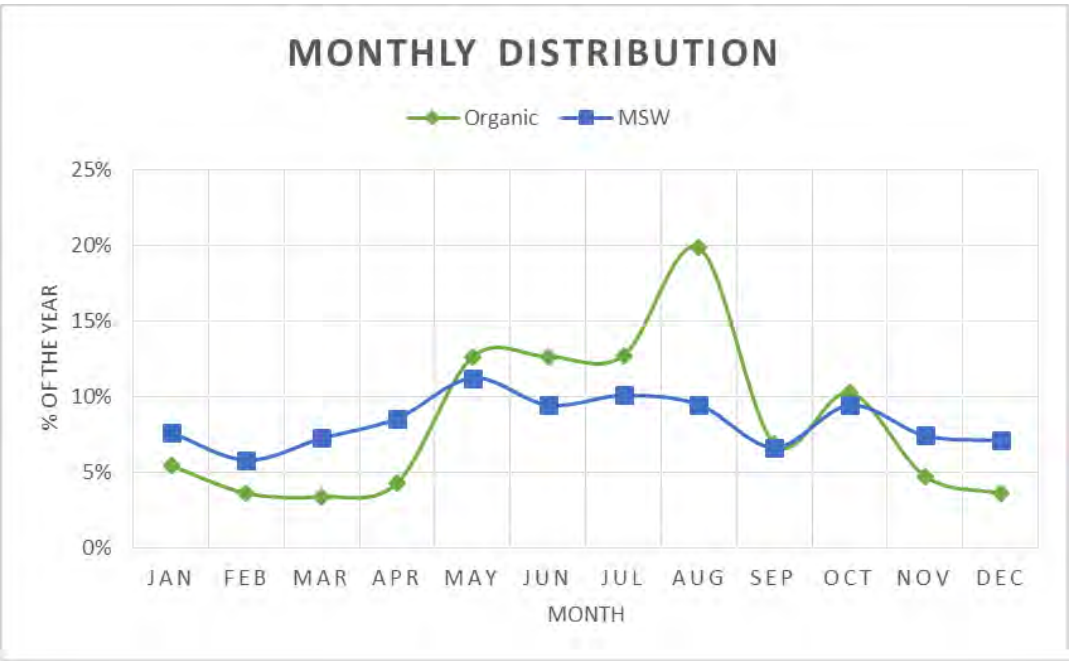


Figure 1 Monthly variation of waste quantities collected

Commercial organic waste collection has been initiated recently in Whitehorse and is being expanded to include additional local businesses. The municipality is also expecting an increase in the quantity of material collected by residential and commercial clients over the next few years. The following curve shows the expected organic waste amounts collected for the next 20 years.

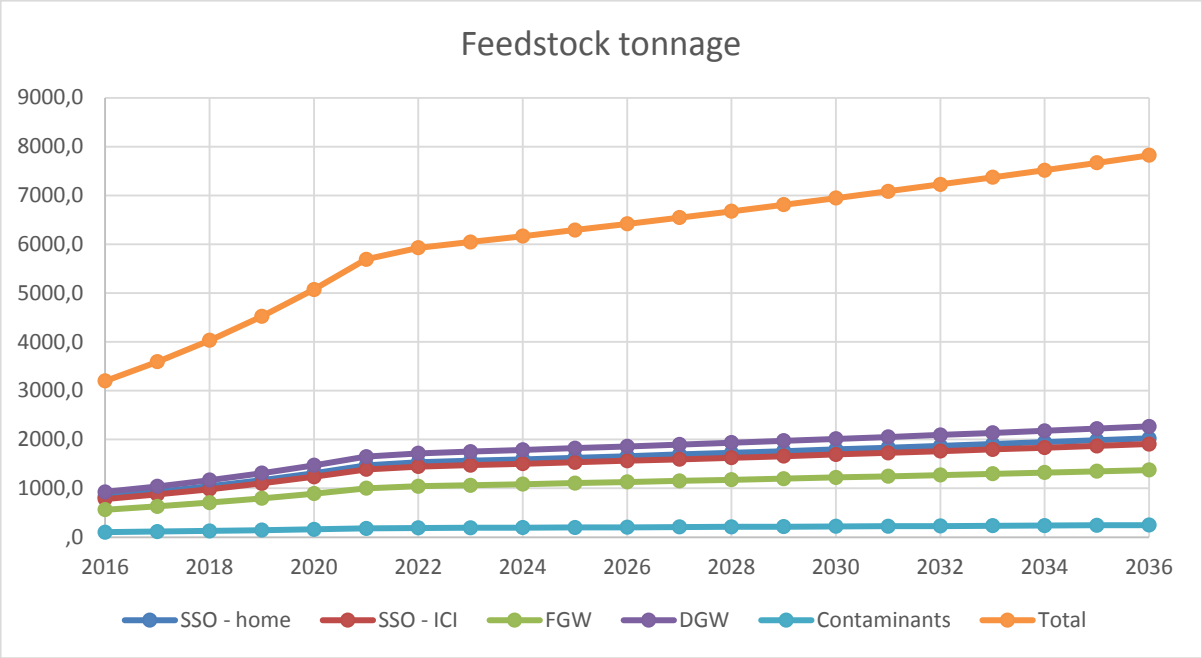


Figure 2 Amount of organic waste collected (2016-2036)

Because of waste volumes and the existing composting platform/equipment, a dry (high solids) garage style anaerobic digester is recommended because it is simple to operate, affordable, uses or discharges virtually no water and requires no front-end contaminant removal (performed by compost sieving) at the Whitehorse compost facility. To reduce unnecessary investment, operational cost and to avoid noise and odor nuisance to neighbouring properties, the proposed plant would be located at the landfill next to the existing composting site.

The proposed biogas plant rated at approximately 150 kW(e) would be composed mainly of a building that includes four anaerobic digestion tunnels and a reception/mixing hall. The combined heat and power (CHP) unit, flare, biofilter and percolate tank are to be placed adjacent to the building. The operation of the plant would be based on a 28-day schedule and the material will be received and stored inside a receiving hall 7 days before entering a garage. In a garage-style digester the material is moved with a front-end loader and each week the operator empties part of the garage before filling with fresh material. The digestate is then sent to the compost facility. The biogas is temporally stored in a 599 m3 biogas holder that is placed on top of the percolate tank. The biogas is then sent to two (2) 100 kW(e) CHP units for production of renewable power and hot water. Two smaller generators are necessary to match significant seasonal biogas production variations, a larger unit could not accommodate these significant "turndowns".

The scenario for production and sale of heat, in the form of hot water, generated by a 500 HP biogas boiler is not recommended because of the cost of deploying a district heating network over to the nearest client for minimum of three (3) kilometers and the heat production being "out of phase" with heating needs (peaking in winter) and biogas production (peaking in summer).

For a "heat only" project to be viable it would have to significantly raise the organic treatment gate fee, gather important capital subsidies and sell 100% of the heat produced during winter and summer months. The following table shows the levelized cost of energy (heat) for different organic treatment gates fees and capital subsidy support.

Table 1 Boiler scenario: financial analysis

Gate fees $/ton	Subsidy % of CAPEX	Lcoe (real) $/ kWh(th)	Lcoe (real) $/GJ
38	0%	0.227	62.996
38	70%	0.085	23.488
45	0%	0.203	56.405
45	60%	0.081	22.541
50	0%	0.186	51.697
50	40%	0.105	29.121

This scenario, estimated at approximately $6.1M, is unlikely to attract industrial clients (green houses, industrial thermal processes, etc.) because energy prices are not discounted significantly. The utilization of biogas in CHP units is better adapted to this location since it allows selling of energy in the summer and during power demand peaks. The deployment of CHP units would be phased in with one 100 kW unit installed initially and a second 100 kW unit (or more if landfill gas is exploited) 5 years later. It is assumed that the heat generated by the CHP would be used entirely at the composting building to heat the facility and potentially dry further the compost before bagging it.

The CHP project is estimated to require a total capital investment of approximately C$7.1M and to cost over $255,000 per year to operate.

The revenue from the biogas plant will come from gate fees, electricity and heat sales. With a current market pricing of $0.21/kWh for the electricity sold to the grid, a $38/t gate fee, and savings of $12/GJ for heat, the project is not economically viable. With these market conditions the project would require significant capital subsidies. The following table shows the levelized cost of energy (electricity) for different organic treatment gates fees and capital subsidy support:

Table 2 CHP scenario: financial analysis

Gate fees $/ton	Heat sales $/GJ	Subsidy % of Capex	LCOE ($/kWh(e))
38	12	0%	$0.638
38	12	70%	$0.206
45	12	0%	$0.576
45	12	50%	$0.267
50	12	0%	$0.531
50	12	40%	$0.284

Biogas captured from the landfill could potentially help boost electrical production and provide better project economics. Further study of this scenario would be needed.

Nevertheless, it is clear that this project will require organic treatment gate fee adjustment and capital investment in form of subsidies because the revenues generated by the project are insufficient to warrant the high capital investment.

Based on the current market conditions it is unlikely that the project would attract independent project developers. The project would probably have to be developed by Yukon Energy Corporation and/or the City of Whitehorse with the support of capital grants.

TABLE OF CONTENTS

1 INTRODUCTION 1
1.1 PROJECT DRIVERS 1
1.1.1 POLICIES 1
1.1.2 ECONOMIC CONTEXT 2
1.2 PROJECT HISTORY 4
1.2.1 COMPOST MARKETS 5
1.3 OBJECTIVES OF THIS STUDY 5
1.4 DATA PROVIDED BY THE CLIENT 5
1.4.1 PROBABLE SITE 5
1.4.2 WHITEHORSE ORGANIC WASTE COLLECTION 6
1.4.3 RESIDENTIAL SSO 6
1.4.4 COMMERCIAL SSO 9
1.5 APPLICABLE TECHNOLOGIES 10
1.5.1 REVIEW OF RFI PROPOSALS RECEIVED FOR THE PROPOSED BIOGAS SYSTEM 10
1.5.1.1 DRY VS WET DIGESTION TECHNOLOGY 10
1.5.1.2 MESOPHILIC VS THERMOPHILIC ANAEROBIC DIGESTION 10
1.5.1.3 RECOMMENDATIONS 10

2 FEEDSTOCK 15
2.1 QUANTITY 15
2.2 COMPOSITION 15
2.2.1 SAMPLING AND TESTING PROCEDURE 15
2.3 FEEDSTOCK TESTING RESULTS AND ASSUMPTIONS 16
2.4 FEEDSTOCK DESIGN CURVE 17

3 PROCESS 18
3.1 PROCESS SELECTION 18
3.2 BIOGAS CALCULATIONS 18
3.3 MASS BALANCE 20
3.4 ENERGY BALANCE 20
3.4.1 BIOGAS UTILISATION 20
3.4.2 PROCESS HEAT LOAD 21
3.4.3 ESTIMATED EXPORTABLE ELECTRICITY 23
3.4.4 ESTIMATED EXPORTABLE THERMAL ENERGY 23
3.4.4.1 HEAT UTILIZATION SCENARIO EVALUATION 23

4 PLANT PRELIMINARY DESIGN 29
4.1 GENERAL PLANT DESCRIPTION 29
4.1.1 EQUIPMENT LIST WITH DESCRIPTIONS 29
4.1.2 P&ID 35
4.2 PLANT LAYOUT 36
4.3 PLANT UTILITIES 37
4.4 POTENTIAL SUPPLIERS 38
4.5 PRELIMINARY ELECTRICAL SLD 38
5 BUSINESS CASE EVALUATION 40
5.1 CHP SCENARIO 40
5.1.1 CAPITAL COST 41
5.1.2 OPERATIONAL COSTS 43
5.1.3 FINANCIAL ANALYSIS 46
5.2 BOILER SCENARIO 49
5.2.1 CAPITAL COSTS 49
5.2.2 OPERATIONAL COSTS 51
5.2.3 FINANCIAL ANALYSES 55
6 CONCLUSION 59
7 REFERENCES 61

APPENDICES

APPENDIX A SAMPLING PROCEDURE
APPENDIX B SAMPLING RESULTS REPORT
APPENDIX C TECHNOLOGY REVIEW

TABLES

TABLE 1 BOILER SCENARIO: FINANCIAL ANALYSIS IX
TABLE 2 CHP SCENARIO: FINANCIAL ANALYSIS IX
TABLE 3 SUPPORT PROGRAMS FOR RENEWABLE ENERGY PROJECTS 4
TABLE 4 2015 COMPOST SALES AND REVENUE 5
TABLE 5 TONS OF WASTE COLLECTED (2000-2013) 7
TABLE 6 RANKING OF RECOMMENDED SUPPLIERS: (++++) HIGHEST SCORE, (-) NO SCORE 12
TABLE 7 MONTHLY SSO COMPOSITION RESULTS AND ASSUMPTIONS 16
TABLE 8 FEEDSTOCK CHARACTERISTICS 17
TABLE 9 ENERGY BALANCE FOR 2016 21
TABLE 10 TEMPERATURE DIFFERENTIAL IN WHITEHORSE 22
TABLE 11 INTERNAL HEAT LOAD TO MAINTAIN DIGESTER AT 37°C 22
TABLE 12 GROSS POWER PRODUCTION (KW(E)) 23
TABLE 13 EXPECTED HEATING DEMAND FOR THREE PRODUCTION SCENARIOS 24
TABLE 14 ESTIMATED MONTHLY EXPORTABLE HEAT AND MAXIMUM THERMAL POWER PRODUCTION FROM CHP SCENARIO 25
TABLE 15 ESTIMATED MONTHLY EXPORTABLE HEAT AND MAXIMUM THERMAL POWER PRODUCTION FROM BOILER SCENARIO 26
TABLE 16 CHP SCENARIO: ECONOMIC ASSUMPTIONS 40
TABLE 17 CHP SCENARIO: CAPITAL COSTS 42
TABLE 18 CHP SCENARIO: OPERATIONAL COSTS (FOR YEAR 1 TO 9) 44
TABLE 19 CHP SCENARIO: OPERATIONAL COSTS (FOR YEAR 10 TO 20) 45
TABLE 20 CHP SCENARIO: CAPITAL COSTS BREAKDOWN 46
TABLE 21 CHP SCENARIO: FINANCIAL ANALYSIS 46
TABLE 22 CHP SCENARIO: FINANCIAL RESULTS (FOR YEARS 0 TO 9) 47
TABLE 23 CHP SCENARIO: FINANCIAL RESULTS (FOR YEARS 10 TO 20) 48
TABLE 26 BOILER SCENARIO: ECONOMIC ASSUMPTIONS 49
TABLE 28 BOILER SCENARIO: CAPITAL COSTS 50
TABLE 29 BOILER SCENARIO: OPERATIONAL COSTS (FOR YEARS 1 TO 9) 53
TABLE 30 BOILER SCENARIO: OPERATIONAL COSTS (FOR YEARS 10 TO 20) 54
TABLE 31 BOILER SCENARIO: CAPITAL COSTS BREAKDOWN 55
TABLE 32 BOILER SCENARIO: FINANCIAL ANALYSIS 55
TABLE 33 BOILER SCENARIO: FINANCIAL RESULTS (FOR YEARS 0 TO 9) 57
TABLE 34 BOILER SCENARIO: FINANCIAL RESULTS (FOR YEAR 10 TO 20) 58
TABLE 37 BOILER SCENARIO: FINANCIAL ANALYSIS 59

TABLE 38 CHP SCENARIO: FINANCIAL ANALYSIS 60

FIGURES

FIGURE 1 MONTHLY VARIATION OF WASTE QUANTITIES COLLECTED VII
FIGURE 2 AMOUNT OF ORGANIC WASTE COLLECTED (2016-2036) VIII
FIGURE 3 WHITEHORSE, YK 6
FIGURE 4 WHITEHORSE MUNICIPAL LANDFILL (IN RED) AND COMPOSTING SITE (IN GREEN) 6
FIGURE 5 MONTHLY VARIATION OF WASTE QUANTITIES COLLECTED 8
FIGURE 6 CURBSIDE COLLECTION SCHEDULE 2015 9
FIGURE 7 AMOUNT OF ORGANIC WASTE COLLECTED (2016-2036) 17
FIGURE 8 ANNUAL BIOGAS PRODUCTION BY FRACTION (2016-2036) 18
FIGURE 9 2016 MONTHLY BIOGAS PRODUCTION 19
FIGURE 10 MONTHLY BIOGAS PRODUCTION. 2016-2036 19
FIGURE 11 MASS BALANCE 20
FIGURE 12 OSHKOSH GARAGE-STYLE BIOGAS PLANT 29
FIGURE 13 P&ID 35
FIGURE 14 BIOGAS PLANT LOCALISATION 36
FIGURE 15 BIOGAS PLANT LAYOUT 37
FIGURE 16 ELECTRICAL SLD 39

1 INTRODUCTION

Yukon Energy Corporation (YEC) is studying the viability of developing a biogas plant to treat Whitehorse residential and commercial source separated organic (SSO) waste and utilize the biogas to produce power and/or heat. The biogas production is placed in a large effort from YEC to expand electrical generation capacity in Yukon.

1.1 PROJECT DRIVERS

1.1.1 POLICIES

The 2009 Energy Strategy for Yukon identifies the increased use and supply of renewable energy as a priority for the Yukon government: it seeks to expand the supply of renewable energy by 20 per cent by 2020 and to update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy. The Strategy aims at being self-sufficient in terms of energy, using local resources, which would include biomass. On the other hand, when the Strategy refers to biomass it means wood, and does not mention biogas as an opportunity in Yukon. It gives priority to renewable energy development in diesel-powered communities, yet also mentions the hydro grid may reach its capacity in the near future. Indigenous gas (LNG) resources could, however, be used to make up for any shortfall. Yukon released a draft policy for independent power production earlier this year.

The Strategy complements the Yukon government's 2009 Climate Change Strategy and Action Plan. It mentions waste management as a specific priority and states that "the Yukon government is undertaking a study to review the administration and operations of territorial solid waste sites to assist the government with determining sustainable management practices." This study, however, although put out per RFP, was never commissioned [YG 2015c]. Although landfill emissions are identified as a major GHG emission source, it is not clear how the biogas initiative fits into the Plan, which mainly focuses on the territorial government's own emissions, as well as industrial emissions. It does have a target to reduce electricity use by demand-side management programs by 5 GWh by 2016, yet electricity production projects, as the one under consideration, are usually not seen as elements of demand management.

The Yukon government provides a number of programs to help Yukon residents, businesses, First Nations, and municipalities reduce their energy consumption and replace fossil fuels with local renewable energy resources. None of these seem applicable to the proposed project.

Yukon Energy Corporation: As a renewable energy company, YEC is exploring all potential renewable energy options. YEC is interested in harnessing biogas as an energy source and has conducted testing on organic material to assess its biogas potential in 2014 [YEC 2015]. This present report is the next step of this project, by presenting a feasibility analysis in order to determine whether the biogas project in Whitehorse could move forward.

City of Whitehorse: The city's Sustainability Plan aims at increased renewable energy, reducing GHG emissions, and operational cost savings – all reflected in the scope of the biogas project. Waste diversion and composting are mentioned as goals, but no connection is made between energy and waste. "Work with private businesses on innovative ideas in waste management" is one of the ideas mentioned as an appendix to the Plan.

Solid waste management is identified as a key element of the current 2013-2015 Council priorities on the city's website. With a goal of Zero Waste by 2040, the City's Solid Waste Action Plan sets an initial target of a 50% reduction in the amount of waste sent to landfill by 2015. Sixty two percent (62%) of the waste

landfilled comes from the institutional, commercial, and industrial sectors. In year 2015, landfill disposal rates for businesses are [CoW 2015]:

- Unsorted waste: $ 250/ton (food service businesses only)
- Sorted waste free of organics: $ 94/ton
- Organic waste (separated): $ 36/ton

On June 1st, 2015, the City of Whitehorse enacted the first phase of the commercial organic waste management bylaw, which bans organic waste (food scraps, compostable paper and packaging, food soiled cardboard and waxed cardboard) from disposal as garbage from Food Service Businesses. These businesses now have to pay a much higher disposal rate for unsorted waste containing organics. The city's Sewer and Storm Bylaw requires all commercial, industrial and institutional food facilities to dispose of fats, oils and grease properly and to install and maintain a proper grease interceptor (grease trap) to appropriate plumbing fixtures. Such fat would be a valuable ingredient for a digester. The City's commercial organic waste diversion efforts have diverted 96 tonnes of organics in 2013/14 and also target other commercial, institutional, and multi-family buildings. At that time, 5,700 residential homes were participating in bi-weekly organics collections [CoW 2015b].

1.1.2 ECONOMIC CONTEXT

Microgeneration Program: This program is administered by the Energy Solutions Centre and offers $0.21 per kWh of electricity fed into the grid in the Whitehorse area. It is mainly aimed at residential customers, with an upper capacity limit of 50 kW. As such, it is not suitable for the proposed project.

Carbon credits: Emission reduction projects, which reduce after-project emissions to below current baseline emission levels, can leverage the sale of carbon credits to part-finance the project. In this case, however, carbon credits are an unlikely source for financing because:

- The project is small. This means few credits would be generated and their monetization is then not cost-effective. To certify credits for sale, it is necessary to engage two consultants for emission quantification and verification. This annual process can cost more than $10,000 and is usually only employed for larger projects.
- Emission reductions will be small. The waste heat produced will likely be used on-site with a large portion being consumed to heat the digester (fermentation usually occurs at temperatures around 35°C, which requires heating). The electricity produced will also partly be used internally to operate the digester, and the amount exported to the local grid will mainly displace hydro or in the future, LNG, given that Whitehorse's electricity comes from the hydro-based Yukon Integrated System.
- Selling carbon credits means that any carbon emission reductions achieved by the project are lost to the purchaser: it is as if the credit purchaser had created these emission reductions himself and they can then no longer be claimed for the city's internal reduction targets.

IPP Policy: The draft (May 2015) independent power producer (IPP) policy identifies the proposed project as a "Tier 1" project, since it is less than 2 MW in size and would be connected to the Yukon Integrated System. A Standing Offer Program is expected to be operational by the end of 2015. Biomass (potentially including municipal SSO) is explicitly included as an eligible energy source. The proposed IPP rate for projects on the Integrated System is 21 ¢/kWh, which is the avoided cost of generations of YEC (rates will be updated every three years and posted publicly to reflect changes in the avoided cost of new generations).

Heat: Some of the waste heat produced by the biogas engines will be required to heat the digester. Surplus heat is likely too little to warrant a hot water pipeline to customers off the landfill premises. The landfill's own buildings could, however, be heated. They are currently heated with electricity and some propane for peaking purposes in the winter, as well as for backup. The forced air heating system (as opposed to replacing baseboard heaters) would simplify the use of waste heat to supplement or replace the current heating fuels. General electricity service costs (on a monthly basis) for municipal clients on the Integrated System are [YHC 2012]:

- 11.36 ¢/kWh for the first 2,000 kWh;
- 14.59 ¢/kWh for the next block up to 15,000 kWh;
- 17.72 ¢/kWh for over 15,000 up to 20,000 kWh;
- A demand charge of $8.26/kWp also applies (this could be reduced if electric heating is replaced);
- A monthly base fee of $41.28 is charged to municipal customers (not affected by project).

Although no electricity bill from the landfill was available, compiled billing data suggests the landfill consumes between 1,000 and 4,000 kWh of electricity per month [CoW 2015c], placing it into the 14.59 ¢/kWh class for its marginal electricity cost. This would then be the cost to be paid for any extra grid electricity required to operate the digester. Since the municipal government and non-governmental service rates are almost identical, no material economic impact would result if the digester would be operated by a private entity required to pay its own electricity bills.

Cooking oil: MacDonald's (and possibly, other businesses) are currently shipping used cooking oil to Alberta for processing. This occurs at considerable cost [YN 2013] and a digester could reduce this cost while producing a large amount of biogas from the material. Smaller amounts of used oil from other sources are currently either landfilled or mixed in with composting material. Some smaller operations use their own used oil to operate vehicles converted for using filtered cooking oil, or for heating [ibid.].

Financing: The Yukon Government has no particular program to provide financial incentives for renewable energy projects; their support is based on the IPP policy outlined above. Some federal programs exist that could fund or co-fund the biogas project (see Table 1). For example, the ecoENERGY program for aboriginal and northern communities offers financial support for heat and power production in northern Canada (the potential amount available is unknown since program rules are currently under revision). Note that funding programs are often not accessible to private project proponents (such as IPPs) but only to municipal or aboriginal groups.

Table 3 Support Programs for Renewable Energy Projects

Program Name	Program Authority	Eligibility
ecoENERGY for Aboriginal and Northern Communities	Aboriginal Affairs and Northern Development Canada	First Nations Municipalities
EcoAction	Environment Canada	Non-profit community groups only
Green Municipal Fund	Federation of Canadian Municipalities	Municipalities (energy projects must displace at least 40% of current energy use)
Philantropic project funding	Bullfrog Power	Contact Bullfrog for details; typical funding amount is $10,000 per project

1.2 PROJECT HISTORY

Over the years, several studies have been conducted to assess the technical feasibility of an organic waste treatment plant in Whitehorse. The first major study specific to biogas was conducted by Aecom Canada Ltd. in 2010 and the conclusion was that renewable biofuel production will help the reduction of greenhouse gas (GHG) emissions, will enhance local energy security and displace fossil fuel usage. The second major study was conducted by Morrison Hershfield in 2012; the conclusion was that the value of the electricity produced would have to be between $0.21 and $0.66 per kWh. Both studies mention the technical feasibility of the future plant and the need of a feasibility study that would evaluate the real cost.

In 2014, YEC conducted an RFI to measure market interest for supplying equipment and/or project development for this project. The RFI was for 4,000 tons per year of organic material. YEC received four complete proposals from Bio-en Power, Bioferm, Himark and Gicon. They also received two CHP proposals from 2G Cenergy and AB Energy,in 2015. The proposals can be resumed as follows:

- The Bio-en power system costs $2,608,277 +/- 20%, with a 100 kW(e) CHP unit.
- The Himark system costs $2,264,821, with a 132 kW(e) CHP unit
- The Bioferm system costs $4,037,000 USD, with two 100 kW(e) CHP units
- The Gicon system costs $7,440,727,with a 125 kW(e) CHP unit

The RFI process also provided information on:

- Modular approach to manage increases in amounts of biowaste collected
- Digester performance for each company
- Input characterization requirements
- Operation of each system
- Operation and maintenance cost

1.2.1 COMPOST MARKETS

There are two markets for the compost currently produced at the landfill: retail to residential and commercial clients, and wholesale to local farmers. The latter market is currently not yet active but could be developed in the near future. The City of Whitehorse believes that "organic" certification for the compost – expected to be achieved soon – would open up the farming market for its product, for any amounts produced that cannot be sold to the retail market.

The retail market has a volume of about 400 tons per year, with an increasing trend. The compost is well liked by local customers and so, sales have been growing over the past years. According to the city, retail sales occur at the rates and volumes shown in Table 2.

Table 4 2015 Compost Sales and Revenue

Sales Unit	Price	Annual Volume	Total Sales
20 litre bags	$5 each	1,810 bags (≈36 yd^3)	$9,065
1-9 cubic yards	$45/$yd^3$	113 yd^3	$5,085
10+ cubic yards	$25/$yd^3$	758 yd^3	$18,950
Agricultural (bulk)	$25/$yd^3$	Not yet developed	$0
TOTAL		400+ tons*	$33,100

Source: CoW 2015b
Note: Sales from January 1 through September 30. Sales end in early October.
* Assuming a bulk density of 1000 lb/yd3 [NCSU 2015

If the farming market were to take up any incremental volumes, the compost would likely be sold at the same $25/$yd^3$ price that is currently in use for larger bulk customers [CoW 2015b]. In 2014, the amount of food waste accepted for composting was 2,225 tons. This resulted in about 500 tons of compost produced. Much of the weight loss is due to lost moisture but another 500 tons are used at the landfill as cover material since the material is too contaminated with rocks, plastics, etc. to be sold [ibid.].

1.3 OBJECTIVES OF THIS STUDY

YEC hired Electrigaz/WSP to prepare a preliminary design of a biogas plant for Whitehorse organic waste and to assess the economic viability of such a project. The design is based on Whitehorse data and previous reports but also on analysis results that Electrigaz/WSP has obtained from a sampling campaign in September and October 2015.

1.4 DATA PROVIDED BY THE CLIENT

1.4.1 PROBABLE SITE

The AD system is proposed to be constructed on the Whitehorse Municipal Landfill near the actual composting site. Figure 1 is a sky view of Whitehorse and the red box is the landfill location (Figure 2).

Figure 3 Whitehorse, YK

Figure 4 Whitehorse municipal landfill (in red) and composting site (in green)

1.4.2 WHITEHORSE ORGANIC WASTE COLLECTION

The City of Whitehorse has been collecting residential and commercial SSO for several years and is currently composting this material at their composting platform located at the municipal landfill site. There are two types of collection: residential and commercial.

1.4.3 RESIDENTIAL SSO

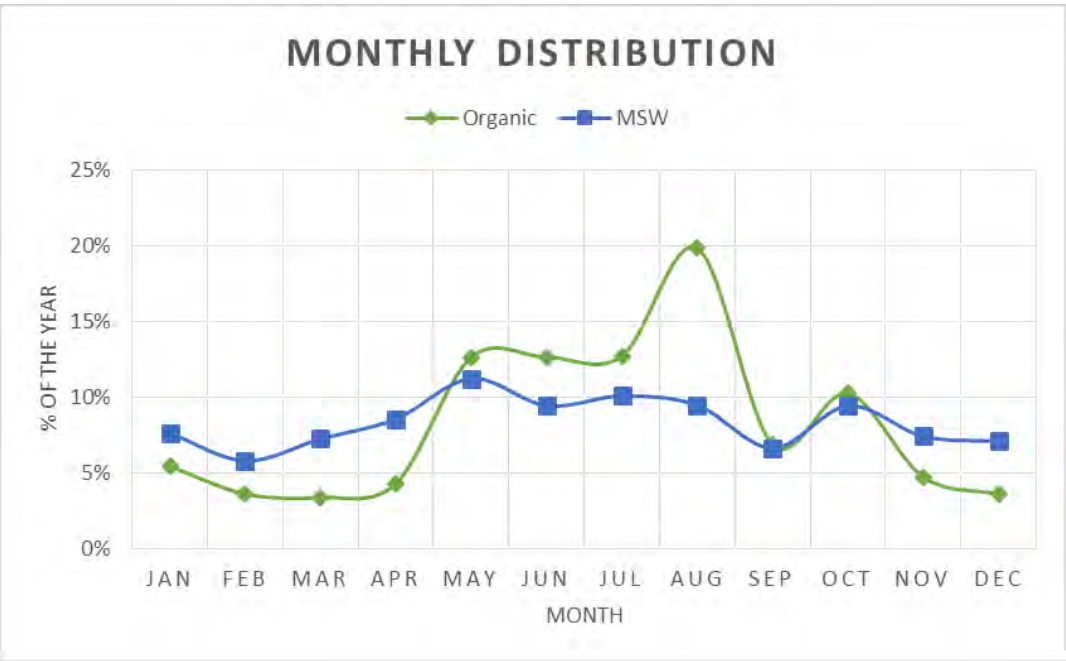
The first organic collection (residential) started in 2000 and the number of participants is growing each year. The collected amounts for organic and total waste from 2000 to 2013 are presented in Table 3. The total organic represents both the residential curbside collection and the ICI collection.

Table 5 Tons of waste collected (2000-2013)

Tons/Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Organic	203	388	852	943	1 005	1 041	977	1 131	1 314	1 828	2 149	2 569	2 117	2 267
Total MSW	10 578	11 455	11 145	11 348	12 232	13 120	13 205	14 615	14 431	14 140	15 870	14 742	14 974	14 093
% organic/MSW	2%	3%	8%	8%	8%	8%	7%	8%	9%	13%	14%	17%	14%	16%

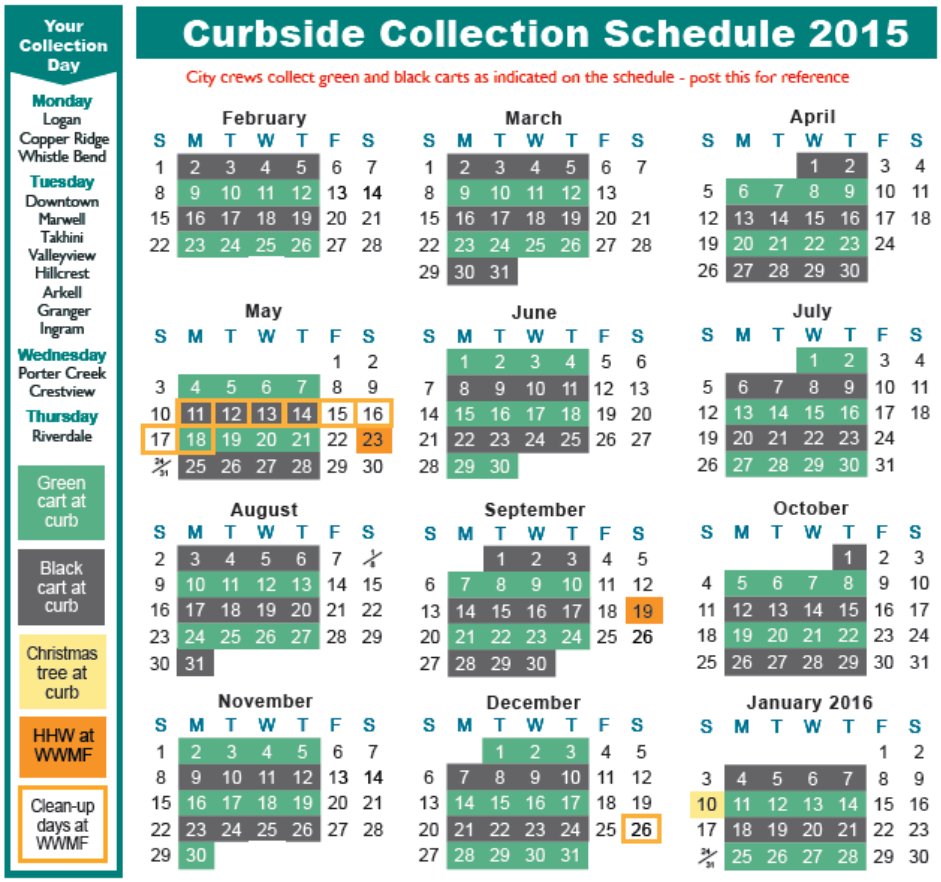
The amounts shown in Table 3 are shown on a monthly basis in the figure below, based on Whitehorse previous reports. This figure demonstrates the variation of amounts collected throughout the year, with a peak in August.

Figure 5 Monthly variation of waste quantities collected



SSO regroups all organic waste separately collected from residential sources. In Whitehorse, residential SSO has been collected for more than 10 years and the number of participants is growing each year. The SSO is collected in green bins on curbsides every two weeks (see Figure 4 for details on curbside collection).

Figure 6 Curbside Collection Schedule 2015



The SSO includes food waste like meat, fish and any dairy product but also garden waste and food soiled paper. Electrigaz/WSP separated the SSO into four different fractions to determine the gas production potential of the material in an AD:

1. Food waste (SSO)
2. Green yard waste (GYW)
3. Dry yard waste (DYW)
4. Contaminants (rocks, sand, plastic, non-organic materials)

Prior to this report, a sampling and analysis campaign was undertaken to determine the percentages of each fraction. The sampling and analysis procedure can be found in Appendix A.

1.4.4 COMMERCIAL SSO

ICI includes multi-family residential, restaurant and grocery food waste, as well as materials collected from the hospital and the correctional centre. Collections recover material from large bins near each facility and arrive each Friday.

Like residential organics, ICI is also separated into four fractions (SSO, GYW, DYW, contaminants)

1.5 APPLICABLE TECHNOLOGIES

1.5.1 REVIEW OF RFI PROPOSALS RECEIVED FOR THE PROPOSED BIOGAS SYSTEM

YEC has received replies from five suppliers to its request for information; Himark, Viessmann/BIOFerm (BIOFerm), Bio-en Power, Wildstone/Gicon (Wildstone), and Enerpedia. The suppliers propose different technology solutions, which have been reviewed in order to give a recommendation on a preferable technology. More in-depth information on each supplier is presented in Annex 7.3 Technology review.

Which technology to use, in this particular project is a function of the feedstock characteristics (the substrate) as well as the specific conditions, on-site. The substrate is predominantly source sorted organic waste collected by City of Whitehorse's municipal organics collection system. It consists mainly of food waste with some yard clippings in the spring, summer and fall. The substrate is considered dry, i.e. containing relatively high solids. The design of the biogas production system also needs to consider the large variations in the amount of waste as well as changes to the composition of the waste throughout the year.

There are some site conditions to specifically take into consideration; the cold climate, the scarcity of water supply at the site and the fact that the facility does not provide room for additional composting beyond 2,200 tons per year.

1.5.1.1 DRY VS WET DIGESTION TECHNOLOGY

Anaerobic digestion systems can be divided into dry and wet technologies. The dry technologies are used for substrates with a high concentration of total solids (TS), i.e. over 25 % TS. According to the feedstock characteristics determined by the feedstock samples, TS is never less than 24 %. This indicates that a dry technology is preferable. An additional argument for using a dry digestion technology is the scarcity of water at the site. Dry digestion technologies use only a fraction of the water used by wet technologies. Therefore, a dry (high solids) digester technology is recommended. Such systems are also in use at other municipal organic waste processing facilities, such as the Harvest Power system in Richmond, BC.

1.5.1.2 MESOPHILIC VS THERMOPHILIC ANAEROBIC DIGESTION

The anaerobic digestion process can function over a wide range of temperatures. From psychrophilic temperatures at around 10°C, to mesophilic temperatures at around 35°C and thermophilic temperatures at around 55°C. Mesophilic and thermophilic digesters are most commonly used, given the higher gas production from those systems.

Thermophilic conditions offer a higher biogas yield by reactor volume, but require a higher energy input for heating. In a mesophilic reactor, the digestive process is more stable and less subject to process inhibition.

Since every supplier has a preferable temperature range, this parameter will be determined by the type of system and supplier chosen. At this point, there is no recommendation as to which temperature range is preferable.

1.5.1.3 RECOMMENDATIONS

Since the water supply is a concern for the project, a wet digestion technology is not preferable. Bio-en power proposes a biogas facility using wet digestion, which according to the RFIs uses, approximately,

twice as much water as the dry technologies. Therefore, the proposal from Bio-en power is not recommended.

Even though the proposal from Enerpedia includes a dry digestion technology, it is not designed for this specific project. It is therefore hard to say whether the proposal meets the requirements for this site or not. One concern is whether the design, which was originally prepared for the market in France, is resilient enough for the much colder climatic conditions in Yukon.

Himark's, BIOFerm's, Wildstone's and Bekon's proposals are based on essentially the same technology, even though they present it in different terminologies. The proposed designs operate in different temperature ranges. As mentioned earlier, a recommendation as to the preferable temperature range cannot be given at this stage of the project. To make an adequate choice of supplier, more specific and detailed information is required.

Since the proposals are designed for different capacities and feedstocks, the figures are hard to compare. It may not be accurate enough to simply convert the figures to a certain feedstock amount since other elements of the plant design and setup may change as a result. Instead, the numbers are presented per ton input. Comparisons between the numbers should be performed with caution. The heat and electricity output as well as the water usage are especially hard to compare, since not all suppliers present data or use different units.

The following table shows a preliminary ranking of each supplier. The values are based on the original amounts of feedstock used in each proposal.

Table 6 Ranking of recommended suppliers: (++++) Highest score, (-) No score

Supplier	Cost estimate	Biogas production	Chp output	Water usage
Himark	Total cost based on 4000 tons input: C$ 3,005,694* C$ 751/ton input (+++)	Total based of 4000 tons input: 806,285 m^3/year 201.6 m^3/ton input (++++)	Gross power output: 134 kW_e Net power output: 121 kW_e Thermal output: 265 kW_{th} Process heat input: 173 kW_{th} (-)	Total based on 4000 tons input: 504 tons/year 0.126 tons/ ton input (++++)
BIOFerm	Total cost based on 3,202 tons input: C$ 5,211,191* C$ 1,627/ton input (++)	Total based of 3,202 tons input: 266,316 m^3/year 83.2 m^3/ton input (+)	Gross power output: 583 MWh_e/year Gross thermal output: 817 MWh/year (++++)	(-)
Wildstone	Total cost based on 2,334 tons input: C$7,440,727 C$ 3,188/ton input (+)	Total based on 2,334 tons input: 232,403 Nm^3/year 100.4 m^3/ton input (++)	Gross power output: 472 MWh_e/year Net power output: 245 MWh_e/year Gross thermal output: 609 MWh_{th}/year Net thermal output: 477 MWh_{th}/year (+++)	Total based on 2,334 tons input: 467 tons/year 0.2 tons/ton input (+++)
Bekon	Total cost based on 4,500 tons input: C$ 3,085,000 C$ 685.5/ton input (++++)	Total based on 4,500 tons input: 512,820 m^3/year 113.9 m^3/ton input (+++)	(-)	Total based on 4500 tons input: 2500 tons/year 0.56 tons/ ton input (++)

* Exchange rate 1.326903, 2015-11-19

Himark made the lowest cost estimate and projects the highest biogas output. However, Himark's biogas output per ton input seems overrated since the figure is about double compared to BIOFerm, Bekon and Wildstone. The project cost estimate seems very low compared to the other proposals. Bekon's proposal also estimated a very low cost but that is explained by not including the CHP unit.

BIOFerm has excluded some items from the budgetary costs. For example, engineering design, earthworks, odor control system, fire suppress system design and installation, front end loader, biofilter, composting equipment, etc. Wildstone on the other hand has, in addition to the engineering, equipment, installation, commissioning and support connected to the process, also included engineering, civil, structural, mechanical and electrical costs connected to the building. This might explain why Wildstone's budgetary costs are higher than the others.

Himark, Bekon and Wildstone have provided figures for the water usage. Himark uses the lowest amount of water per ton input. Bekon's water usage estimation represents more than two times the water

consumption of the other suppliers. This higher water consumption may be explained by using water for cleaning the fermenter doors and drains.

Regarding the electricity and heat output, the figures cannot be meaningfully compared since Himark only presents the capacity rating of the CHP, BIOFerm does not present net outputs and Bekon presents no output at all. For the economic analysis of the project, the heat and electricity net output provided to the market is of crucial importance.

To conduct a proper ranking, more information is needed and the different categories would have to be weighted. It is recommended to ask for more specific information from Himark, BIOFerm, Wildstone and Bekon regarding annual fresh water usage, annual heat and electricity net output, biogas production, and estimated costs.

2 FEEDSTOCK

2.1 QUANTITY

The organic waste volume was monitored from the year 2000 to 2013 (Table 3). Electrigaz/WSP estimated the volume of organic waste for the lifetime of the future biogas plant (2016 to 2036).

Hypothesis

- 44% of the total waste is organic (source: Recyc-Quebec)
- 2% increase of total waste generated per year
- 10% increase of organic waste diverted per year
- 80% maximum collection efficiency for the separated organic fraction
- 30% of the total organic waste is from the ICI sector

The historical amounts are shown in Table 3 and the future estimate is shown in Section 2.4 below. The amount of organic waste collected in 2016 should be around 3,200 tons and after 20 years of operation, the plant should be operating at around 7,800 tons per year. The tonnage will grow rapidly in the first five years to reach around 6,000 tons per year as more residential and commercial clients get involved and are educated in the process. The assumed growth in waste generation comes from the City of Whitehorse expected organic diversion resident's participation. All others assumptions come from the consultant experience and extrapolation of previous studies.

2.2 COMPOSITION

A sampling and testing campaign was performed to assess SSO composition and overall quality of the feedstock for biogas production.

2.2.1 SAMPLING AND TESTING PROCEDURE

The sampling campaign took place in May, September and October 2015 and was followed by lab analyses. The objectives of this campaign were to estimate the nature and proportion of contaminants and to estimate the monthly tonnage and characterize the variation of its composition throughout the year. The principal results are in Tables 5 and 6. For detailed results, see the sampling report in Appendix B. The sample procedure and the on-site assessment are described in the sampling report appendix.

The principal on-site observation is the low content of contaminants (less than 5% of weight) and the very high content of green and dry yard waste in summer and fall for residential collections. The contaminants are mostly plastic bags but cardboard, recyclable material, styrofoam, bottles, wood and landfill material are also found.

Samples were analyzed for total solid, volatile solid and NPK contents. WSP/Electrigaz decided not to perform a biochemical methane potential (BMP) test because the nature of the materials found is common to AD projects and the high cost of a BMP test was not justified, given reliable estimates can be made based on feedstock composition and literature values.

2.3 FEEDSTOCK TESTING RESULTS AND ASSUMPTIONS

Table 5 represents the quality hypothesis used to calculate biogas production. The hypothesis is based on consultant expertise combined with sampling campaign results from three different months. The organic waste from ICI and residential sources was sampled in May, September and October 2015. Samples were analyzed on a mass basis to evaluate the percentage of each waste fraction.

All samples reveal less than 5% of contaminants. Organics from the ICI sector were generally less contaminated than those collected from the residential sector.

ICI waste is mainly composed of SSO through the year, with a peak of yard waste in September. Residential waste is mainly composed of SSO from November to April. During the rest of the year, yard waste can make up for more than 80% of the mass.

Table 7 Monthly SSO composition results and assumptions

Period	Ici				Residential			
	SSO	Green Yard Waste	Dry yard waste	Contaminants	SSO	Green Yard Waste	Dry Yard waste	Contaminants
Jan	93,0%	0,5%	3,0%	3,5%	91,0%	0,5%	5,0%	3,5%
Feb	95,0%	0,5%	1,0%	3,5%	95,0%	0,5%	1,0%	3,5%
Mar	96,0%	1,0%	1,0%	2,0%	90,5%	0,5%	5,0%	4,0%
Apr	96,5%	1,0%	1,5%	1,0%	51,0%	0,5%	44,0%	4,5%
May	95,9%	0,3%	2,9%	1,0%	11,7%	0,5%	83,2%	4,6%
Jun	90,0%	4,0%	4,0%	2,0%	15,5%	30,0%	50,0%	4,5%
Jul	75,0%	10,0%	12,0%	3,0%	16,0%	45,0%	35,0%	4,0%
Aug	65,0%	15,0%	15,0%	5,0%	26,5%	40,0%	30,0%	3,5%
Sep	46,4%	44,5%	8,5%	0,6%	38,8%	30,7%	29,4%	1,1%
Oct	84,0%	13,1%	2,4%	0,5%	32,1%	11,0%	56,3%	0,6%
Nov	91,5%	2,5%	2,5%	3,5%	71,5%	5,0%	20,0%	3,5%
Dec	93,0%	0,5%	3,0%	3,5%	90,5%	1,0%	5,0%	3,5%

Three samples from May, September and October were sent to the Environmental Research and Innovation Center of the University of Wisconsin for further analysis. The sampling and analysis protocols described in appendix A were designed to provide the most accurate picture of organic waste seasonal volumes and composition. The principal information that was necessary for the present report was the total solid (%TS) and the volatile solids (%VS). Both results are shown in Table 6. The lab also analyzed total nitrogen, phosphorus and potassium content (NPK) to see if there may be potential for inhibition during the digestion process. The tolerance to inhibitors will depend on the AD process but should not be a concern at this point regarding the result in the lab.

Table 8 Feedstock characteristics

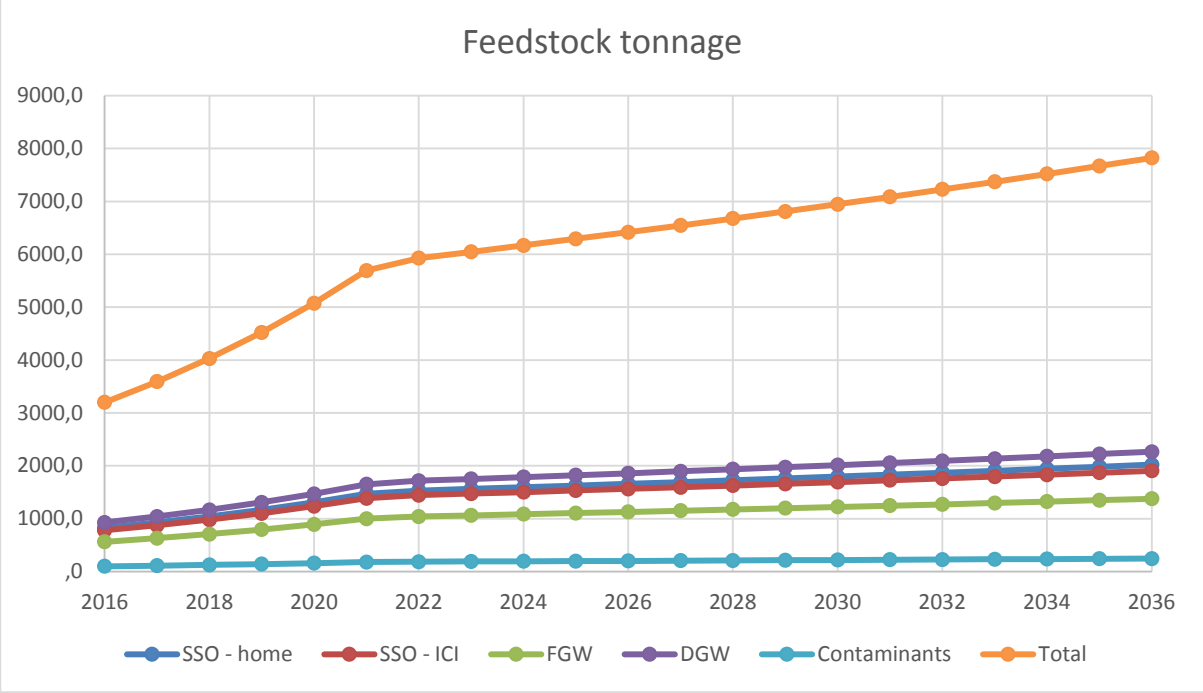
Feedstocks	%TS	%VS	M³ Biogas/T VS	Density (KG/L)	Methane (%CH_4)
SSO from residential collection	36%	82%	600	0,9	60%
Green yard waste	31%	81%	380	0,8	55%
Dry yard waste	44%	86%	100	0,8	55%
SSO from ICI	23%	83%	600	0,9	60%

Note: %TS and %VS come from Wisconsin laboratory results and the other parameters come from the consultant's database.

2.4 FEEDSTOCK DESIGN CURVE

The figure below shows the amount of each organic waste fraction collected and the total amount of organic waste expected to be collected from 2016 to 2036. To produce those curves we applied the hypothesis in section 2.1 to Tables 3 and 5. Based on the City of Whitehorse's organic program forecast, the first five years show the learning and adaption curves as the collection is expanded to include more and more of the existing buildings, and after the first five years, the amount is growing as the waste amount is growing with demographics (2%/year). The feedstock is separated in different SSO fractions including fresh garden waste (FGW) and death garden waste (DGW).

Figure 7 Amount of organic waste collected (2016-2036)



3 PROCESS

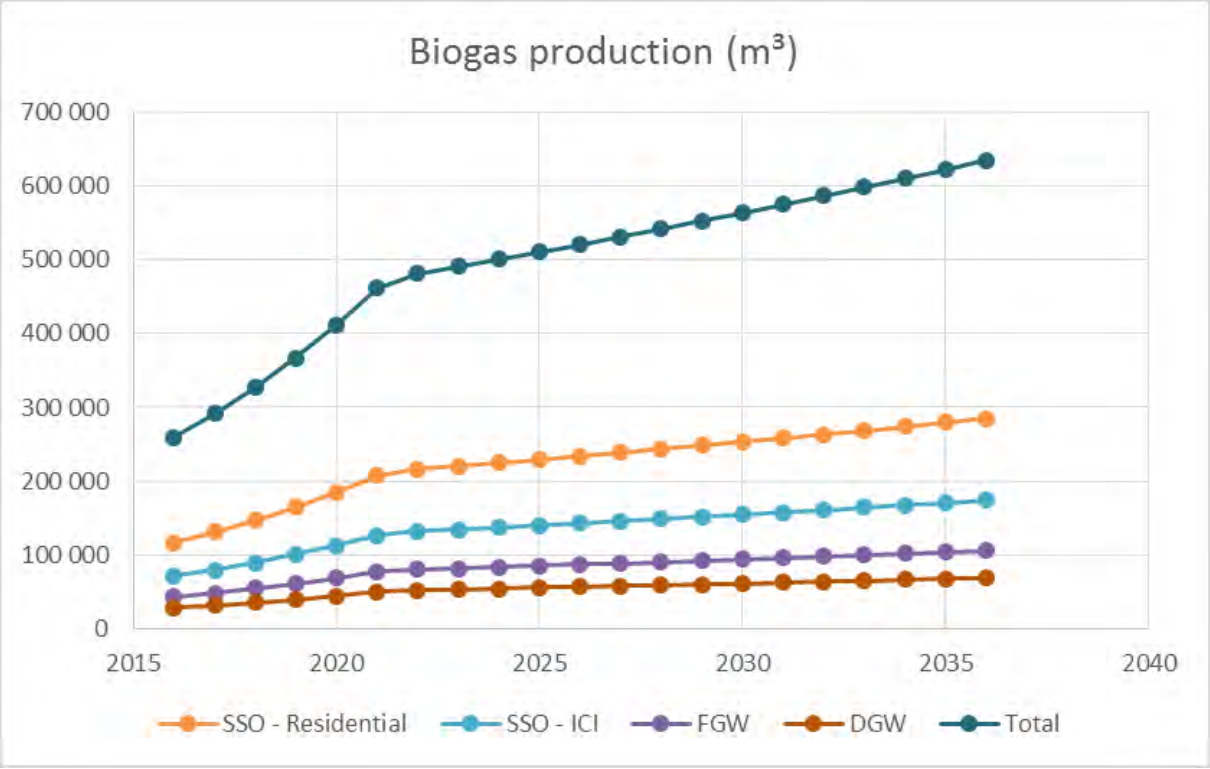
3.1 PROCESS SELECTION

Because of waste volumes and existing composting platform/equipment, a dry garage-style anaerobic digester is recommended since it is simple to operate, affordable, uses or discharges little water and requires no front-end contaminant removal. To reduce capital costs and to avoid odour or noise nuisance to neighbouring properties, the proposed plant would be located at the landfill, next to the existing composting site.

3.2 BIOGAS CALCULATIONS

The figure below shows the biogas production per year from all organic fractions from 2016 to 2036. The biogas production calculation is using the tonnage, the quality and the methane potential of each organic waste fraction. Each SSO fraction has different composition leading to specific biogas production.

Figure 8 Annual biogas production by fraction (2016-2036)



The biogas production will vary in quality and quantity through the year but will average 5.63 kWh thermal per normal cubic meter. The potential production of biogas (Figure 7) is close to 15.000 m³/month in April and near 65 000 m³/month in August. This variation can be expressed in m³/hr, as shown in Figure 8. Note that the biogas storage capacity can only allow biogas storage for hours (3 to 10 hours) and therefore cannot store summer biogas production for usage in the winter.

Figure 9 2016 monthly biogas production

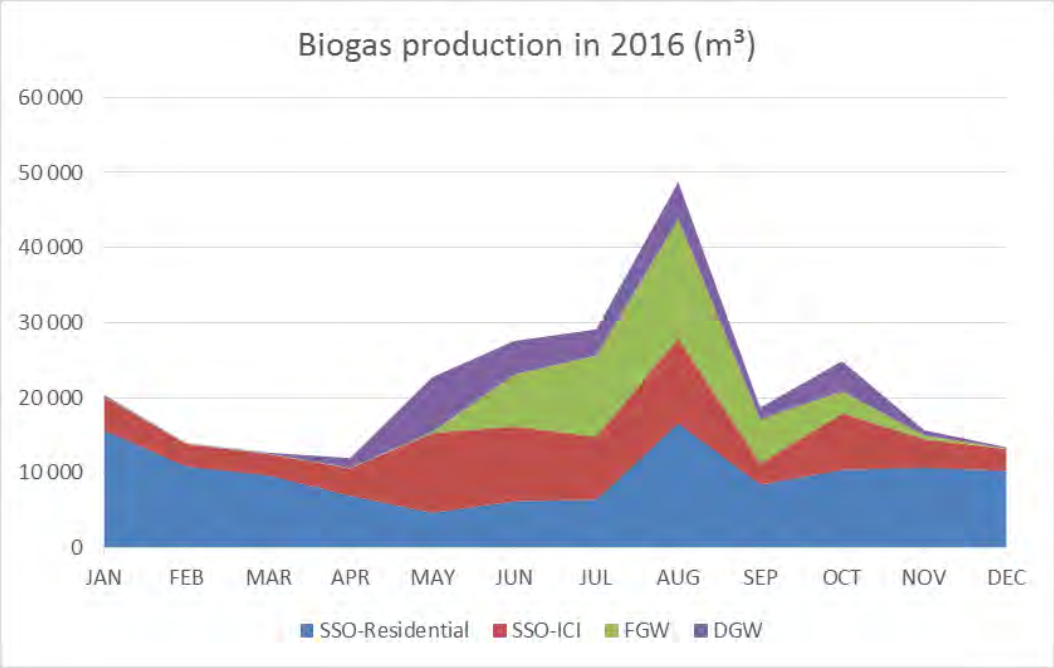
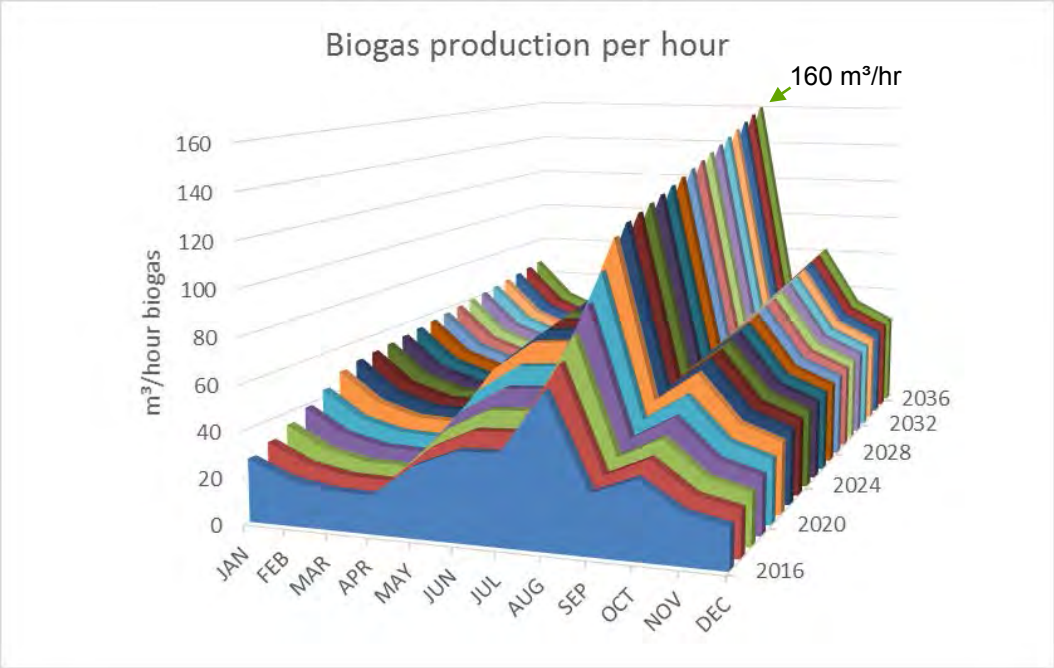


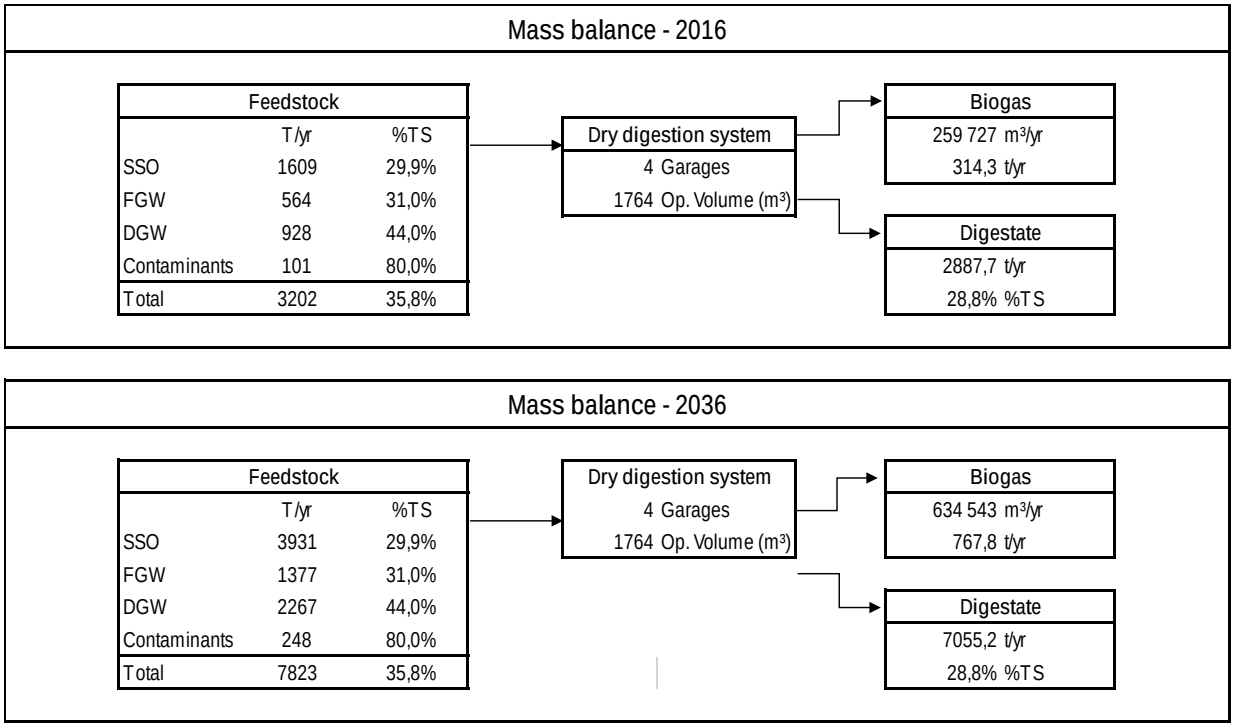
Figure 10 Monthly biogas production. 2016-2036



3.3 MASS BALANCE

The next figure shows the mass balance of a dry digestion batch system for 2016 and 2036. The mass balance represents a typical system; the final mass balance for the Whitehorse site should be provided by the technology supplier. The addition of water and operational parameters will impact the final mass balance. The facility processing capacity is flexible, allowing to process 2016 tonnage as well as 2036. The process elasticity is possible by adjusting chambers retention time and filling levels.

Figure 11 Mass balance



3.4 ENERGY BALANCE

3.4.1 BIOGAS UTILISATION

Biogas utilisation was analyzed for two cases. The first case is the utilisation of a boiler to produce heat (hot water) and the second case is the use of a combined heat and power (CHP) system to produce electricity and heat (hot water).

For the boiler scenario, it has been estimated that all biogas will be injected to a boiler with a thermal efficiency of 90%.

For the CHP scenario, the use of two 100 kW(e) CHP provides more flexibility to the operator, producing electricity for sale and heat for self-consumption. Section 4.5 contains more details on the potential utilisation of thermal heat for both cases.

WSP/Electrigaz recommends a phased acquisition of the CHP system by installing only one 100 kW CHP unit at project start and adding the other one after about five years. Phased construction will increase the use factor of each CHP unit and will lead to a steadier electricity output curve.

Normally a 100 kW(e) CHP unit can be used at a 50 to 100 kW(e) output. The electric efficiency of these units is between 30 to 39% and the thermal efficiency is between 40 to 49%. To model the CHP unit for the economic analysis, 35% was used as the average electric efficiency and 40% for thermal efficiency.

The project will have an average electricity output capacity of 56 kW(e) in 2016, dropping to 33 kW(e) in April and reaching the full 100 kW(e) in August. In 2036, the average output level will be 132 kW(e), dropping to 80 kW(e) in April and reaching 200 kW(e) in August. During the winter months, when the biogas production is low, the CHP system cannot run 24/24h because the minimum range of the CHP is 50 kW. In this case, the biogas holder will help utilize biogas during peak hours.

The average thermal output level will be around 64 kW in 2016, with 37 kW in April and 114 kW in August. In 2036, the average thermal output level will be around 151 kW, with 91 kW in April and 229 kW in August. The energy balance can also be estimated in percentage as shown in table 9.

Table 9 Energy balance for 2016

	Boiler Scenario	CHP Scenario
Total biogas energy	100.0%	100.0%
Electricity production	0.0%	35.0%
Heat production	78.7%	28.7%
Internal heat use	11.3%	11.3%
Energy loss	10.0%	25.0%

The electricity production represents the percentage of energy used to produce the electricity with the CHP. The heat production percentage represents the heat output amount after the internal heat use (heating of feedstock and digesters). The internal heat use represents the percentage of energy production used for internal heat load.

The energy loss is based on the efficiency of the equipment for each scenario. In the CHP scenario the electricity production has an efficiency of 35% and the heat production of 40%, this means that there's a loss of 25%. For the boiler scenario the efficiency is 90%.

3.4.2 PROCESS HEAT LOAD

The process heat load is based on the need of heat to bring the feedstock to 37°C from its original temperature (assuming a mesophilic system) during each month of the year and the heat that is necessary for maintaining the complete system at 37°C.

The next equation was used to determine the heat needed to bring the feedstock to the operation temperature.

$$Q=M*Cp*\Delta T$$

Where:

- Q = Amount of thermal energy transferred (kJ)
- M = Mass of feedstock (kg)

→ Cp = 4.19 kJ / kg * K

→ ΔT = Temperature differential (K)

The ΔT used in this report was based on average temperature in Whitehorse and the differential is presented in the next table.

Table 10 Temperature differential in Whitehorse

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ΔT	55.7	50.1	44.2	36.7	30.4	25.4	23.0	24.7	29.7	36.3	47.0	52.9

The heat necessary to maintain the system at 37°C was calculated by using the percentage of the thermal energy that was needed to heat the feedstock. In this study, WSP/Electrigaz estimated 11.3% of the energy produced used to heat the process. The total heat load is presented in the next table in gigajoule.

Table 11 Internal heat load to maintain digester at 37°C

Heat Load	2016		2020		2024		2028		2032		2036	
	GJ	MWh (th)	GJ	MWh (th)	GJ	MWh (th)	GJ	MWh (th)	GJ	MWh (th)	GJ	MWh (th)
Jan	55	15	87	24	106	29	102	28	124	35	135	37
Feb	33	9	52	14	63	18	61	17	74	21	80	22
Mar	27	8	43	12	52	14	50	14	61	17	66	18
Apr	29	8	45	13	55	15	53	15	65	18	70	19
May	70	19	110	31	134	37	129	36	157	44	170	47
Jun	58	16	92	26	112	31	108	30	132	37	142	40
Jul	53	15	84	23	102	28	98	27	120	33	130	36
Aug	89	25	141	39	171	48	165	46	201	56	217	60
Sep	37	10	59	16	71	20	69	19	84	23	91	25
Oct	68	19	107	30	130	36	125	35	152	42	165	46
Nov	40	11	64	18	78	22	75	21	91	25	99	27
Dec	34	10	55	15	66	18	64	18	78	22	84	23
Total	593	165	940	261	1,142	317	1,098	305	1,339	372	1,449	402

3.4.3 ESTIMATED EXPORTABLE ELECTRICITY

The power that can be exported to the grid is shown in the next table, using a simplified approach based on an average kW(e) per month output level and continuous operation. This calculation represents 100% of the system's gross power output and does not deduct internal power use to operate the digester (assumed to be provided from the grid at the landfill's current electricity rate).

Table 12 Gross power production (kW(e))

KW(E)	2016	2020	2024	2028	2032	2036
Jan	54	86	104	113	122	132
Feb	39	63	76	82	89	96
Mar	34	53	65	70	76	82
Apr	33	52	63	68	74	80
May	60	95	116	125	136	147
Jun	75	119	145	157	170	184
Jul	77	122	148	161	174	188
Aug	100	200	200	200	200	200
Sep	51	81	98	107	115	125
Oct	66	104	127	137	149	161
Nov	43	68	83	89	97	105
Dec	35	56	68	74	80	87

These gross power production figures can also be represented has the potential of electricity production each hour of the day (capacity factor already factored in)

3.4.4 ESTIMATED EXPORTABLE THERMAL ENERGY

3.4.4.1 HEAT UTILIZATION SCENARIO EVALUATION

Waste heat utilization scenarios have already been evaluated in a previous study. Two surplus heat utilization scenarios were analyzed:

- District energy system
- Greenhouse heating

For the district energy system the study targeted some main buildings that could be powered by an energy generation unit. Some public buildings in the Whitehorse area include the correctional center and Yukon College, situated approximately 3 km from the composting site. However, even this distance is considered too far to be economically viable primarily because of the capital cost of such a heat

transportation grid[1]. There is also the possibility to sell heat to nearby industrial facilities or composting sites. The scenario has been assumed in the present study for economic analysis.

The other possibility analyzed in a previous study is greenhouse heating. The study analyzed different scenarios considering the market demand on typical vegetables such as tomatoes, cucumbers and lettuce. The study established different footprint areas required to respond to market demand. These scenarios have been taken to estimate energy requirements for different greenhouse footprints. Note that these values have only been taken to analyze if such scenarios would be feasible in the present analyzed project. In the previous study, vegetable market demands for Haines Junction community and Whitehorse were analyzed. Three different scenarios were established. The first one was to respond to 100% of Haines Junction's demand which would represent approximately 2% of the Whitehorse demand. This scenario would require a greenhouse of 486 m^2. This is the smallest scenario considered by the study as the two other scenarios required a footprint of 5,338 and 5,824 m^2 to respectively respond to 25% of Whitehorse's demand and 27% of Whitehorse's demand. From these footprints, the study established energy demand peaks presented in the following table.

Table 13 Expected heating demand for three production scenarios

Heating Demand	Whitehorse (2%)	Whitehorse (25%)	Whitehorse (27%))
Greenhouse footprint area required (m^2)	486	5,338	5,824
Maximum heating energy required (kW_{th})	167	1,829	1,995
Total capital/construction & Durable goods cost	$ 167,625.70	$ 1,539,359.82	$ 1,436,720.50
Yearly O&M costs	$ 79,485.26	$ 883,065.32	$ 963,446.89

Haines Junction Bioenergy Project – Evaluation of waste heat potential, Clean Technology Community Gateway, 2012.

The previous table also shows the capital investment that would be needed to build these greenhouses as well as the operational cost for each scenario.

However, it must be noted that these values represent peak energy demand and were calculated considering an outdoor temperature of -54ºC. This extreme temperature is not expected on a regular basis.

The following section will analyze the feasibility of such scenarios, considering the thermal energy availability from the proposed AD plant.

The highest energy availability from an AD plant occurs during the summer months. Two main reasons explain this fact. First, the input tonnages are higher in summer, which leads to higher biogas production. At the same time, in the summer months, internal energy consumption is lower due to higher outdoor temperatures. These two facts combined lead to much higher energy availability in the summer when heat energy demand is at its lowest. Greenhouse heat demand is not different from any other energy consumers, i.e. it needs more energy in winter. This means there is an imbalance between energy production and energy demand in this kind of project.

The following table presents the estimated monthly usable waste heat production from the AD project, using a CHP unit for three targeted years. The analyzed years have been targeted considering the CHP

[1] Haines Junction Community study assumed a cost of $944/m for distribution pipe (typical for Canadian provinces; may be a low estimate for Yukon). A 3 km pipe would then cost $2.8M.

purchase phases of the project (a second CHP unit would be installed in 2020) and to illustrate the impact of increased organic waste collection rates throughout the years.

Table 14 Estimated monthly exportable heat and maximum thermal power production from CHP scenario

Maximum KW_{TH} And GJ Exportable With CHP	2016		2020		2036	
	Total GJ	Maximum kW_{th}	Total GJ	Maximum kW_{th}	Total GJ	Maximum kW_{th}
Jan	110	41	175	65	269	100
Feb	80	33	127	52	196	81
Mar	76	28	120	45	185	69
Apr	68	26	108	42	167	64
May	114	43	181	68	279	104
Jun	165	64	262	101	403	156
Jul	183	68	290	108	446	167
Aug	217	81	471	176	395	148
Sep	114	44	181	70	279	108
Oct	134	50	212	79	328	122
Nov	87	33	137	53	211	82
Dec	74	28	117	44	181	68
Total	**1,423**	**n/a**	**2,381**	**n/a**	**3,340**	**n/a**

This table shows that only a small amount of heat could be exported - especially in the winter months.

If greenhouse scenarios are analyzed thoroughly, only the smallest scenario (representing 2% of Whitehorse vegetable demand) could possibly be fed with heat as its maximum heat demand is reached in July 2036 (167 kWth). However, this heat generation peak is reached only after 20 years and is in July, when there is little heat demand from a greenhouse. The heat demand peak will be in winter months when the exportable heat is expected to be very low due to internal plant consumption.

Note that for this scenario and for the purpose of the economic analysis of this study, it has been estimated that all heat would be sold to nearby composting site.

However, biogas could also be directly directed to a 500 HP boiler and only generate heat that could be used the same way. This option would produce no electricity but could generate approximately twice the amount of heat to be gained from the CHP unit's waste heat. The following table shows heat generation values with a boiler scenario.

Table 15 Estimated monthly exportable heat and maximum thermal power production from boiler scenario

Maximum KW_{TH} And GJ Exportable With Boiler	2016		2020		2036	
	Total GJ	Maximum kW_{th}	Total GJ	Maximum kW_{th}	Total GJ	Maximum kW_{th}
Jan	317	118	502	187	774	289
Feb	221	91	351	145	541	223
Mar	204	76	323	121	498	186
Apr	189	73	300	116	463	179
May	345	129	546	204	842	314
Jun	444	171	704	272	1 085	419
Jul	477	178	757	283	1 167	436
Aug	799	298	1 267	473	1 953	729
Sep	304	117	481	186	742	286
Oct	386	144	612	228	943	352
Nov	245	95	389	150	599	231
Dec	210	78	333	124	513	191
Total	**4,141**	**n/a**	**6,563**	**n/a**	**10,118**	**n/a**

The winter heat demand peak would be reached in January 2020 but not in December or February - two months that have the same energy demand peaks. However, the January heat availability means that it could be possible to fill heat demand even in the winter months. Therefore, an auxiliary heating system could be used when extreme conditions occur, whereas the biogas could generate enough energy to maintain the temperature of a 486 m^2 greenhouse.

Previous study found that to be economically viable, a greenhouse project will have to be highly subsidized and similarly so would a greenhouse at the Whitehorse compost facility using biogas waste heat. In fact, all scenarios analyzed were generating high annual losses. It must be noted that this study assumed waste heat would be provided free of charge. This means that with any price of energy, these scenarios would be even less viable.

Note that for this scenario (thermal power production from boiler scenario) and for the purpose of the economic analysis of this study, it has been estimated that all heat would be sold to nearby composting site and any other industrial company that could be situated in a radius of approximately 700 m from the site. At the moment, KBL is actually present in a radius of 700 m but its heat consumption would probably be "out of phase" with biogas production (peaking in summer). Moreover, actual yearly heat consumption only adds up to 8 550$[2], which would not be enough for the present estimated heat production.

[2] Value extracted from Doug Dawley email received on the 7th of December 2015

Also note that because no greenhouse scenario proved to be viable in the previous report and because of the imbalance of energy production and consumption, no greenhouse scenario has been analyzed further in this report. The economic analysis in section 5 shows both boiler and CHP scenarios would need subsidies or higher gate fees to be viable and, considering the capital investment and operational cost of greenhouses, the addition of one of any size to these projects would only bring down their economic viability.

4 PLANT PRELIMINARY DESIGN

4.1 GENERAL PLANT DESCRIPTION

The plant is composed mainly of a building (garage) that houses four anaerobic digestion tunnels and a reception/mixing hall (Figure 10). The CHP unit, flare, biofilter and percolate tank are located outside the building. The operation of the plant is based on a 28-day schedule and the material is stored outside for seven days before entering the garage. In a garage-style digester the material is moved with a front-end loader and each week the operator empties part of the garage before filling the tunnels with fresh material. The digestate is then sent to the compost facility.

Before the opening of the garage, air is injected to reach a safe atmosphere. The air in the garage is always monitored to assure safety. Batch operation forces the operator to leave at least 40% of the digestate in the garage to accelerate the digestion process of the new material. A biolfiter is used to treat the air inside the building.

The percolate and the process water are sent to the percolate tank and recirculated in the garage to humidify and inoculate the fresh material. The biogas is stored in a 599 m³ biogas holder that is placed above the percolate tank. The biogas is then sent to the CHP unit or a boiler. Typically these systems come equipped with health and safety systems to detect biogas leaks and other hazards.

Figure 12 Oshkosh garage-style biogas plant

4.1.1 EQUIPMENT LIST WITH DESCRIPTIONS

- 4 x Dry digester (garage style) : 21 m L x 7 m W x 5 m H
- 2 x Biogas blower
- 1 x Biogas holder (600 m3) and percolate tank (1000 m3)
- 1 x Biogas H2S removal and water trap with one pump
- 2 x CHP unit (gas engine) with exhaust gas heat recovery
- 3 x Percolate pumps
- 1 x Open flare

- 1 x Biofilter
- 1 x Air blower
- 1 x Heat exchanger with one pump
- Biogas piping
- Percolate piping
- Air piping
- Hydraulic system
- Control (SCADA, PLC)
- Instrumentation (flow meter, thermocouple, LEL/HEL sensors, biogas analyzer, etc.)

A process schematic is presented in section 4.1.2 below.

Reception and composting area

A designated area within the building is reserved for feedstock mixing. This area will have sufficient space to receive feedstock for a minimum of seven days and to allow proper mixing of the incoming feedstock with up to 40% of the actual digestate used as an inoculum. The feedstock mass is transported with a front-end loader to the digester building, then directly to the feedstock mixing/staging area. The mixed substrates are then transported to the respective digester, again using a front-end loader.

As discussed in section 2.3, the incoming feedstock contains less than 5% contaminants. Throughout the year, the yard waste portion of ICI and residential organic waste will vary. ICI waste will have its yard waste peak in September, while residential waste will contain 80% of its mass in yard waste from May through October. Depending on the technology that will be used, part of the yard waste can be diverted directly to composting, if needed.

Whitehorse Composting Facility

The Whitehorse Composting Facility has been optimized recently (2014) to operate more consistently throughout the year (particularly during the winter), to reduce the space required for composting, to reduce operation and maintenance cost, and to reduce issues associated with plastics films. The production of compost from SSO and yard waste is achieved using outdoor highly aerated windrows. The windrows' dimensions are 30 ft wide by 14 ft high. Note that the City of Whitehorse is planning future upgrades to the current composting facility that include perforated concrete pads to aerate the composting windrows as well as computer-controlled aeration and temperature monitoring using wireless temperature probes.

Whitehorse's SSO and yard waste are delivered to the composting facility via the city's waste collection program. The feedstock is dropped by the organic waste trucks at the designated reception area onto the compost pad. Each load is inspected in order to manually remove coarse contaminants. The bags (compostable or plastic) containing the different feedstock materials and the bulking agents are taken to a mixer with a front-end loader. The bulking agent may be a combination of yard waste and separated compost overs. The equipment, a twin vertical screw-mixer that can process approximately six tons of a blend of composting material at a time, is used mainly to break open bags, to shred food waste, and to prepare a homogeneous blend. The mixer is powered by a 120 horsepower farm tractor. The screws in the mixer have very sharp knives rotating at 40 rpm. The cutting action of the mixer knives allows breaking open the plastic bags without shredding them to small pieces, which can be very difficult to screen afterwards. The plastic bits are small enough that they do not hinder the composting process.

The blended material is then discharged from the mixer and piled up, forming aerated windrows to begin the composting process. The composted material reaches temperatures up to 80°C and is turned at least once during the composting process to allow all the material to be exposed to the temperatures required for potential pathogen elimination. The total composting process residence time can vary from four months to a year, depending on operational parameters (i.e.: temperature, air flow, humidity, etc.) After the compost is cured, it is screened to ¼ of an inch diameter using a trommel screener with a stainless steel mesh. The resulting compost is a clean high organic material that is sought after by the community.

High Solids Digestion – Garage style digester

The proposed garage style digester system operates on a sequential batch basis, where four garage boxes / chambers are deployed in the dedicated digester building. Each of these chambers accommodates 7 days' worth of feedstock. The process involved in the sequential batch operation cycle is described below:

1. Feed mixing & preparation
2. Loading
3. Percolation and fermentation – anaerobic system
4. Purging and ventilation
5. Unloading

The four rectangular digesters are of carbon steel construction with epoxy coating, and stainless steel lining in the headspace. They are sealed, gas-tight, in order to contain the biogas produced and minimize heat loss. Their key design features are as follows:

1. Dimensions: 21 m Long x 7 m Wide x 5 m High, with at least 0.6 m of free head space
2. Door arrangement: hydraulically operated gas-proof gates with inflatable sealing lip placed on the gate frame for sealing. The door can open horizontally as well as vertically, depending on design.
3. Drainage to be provided on the floor periphery and mid-line to channel the percolate/percolation flow towards a below-grade collection sump with a passive screening system to prevent collection of larger solid particles.
4. Fine mesh grating covering the drainage trough on the periphery and in the center of the floor. The entire floor is to be used as the loading surface for the feedstock stack (the material inside each digester tunnel). This surface will be slightly inclined to direct the liquid flow towards the troughs.
5. Nozzle spray system (i.e.: 6 rows of 12 percolation sprinklers) that allows the percolate reuse to further expose the material to micro-organisms for material decomposition and methane production. This system ensures effective distribution of the percolate stream over the feedstock.
6. The garage digesters are completely sealed with alarms to indicate loss of pressure. All doors are sealed with a system for detecting seal failure as well as sensors capable of sensing liquid levels, pressure, and gas composition in digesters and gas and liquid flow from digesters on a continuous basis.

Percolate recycling and fermentation

The percolate storage is designed to serve as a reservoir for heat and anaerobic cultures and provides buffering capacity against acids generated at batch start-up. The percolate that filters through the feedstock is collected and stored in a continuous stirred tank reactor (CSTR) located close to the garage digesters. The CSTR tank has a membrane roof system that temporarily acts as gas storage. This keeps the biogas at constant pressure and houses incoming gas from the four digestion chambers. In order to conserve heat and protect the digester membrane from the climate, it is recommended to include an additional hard shell roof. The biogas captured from each garage digester is routed through a piped ventilation system to the dual membrane CSTR tank. The tank is usually operated at mesophilic temperature and includes paddle mixers. The mixers are controlled via variable frequency drives and the drive motor of the mixer is mounted onto the outside wall of the tank.

The key functions of the percolation system are:

1. Inoculation of the feedstock with a stream that contains fine particles and is a biologically active substrate
2. Maintaining adequate moisture content in the feedstock stack
3. Initial soaking and heating to thermophilic temperatures of the freshly loaded feedstock, with higher percolation flow rates.
4. Tempered low-source heating of feedstock
5. Hydrolysis of the feedstock stack material, and carry-over of dissolved solids in the stream
6. Generation of biogas from the percolation tank

The key elements of the percolation system are:

1. Percolation tank; Carbon steel tank, used for storage of the percolate stream as well as production of biogas from the percolation stream. The percolation tank is furnished with a heating loop to maintain its operating temperature constant. The head space of the tank is epoxy power coated to prevent corrosion from H2S. The membrane roof system temporarily acts as gas storage
2. Percolation Tank Supply pump/s (2): centrifugal pump(s) with interconnected piping that transfer percolate collected flow from the garage digesters to the percolation tank
3. Percolation feed pump/s: centrifugal pump(s) with interconnected piping that transfer percolate stream from the tank to the spray nozzles in the fermenters.

Biogas Treatment

The biogas is driven from the garage digester and the percolation tank by blowers. It is then sent to a gas conditioning system to ensure acceptable gas parameters (i.e.: temperature, humidity, contaminant levels). The water in the biogas is removed by reducing the gas temperature to condense and remove surplus moisture. Corrosive compounds, such as H2S, are also removed via a carbon filter and/or iron sponge before leaving the gas conditioning unit. The biogas is then ready for use in the CHP unit or it will be combusted in the process flare.

The following step in the biogas polishing process is to remove the remaining moisture from the gas. This is achieved when it passes through a condenser where chilled water is used to decrease the temperature of the biogas. A diaphragm pump delivers the condensate to the percolate tank as make-up water, thereby minimizing offsite disposal. The pressure of the biogas is adjusted by modifying the blower power to ensure that it is delivered at the correct pressure.

Biogas Flare

A biogas flare is incorporated into the proposed biogas plant concept. The flare is used to burn off spec gas during start-up of each digester, and in instances when more biogas is being produced than can be utilized by the CHP system.

CHP System

The biogas generated via the fermentation process in the digesters at the Whitehorse Facility will be utilized as a fuel source in 2 X 100 kW(e) CHP biogas engines. The biogas produced should have a suitable methane concentration to be used as fuel for a gas engine. In a CHP plant, the gas will be combusted in the engine and converted to mechanical and thermal energy for the process and/or electric energy for the community.

The CHP system is supplied with its own control system, which communicates with the digester control system (DCS) for the rest of the plant. Waste heat from the CHP system's exhaust gas is captured in a water/glycol stream and then utilized in the biogas plant.

Ventilation and purge system

Prior to digester loading/unloading (digester exchange), a purge system will safely dilute methane to below flammable levels, using air. At the time of digester exchange, air composition inside the chamber will continuously be monitored and stored. This data will be used to evaluate production levels and biogas quality, as well as to ensure safety when performing operations inside the chambers. The values will be communicated to the security system controlling the chamber doors, which cannot be opened until all methane is completely removed from the chamber and safe atmospheric levels of CO2 and H2S are reached. During a normal purging sequence, air will be brought in to dilute the fermenter chamber, resulting in a very small period of time and range at which the fermenter will pass through the explosive zone. Hence, the potential explosion risks will be avoided. The purging of a garage digester, through the biofilter, can take from 3 to 6 hours. The rate of air changes is set at a minimum of 12 changes per hour. The key components of the purging system are:

1. Forced air blower/s
2. Fibreglass reinforced plastic piping from the blower up the garage digester, and to the exhaust system
3. Explosivity (lower/higher explosive limit) Sensor (1 per digester)
4. Gas chromatograph inlet in the common Air/Biogas exhaust line

Odor control

The building and process air from the reception and mixing area, digestate processing area, and the digester purge gas will be treated to minimize the odor. An odor control system, in this case a biofilter, will remove the odors from the air stream. The complete air system will be controlled and monitored by software and will operate optimally to reduce water and energy consumption. An acid wet-scrubber will be installed upstream to the fans under negative pressure and will send the scrubbed air to the biofilter. To facilitate the operation, the biofilter can be designed for 120 to 150% of the required capacity. The air-to-surface ratio of the biofilter will allow a residence time greater than 60 seconds.

The key components of the odor control system are:

1. Corrosion resistant duct system
2. Corrosion resistant fan

3. Biofilter, complete with watering and water circulation system

During the cold season, the process water will be heated to prevent the piping freezing and to increase the temperature of the air stream going to the biofilter.

Wastewater reuse

The water used in the air scrubber is continuously recirculated and only a fraction (blow-down) requires disposal to the CSTR tank. The precipitate from the process is a desirable nutrient-rich additive to the compost product.

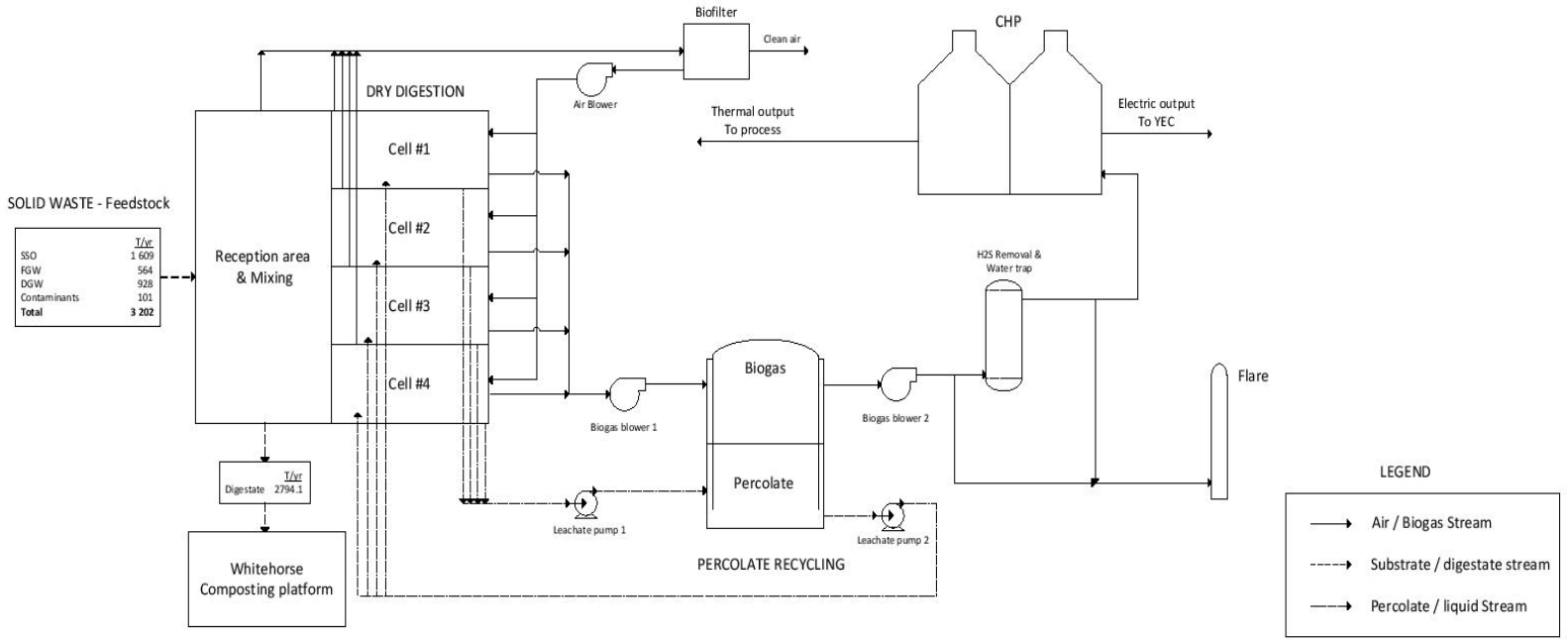
The percolate of the biofilter is filtered and recirculated on the biofilter surface for maintaining an adequate moisture level in the filter bed. Any excess water due to precipitation is collected and captured in the CSTR tank.

Plant Instrumentation, Control and Analysis

The proposed biogas plant is fully automated by a supervisory control and data acquisition (SCADA) system. The SCADA system monitors and controls the various unit processes and the operation of the mechanical equipment that comprise the digestion and biogas processing systems. The SCADA system consists of sensors, indicators, actuators, final control elements, interface equipment, and accessories connected to distributed programmable controllers operating in a multi-user, multitasking environment. The SCADA system is designed to allow trending of process information and notification of plant alarms. Programmable Logic Controllers (PLC) provide for distributed control of the digestion and biogas processing systems. Both discrete and analog interfaces are used for the field devices, such as motors, valves, switches, thermocouples, and transmitters. The fermentation system's instrumentation and control system will provide data to the operations personnel required to monitor the digestion and biogas system process instrumentation. The corporate personnel would also be able to view the performance of, and make changes to the processes remotely over the Internet if needed.

4.1.2 P&ID

Figure 13 P&ID

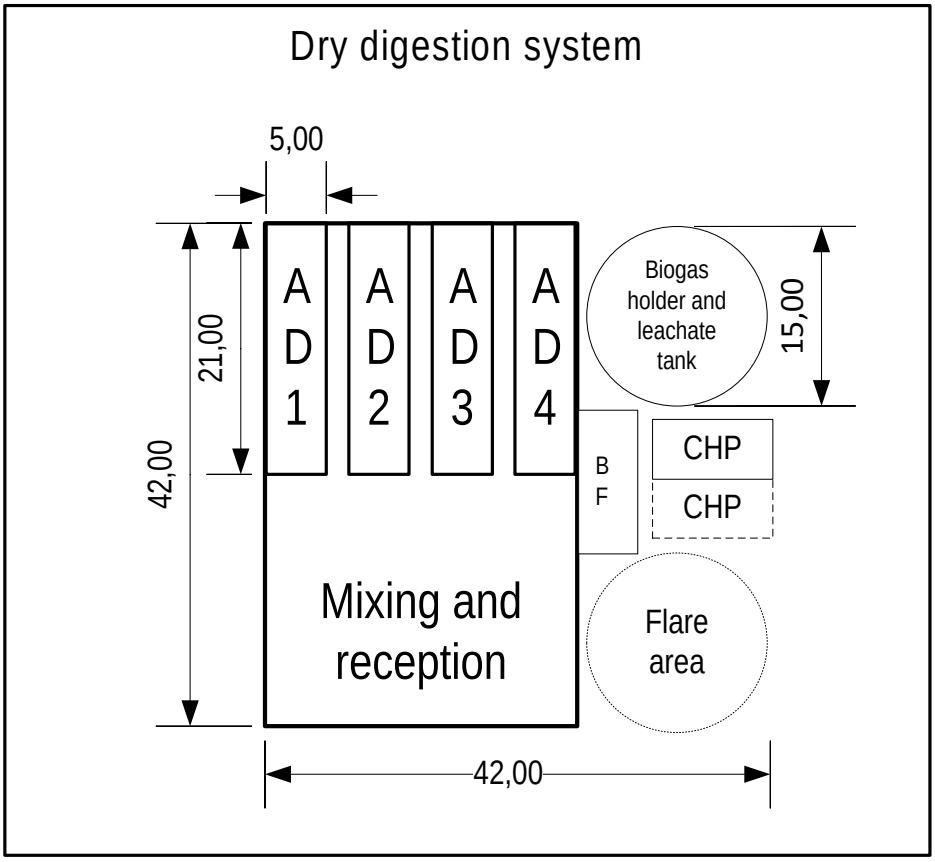


4.2 PLANT LAYOUT

The next two figures show the onsite location and the plant layout. The footprint for the plant is around 1,800 m2. The Plant layout includes all equipment that will be installed. In this project, there will be one 100 kW(e) CHP unit installed at the beginning and the other will be installed few years after. The description of the plant and the equipment list are in section 4.1 above.

Figure 14 Biogas plant localisation

Figure 15 Biogas plant layout



*BF is the Biofilter

4.3 PLANT UTILITIES

The plant requires the connections to water and electricity utilities. The need for water comes from the mixing and reception hall where water can be added to feedstock and where water is also used for cleaning. The percolate, the captured storm water and any other process water are collected in the percolate tank and recirculated to the AD tunnels. There is no need for a wastewater treatment plant because the percolate can be directly sent to the landfill percolate treatment plant if needed. The percolate tank should be filled up in the commissioning phase.

The electricity connection is mainly for the safety equipment and the air treatment, as well as for percolate mixers. Dry digestion requires less electricity than conventional wet digestion because there are less pumps and mixing equipment. The feedstock stack in each tunnel remains unmoved until a digester exchange, when new material is inserted at one end of the tunnel and old, digested material is removed at the other using a front loader.

4.4 POTENTIAL SUPPLIERS

Considering the solid content of the waste, the digestion technology should be a dry (high solids) digestion. Many suppliers offer turnkey systems for dry digestion, including:

- OWS – Dranco
- Valorga
- Bio-En power*
- Kompogas
- Bioferm*
- Bekon
- Gicon*
- Himark*

*Suppliers present for the RFI in 2014

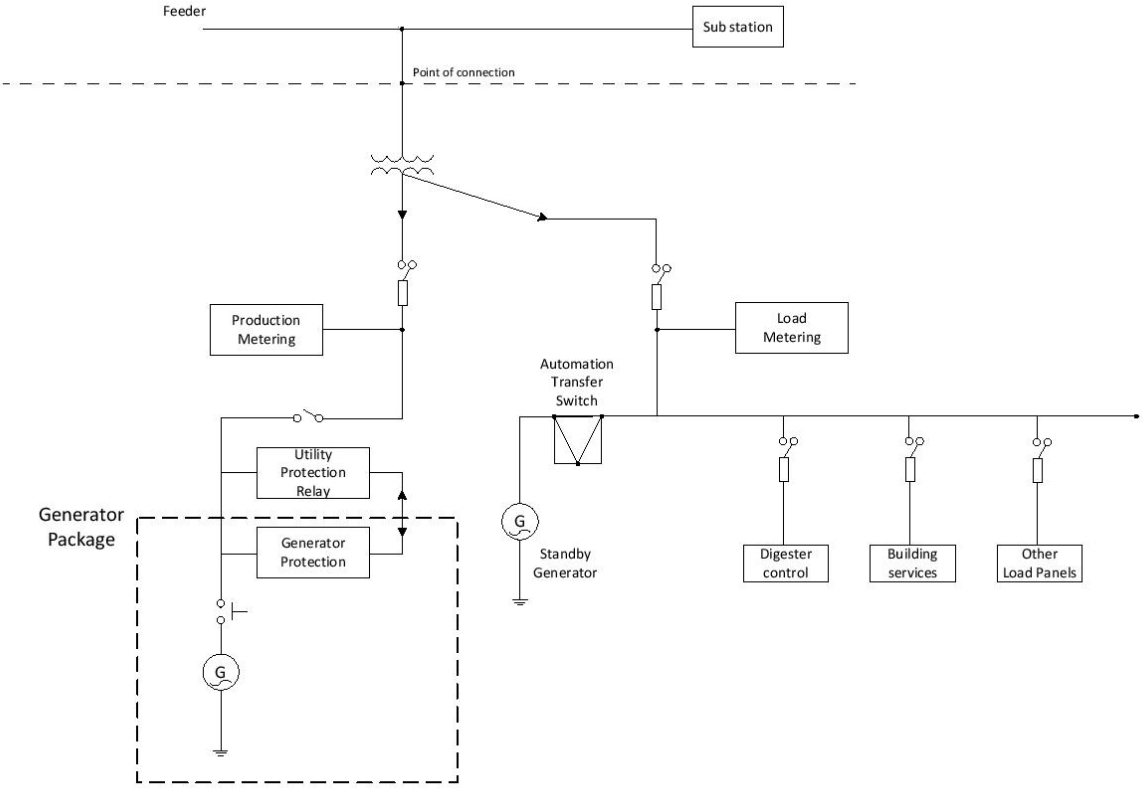
The system will be different in terms of:

- Temperature (mesophilic or thermophilic)
- Operation (batch or continuous)
- Digester shape (horizontal or vertical)
- Retention time (2 to 5 weeks)

4.5 PRELIMINARY ELECTRICAL SLD

The information provided by the previously mentioned suppliers allowed Electrigaz/WSP to prepare preliminary electrical schematics – a Single Line Diagram (SLD) – for the Whitehorse organic waste biogas plant. It is important to mention that the proposed concept will be subject to future modifications, as the engineering process will progress.

Figure 16 Electrical SLD



From this SLD, a preliminary motor and generator list can be generated:

- Percolate pump motors
- CHP Generator
- Blowers (2)
- Biogas H2S removal water pump motor
- Heat exchange pump motors

5 BUSINESS CASE EVALUATION

This section develops the financial parameters for both the CHP and Boiler scenarios and draws conclusions as to their economic viability.

5.1 CHP SCENARIO

In this scenario, several technical and economic assumptions have been made. The most essential parameters used are shown below:

Table 16 CHP scenario: economic assumptions

Economic Assumptions			
Inflation	2.00%	Life cycle/amortization (yrs)	20
Interest on loan	3.58%	Operating supervision	5%
Equity	40%	Plant overhead	3%
Debt	60%	Admin cost	2%
Electrical efficiency	35%	Boiler efficiency	90%
Heat recovery efficiency	40%	Electricity rate ($/MWh)	$210.00
Capacity factor	95%	CND$-USD$	1.30
NPV rate	3.38%	Property tax	-
Real discount rate	3.38%	Return on equity	8.25%
Contaminant disposal ($/t)	$94.00	Insurance	0.3%
Loader operation (hrs/d)	8	Wastewater disposal ($/t)	-
Global loader cost ($/hr)	130	Compost disposal ($/t)	-
Plant technician (hrs/d)	2	Maintenance & repair (%capex)	0.50%
Plant technician cost ($/hr)	40	CHP maintenance ($/kWh)	0.015

The equipment and material portion of the capital cost was increased by 7% to factor in typical additional costs for the Whitehorse remote/northern market. These assumptions, as well as the 4.5% lending rate, are on the optimistic side. A private project developer will probably have to work under less advantageous conditions.

5.1.1 CAPITAL COST

The capital cost estimation has been made considering RFI received as well as experience from WSP/Electrigaz group.

The following tables provide Class 4 cost details of capital expenses necessary to realize this project.

Table 17 CHP scenario: capital costs

Equipment List (Anaerobic Digestion) +/- 20%

Categories	Items	Total Including Installation
Civil		$350,000
	Site preparation	
	Ground structuring	
	Utility services	
AD process		$2,405,000
	Process building	
	Reception/mixing hall	
	Dry digestion (4 tunnels)	
	Percolate tank	
	Piping (percolate/biogas)	
	Automation system	
Ancillary process building systems		$198,000
	Ventilation equipment	
	Fire suppression system	
	Offices	
Odour management		$193,000
	Acid scrubber + facilities	
	Biofilter + facilities	
Heating equipment		$245,000
	Heat exchanger	
	Biogas boiler	
	Hot water pump	
Biogas management equipment		$164,000
	Biogas storage (percolate tank roof)	
	Flare	
	Gas blower	
Indirect costs		$967,000
	Permiting, Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)		$533,000
Contingency		$533,000
Total cost		**$5,588,000**

Equipment List (Biogas CHP) +/- 20%

Categories	Items	Total Including Installation
CHP		$955,000
	H2S scrubber	
	CHP (2x 100 kWe)	
	Heat pipes	
	Interconnection to grid	
Indirect costs		$151,000
	Permiting, Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)		$143,000
Contingency		$143,000
Total cost		**$1,392,000**

As it is stated in the previous sections, the capital costs in the RFI responses received were ranged between $685 and $3,188 per ton of annual treatment capacity.

Since, in the first year of the project, the plant input is estimated at 3202 tons per year, the present capital cost estimation fit in this range at $2,180 /tons (considering AD and CHP equipment). It must also be noted however that the plant is sized to process incoming substrate until 2036 which is estimated at 7,823 tons. With this annual tonnage the capital costs per tonnage is $892 which also fits in the range.

5.1.2 OPERATIONAL COSTS

The following tables provide Class 4 operational cost details for the first 20 years of operation.

Table 18 CHP scenario: operational costs (for year 1 to 9)

Operational Costs +/- 20%	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
AD/Biogas technician	$29,200	$29,784	$30,380	$30,987	$31,607	$32,239	$32,884	$33,542	$34,212	$34,897
Loader operation (machinery/fuel/labour)	$116,800	$119,136	$121,519	$123,949	$126,428	$128,957	$131,536	$134,166	$136,850	$139,587
Operating supervision	$1,460	$1,489	$1,519	$1,549	$1,580	$1,612	$1,644	$1,677	$1,711	$1,745
Process Water	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Electricity	$13,888	$15,632	$17,622	$19,556	$24,773	$27,782	$29,312	$30,400	$31,529	$32,702
Waste water disposal costs	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Solid digestate disposal costs	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Contaminant disposal costs	$9,535	$10,913	$12,489	$14,293	$16,357	$18,720	$19,883	$20,686	$21,522	$22,391
Maintenance and repair (AD+ CHP+Heat)	$34,900	$35,598	$36,310	$37,036	$37,777	$38,532	$39,303	$40,089	$40,891	$41,709
Operating supplies	$15,000	$15,300	$15,606	$15,918	$16,236	$16,561	$16,892	$17,230	$17,575	$17,926
Laboratory charges	$5,000	$5,100	$5,202	$5,306	$5,412	$5,520	$5,631	$5,743	$5,858	$5,975
Taxes (property)	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Insurance	$20,940	$21,359	$21,786	$22,222	$22,666	$23,119	$23,582	$24,053	$24,535	$25,025
Plant overhead costs	$5,471	$5,580	$5,692	$5,806	$5,922	$6,040	$6,161	$6,284	$6,410	$6,538
Administration costs	$584	$596	$608	$620	$632	$645	$658	$671	$684	$698
Distribution + marketing costs	$2,528	$2,605	$2,657	$2,710	$2,764	$2,820	$2,876	$2,934	$2,992	$3,052
Total operational costs	$255,306	$263,091	$271,389	$279,952	$292,155	$302,548	$310,362	$317,476	$324,769	$332,246
Processing costs per ton	$79.74	$73.23	$67.33	$61.90	$57.58	$53.14	$52.35	$52.50	$52.65	$52.81

Table 19 CHP scenario: operational costs (for year 10 to 20)

Operational Costs +/- 20%	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AD/Biogas technician	$35,595	$36,307	$37,033	$37,773	$38,529	$39,299	$40,085	$40,887	$41,705	$42,539
Loader operation (machinery/fuel/labour)	$142,379	$145,226	$148,131	$151,093	$154,115	$157,197	$160,341	$163,548	$166,819	$170,156
Operating supervision	$1,780	$1,815	$1,852	$1,889	$1,926	$1,965	$2,004	$2,044	$2,085	$2,127
Process Water	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Electricity	$33,920	$35,186	$36,500	$37,866	$39,284	$40,758	$42,288	$43,879	$45,531	$47,248
Waste water disposal costs	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Solid digestate disposal costs	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Contaminant disposal costs	$23,296	$24,237	$25,216	$26,235	$27,295	$28,398	$29,545	$30,739	$31,980	$33,272
Maintenance and repair (AD+ CHP+Heat)	$42,543	$43,394	$44,262	$45,147	$46,050	$46,971	$47,910	$48,868	$49,846	$50,843
Operating supplies	$18,285	$18,651	$19,024	$19,404	$19,792	$20,188	$20,592	$21,004	$21,424	$21,852
Laboratory charges	$6,095	$6,217	$6,341	$6,468	$6,597	$6,729	$6,864	$7,001	$7,141	$7,284
Taxes (property)	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Insurance	$25,526	$26,036	$26,557	$27,088	$27,630	$28,182	$28,746	$29,321	$29,907	$30,506
Plant overhead costs	$6,669	$6,802	$6,938	$7,077	$7,219	$7,363	$7,510	$7,660	$7,814	$7,970
Administration costs	$712	$726	$741	$755	$771	$786	$802	$818	$834	$851
Distribution + marketing costs	$3,113	$3,175	$3,239	$3,304	$3,370	$3,437	$3,506	$3,576	$3,647	$3,720
Total operational costs	$339,912	$347,772	$355,833	$364,099	$372,578	$381,274	$390,194	$399,345	$408,734	$418,367
Processing costs per ton	$52.97	$53.13	$53.30	$53.47	$53.64	$53.81	$53.99	$54.18	$54.36	$54.55

5.1.3 FINANCIAL ANALYSIS

Capital cost was adjusted to take into consideration phased capital investment (5th year CHP) and interest during construction (IDC).

Table 20 CHP scenario: Capital costs breakdown

Capex Breakdown (+/- 20%)	
AD process	$5,588,000
CHP (Yr 0)	$892,000
CHP (Yr 5)	$500,000
Total	$6,980,000
Interest during construction (IDC)	$69,923
Subsidy	----
Fixed capital investment (Yr 0)	$6,549,923
Fixed capital investment (Yr 5)	$500,000
Capital outlay (Yr 0)	$2,619,969
Capital outlay (Yr 5)	$200,000
Loan (Yr 0)	$3,929,954
Loan (Yr 5)	$300,000

Repeated financial analyses were performed for several price points to determine the levelized cost of energy (LCOE). Exportable heat is assumed to be sold entirely at the price of $12/GJ or $43/MWh (th)

Table 21 CHP scenario: financial analysis

Gate Fees $/ton	**Heat Sales** $/GJ	**Subsidy** % of Capex	**LCOE ($/KWH(E))** Real
38	12	0%	$0.638
38	12	70%	$0.206
45	12	0%	$0.576
45	12	50%	$0.267
50	12	0%	$0.531
50	12	40%	$0.284

The following financial results are presented for a gate fee of $38/ton (2016 rate) and $0.21/kWh, which are market financial parameters currently in force for the proposed project (see Section 1.1.1).

Table 22 CHP scenario: financial results (for years 0 to 9)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Electricity revenue		$92,590	$102,170	$112,919	$122,856	$152,573	$167,756	$173,524	$176,432	$179,398	$182,424
Gate fees		$121,671	$139,246	$159,358	$182,376	$208,718	$238,865	$253,706	$263,956	$274,620	$285,715
Heat sales		$17,070	$19,079	$21,368	$23,390	$30,933	$34,412	$36,208	$37,502	$38,845	$40,239
Total revenue		$231,331	$260,494	$293,645	$328,623	$392,225	$441,033	$463,438	$477,890	$492,863	$508,377
Expenses											
Total expenses		$255,306	$263,091	$271,389	$279,952	$292,155	$302,548	$310,362	$317,476	$324,769	$332,246
EBITDA		-$23,975	-$2,597	$22,257	$48,670	$100,070	$138,485	$153,076	$160,414	$168,094	$176,131
Depreciation		$327,496	$327,496	$327,496	$327,496	$327,496	$360,829	$360,829	$360,829	$360,829	$360,829
EBIT		-$351,472	-$330,094	-$305,240	-$278,826	-$227,426	-$222,344	-$207,753	-$200,415	-$192,735	-$184,698
Interest payment		$140,692	$135,758	$130,647	$125,353	$119,870	$124,930	$118,494	$111,827	$104,921	$97,769
Net Income (before tax)		-$492,164	-$465,852	-$435,887	-$404,179	-$347,296	-$347,274	-$326,247	-$312,242	-$297,657	-$282,467
Cash flow	-$6,549,923	-$23,975	-$2,597	$22,257	$48,670	-$399,930	$138,485	$153,076	$160,414	$168,094	$176,131
NPV	-$4,883,719										

EBITDA: Earnings before interest, taxes, depreciation and amortization

Table 23 CHP scenario: financial results (for years 10 to 20)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Electricity revenue	$185,510	$188,657	$191,868	$195,143	$198,483	$201,890	$205,366	$208,911	$212,526	$216,214
Gate fees	$297,258	$309,267	$321,761	$334,760	$348,285	$362,355	$376,995	$392,225	$408,071	$424,557
Heat sales	$41,685	$43,187	$44,745	$46,363	$48,042	$49,785	$51,595	$53,473	$55,424	$57,449
Total revenue	$524,452	$541,111	$558,374	$576,266	$594,810	$614,031	$633,955	$654,609	$676,021	$698,220
Expenses										
Total expenses	$339,912	$347,772	$355,833	$364,099	$372,578	$381,274	$390,194	$399,345	$408,734	$418,367
EBITDA	$184,541	$193,339	$202,542	$212,167	$222,232	$232,757	$243,761	$255,264	$267,287	$279,853
Depreciation	$360,829	$360,829	$360,829	$360,829	$360,829	$360,829	$360,829	$360,829	$360,829	$360,829
EBIT	-$176,289	-$167,491	-$158,288	-$148,663	-$138,597	-$128,072	-$117,069	-$105,566	-$93,542	-$80,976
Interest payment	$90,360	$82,686	$74,737	$66,504	$57,976	$49,143	$39,993	$30,516	$20,700	$10,532
Net Income (before tax)	-$266,649	-$250,177	-$233,025	-$215,167	-$196,573	-$177,215	-$157,062	-$136,082	-$114,242	-$91,508
Cash flow	$184,541	$193,339	$202,542	$212,167	$222,232	$232,757	$243,761	$255,264	$267,287	$279,853

5.2 BOILER SCENARIO

In this scenario the biogas is used to generate hot water to be sold, entirely, to existing and hypothetical heat clients located at less than 700 m of the biogas plant.

Key technical and economic assumptions made for this scenario are summarized below:

Table 24 Boiler scenario: economic assumptions

Economic Assumptions			
Inflation	2.00%	Plant depreciation (yrs)	20
Interest on loan	3.58%	Operating supervision	5%
Equity	40%	Plant overhead	3%
Debt	60%	Admin cost	2%
Electrical efficiency	35%	Boiler efficiency	90%
Heat recovery efficiency	40%	Electricity rate ($/MWh)	$210.00
Capacity factor	95%	CND$-USD$	1.3
NPV rate	3.38%	Property tax	-
Real discount rate	3.38%	Return on equity	8.25%
Contaminant disposal ($/t)	$94.00	Insurance	0.3%
Loader operation (hrs/d)	8	Wastewater disposal ($/t)	-
Global loader cost ($/hr)	130	Compost disposal ($/t)	-
Plant technician (hrs/d)	2	Maintenance & repair (%capex)	0.50%
Plant technician cost ($/hr)	40	CHP maintenance ($/kWh)	0.015

The equipment and material portion of the capital cost was augmented by 7% to factor in additional costs typical for the Whitehorse remote/northern market.

5.2.1 CAPITAL COSTS

The capital cost estimation has been made considering RFI received as well as experience from WSP/Electrigaz group.

The following tables provide Class 4 cost details of capital expenses necessary to realize this project.

Table 25 Boiler scenario: capital costs

Equipment List (Anaerobic Digestion) +/- 20%

Categories	Items	Total Including Installation
Civil		$350,000
	Site preparation	
	Ground structuring	
	Utility services	
AD process		$2,405,000
	Process building	
	Reception/mixing hall	
	Dry digestion (4 tunnels)	
	Percolate tank	
	Piping (percolate/biogas)	
	Automation system	
Ancillary process building systems		$198,000
	Ventilation equipment	
	Fire suppression system	
	Offices	
Odour management		$193,000
	Acid scrubber + facilities	
	Biofilter + facilities	
Heating equipment		$65,000
	Heat exchanger	
	Hot water pump	
Biogas management equipment		$164,000
	Biogas storage (percolate tank roof)	
	Flare	
	Gas blower	
Indirect costs		$918,000
	Permiting, Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)		$506,000
Contingency		$506,000
Total cost		**$5,305,000**

Equipment List (Heat Network) +/- 20%

Categories	Items	Total Including Installation
Heat network		$519,000
	Biogas boiler	
	Heat pipes	
	Heat network water pump	
	Delivery heat exchanger	
Indirect costs		$42,000
	Permiting, Engineering, supervision, project management	
	Legal expenses	
	Start-up, commissioning	
	Temporary services (trailers, utilities, etc.)	
Contractor profit (EPC construction)		$78,000
Contingency		$78,000
Total cost		$717,000

The only differences between the capital cost estimation from CHP scenario and boiler scenario are the heat network cost and the CHP unit cost. In the CHP scenario, it is assumed that heat is sold across the street to the composting building (minimal heat network). In the boiler scenario, the CHP unit is replaced by a boiler which cost less but also embeds the cost of deployment of a heat network to existing KBL and/other hypothetical proximity clients.

For this scenario, it has been estimated that a heat consumer would be in a 700 m radius from site.

5.2.2 OPERATIONAL COSTS

The following tables provide (+/-20%) operational cost details for the first 20 years of operation:

Table 26 Boiler scenario: operational costs (for years 1 to 9)

Operational Costs +/- 20%	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
AD/Biogas technician	$29,200	$29,784	$30,380	$30,987	$31,607	$32,239	$32,884	$33,542	$34,212	$34,897
Loader operation (machinery/fuel/labor)	$116,800	$119,136	$121,519	$123,949	$126,428	$128,957	$131,536	$134,166	$136,850	$139,587
Operating supervision	$1,460	$1,489	$1,519	$1,549	$1,580	$1,612	$1,644	$1,677	$1,711	$1,745
Process Water	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Electricity	$13,888	$15,632	$17,622	$19,556	$24,773	$27,782	$29,312	$30,400	$31,529	$32,702
Waste water disposal cost	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Solid digestate disposal cost	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Contaminant disposal cost	$9,535	$10,913	$12,489	$14,293	$16,357	$18,720	$19,883	$20,686	$21,522	$22,391
Maintenance and repair (AD+Heat)	$30,110	$30,712	$31,326	$31,953	$32,592	$33,244	$33,909	$34,587	$35,279	$35,984
Operating supplies	$15,000	$15,300	$15,606	$15,918	$16,236	$16,561	$16,892	$17,230	$17,575	$17,926
Laboratory charges	$5,000	$5,100	$5,202	$5,306	$5,412	$5,520	$5,631	$5,743	$5,858	$5,975
Taxes (property)	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Insurance	$18,066	$18,427	$18,796	$19,172	$19,555	$19,946	$20,345	$20,752	$21,167	$21,591
Plant overhead cost	$5,327	$5,434	$5,542	$5,653	$5,766	$5,882	$5,999	$6,119	$6,242	$6,366
Administration costs	$584	$596	$608	$620	$632	$645	$658	$671	$684	$698
Distribution + marketing costs	$2,450	$2,525	$2,576	$2,627	$2,680	$2,733	$2,788	$2,844	$2,901	$2,959
Total operational cost	$247,421	$255,048	$263,184	$271,584	$283,619	$293,842	$301,481	$308,418	$315,529	$322,821
Processing cost per ton	$77.27	$70.99	$65.29	$60.05	$55.89	$51.61	$50.85	$51.00	$51.16	$51.31

Table 27 Boiler scenario: operational costs (for years 10 to 20)

Operational Costs +/- 20%	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AD/Biogas technician	$35,595	$36,307	$37,033	$37,773	$38,529	$39,299	$40,085	$40,887	$41,705	$42,539
Loader operation (machinery/fuel/labor)	$142,379	$145,226	$148,131	$151,093	$154,115	$157,197	$160,341	$163,548	$166,819	$170,156
Operating supervision	$1,780	$1,815	$1,852	$1,889	$1,926	$1,965	$2,004	$2,044	$2,085	$2,127
Process Water	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Electricity	$33,920	$35,186	$36,500	$37,866	$39,284	$40,758	$42,288	$43,879	$45,531	$47,248
Waste water disposal cost	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Solid digestate disposal cost	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Contaminant disposal cost	$23,296	$24,237	$25,216	$26,235	$27,295	$28,398	$29,545	$30,739	$31,980	$33,272
Maintenance and repair (AD+Heat)	$36,704	$37,438	$38,187	$38,950	$39,730	$40,524	$41,335	$42,161	$43,004	$43,865
Operating supplies	$18,285	$18,651	$19,024	$19,404	$19,792	$20,188	$20,592	$21,004	$21,424	$21,852
Laboratory charges	$6,095	$6,217	$6,341	$6,468	$6,597	$6,729	$6,864	$7,001	$7,141	$7,284
Taxes (property)	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Insurance	$22,022	$22,463	$22,912	$23,370	$23,838	$24,314	$24,801	$25,297	$25,803	$26,319
Plant overhead cost	$6,494	$6,624	$6,756	$6,891	$7,029	$7,170	$7,313	$7,459	$7,608	$7,761
Administration costs	$712	$726	$741	$755	$771	$786	$802	$818	$834	$851
Distribution + marketing costs	$3,018	$3,078	$3,140	$3,203	$3,267	$3,332	$3,399	$3,467	$3,536	$3,607
Total operational cost	$330,299	$337,967	$345,832	$353,898	$362,172	$370,661	$379,369	$388,303	$397,471	$406,879
Processing cost per ton	$51.47	$51.63	$51.80	$51.97	$52.14	$52.32	$52.49	$52.68	$52.86	$53.05

5.2.3 FINANCIAL ANALYSES

The capital cost was adjusted to take into consideration interest during construction (IDC).

Table 28 Boiler scenario: Capital costs breakdown

Capex Breakdown	
AD process	$5,305,000
Heat network	$717,000
Total	$6,022,000
Interest during construction (IDC)	$64,981
Subsidy	$-
Fixed capital investment	$6,086,981
Capital outlay	$2,434,792
Loan	$3,652,189

Repeated financial analyses were performed for several price points to determine the levelized cost of energy (LCOE).

Table 29 Boiler scenario: financial analysis

Gate Fees $/ton	Subsidy % of CAPEX	LCOE (REAL) $/KWh(th)	LCOE (REAL) $/GJ
38	0%	0.227	62.996
38	70%	0.085	23.488
45	0%	0.203	56.405
45	60%	0.081	22.541
50	0%	0.186	51.697
50	40%	0.105	29.121

The analyses show that without significant subsidies the heat only project has difficulty competing with other heat sources.

The following financial results are presented for a gate fee of $38/ton (2016 rate) and heat at $15/GJ. Note that it has been assumed that all generated heat will be sold to a client situated in a 700 m radius.

Table 30 Boiler scenario: financial results (for years 0 to 9)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Gate fees		$121,671	$139,246	$159,358	$182,376	$208,718	$238,865	$253,706	$263,956	$274,620	$285,715
Heat sales		$62,120	$69,698	$78,201	$87,742	$98,446	$110,457	$115,019	$117,320	$119,666	$122,059
Total revenue		$121,671	$139,246	$159,358	$182,376	$208,718	$238,865	$253,706	$263,956	$274,620	$285,715
Expenses											
Total expenses		$247,421	$255,048	$263,184	$271,584	$283,619	$293,842	$301,481	$308,418	$315,529	$322,821
EBITDA		-$125,749	-$115,802	-$103,826	-$89,208	-$74,901	-$54,976	-$47,775	-$44,461	-$40,909	-$37,107
Depreciation		$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349
EBIT		-$430,098	-$420,151	-$408,175	-$393,557	-$379,250	-$359,325	-$352,124	-$348,810	-$345,258	-$341,456
Interest payment		$130,748	$126,163	$121,413	$116,493	$111,398	$106,119	$100,652	$94,989	$89,123	$83,048
Net Income (before tax)		-$560,847	-$546,314	-$529,588	-$510,051	-$490,648	-$465,444	-$452,776	-$443,800	-$434,382	-$424,503
Cash flow	-$6,086,981	-$63,630	-$46,104	-$25,625	-$1,466	$23,545	$55,481	$67,244	$72,858	$78,757	$84,953
NPV	-$5,176,273										

Table 31 Boiler scenario: financial results (for year 10 to 20)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gate fees	$297,258	$309,267	$321,761	$334,760	$348,285	$362,355	$376,995	$392,225	$408,071	$424,557
Heat sales	$124,501	$126,991	$129,530	$132,121	$134,763	$137,459	$140,208	$143,012	$145,872	$148,790
Total revenue	$297,258	$309,267	$321,761	$334,760	$348,285	$362,355	$376,995	$392,225	$408,071	$424,557
Expenses										
Total expenses	$330,299	$337,967	$345,832	$353,898	$362,172	$370,661	$379,369	$388,303	$397,471	$406,879
EBITDA	-$33,041	-$28,700	-$24,070	-$19,138	-$13,888	-$8,305	-$2,374	$3,922	$10,600	$17,678
Depreciation	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349	$304,349
EBIT	-$337,390	-$333,049	-$328,420	-$323,487	-$318,237	-$312,654	-$306,723	-$300,427	-$293,749	-$286,671
Interest payment	$76,754	$70,236	$63,484	$56,491	$49,247	$41,743	$33,971	$25,921	$17,583	$8,946
Net Income (before tax)	-$414,145	-$403,285	-$391,904	-$379,977	-$367,483	-$354,398	-$340,695	-$326,349	-$311,332	-$295,617
Cash flow	$91,459	$98,290	$105,460	$112,983	$120,876	$129,153	$137,834	$146,934	$156,472	$166,468

6 CONCLUSION

The proposed CHP and heat only biogas projects at the current composting site, with a respective capital investment of $7.1M and $6.1M, were found to be uneconomic without a subsidy based on the current cost and revenue parameters determined above.

The scenario of production and sale of heat, in the form of hot water, generated by a 500 HP biogas boiler is not recommended because of the cost of deploying a district heating network over to the nearest client. At the moment, KBL is actually present in a radius of 700 m but its actual yearly heat consumption only adds up to $8,550 of propane, which would not be enough revenue to warrant such an investment. Moreover, its heat consumption is "out of phase" with and biogas production (peaking in summer).

For a "heat only" project to be viable it would have to significantly raise the organic treatment gate fee, gather important capital subsidies and sell 100% of the heat produced during winter and summer months. The following table shows the levelized cost of energy (heat) for different organic treatment gates fees and capital subsidy support

Table 32 Boiler scenario: financial analysis

Gate Fees $/ton	Subsidy % of CAPEX	LCOE (REAL) $/KWh(th)	LCOE (REAL) $/GJ
38	0%	0.227	62.996
38	70%	0.085	23.488
45	0%	0.203	56.405
45	60%	0.081	22.541
50	0%	0.186	51.697
50	40%	0.105	29.121

This scenario, estimated at $6.1M, is unlikely to attract industrial clients (green houses, industrial thermal processes, etc.) because energy prices are not discounted significantly.

The utilization of biogas in CHP units is better adapted to this location since it allows selling of heat and electricity in the summer and during power demand peaks. The deployment of CHP units would be phased in with one 100 kW unit installed initially and a second 100 kW unit (or more if landfill gas is exploited) 5 years later. The heat generated by the CHP would be used entirely at the composting building to heat the facility and potentially dry further the compost before bagging it.

The project is estimated to require a total capital investment of approximately C$7.1M and to cost over $255,000 per year to operate.

The revenue from the biogas plant will come from gate fees, electricity and heat sales. With a current market pricing of $0.21/kWh for the electricity sold to the grid, a $38/t gate fee (2016 rate), and savings of $12/GJ for heat, the project is not economically viable. With these market conditions the project would require significant capital subsidies. The following table shows the levelized cost of energy (electricity) for different organic treatment gates fees and capital subsidy support:

Table 33 CHP scenario: financial analysis

Gate Fees $/ton	Heat Sales $/Gj	Subsidy % of CAPEX	LCOE ($/KWh(E)) REAL
38	12	0%	$0.638
38	12	70%	$0.206
45	12	0%	$0.576
45	12	50%	$0.267
50	12	0%	$0.531
50	12	40%	$0.284

Biogas captured from the landfill could potentially help boost electrical production and provide better project economics. Further study of this scenario would be needed.

Nevertheless, it is clear that this project will require organic treatment gate fee adjustment and capital investment in form of subsidies because the revenues generated by the project are insufficient to warrant the high capital investment.

Based on the current market conditions it is unlikely that the project would attract independent project developers. The project would probably have to be developed by Yukon Energy Corporation and/or the City of Whitehorse with the support of capital grants.

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Appendix A

SAMPLING PROCEDURE

YUKON ENERGY CORPORATION

SAMPLING AND ANALYSIS PROCEDURE

FEEDSTOCK VALIDATION

AUGUST 2015

SAMPLING AND ANALYSIS PROCEDURE

FEEDSTOCK VALIDATION

Yukon Energy Corporation

Report (Final Version)

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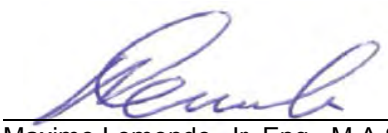

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TABLE OF CONTENTS

1 INTRODUCTION 1

2 FEEDSTOCK 1

3 PROPOSED APPROACH 2

3.1 WASTE SAMPLING AND ANALYSIS 2

3.2 CONTINUOUS ON SITE VISUAL ASSESSMENT 2

4 VISUAL ASSESSMENT METHODOLOGY 2

5 WASTE SAMPLING METHODOLOGY 3

5.1 SAMPLING METHOD 3

5.2 WEIGH ANALYSIS 4

5.3 QUARTERS DIVISION METHOD 4

6 PERFORMED LAB ANALYSIS 4

7 REQUIRED TECHNICIAN EQUIPMENT 5

8 DATA SHEETS 5

FIGURES

FIGURE 1 WHITEHORSE 2015 COLLECTION (YELLOW FOR RECYCLING AND GREEN FOR GARDEN AND ORGANIC) 2

1 INTRODUCTION

Electrigaz/WSP are assessing the composition of the residential and ICI organic waste collected in Whitehorse in order to perform a feasibility study of an anaerobic digestion plant processing this material.

2 FEEDSTOCK

The sampling and analysis campaign will be specific to organic waste from the two (2) following streams:

- → Household curbside
- → ICI collection

The sampling and analysis campaign will focus on finding the proportions and digestibility of the following feedstock:

1. Source sorted organic (SSO)
   - Fruit and vegetable
   - Meat
   - Bread and cereal
   - Egg
   - Paper
   - All other food waste
2. Fresh garden waste (FGW)
   - Grass
   - Leave
   - Plants and flower
3. Dead garden waste (DGW)
   - All garden waste that have lost is original color (ex: brown grass)
   - Wood branches, wood chips
4. Contaminants
   - All none organic waste
     - Plastic, metal, glass, rock, sand, Styrofoam, mirror
   - Some organic that are hardly biodegradable

A lot of research studies are already available regarding the biomethane production potential of each of these four categories. Considering this available data, it appears necessary to focus on the proportions of each of them into the feedstock to assess the seasonality of the biomethane production potential of the global feedstock.

3 PROPOSED APPROACH

Electrigaz/WSP are proposing to perform 2 different types of assessments:

3.1 WASTE SAMPLING AND ANALYSIS

Two (2) sampling events (Aug and Oct) would occur where material would be manually separated into the four (4) fractions described above and weighted. The operation will be documented with notes and pictures.

The material sampled would be analysed for total solids, volatile solids, NPK only.

3.2 CONTINUOUS ON SITE VISUAL ASSESSMENT

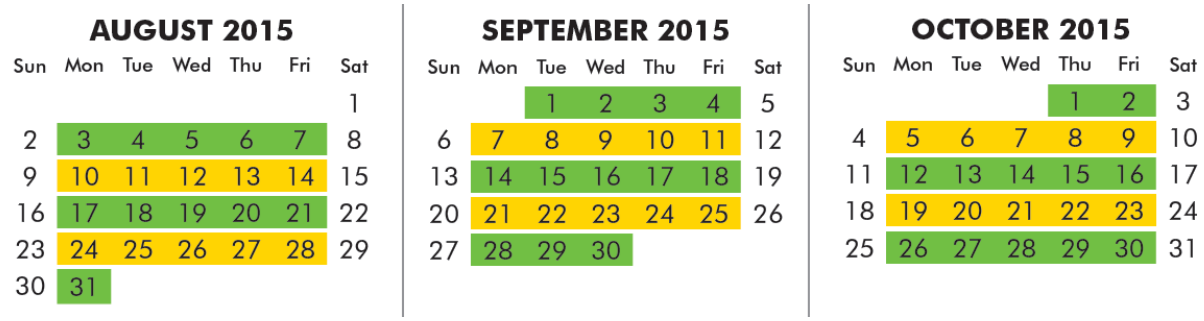
Every other week from August 31st to October 30th, a technician (student) would perform visual assessment (notes + photos) of the material being received on the composting site to assess feedstock composition trends in time.

4 VISUAL ASSESSMENT METHODOLOGY

The technician (student) will have to take multiple pictures and fill a description sheet for all truck loads received at the Whitehorse composting facility. The data sheet is at the end of this report.

This job will be from august 31st to October 30th 2015 and will follow the organic collection of the municipality (visual assessment every other week).

Figure 1 Whitehorse 2015 collection (yellow for recycling and green for garden and organic)



5 WASTE SAMPLING METHODOLOGY

The technician should be on site for 2 period of 2 days.

- August 31 to September 2, 2015
- October 14 to 16, 2015

For each load received on these days the composting site operator will take a representative bucket of the organic waste and put it on the side, in a defined and safe area, to facilitate the technician job. At the end of the day, the composting site operator can process the organics that was put on the side.

Each day on site, the technician should weight and separate all fractions from portions (set aside by loader) for all truck loads.

5.1 SAMPLING METHOD

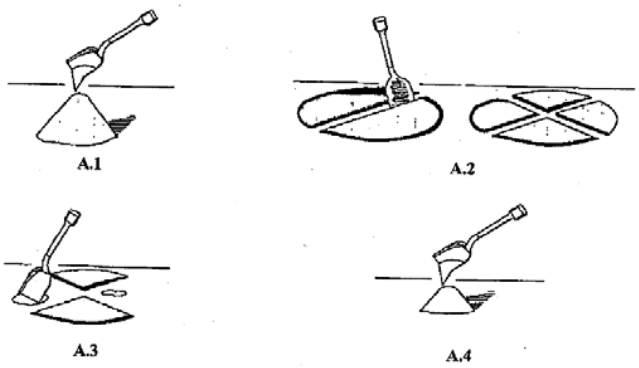
- On each organic reception take a 4.5 gallons sampling
- Remove 30 centimeters of material from point 1
- Take 1,5 gallons from point 1
- Remove 30 centimeters of material from point 2
- Take 1,5 gallons from point 2
- Remove 30 centimeters of material from point 3
- Take 1,5 gallons from point 3

5.2 WEIGH ANALYSIS

- Proceed to one Quarter division method (see next section)
- Weigh the sample
- Separate by hand all fraction
- Weigh all sub-fractions (4)
- Fill the report

5.3 QUARTERS DIVISION METHOD

- **A.1** : Put the sample on a concrete slab or on a tarp. Give the sample a cone shape
- **A.2** : Flatten the top of the cone and split the sample into four piles along two perpendicular diameters with respect to each other.
- **A.3** : Remove and discard two diametrically opposite quarters , leaving a clean surface in this space freed
- **A.4** : Mix the remaining districts and repeat operations A.1 to A.3 until the required amount of the sample for analysis



6 PERFORMED LAB ANALYSIS

For each sampling event (3 days), from the various piles analysed, the technician will create a representative sample of:

- ICI: SSO
- ICI: FGW
- ICI: DGW
- Residential: SSO
- Residential: FGW
- Residential: DGW

These samples will be kept at 4 °C and sent at the end of the sampling week to a local lab for Total Solids (%TS) and Volatile Solids (%VS).

The technician will also perform a separation of the frozen material collected in April by the client to be sent for the same lab analysis

A total of 18 lab tests will be performed.

7 REQUIRED TECHNICIAN EQUIPMENT

- Camera
- Notebook
- Laboratory and/or work gloves
- Steel toe shoes
- Mask (optional)
- Safety helmet and vest
- Disposable coverall
- Shovel and/or fork and several (3-5) 20 liters buckets
- Portable weigh scale
- Tarp and large plastic bag (Ziploc)
- Support from composting site operator (loader)

8 DATA SHEETS

The next two pages present report data sheets that technicians will use to collection site information.

After filling the report technician and student can allow the organic waste operator to process the material. After each day, clean all material.

VISUAL REPORT

DATE	RECEPTION HOUR	LOAD TONNAGE	TYPE OF ORGANIC (ICI/HOME)	CLIENT NAME IF ICI	PICTURE TAKEN	PICTURE NUMBER	CONTAMINANT DESCRIPTION	COMMENTS
					☐			
					☐			
					☐			
					☐			
					☐			
					☐			
					☐			

SAMPLING REPORT

DATE	RECEPTION HOUR	LOAD TONNAGE	TYPE OF ORGANIC (ICI/ HOME)	SAMPLING WEIGH (KG)	SSO (KG+ PICTURE#)	GW (KG+ PICTURE#)	DGW (KG+ PICTURE#)	CONTAMINANT (KG+ PICTURE#)	CONTAMINANT DESCRIPTION

Appendix B

SAMPLING RESULTS REPORT

YUKON ENERGY CORPORATION

FEEDSTOCK VALIDATION

FEEDSTOCK SAMPLING REPORT

WHITEHORSE

No projet : 151-06935-00

April 6, 2018

A-2745

FEEDSTOCK VALIDATION

0BFEEDSTOCK SAMPLING REPORT

WHITEHORSE

Yukon Energy Corporation

No projet : 151-06935-00
November 2015

Report (Final version)

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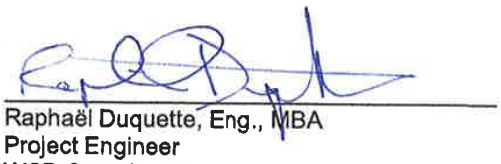

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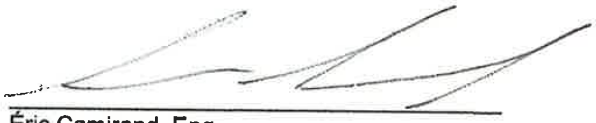

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Reference:

WSP 2015. *Feedstock Validation | 0BFeedstock sampling report, Whitehorse*. Report prepared for Yukon Energy Corporation. No projet : 151-06935-00. 25 pages and tables, figures and appendices.

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TABLE OF CONTENTS

1 INTRODUCTION 1

2 SAMPLING PROCEDURE 3

3 VISUAL ASSESSMENT RESULTS 5

3.1 OBSERVATION LOG 5

3.2 VISIT PICTURES 7

3.2.1 AUGUST 28TH 8
3.2.2 SEPTEMBER 4TH 9
3.2.3 SEPTEMBER 8TH 9
3.2.4 SEPTEMBER 9TH 10
3.2.5 SEPTEMBER 10TH 11
3.2.6 SEPTEMBER 11TH 11
3.2.7 SEPTEMBER 21ST 12
3.2.8 SEPTEMBER 23RD 12
3.2.9 SEPTEMBER 24TH 13
3.2.10 SEPTEMBER 25TH 13
3.2.11 OCTOBER 5TH 14
3.2.12 OCTOBER 6TH 14
3.2.13 OCTOBER 7TH 15
3.2.14 OCTOBER 8TH 15
3.2.15 OCTOBER 9TH 16
3.2.16 OCTOBER 20TH 16
3.2.17 OCTOBER 21ST 17
3.2.18 OCTOBER 22ND 17
3.2.19 OCTOBER 23RD 18

3.3 COMPOSITION ESTIMATION 18

4 LAB ANALYSIS 19

4.1 RATIONALE 19

4.2 RESULTS 19

5 FEEDSTOCK CHARACTERIZATION 25

TABLES

TABLE 1 VISUAL ASSESSMENT LOG 5
TABLE 2 LAB RESULTS 21
TABLE 3 FEEDSTOCK COMPOSITION ESTIMATION 25

FIGURES

FIGURE 1 AUGUST 28TH PICTURES 8
FIGURE 2 SEPTEMBER 4TH PICTURES 9
FIGURE 3 SEPTEMBER 8TH PICTURES 9
FIGURE 4 SEPTEMBER 9TH PICTURES 10
FIGURE 5 SEPTEMBER 10TH PICTURES 11
FIGURE 6 SEPTEMBER 11TH PICTURES 11
FIGURE 7 SEPTEMBER 21ST PICTURES 12
FIGURE 8 SEPTEMBER 23RD PICTURES 12
FIGURE 9 SEPTEMBER 24TH PICTURES 13
FIGURE 10 SEPTEMBER 25TH PICTURES 13
FIGURE 11 SEPTEMBER 5TH PICTURES 14
FIGURE 12 OCTOBER 6TH PICTURES 14
FIGURE 13 OCTOBER 7TH PICTURES 15
FIGURE 14 OCTOBER 8TH PICTURES 15
FIGURE 15 OCTOBER 9TH PICTURES 16
FIGURE 16 OCTOBER 20TH PICTURES 16
FIGURE 17 OCTOBER 21ST PICTURES 17
FIGURE 18 OCTOBER 22ND PICTURES 17
FIGURE 19 OCTOBER 23RD PICTURES 18

APPENDICES

APPENDIX A LAB TEST RESULTS

APPENDIX B SAMPLING PROCEDURE

1 INTRODUCTION

A sampling and analysis campaign has been performed to estimate input tonnage and quality to a possible AD plant that would treat organic waste from Whitehorse ICI and residential.

Objectives of this campaign were the following:

- Estimate contaminant nature and proportion
- Estimate possible monthly and seasonal tonnage and characterization variation throughout the years.

Results would mainly focus on characterizing contaminant nature and composition as well as determining proportion of three main feedstock categories (SSO, DGW, and FGW).

SSO stands for source sorted organics and mostly represents food waste or kitchen waste like fruit or vegetable peels and trimmings. FGW is fresh garden waste which is typically fresh cut grass or garden trimmings. DGW stands for death garden waste which is mainly fallen leaves or tree trimmings.

This information will enable WSP/Electrigaz to properly estimate AD system requirements as well as biogas production.

2 SAMPLING PROCEDURE

A sampling procedure has been generated and accepted by both the client and WSP/Electrigaz. The procedure is available in the appendix B.

This procedure has been followed by the technician on site to assure representativeness of the sampling results. The sampling procedure also included a visual assessment campaign performed by a local student.

3 VISUAL ASSESSMENT RESULTS

A visual assessment is the first step to the characterization of the input material. This step offers the possibility to physically evaluate the input and to testify some unpredictable contaminant scenarios. Electrigaz/ WSP consider this evaluation primordial to establish contaminant removal and input handling strategies. Visual assessments may be, in some cases, the only way to establish worst case scenarios or to verify if these scenarios are plausible. It gives the opportunity to evaluate the possibility a plant will receive in logs, gas canisters or any other cumbersome or unusual contaminant during operation.

Visual assessments were made to establish a preliminary estimation of feedstock available for an AD process. The main objective of these assessments is to provide a rough estimation of main components present in feedstock (SSO, DGW, FGW and contaminants) and seasonal variations of these components.

A total of 20 visits have been made on site to visually inspect feedstock. These visits were made from August 28th until the 22nd of October 2015. This period of time spreads over 2 seasons and represents a typical sample from which it will be possible to derive a yearly average. On each visit, the technician was asked to note input composition and nature of contaminants found in daily loads brought on site.

Note that this visual estimation will also be used to compare lab result characterizations made afterward

3.1 OBSERVATION LOG

The following table sums up the contaminant observations made on each visit.

Table 1 Visual Assessment Log

Date	Load #	Reception hour	Load tonnage (kg)	Comments	Contaminant description
Aug 28	1	1:00 PM	8 250	Yard and garden waste	Plastic bags, Cardboard, Boxboard, Mixed paper
	2	1:00 PM	8 680		
Sept 4	1	12:02 PM	2 090	Mixed compost and paper, food,	Plastic bags, Cardboard, Boxboard, Recyclables, Mixed paper
Sep 8	1	12:50 PM	5 380	Yard and garden waste, Mixed paper, food, bale of straw	Plastic bags, Cardboard, Boxboard, Recyclables, Styrofoams, Bleach bottles
Sept 9	1	12:35 PM	7 860	Yard and garden waste	Plastic bags, Cardboard, Boxboard, Recyclables, Mixed paper, Landfill waste
	2	2:00 PM	2 100		
	3	2:17 PM	3 250		
	4	1:56 PM	8 950		
	5	1:57 PM	8 470		

Date	Load #	Reception hour	Load tonnage (kg)	Comments	Contaminant description
Sept 11	1	11:29 PM	2 440	Yard, garden and food waste	Plastic bags, Cardboard,
Sept 21	1	12:40 PM	7 970	Yard, garden and food waste, Mixed paper	Plastic bags, Cardboard, Boxboard, Recyclables, Mixed paper, Landfill waste
	2	12:39 PM	7 070		
	3	2:00 PM	3 070		
	4	2:14 PM	3 910		
Sept 22	1	12:46 PM	9 060	Yard, garden and food waste, Mixed paper	Plastic bags, Cardboard, Boxboard, Recyclables, Landfill waste, Timber
	2	12:46 PM	7 890		
	3	2:17 PM	3 100		
	4	2:18 PM	2 520		
Sept 23	1	12:57 PM	11 260	Yard and garden waste, Mixed paper	Plastic bags, Cardboard, Boxboard, Landfill waste, Propane canister
	2	12:59 PM	10 940		
	3	2:00 PM	8 630		
	4	2:01 PM	1 880		
Sept 24	1	11:29 PM	11 080	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Cardboard, mixed paper
	2	11:30 PM	11 920		
Sept 25	1	10:53 PM	1 780	Yard, garden and food waste, Mixed paper	Plastic bags, Cardboard, Boxboard, Recyclables, Mixed paper, Landfill waste
Oct 5	1	11:45 PM	420	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Recyclables, 1*4 wood board
Oct 6	1	12:42 PM	6 420	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Cardboard, mixed paper
	2	12:49 PM	8 190		
Oct 7	1	12:34 PM	9 060	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Cardboard, Boxboard, Landfill waste
	2	12:35 PM	10 380		
	3	3:07 PM	1 370		

Date	Load #	Reception hour	Load tonnage (kg)	Comments	Contaminant description
Oct 8	1	12:32 PM	12 070	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Cardboard, mixed paper
	2	12:32 PM	11 020		
Oct 9	1	1:03 PM	2 560	Yard, garden and food waste, Leaves	Plastic bags, Cardboard, Boxboard
Oct 19	1	12:12 PM	1 830	N/D	N/D
Oct 20	1	N/D	N/D	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Cardboard, Boxboard, Recyclables
Oct 21	1	12:40 PM	7 440	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Cardboard, Boxboard
	2	12:41 PM	8 770		
Oct 22	1	12:42 PM	8 720	Yard and garden waste, Mixed paper, Leaves	Plastic bags, Cardboard, Boxboard, 2*4 wood board
	2	12:43 PM	10 990		

3.2 VISIT PICTURES

On each visit pictures have been taken to document visual assessments and estimate contaminant composition. The following pictures sum up the visits.

3.2.1 AUGUST 28TH

Figure 1 August 28th pictures

3.2.2 SEPTEMBER 4TH

Figure 2 September 4th pictures

3.2.3 SEPTEMBER 8TH

Figure 3 September 8th pictures

3.2.4 SEPTEMBER 9TH

Figure 4 September 9th pictures

3.2.5 SEPTEMBER 10TH

Figure 5 September 10th pictures

3.2.6 SEPTEMBER 11TH

Figure 6 September 11th pictures

3.2.7 SEPTEMBER 21ST

Figure 7 September 21st pictures

3.2.8 SEPTEMBER 23RD

Figure 8 September 23rd pictures

3.2.9 SEPTEMBER 24TH

Figure 9 September 24th pictures

3.2.10 SEPTEMBER 25TH

Figure 10 September 25th pictures

3.2.11 OCTOBER 5TH

Figure 11 September 5th pictures

3.2.12 OCTOBER 6TH

Figure 12 October 6th pictures

3.2.13 OCTOBER 7TH

Figure 13 October 7th pictures

3.2.14 OCTOBER 8TH

Figure 14 October 8th pictures

3.2.15 OCTOBER 9TH

Figure 15 October 9th pictures

3.2.16 OCTOBER 20TH

Figure 16 October 20th pictures

3.2.17 OCTOBER 21ST

Figure 17 October 21st pictures

3.2.18 OCTOBER 22ND

Figure 18 October 22nd pictures

3.2.19 OCTOBER 23RD

Figure 19 October 23rd pictures

3.3 COMPOSITION ESTIMATION

The following estimations have been made from visual assessments.

SEASON	SSO (%)	FGW (%)	DGW (%)	CONTAMINANT
				(%)
Summer	19%	37%	41%	3%
Fall	5%	10%	83%	2%

This composition estimation has been made considering tonnage of loads fed on compost platforms when the technician was on site and a rough proportion analysis based only on visual analysis.

It can be noted that SSO and FGW seem much higher in summer compared to fall in which a high amount of DGW is observed. As expected, this is mainly due to leaf input that represents the main organic waste in fall.

Also note that contaminant proportion seems quite constant from summer to fall and is relatively low. The main contaminants noted are non-compostable plastic bags. From these conclusions it seems population has already been well educated. Implementation of an AD plant would not change their habits and it is reasonable to estimate that contaminant proportion would not drastically change.

4 LAB ANALYSIS

4.1 RATIONALE

It is important to mention that the analysis and process estimation approach privileged by Electrigaz/WSP differs slightly from YEC requests. YEC requested biochemical methane potential (BMP) tests on the inputs fed to the composting facility but at this point of the project Electrigaz/ WSP estimate it would be premature and unrepresentative to conduct such analyses.

In our experience, the challenge of BMP testing is the representativeness of the samples. Since SSO substrate quality varies on every load received, it is almost impossible to generate a homogeneous sample that would be representative of the total input.

Moreover, in such small projects biogas yield precision is considered secondary since costs associated to material handling and contaminants removal will deeply influence the economics and viability of the project as well as the produced energy price. This is why general composition of the inputs is more a concern than the actual biogas production.

More specifically ratios between food waste, fresh garden waste, dead garden waste and contaminants and how they may vary in volume and ratios over the seasons are all crucial information to estimate operation strategy and timeline.

It has to be noted that Electrigaz/ WSP and its partner Krieg und Fischer (Germany) cumulates over 30 years of specialized biogas engineering. The consortium has charts for biochemical methane potential (BMP) for every typically processed substrate. This chart presents CH4 yield per kg of organic dry matter. Organic dry matter represents the digestible part of dry matter in a substrate. It is then possible, from substrate characterization, to accurately evaluate biogas production.

By knowing CH4 volume produced from every kg of organic dry matter, the exact degradation of the substrate is calculated and biogas volume production is known as well as mass balance of the entire plant. Therefore, the newly adopted protocol is not focused on biogas production only but focused on composition through sorting protocols and testing for basic parameters such as dry matter and organic dry matter composition and NPK which are the main values considered to design an AD plant.

By experience the consortium only does BMP on exotic and poorly documented substrates. As North American SSO is well documented it has been recommend that lab analyses mainly focus on dry matter and organic dry matter content.

4.2 RESULTS

Lab analyses have been made on representative samples taken on site to support the visual assessments and to precisely define substrate composition and characteristics.

Each sample has been primarily separated in waste type, as defined in the previous sections, SSO, FGW and DGW. It is known that each type of substrate will degrade differently in an AD process and this is why it is important to separate them before proceeding to lab characterization. This separation will enable to precisely define the feedstock seasonality and its impact on AD biogas production, mass balance and equipment sizing.

Each separated sample was analysed to determine the following

- Dry matter,
- Organic dry matter,
- NPK

These results will enable WSP/ Electrigaz to develop process designs. The following table presents the results of the analysis.

Note that sample details (sampling date, sample mass) are available in the appendix

Table 2 Lab Results

SAMPLE DATE	SAMPLE PORTION	SAMPLE WEIGHT	COMPOSITION	DRY MATTER	ORGANIC DRY MATTER	NITROGEN			PHOSPHORUS (P)	POTASSIUM (K)
						NITRATE + NITRITE	NKT	N TOTAL		
		(kg)	(%)	(%)	(%DM)	mg/kg WWB	mg/kg WWB	mg/kg WWB	mg/kg WWB	mg/kg WWB
May 15th - HOME	SSO	0,76	11,71%	61,60%	77,30%	18,6	4 562	4 581	351	3 345
	FGW	0,03	0,46%	64,40%	91,70%	30,0	6 751	6 781	533	12 503
	DGW	5,4	83,20%	74,30%	80,60%	34,7	1 317	1 352	81	5 855
	Contaminant	0,3	4,62%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	6,49	100,00%	69,33%	76,54%	31,2	1 661	1 693	111	5 321
May 15th - ICI	SSO	16,12	94,10%	27,00%	85,80%	16,9	4 747	4 764	86	429
	FGW	0,05	0,29%	42,70%	80,40%	15,9	3 042	3 058	586	7 681
	DGW	0,48	2,80%	48,10%	99,60%	19,8	6892	6912	621	3971
	Contaminant	0,48	2,80%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	17,13	100,00%	26,88%	83,77%	16,5	4 669	4 686	100	537
Sept 10th - HOME - 1st truck	SSO	1,22	39,74%	17,30%	91,70%	13,2	2 171	2 184	180	1 766
	FGW	0,8	26,06%	24,70%	85,20%	41,2	3 010	3 051	339	2 443
	DGW	1,05	34,20%	43,00%	85,50%	14,0	4996	5010	474	3594
	Contaminant	0	0,00%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	3,07	100,00%	28,02%	87,89%	20,8	3 356	3 376	322	2 568

SAMPLE DATE	SAMPLE PORTION	SAMPLE WEIGHT	COMPOSITION	DRY MATTER	ORGANIC DRY MATTER	NITROGEN			PHOSPHORUS (P)	POTASSIUM (K)
						NITRATE + NITRITE	NKT	N TOTAL		
Sept 10th - HOME - 2nd truck	SSO	0,89	37,87%	27,50%	79,70%	15,5	3 144	3 160	284	5 293
	FGW	0,83	35,32%	29,30%	78,00%	17,7	3 457	3 475	581	1 456
	DGW	0,58	24,68%	44,00%	70,70%	16,4	3 182	3 198	597	3 589
	Contaminant	0,05	2,13%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	2,35	100,00%	31,62%	75,18%	16,2	3 197	3 213	460	3 405
Sept 11th - ICI	SSO	1,53	46,36%	20,30%	75,10%	22,6	3 183	3 206	528	4 403
	FGW	1,47	44,55%	26,60%	72,80%	14,9	6 292	6 307	577	3 712
	DGW	0,28	8,48%	32,90%	87,20%	18,3	3 186	3 204	486	6 212
	Contaminant	0,02	0,61%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	3,3	100,00%	24,05%	74,65%	18,7	4 549	4 568	543	4 222
Oct 23th - HOME	SSO	0,72	24,32%	40,00%	89,50%	63,1	7 449	7 512	2 892	1 960
	FGW	0,31	10,47%	18,40%	84,30%	14,4	3 432	3 446	84	3 534
	DGW	1,92	64,86%	48,60%	91,00%	8,4	1 808	1 816	111	1 003
	Contaminant	0,01	0,34%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	2,96	100,00%	43,18%	89,63%	22,3	3 344	3 366	784	1 497

SAMPLE DATE	SAMPLE PORTION	SAMPLE WEIGHT	COMPOSITION	DRY MATTER	ORGANIC DRY MATTER	NITROGEN			PHOSPHORUS (P)	POTASSIUM (K)
						NITRATE + NITRITE	NKT	N TOTAL		
Oct 23th - HOME - 2nd truck	SSO	0,9	39,82%	32,40%	72,20%	32,7	10 252	10 285	81	2 944
	FGW	0,26	11,50%	28,60%	86,20%	16,1	5 739	5 755	155	4 863
	DGW	1,08	47,79%	34,60%	88,60%	6,4	6 815	6 822	85	2 330
	Contaminant	0,02	0,88%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	2,26	100,00%	32,73%	81,01%	17,9	8 000	8 018	91	2 845
Oct 23th - ICI	SSO	3,15	84,00%	21,80%	86,90%	16,7	5 325	5 342	83	1 921
	FGW	0,49	13,07%	18,20%	80,20%	16,7	2 470	2 484	429	4 118
	DGW	0,09	2,40%	37,10%	82,00%	6,4	8 149	8 156	85	1 026
	Contaminant	0,02	0,53%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total (estimated value)	3,75	100,00%	21,58%	85,44%	16,4	4 991	5 008	128	2 176

5 FEEDSTOCK CHARACTERIZATION

From results obtained on both visual assessments and lab results it is possible to generate a seasonal substrate composition estimation. Tables below show these estimations

Table 3 Feedstock Composition Estimation

DISTRIBUTION	ICI				HOUSEHOLD			
	SSO	Garden Waste	Death garden waste	Contaminants	SSO	Garden Waste	Death garden waste	Contaminants
JAN	93,0%	0,5%	3,0%	3,5%	91,0%	0,5%	5,0%	3,5%
FEB	95,0%	0,5%	1,0%	3,5%	95,0%	0,5%	1,0%	3,5%
MAR	96,0%	1,0%	1,0%	2,0%	90,5%	0,5%	5,0%	4,0%
APR	96,5%	1,0%	1,5%	1,0%	51,0%	0,5%	44,0%	4,5%
MAY	95,9%	0,3%	2,9%	1,0%	11,7%	0,5%	83,2%	4,6%
JUN	90,0%	4,0%	4,0%	2,0%	15,5%	30,0%	50,0%	4,5%
JUL	75,0%	10,0%	12,0%	3,0%	16,0%	45,0%	35,0%	4,0%
AUG	65,0%	15,0%	15,0%	5,0%	26,5%	40,0%	30,0%	3,5%
SEP	46,4%	44,5%	8,5%	0,6%	38,8%	30,7%	29,4%	1,1%
OCT	84,0%	13,1%	2,4%	0,5%	32,1%	11,0%	56,3%	0,6%
NOV	91,5%	2,5%	2,5%	3,5%	71,5%	5,0%	20,0%	3,5%
DEC	93,0%	0,5%	3,0%	3,5%	90,5%	1,0%	5,0%	3,5%

Since samples have been taken in May, September and October, the other months have been extrapolated from these lab results

Appendix

LAB TEST RESULTS

LAB TEST RESULTS

DATE	RECEPTION HOUR	SAMPLE	ICI OR HOME	DESCRIPTION	TOTAL TRUCK LOAD WEIGHT	TOTAL SAMPLE PILE WEIGHT	SAMPLE WEIGHT	SSO	FGW	DGW	CONTAMINANT
10-sept	11:18	15-mai	Home	Mass (kg)	n/a	n/a	6,55	0,76	0,03	5,4	0,3
				Photo Name	n/a	n/a	yukon 005, yukon 006	yukon 007	yukon 010	yukon 008	yukon 009
				Description	n/a	n/a	In blue container, in garbage bag. Fully thawed, mostly DGW	mostly paper, some fruit/veg peels	pine, moss, not be enough material to sample	leaves, grass, pine needles, acorns, twigs	rocks, plastic
				Sample Name	n/a	n/a	n/a	Exc#1 15SSOA (0cm)	Exc#1 15FGWA (0cm)	Exc#1 15DGWA (0cm)	n/a
10-sept	12:44	15-mai	ICI	Mass (kg)	n/a	n/a	16,98	16,12	0,05	0,48	0,16
				Photo Name	n/a	n/a	n/a	yukon 012	yukon 013	yukon 014	yukon 015
				Description	n/a	n/a	in blue container, in garbage bag. Partially frozen in middle, mostly SSO	Coffee grounds, sunflower seeds, potatoes, other fruit/veg peels	pine, not be enough material to sample	twigs, leaves	rocks, plastic
				Sample Name	n/a	n/a	n/a	Exc#2 15SSOA (0cm)	Exc#2 15FGWA (0cm)	Exc#2 15DGWA (0cm)	n/a

DATE	RECEPTION HOUR	SAMPLE	ICI OR HOME	DESCRIPTION	TOTAL TRUCK LOAD WEIGHT	TOTAL SAMPLE PILE WEIGHT	SAMPLE WEIGHT	SSO	FGW	DGW	CONTAMINANT
23-oct	12:44	Oct. 22 First Truck	Home	Mass (kg)	8720	111	3	0,72	0,31	1,92	0,01
				Photo Name	yukon2 019, yukon2 020	yukon2 033, yukon2 034, yukon2 035	n/a	yukon2 037	yukon2 038	yukon2 039	yukon2 040
				Description	n/a	n/a	mostly DGW, loose and in paper bags. Some SSO	veg/fruit, paper	whole plants	leaves, twigs	rocks, duct tape
				Sample Name	n/a	n/a	n/a	Exc#6 15SSOA (30cm)	Exc#6 15FGWA (30cm)	Exc#6 15DGWA (30cm)	n/a
23-oct	12:45	Oct. 22 Second Truck	Home	Mass (kg)	10990	445	2,23	0,9	0,26	1,08	0,02
				Photo Name	yukon2 026, yukon2 027	yukon2 041, yukon2 042, yukon2 043	n/a	yukon2 044	yukon2 045	yukon2 046	yukon2 047
				Description	n/a	n/a	mostly DGW, loose and in paper bags. Some SSO	paper towel, veg/fruit	Flowers, grass	leaves, twigs	sticky fabric
				Sample Name	n/a	n/a	n/a	Exc#7 15SSOA (30cm)	Exc#7 15FGWA (30cm)	Exc#7 15DGWA (30cm)	n/a

DATE	RECEPTION HOUR	SAMPLE	ICI OR HOME	DESCRIPTION	TOTAL TRUCK LOAD WEIGHT	TOTAL SAMPLE PILE WEIGHT	SAMPLE WEIGHT	SSO	FGW	DGW	CONTAMINANT
10-sept	14:50	Sept 10 First Truck	Home	Mass (kg)	8470	445	3,1	1,22	0,8	1,05	none
				Photo Name	n/a	n/a	yukon 016, yukon 017	yukon 018	yukon 019	yukon 020	n/a
				Description	n/a	n/a	mostly FGW	Fruit/veg, coffee grounds, paper	Flowers, grass	twigs, leaves	n/a
				Sample Name	n/a	n/a	n/a	Exc#3 15SSOA (30cm)	Exc#3 15FGWA (30cm)	Exc#3 15DGWA (30cm)	n/a
10-sept	15:30	Sept. 10 Second Truck	Home	Mass (kg)	8950	111	2,39	0,89	0,83	0,58	0,05
				Photo Name	n/a	n/a	yukon 021, yukon 022, yukon 023	yukon 024	yukon 026	yukon 025	yukon 027
				Description	n/a	n/a	mostly SSO and FGW	Fruit/veg, paper	grass	twigs, leaves ,grass	foild lined candy wrapper
				Sample Name	n/a	n/a	n/a	Exc#4 15SSOA (30cm)	Exc#4 15FGWA (30cm)	Exc#4 15DGWA (30cm)	n/a

DATE	RECEPTION HOUR	SAMPLE	ICI OR HOME	DESCRIPTION	TOTAL TRUCK LOAD WEIGHT	TOTAL SAMPLE PILE WEIGHT	SAMPLE WEIGHT	SSO	FGW	DGW	CONTAMINANT
11-sept	12:20	Sept. 11 Truck	ICI	Mass (kg)	2440	445	3,43	1,53	1,47	0,28	0,02
				Photo Name	n/a	yukon 029, yukon 031	yukon 038, yukon 039, yukon 040	yukon 041	yukon 042	yukon 043	yukon 044
				Description	n/a	n/a	FGW with dirt and roots, bags of SSO	Fruit/veg	whole plants, flowers, shrubs	whole bushes	plastic
				Sample Name	n/a	n/a	n/a	Exc#5 15SSOA (30cm)	Exc#5 15FGWA (30cm)	Exc#5 15DGWA (30cm)	n/a
23-oct	12:30	Oct. 23 Truck	ICI	Mass (kg)	1760	1760	3,79	3,15	0,49	0,09	0,02
				Photo Name	yukon2 048, yukon2 049, yukon2 050	yukon2 048, yukon2 049, yukon2 050	n/a	yukon2 051	yukon2 052	yukon2 053	yukon2 054
				Description	n/a	n/a	Mostly SSO, ~5%DGW, ~5%FGW	veg/fruit, paper, eggs, coffee	whole plants, flowers	leaves, twigs	plastic
				Sample Name	n/a	n/a	n/a	Exc#8 15SSOA (30cm)	Exc#8 15FGWA (30cm)	Exc#8 15DGWA (30cm)	n/a

n/a Not applicable or not available

1 - Total sample pile weight estimated by visual fraction of loader bucket used and an estimated loader bucket volume of 3.3 m3 and estimated waste density of 270 kg/m3

Appendix C

TECHNOLOGY REVIEW

Appendix Technology review

Proposed systems in RFIs

In this appendix, each of the five proposed biogas systems is summarized. The information provided in the proposals varies greatly.

Himark Biogas Inc.

Himark Biogas Inc. proposes a biogas system using a dry digestion technology. The design includes four dry fermentation chambers, a percolate recirculation system, a biogas polishing system and a cogeneration system. The proposed facility has a capacity of 4000 tons per year, but the capacity can be increased by installing additional fermentation chambers.

The dry fermentation system operates on a sequential batch basis. Each of the four chambers has a volume of 306 m^3 and can accommodate seven days' worth of feedstock (assumingly based on average annual substrate). Before loading the fermentation chambers, the substrate is prepared by mixing it with a bulking agent, potentially dehydrated digestate. Himark however mention that bulking agent addition might not be necessary in this case. The mixing is performed within the digester building, which can accommodate for eight days' worth of feedstock and up to 90 tons of recalcitrant digestate. The fermentation chambers are heated by an internal glycol heating system, with heat provided by the cogeneration system.

Complete pathogen destruction is achieved by operating the fermenter at a temperature of 55 °C, i.e. thermophilic temperature range. According to the supplier, the fermentation chambers can reach the thermophilic operating conditions without external energy requirements due to internal heat generation at the beginning of the digestion process. Typically this lasts for 10 to 16 hours from the beginning of the cycle. Thereafter the fermentation chambers are heated by the internal glycol heating system.

The fermentation chambers are connected to a percolation sprinkler system. It is used to spray the feed with percolate in order to accelerate the anaerobic fermentation process. The percolate is biologically active and contains microorganisms that will enhance the digestion process. The excess percolate from the fermenters drains to a percolation sump where it is fed to a separate percolate tank. In the tank the percolate recharges with the thermophilic organisms required for digestion. The percolate tank is heated to a temperature of 55 C° with internal glycol heating loops. The percolate stream is sprayed on top of the substrate at a temperature of about 62 °C.

The percolate tank is a significant generator of biogas and will approximately produce 25-40 % of the total amount of biogas. The percolate tank is equipped with pumps transporting the percolate drained from the fermenters to the tank as well as from the tank and to the sprinkler nozzles. The percolate tank is equipped with Blown down and Make up water systems to prevent salts from cycling up in the percolation stream.

The proposal includes a cogeneration system containing internal combustion engines, which drives generators to produce electricity. The waste heat is captured in a stream of glycol and utilized in the anaerobic digestion plant. In order to utilize the biogas in the cogeneration system, the gas needs to be pretreated in a scrubbing and polishing process. Contamination of H_2S needs to be removed to prevent oxidation of cogeneration system equipment. Before the biogas can be utilized the moisture content needs to be decreased and the gas must be delivered within specified

temperature and pressure ranges (not specified in the proposal). The proposal includes a biogas scrubbing system using ferric chloride injections into the percolate stream.

Table 1: Proposal specifics Himark Biogas

Mass and energy balances summary	Total project estimate	Used technology and major components for biogas production
Biogas production: 806,285 m^3/year (Based on a 4000 ton feedstock) Cogeneration system: Gross power: 134 kW_e Net power 121 kW_e Thermal output: 265 kW_{th} Water use: 504 tonnes/year Liquid waste: 504 tonnes/year Sludge: 3.1 tonnes/year (% TS of around 34 %)	$ 2,264,821 USD	Biogas is produced in dry fermentation chambers and a percolate tank. Major components: ◦ Fermentation chambers ◦ Percolate tank and recirculation system ◦ Purge and ventilation system ◦ Biogas scrubber and polishing system ◦ Cogeneration unit ◦ Biogas storage ◦ Biogas flare

Himark has experience on biogas production from source sorted organic waste (SSO). It has conducted the detailed design for a biogas plant in Hairy Hill, Alberta, Canada where the hot and extreme cold climates needed to be taken into consideration. Himark has also conducted three integrated anaerobic digestion and fertilizer projects with SSO as feedstock in Hampshire, USA.

Viessmann/BIOFerm

BIOFerm, a part of the Viessmann group, propose a biogas system that includes a combined anaerobic digestion and compost facility. The design includes four dry fermentation chambers, a percolate storage tank, a biogas treatment system, gas storage, a CHP plant and an odor control system. The proposed sizing of the fermentation chambers allows for potential increase of feedstock quantity from 3,202 tons per year to 7,823 tons per year. The design enables this expansion by increasing the loading height in the fermentation chambers. While running below maximum capacity, the amount of recycled digestate can be increased to lengthen the retention time and utilize more digester space.

The substrate is fed in batches to the four dry fermentation chambers where biogas, digestate and percolate are produced. At the start-up of the plant, each fermenter will be staggered in start-up by one week, which allows the waste to be received and stored no longer than 7 days prior to entering into a fermenter unit. When a fermentation chamber is at the end of a single digestion cycle, typically 28 days, the digested material is removed. A portion of the digestate is mixed with the fresh material and reloaded to a fermenter to begin a new cycle. At full capacity, 40 % of the digestate will be recycled. The digestate that was not mixed and reloaded into the fermentation chamber is then ready for composting or to be used as landfill cover. The fermentation chambers are connected to an in-floor heating system keeping the substrate at a constant temperature of 40 °C, i.e. optimum condition for mesophilic anaerobic digestion. Heat is provided from the CHP system. BIOFerm argues that mesophilic conditions are preferable because the majority of methane producing bacteria thrives in mesophilic temperature ranges and has higher growth rates than the minority existing in the thermophilic temperature ranges. This has been demonstrated to increase the resistance to toxic impacts and variations in the feedstock characteristics. However, digestion in the thermophilic range has been noted for a higher pathogen destruction rate. BIOFerm further argues that the possible gains in gas production with thermophilic conditions are offset by the increased costs.

The substrate stored in the fermentation chambers is sprayed with percolate containing microorganisms to optimize the digestion process. The percolate drained from the fermentation chambers is collected into a percolate storage tank, a continuously stirred-tank reactor. The BIOFerm dry fermentation process is distinguished by pairing a wet fermenter to the process, which enables handling of liquid feedstock in addition to dry waste. Biogas is captured by a gas blower from both the fermenters and the percolate storage tank. The percolate storage tank is operated at 38-44 °C temperature range.

The biogas is treated by removing water and toxic compounds such as H2S or siloxanes. The water condensate by decreasing the gas temperature and toxic compounds are removed via a carbon filter and/or an iron sponge. A biological desulfurization is integrated into the roof structure of the gas storage. The gas can now be used in a CHP or be upgraded to vehicle fuel. The design include two 100 kW CHP biogas engines utilizing the produced biogas.

The BIOFerm system includes an odor control using a biofilter. The odor control system uses water that is recirculated. Only a fraction of the water is sent to the percolation tank.

Viessmann anticipate that no wastewater will be generated for offsite disposal due to the high solids nature of the feedstock. Additional liquid will be required to ensure the anaerobic digestion facility runs efficiently. The amount may vary du to potential of liquid collected from source separated organic material.

Table 2: Proposal specifics Viessmann/BIOFerm

Mass and energy balances summary	Total project estimate	Used technology and major components for biogas production
Biogas production: 266,316 m^3/year (Based on a 3,202 tons feedstock) 650,652 m^3/year (Based on a 7,823 tons feedstock) CHP output: 3,202 tons feedstock Gross power: 583 MWh_e/year Gross thermal output: 2,790 MMBTU/year 7,823 tones feedstock Gross power: 1,499 MWh_e/year Gross thermal output: 6,329 MMBTU/year Water use: Required. (Amount dependent on feedstock) Liquid waste: 0 tons/year Digestate: 4,072 tons/year (Based on a 3,202 tons feedstock) 9,950 tons/year (Based on a 7,823 tons feedstock)	$ 3,927,270 USD	Biogas is produced in dry fermentation chambers and a percolate tank. Major components: ◦ Mixing hall with compost boxers and digesters ◦ COCCUS 1000 Percolate tank ◦ Exhaust system with biofilter ◦ Gas dome ◦ Substrate storage ◦ CHP (2x100 kW)

BIOFerm describes three reference facilities in Europe that utilize municipal organic waste, food waste and materials from landscape conservation. It also presents a case study from an industry-scale dry fermentation anaerobic digester at the University of Wisconsin-Oshkosh, which uses 8000 tons of food waste, yard waste and crop residuals annually.

Bio-en power Inc.

Bio-en power proposes a facility with a wet digestion technology that will eliminate the need for the current composting system. The design include one 1,590 m^3 insulated anaerobic digestion fermentation tank, two 100 m^3 pasteurization tanks and a CHP. The system can handle 4000 tons of feedstock per year, with monthly fluctuations.

The incoming waste will be preprocessed by chopping and mixing in the preprocessing pit. It will then be fed to the pasteurization tanks before fed into the main fermenter via a pump station. The dry substrates are stored in a driving silo and then fed as required to the main fermenter via the dry loading unit. The substrate is fermented in the fermenter at a temperature between 35°C and 55°C. The digesters will eliminate pathogens and weeds and therefore no additional composting is required. The digestate is separated into a solid fraction and a liquid residue. The digestate can be used as a fertilizer.

Table 3: Proposal specifics Bio-en power Inc.

Mass and energy balances summary	Total project estimate	Used technology and major components for biogas production
(Based on 2,220 tons feedstock) Biogas production: 306,600 m^3/year CHP output: Power output: 560 MWh_e/year Thermal output: 720 MWh_{th}/year Water use: 1,000 tons/year Solid waste: 1,825 tons/year Liquid waste: 1,095 tons/year	$ 2,608,277 CAD	Biogas is produced by using wet anaerobic digestion technology. Major components: ◦ Insulated anaerobic digestion fermentation tank ◦ Pasteurization tanks ◦ Preprocessing pit ◦ Gas storage ◦ Driving silo ◦ CHP

According to the references in the RFI, Bio-en has no experience from SSO feedstock. From the references, all located in Europe, it seems Bio-en instead has experience of feedstock such as corn silage, rye, cattle dung, slaughter waste, blood and biogenic wastes.

Wildstone/Gicon

Gicon proposes a biogas facility using the patented GICON® Process consist of a two-stage, dry-wet anaerobic digestion process. The design includes a pretreatment area, ten percolation tunnels, two methane digesters, a percolate buffer tank, a digestate storage tank, gas storage, an emergency flare and a CHP.

The process begins with feedstock pretreatment by shredding and mixing. The feedstock is then loaded into percolation tunnels, for an initial hydrolysis stage, where it remains for a retention time of 14-20 days. In the percolation tunnels the substrate is irrigated with process water and liquid digestate resulting in an organically-laden liquid. This liquid substrate in then pumped to a buffer tank which continuously feeds the methane digesters (fixed bed reactors), where the methanogenesis stage begins. The two methane digesters operate at 38 °C, i.e. mesophilic conditions, and produce the majority of the biogas. The remaining solid residuals are composed mainly of difficult-to-degrade material and can subsequently be treated under aerobic conditions by means of composting.

Table 4: Proposal specifics Wildstone/Gicon

Mass and energy balances summary	Total project estimate	Used technology and major components for biogas production
(Based on a 2,334 tons feedstock) Biogas production: 232,403 Nm^3/year CHP output: Gross power output: 472 MWh_e/year Net power output: 245 MWh_e/year Gross thermal output: 609 MWh/year Net thermal output: 477 MWh/year Water use: 467 tons/year for the anaerobic digestion process 36-108 tons/year for biological desulfurization Liquid waste: 1500 tons/year Contaminant materials: 120 tons/year Final compost: 474 tons/year	$ 7,440,727 CAD	Biogas is produced by using a two-stage, dry-wet anaerobic digestion technology. Major components: ◦ Pretreatment area ◦ Percolation tunnels ◦ Methane digesters ◦ Percolate buffer tank ◦ Digestate storage tank ◦ Process water tanks ◦ Gas storage ◦ Emergency flare ◦ Building ventilation system ◦ CHP

Gicon has delivered more than 60 biogas facilities worldwide. The patented GICON® process has been implemented at Harvest Power's Richmond Energy Garden biogas plant near Vancouver. 40,000 tons of residential/commercial SSO and lawn/garden waste is processed in the facility annually.

Enerpedia

Enerpedia presents a number of case studies for small-scale anaerobic digestion facilities in Western Europe. Enerpedia does not provide a specific proposal for the Whitehorse project. However, one case that can be interesting is a dry pocket digester facility installed on the horse farm of Thierry de Pas in France.

The digester's biomass input on a yearly basis consists of 650 tons of litter and 850 tons of communal bio-organic waste and other biomass. Biogas is produced by mesophilic dry digestion and then utilized in a 50 kW_e CHP. The system included of six modular digestion containers of a standard size of 30 m^3 with a residence time of 25-30 days. Percolate from the anaerobic digestion is recirculated to maintain a favorable microbial community in each of the containers.

The biogas is captured and stored in a gas balloon before it is utilized in the CHP. The digestate is spread out on proprietary grassland and cropland.

Table 5: Case study of dry type pocket digester in France.

Mass and energy balances summary	Total project estimate	Used technology and major components for biogas production
(Based on 1500 tons feedstock) CHP output: Gross power output: 253 MWh_e/year Heat use: 425 MWh_{th}/year	684,000 €	Biogas produced by using a two-stage, dry-wet anaerobic digestion technology. Major components: ◦ Digestion containers ◦ Heating network ◦ "Gas balloon" storage ◦ CHP

Enerpedia has only collected information from different case studies and installations across Western Europe. The only case operating with a dry fermentation technology uses litter, communal bio-organic waste and other biomass as feedstock.

Appendix 5.14
Waste-to-Energy Design Basis and Business Case Analysis
(Morrison Hershfield 2012)

MORRISON HERSHFIELD

November 13, 2015

Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, Yukon Y1A 6S7

Attention: Shannon Mallory, Environmental Coordinator

Dear Shannon:

Re: 5160120 - Review of Waste to Energy Business Case Analysis

Introduction

Morrison Hershfield completed a business case analysis for Yukon Energy Corporation (YEC) in 2012 exploring the feasibility of developing a Waste to Energy facility in Whitehorse ("Waste to Energy Updated Design Basis and Business Case Analysis", April 24, 2012). The primary purpose of the proposed facility was to increase firm electrical generation capacity in Yukon (1.6 MW capacity; 9,975 MWh generated annually).

We understand that YEC may be including "Waste to Energy" among the options to be considered in an updated Resource Plan and would like to determine if the results of Morrison Hershfield's 2012 business case analysis ("MH 2012") require revisions or updating. This memo includes a brief discussion of the key business case variables and provides an assessment of whether the business case results remain applicable for YEC's current planning initiative.

Review of Key Business Case Variables:

A brief discussion of the key business case variables determined in MH 2012 is provided below:

Feedstock Availability

The design basis for the 2012 business case was predicated on optimizing the use of available City of Whitehorse Municipal Solid Waste (MSW) feedstock and augmenting the MSW with higher cost biomass (wood) feedstock during the winter period when waste volumes decrease. The business case analysis assumed that available MSW volumes would decrease significantly by 2015 coinciding with the City's policy direction of achieving a 50% waste diversion target by 2015. The business case also included a number of sensitivity analyses that examined alternative waste diversion scenarios.

We understand the City of Whitehorse has not yet achieved its 50% diversion target and higher volumes of MSW are currently being disposed in landfill than predicted in the business case analysis. However, since the City is continuing to implement their Zero Waste programs outlined in the Solid Waste Action Plan (City of Whitehorse, 2013) the assumption of reduced future MSW volumes (used in the business case analysis) remains valid.

It was assumed that biomass (to augment the MSW feedstock) would be obtained from a variety of sources including spruce beetle-killed wood, local brushing and clearing, and Construction & Demolition waste. We are not aware of any significant changes in either the availability or competitive end uses for these biomass sources.

Technology and Conversion Efficiency

In the RFI process used to support the 2012 business case, seven vendors provided technical and price information. Some of these vendors are no longer active in the marketplace. However, one vendor, namely EcoWaste Solutions, has been expanding its operations and added additional capabilities. Since this was also one of the highest rated vendors in our assessment, we can confirm that the standard module size originally chosen is still valid.

There have been no new technologies for energy from waste that have reached maturity in this size range to the best of our knowledge in the past 4 years. From other recent projects and technology reviews we can confirm that controlled-air two-stage technology is still the most appropriate technology for this size range, fuel type and location.

The conversion efficiency of waste into heat and power depends on the heating value of the feedstock and the efficiency of the technology. Since neither have changed, the conversion efficiency will also not have changed.

Capital Cost Estimates

The major variables in the capital cost estimates are:

- Chute to stack combustion and energy recovery technology
- Site costs
- Installation and commissioning costs
- Interest rates

Given that the technology assumptions have not changed, the facility size is the same, and inflation has been minimal we estimate that the original cost used in the financial analysis is still valid.

Since it is premature to select a site for this facility (at this planning stage) there is no basis for updating estimated site costs.

Inflation rates have been low (or even negative) in Yukon over the past few years indicating that there is no basis for updating installation and commissioning costs.

Interest rates have actually dropped since the business case analysis was conducted, but only minimally. Since they are expected to rise again, we suggest that the 5.5% annual rate used in the business case analysis is still valid.

In summary, capital costs can be expected to be in the same range as projected in the original financial analysis.

Operating Costs

The most significant operating costs accounted for in the 2012 business case analysis were labour, variable O&M costs, and cost of biomass (wood) supply. Similar to the discussion of capital cost estimates (above), it is assumed that labour and variable O&M costs have not changed significantly as a result of low inflation experienced in Yukon (Whitehorse). We are also not aware of any reason that costs for procuring local biomass (wood) will have changed significantly over the past 4 years.

Revenues

The 2012 business case analysis is highly dependent on revenues from both MSW tipping fees and the sale of heat to a future District Energy System (DES) in Whitehorse. The business case analysis assumed a tipping fee rate of $108 per tonne of MSW received. Since the current (2015) City of Whitehorse Landfill tipping fees range between $94/tonne for sorted waste to $250 for unsorted waste, the estimate used in the business case analysis is still considered reasonable.

Estimated revenue from heat sales to a future DES were based on heating loads and district energy system capital and operating costs derived from a recent DES study completed for YEC in 2013 ("Whitehorse Community Energy Project: Community Energy System Feasibility Study Report", FVB Energy Inc). This is currently the best available information for assessing District heating opportunities and costs in downtown Whitehorse.

Conclusion

Based on the discussion provided in this letter, the Waste to Energy business case analysis results completed for YEC in 2012 are suitable for the purpose of YEC's current high-level resource options assessment.

Yours truly,
Morrison Hershfield Limited

Don McCallum, MASc., P.Eng.
Vice President, Environment

Morrison Hershfield Limited

Konrad Fichtner, P.Eng.
Global Waste Practice Leader

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MORRISON HERSHFIELD

REPORT

Waste to Energy Updated Design Basis and Business Case Analysis

Presented to:
Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, Yukon
Y1A 6S7

Project No. 510404502 April 24, 2012

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Morrison Hershfield | Suite 310, 4321 Still Creek Drive, Burnaby, BC V5C 6S7, Canada | Tel 604 454 0402 Fax 604 454 0403 | morrisonhershfield.com

MORRISON HERSHFIELD

April 24, 2012

Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, Yukon Y1A 6S7

Attention: David Morrison, President and CEO

Dear Mr. Morrison:

Re: Waste to Energy Updated Design Basis and Business Case Analysis

Morrison Hershfield is pleased to submit this final report to Yukon Energy Corporation to assist the Corporation in their evaluation of waste to energy opportunities in Whitehorse.

We look forward to continuing to support the Corporation in the evaluation and implementation of future energy opportunities in the territory.

Yours truly,

Morrison Hershfield Limited

Don McCallum, MASc., P.Eng.
Director, Environmental Services

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EXECUTIVE SUMMARY

Yukon Energy is considering increasing firm electrical generation capacity in Yukon using municipal solid waste (MSW) as a fuel source in a waste to energy (WTE) process. A preliminary business case analysis completed by Morrison Hershfield in 2011 indicated that WTE could provide firm, dependable electricity at significantly lower cost than diesel-generated electricity, provided waste heat from the process could be utilized and sold in a District Energy System (DES). This report updates the WTE business case analysis incorporating feedback received from key stakeholders, updated facility design, performance and cost information, preliminary District Energy System feasibility results, and a preliminary analysis of siting, environmental and approval considerations.

Several meetings and discussions have been held between Yukon Energy, their consultant team, and key stakeholders including City of Whitehorse, Government of Yukon Community Services Department, Raven Recycling, P&M Recycling, and the Yukon Conservation Society. Issues identified during these meetings included potential impact on City landfill operations and costs, air emissions, ash management, and concerns that WTE would harm and limit recycling opportunities. Yukon Energy organized a half-day workshop and public meeting on October 18, 2011 for the purpose of identifying issues and opportunities and outlining a plan for moving forward. A key theme identified at the workshop and public meeting was support for locally derived energy sources. There was a strong desire expressed to ensure that WTE is part of an integrated waste management system and does not compete with recycling. There was also strong support for increased diversion of materials away from the landfill and future WTE, with discussion of the territory and City potentially establishing a 50% waste diversion target.

The WTE facility design capacity was decreased to 25,000 tonnes per year from 30,000 tonnes per year in response to the desire of the City of Whitehorse to establish and achieve a 50% waste diversion goal. Approximately 7,700 tonnes per year of wood biomass would be required initially to ensure the WTE facility operates at full utilization, assuming the waste diversion target was achieved at plant startup. The amount of wood biomass required would decrease over time based on continued population and waste growth and maintaining a 50% waste diversion target.

A call for Expressions of Interest (EOI) yielded technical responses from seven vendors potentially interested in providing a WTE process. The response confirmed the technical basis of the business case analysis (conventional combustion utilizing either a small mass burn system or different forms of close-coupled gasification), provided expected energy recovery efficiencies, and outlined capital and operating cost estimates.

A preliminary siting assessment, informed by the results obtained from a separate Whitehorse District Energy feasibility study, identified potential site locations in the Marwell Industrial area and along Robert Service Way south of the downtown area. While a more detailed siting assessment and consultation will be required prior to final site selection, the business case analysis assumes siting in the Marwell area because of proximity to potential heat customers, access to municipal services and compatibility with adjacent land uses.

Air emissions have been estimated for a WTE facility and compared to emissions from diesel combustion in electrical generators and furnace oil combustion in space heating applications. Assuming the electricity produced from WTE displaces diesel-generated

electricity, and waste heat is utilized in a DES displacing furnace oil, WTE is expected to result in a net reduction of nitrogen oxide, particulate matter and carbon monoxide emissions and a net increase in sulphur dioxide emissions.

The estimated cost to produce 10,000 MWh per year of electricity from MSW and biomass in the "base case" is $0.31 per kWh. This estimate is similar to the cost of diesel-generated electricity and does not provide a clear incentive to pursue a WTE project. This cost estimate is higher than reported in the September 2011 preliminary business case analysis ($0.16 per kWh) largely as a result of two key factors: (1) requirements for additional biomass (higher cost) feedstock during initial operations, assuming that the waste diversion target of 50% is achieved in 2015; and (2) reduced electricity generation efficiencies reported by vendors when operating in a combined heat and power mode, while meeting the heat quality requirements specified in the initial results of the FVB Energy Whitehorse district energy study.

A sensitivity analysis identified two key areas of uncertainty that have the ability to significantly affect business case viability, as follows:

- An application for federal grant funding has been made under the NRCan ECO II program. If this funding request is successful, the electricity production costs could be reduced to $0.21/kWh.

- The base case analysis assumes an almost immediate drop (by 2015) in residual waste volumes to meet a 50% diversion target. The actual implementation schedule for achieving the diversion target is not yet known. If the diversion target was achieved in seven years (instead of two), the cost to produce electricity using WTE is $0.21 per kWh in 2015.

Based on the study results, it is recommended to determine if project feasibility can be improved through further examination of two key project uncertainties: capital funding grant availability and confirmation of waste diversion strategy implementation.

TABLE OF CONTENTS

Page

TRANSMITTAL LETTER

EXECUTIVE SUMMARY

1. INTRODUCTION 1
1.1 OVERVIEW 1
1.2 STUDY SCOPE AND OBJECTIVE 1

2. ENERGY DEMAND 3
2.1 ELECTRICITY 3
2.2 HEAT 3

3. PUBLIC ENGAGEMENT 7

4. UPDATED DESIGN BASIS 8
4.1 SYSTEM CAPACITY 8
4.2 PROCESS TECHNOLOGY 21
4.3 TECHNOLOGY PERFORMANCE 22

5. SITING, ENVIRONMENTAL & APPROVALS CONSIDERATIONS 23
5.1 SITE CONSIDERATIONS 23
5.2 AIR EMISSIONS 33
5.3 ENVIRONMENTAL APPROVALS AND PERMITTING 37

6. UPDATED BUSINESS CASE ANALYSIS 46
6.1 APPROACH AND KEY ASSUMPTIONS 46
6.2 FEEDSTOCK COSTS AND REVENUES 47
6.3 FACILITY CAPITAL AND OPERATING COSTS 48
6.4 FINANCIAL ANALYSIS BASE CASE 50
6.5 SENSITIVITY ANALYSIS 51

7. CONCLUSIONS AND RECOMMENDATIONS 55
7.1 CONCLUSIONS 55
7.2 RECOMMENDATIONS AND NEXT STEPS 57

8. REFERENCES 58

APPENDIX A: YUKON ENERGY WASTE TO ENERGY WORKSHOP REPORT 60

APPENDIX B: LANDFILL FULL COST ACCOUNTING REPORT (DRAFT) 61

APPENDIX C: EOI QUESTIONNAIRE 62

APPENDIX D: ENVIRONMENTAL ASSESSMENT PROCESS 63

APPENDIX E: NRCAN ECOII FUNDING APPLICATION 64

TABLE OF CONTENTS (Cont.)

Page

List Of Figures

Figure 1: Potential Whitehorse DES distribution lines servicing the Downtown and Hospital area. 4
Figure 2: Heating load-duration curve for Whitehorse Downtown and Hospital District (FVB Energy, 2012) 5
Figure 3: Recent Waste Growth in Whitehorse 9
Figure 4: Projected landfill quantities under enhanced diversion 10
Figure 5: Waste to Energy Feedstock Quantities 12
Figure 6: Waste and Ash to Landfill 13
Figure 7: Historical Landfill Clearing and Grubbing Quantities disposed at City landfill 16
Figure 8: Major Water/Sewer Lines in Whitehorse 24
Figure 9: Electrical infrastructure near downtown Whitehorse 28
Figure 10: Siting areas Robert Service Way (Left) and Marwell Industrial Park (Right). 30
Figure 11: Preliminary Schedule for a Waste to Energy Project in the Yukon. 45
Figure 12: Phased-In Enhanced Diversion Sensitivity 52
Figure 13: Cost of Electricity Production Comparison 54

List of Tables

Table 1: Waste quantity projections based on enhanced diversion rate (tonnes) 11
Table 2: Total Feedstock Quantities and Biomass Requirements (Tonnes) 12
Table 3: Biomass Sources, Anticipated Annual Availability and Delivered Cost. 19
Table 4: Annual Biomass Feedstock Requirements and Average Price 20
Table 5: Comparison of siting options 32
Table 6: Comparison of air emissions from WTE combustion technologies and Ontario Guideline A-7 Standard. 34
Table 7: Comparison of air emission intensities from energy sources in Whitehorse with WTE 35
Table 8: Total annual air emissions displaced by WTE 36
Table 9: Overview of Approvals Requirements for a Whitehorse Waste to Energy facility 40
Table 10: Business Case Parameters and Assumptions 46
Table 11: Base Case WTE Cost Model 50
Table 12: Sensitivity Analysis Summary 53

1. INTRODUCTION

1.1 Overview

Yukon Energy is assessing a range of potential alternatives for increasing firm electrical generation capacity in Yukon. This report examines the social, environmental, technical and economic considerations associated with the development of a waste to energy (WTE) facility located in Whitehorse utilizing municipal solid waste (MSW) as the primary fuel source.

A preliminary WTE business case analysis completed in 2011 (Morrison Hershfield 2011) examined three facility scenarios, with capacities ranging between 20,000 and 30,000 tonnes per year and electricity generation between 14,000 and 17,000 MWh per year. The analysis examined the impact of utilizing wood biomass to augment MSW feedstock during periods of lower waste generation rates and the impact of utilizing low-grade waste heat in a potential District Energy System (DES). Utilizing preliminary facility cost and revenue assumptions, the estimated cost of electricity production ranged between $0.16 and $0.18 per kWh which increased to over $0.27 per kWh if no district energy revenue was available. The most cost-effective and flexible facility scenario incorporated wood biomass as a supplementary feedstock source. The preliminary business case analysis incorporated a number of recommendations for proceeding with the project evaluation including:

- Confirm feedstock (MSW and wood biomass) quantity, quality and costs;
- Refine facility cost estimates;
- Undertake detailed feasibility study of a Whitehorse DES;
- Secure agreements for feedstock supply;
- Select a site for the WTE facility
- Confirm facility permitting and approval requirements
- Prepare a request for proposal (RFP) for the design and construction of a WTE facility.

The specific objectives and study scope addressed in this report is outlined in the following section.

1.2 Study Scope and Objective

The objective of this report is to refine the WTE business case analysis, allowing Yukon Energy and key project stakeholders to determine whether to proceed into more detailed siting, engineering and approval investigations and activities. The study scope incorporates the following elements:

1. *Incorporate stakeholder and public input*

   A one-day WTE stakeholder workshop, public meeting and focused stakeholder meetings have been undertaken for the purpose of communicating preliminary results and obtaining input into the future project direction. The results of these

activities are documented and have been used to update the facility design basis and environmental considerations.

2. *Refine assessment of heat utilization opportunities*

   Since the completion of the preliminary business case analysis, a Whitehorse DES feasibility study conducted by FVB Energy has been initiated by Yukon Energy in partnership with the City of Whitehorse, Yukon Cold Climate Innovation Centre, and Yukon Government. The preliminary results of this separate study are incorporated into this report to determine the potential heat utilization opportunities of a WTE facility.

3. *Update design basis*

   The WTE facility design basis has been updated to incorporate more detailed assessments of feedstock and plant. The MSW feedstock assessment is revised to incorporate stakeholder input on future diversion targets and strategies for addressing seasonal waste generation variability. Sources and volumes of local wood biomass have been assessed for use as supplementary feedstock.

   A call for Expressions of Interest (EOI) provides a basis for updated facility process details, Combined Heat and Power (CHP) efficiencies and facility costs.

4. *Assess siting, environmental and approval considerations*

   Two siting potential areas for siting are identified and described incorporating considerations for waste utilization, transportation impacts, environmental considerations, land availability and compatibility with adjacent land uses. Potential environmental issues, described in the earlier Morrison Hershfield (2011) report are updated, and the project approval process outlined.

5. *Refine WTE business case analysis*

   The WTE business case analysis incorporates updated analyses of facility costs and revenues to determine an estimated cost of electricity production. Key financial inputs include:

   - Potential MSW tipping fee revenue based on an assessment of Whitehorse Landfill life cycle costs;
   - Wood biomass costs based on local supply assessment;
   - Facility capital and operating costs informed by industry responses to the call for EOI;
   - Allowance for land, servicing, and electrical tie-in costs;
   - Heat revenue using results of preliminary Whitehorse DES feasibility study.

   A sensitivity analysis illustrates the impacts to the business case if a capital funding grant is obtained (application has been filed) or if key assumptions are varied for critical project variables.

2. ENERGY DEMAND

2.1 Electricity

Yukon Energy is the primary generator of electricity in Yukon, with the capacity to generate electricity from both hydro and diesel combustion sources. At present almost all of the territory's electricity is generated from hydro sources[1].

The demand for electricity has been steadily rising since 2000 as a result of commercial and residential growth. More recently, increased mining activity in the territory has resulted in an additional industrial load, which is forecasted to continue to grow in the near-term. The result of this forecasted growth in electricity demand is that there is expected to be a shortfall in the supply of clean energy to the grid by 2014 (Yukon Energy, 2011).

Until new electricity generation capacity is installed on Yukon Energy's grid, the shortfall of clean energy, relative to electricity demand, will be met through the combustion of diesel in existing generators. The cost of diesel generation is high (approximately $0.30 per kWh at current fuel prices) compared to the rates charged to Yukon customers in the past decade: $0.13 - $0.14 per kWh for residential customers and $0.15 - $0.16 per kWh for commercial customers (Yukon Energy, 2011). Waste to Energy provides the potential to generate electricity at a lower cost, emitting fewer greenhouse gas emissions, when compared to diesel generation.

2.2 Heat

2.2.1 Whitehorse DES Feasibility Study

Yukon Energy in partnership with the Yukon Government, the City of Whitehorse, and the Yukon Cold Climate Innovation Centre at Yukon College is leading a study aimed at providing an assessment of the technical and economic viability of establishing a DES in the City of Whitehorse. FVB Energy has been retained to conduct the study which is expected to be completed in May 2012.

The scope of this district energy study includes the assessment of a range of alternative system concepts, development of a recommended system and design basis, and definition of a business model. The final deliverables of the work are expected to provide a comprehensive evaluation of technical and business case viability, and a strong foundation for proceeding into more detailed engineering and design if the concept proves feasible.

Key outcomes include:

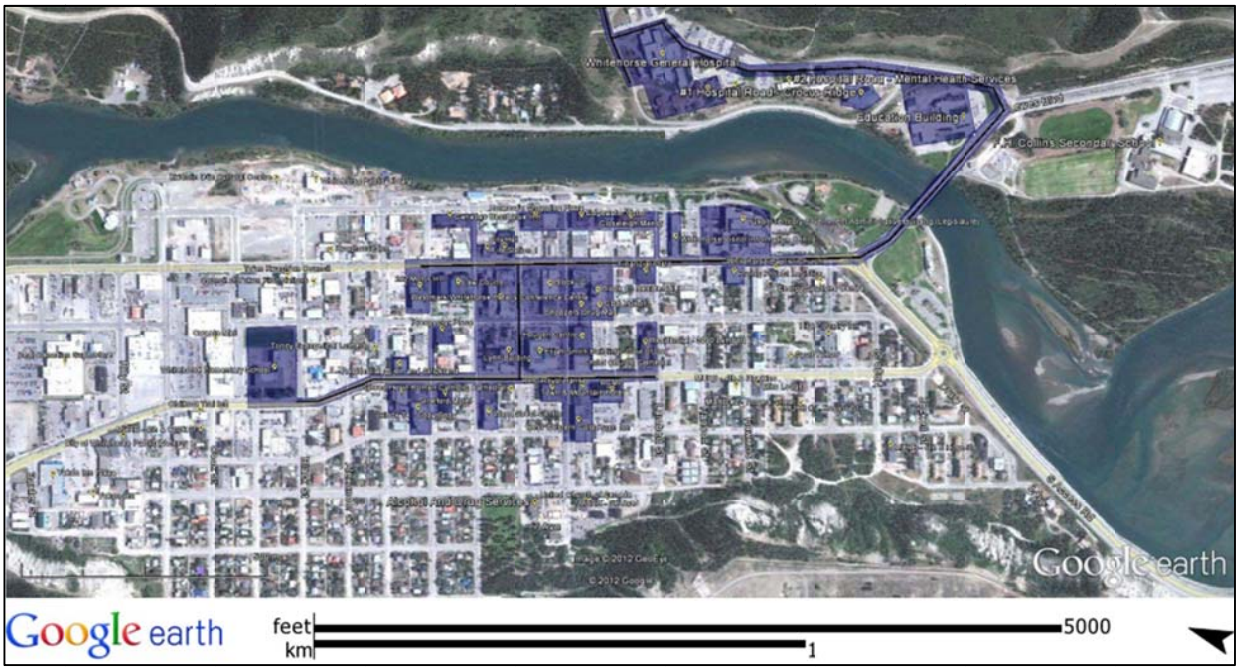
- A review of previous pre-feasibility work (Stantec, 2010), independently reassessing the district energy potential and developing business case scenarios of several alternative heating zones throughout the city.

[1] 94% Hydro in 2009, as reported at the Yukon Energy Charrette in March, 2011

- Development of a DES Business concept and owner/operator models.
- Engagement with potential DES customers.
- Development of a technical concept.
- Development of a memorandum of understanding (MOU) and energy service agreements (ESA) with potential customers.
- Preparation of design basis document (DBD) that includes project definition and business plan.

Currently the project is at its midway point. FVB Energy has completed a high level technical and business case evaluation of seven district energy zones in nine separate scenarios. At this point in the assessment, the scenario including the hospital district and the downtown core area provides the highest heating demand and net revenues and the lowest payback period among the evaluated scenarios. As a result, this scenario has been recommended by FVB for further development and is adopted for the WTE business case. Figure 1 illustrates the potential layout for the Downtown and Hospital district energy scenario.

Figure 1: Potential Whitehorse DES distribution lines servicing the Downtown and Hospital area.



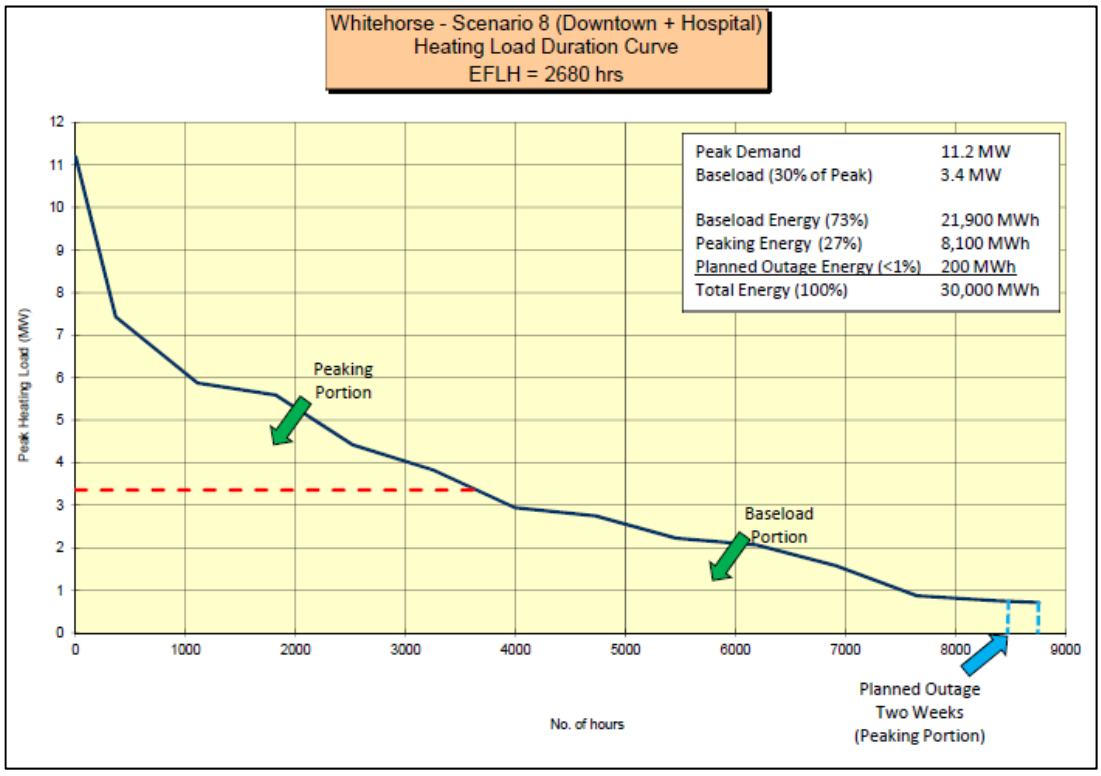
Source: FVB Energy Pre-Screening Scenarios Jan 25, 2012.

2.2.2 Heat Utilization Opportunities

Utilizing waste heat produced in the WTE facility in a future DES will significantly increase the overall energy efficiency of the WTE facility while also providing an additional revenue stream.

Based on the preliminary results of the district energy business case analysis by FVB, a feasible business case exists for implementing a DES in Whitehorse. Assuming a DES is constructed to service the hospital and downtown district (Scenario 8 as described in the FVB study), the DES would distribute 30,000 MWh of heating energy a year. Figure 2 illustrates the heat load-duration relationship for the hospital and downtown district, assuming a central DES biomass heating plant provides a base load heating supply with 3.4 MW capacity (73% of total annual heating demand). The remaining heating demand would be met through peaking boilers.

Figure 2: Heating load-duration curve for Whitehorse Downtown and Hospital District (FVB Energy, 2012)



A WTE plant constructed in Whitehorse would eliminate the need for a central biomass heating plant to service the DES. Assuming a design capacity of 25,000 tonnes per year, the WTE facility could generate up to 4 MW of usable heat energy (in addition to electrical power) that would meet 79% (23,700 MWh) of the total annual DES heating demand.

Total WTE facility energy efficiency increases dramatically if heat is utilized in addition to electrical power production. However, based on the expected heat quality required in a Whitehorse DES, heat utilization will result in some reduced electricity production, compared to an electricity-only process. Further discussion of CHP considerations in the WTE design basis is provided in Section 4.

3. PUBLIC ENGAGEMENT

A public meeting, one-day workshop, and a series of stakeholder meetings have been organized by Yukon Energy since the WTE project was initiated in 2010. The purpose of the public engagement has been to share information and identify the opportunities and issues.

Several meetings and discussions have been held between the Yukon Energy project team and City of Whitehorse senior staff for the purpose of understanding the City's waste management challenges and opportunities and potential impacts of a WTE facility on the City's landfill operations. The project team has made presentations to City Council at Council and Senior Management (CASM) meetings on June 9, 2010, May 18, 2011 and August 3, 2011. The purpose of these presentations has been to communicate project progress, understand City waste issues and priorities, identify joint opportunities, and hear project concerns.

Early in the project development, a project meeting was held on the evening of November 30, 2010 with representatives from Raven Recycling, P&M Recycling, Yukon Conservation Society and Government of Yukon Community Services. A follow-up meeting was held with representatives from the same organizations on August 9, 2011 to discuss the draft results of the Preliminary Business Case Analysis (Morrison Hershfield 2011). Key issues raised at these meetings included air emissions, ash management, and concerns that a WTE facility would harm and limit recycling efforts. Interest was also expressed for utilizing waste heat to increase the overall energy efficiency and displace fossil fuels used in space heating.

Waste to Energy was one of the potential energy sources discussed at the Yukon Energy Charrette in March 2011. Following up from the Charrette, Yukon Energy organized a half-day workshop and evening public meeting focused on WTE on October 18, 2011 (full workshop report included in ***Appendix A***). Over 70 invited participants attended the workshop session and 68 people attended the evening public meeting. Presentations were made by Yukon Energy and their consultant, a representative of Raven Recycling and P&M Recycling, and the City of Whitehorse. Following the presentations, workshop participants were organized into facilitated groups and asked to consider the following:

- Identify the opportunities and the challenges/issues around Waste to Energy
- Can the issues become opportunities? How?
- What does Yukon Energy need to make this project work?
- What does Raven Recycling and P&M Recycling need to make this work?
- What does the City of Whitehorse need to make this work?

A key theme identified during the workshop and public meeting was support for locally derived energy sources. However, there was a strong desire to ensure that WTE was part of an integrated waste management system and did not compete with recycling. There was also strong support for increased diversion of materials away from landfill and future WTE (50% by 2015 identified as a potential target) and strict air emission regulations.

4. UPDATED DESIGN BASIS

4.1 System Capacity

A system capacity of 30,000 tonnes per year was initially studied and used in the preliminary WTE business case analysis (Morrison Hershfield, 2011). This capacity was based on the known waste quantities with current recycling and composting activities in Whitehorse, plus waste coming to the Whitehorse landfill from outside communities.

Internal City of Whitehorse planning plus a Yukon Territorial Government study into waste diversion has resulted in more ambitious recycling goals in the community, with a target of 50% total diversion by 2015 currently being considered. In meetings with the City and local recycling groups, these figures were acknowledged as the new target that would henceforth be used for the planning basis of any energy recovery from residual, non-recycled waste.

As a first step it was necessary to get a thorough understanding of the waste volumes that would be generated with the new recycling targets, and how these might affect a WTE facility. City of Whitehorse Landfill Cost Assessment study was initiated to review the waste disposal situation at the Son of War Eagle landfill (Morrison Hershfield, 2012). The purpose of this study was two-fold: to estimate the future generation of waste that would need to be disposed at the landfill under a recycling only scenario as well as a recycling plus WTE scenario, and what would be the life cycle costs under each scenario. The residual waste volumes would help to determine a WTE facility size and also determine the life expectancy of the current landfill design under the 2002 Solid Waste Management Plan (Gartner Lee, 2003). The life cycle costs would determine unit costs for disposal of residuals and in the case of WTE, of ash and non-combustible residuals. The results of this study, completed as a landfill full cost accounting report is included as ***Appendix B***.

The landfill full cost accounting report was prepared in close consultation and cooperation with the City of Whitehorse. All available data and reports and projections available from the City were used and City staff were interviewed extensively. The study is based on the existing landfill plan from 2003 updated with current fill volumes and projections. The study examines the true cost of landfilling, focusing specifically on the disposal to landfill of the residues that are not recycled, composted or used for energy. The study does not include the cost of collection, recycling or composting in the calculations. These are separate items that need to be dealt with through an integrated zero waste management planning process led by the City of Whitehorse.

4.1.1 Waste Trends

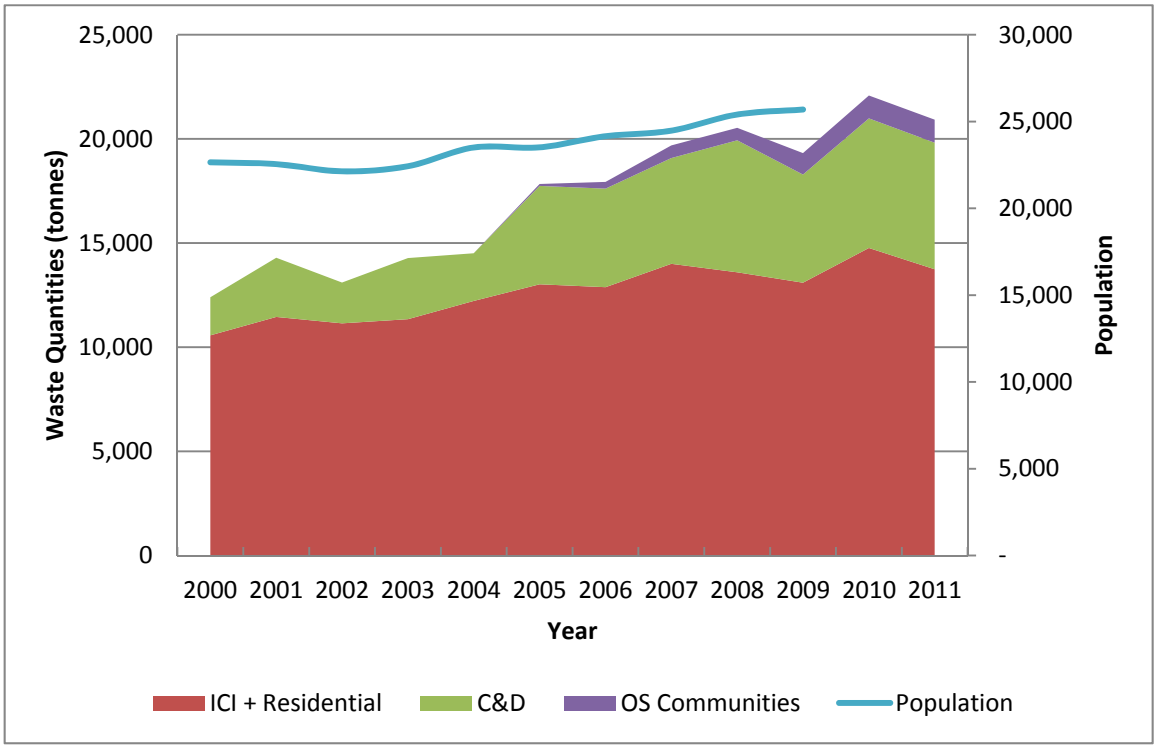
Waste generation quantities were forecast into the future based on historical tipping data obtained from the City for the years 2000 to the end of 2011. Only waste that is permanently disposed of in the landfill cells was included in the analysis. This comprised domestic curbside collected residential waste (RES); Industrial, Commercial, Institutional (ICI) waste including multi-family residential waste; waste from Outside Communities (OS); and, Construction and Demolition (C & D) waste. Excluded from the analysis were tires, white goods, grubbing, etc. which are not permanently disposed of in the landfill cells.

Figure 3 illustrates the quantities of waste managed at the city landfill over the last 11 years along with population statistics[2] over the same time period. It is apparent from this figure that waste growth rates have exceeded the rate of population growth.

Domestic waste (residential and IC&I) has consistently been the largest contributor of waste disposed at the landfill, although C & D waste has shown the largest increase in waste volumes over the past 11 years. In particular, C & D waste volumes exhibited a significant jump between 2004 and 2005 from 2,290 tonnes in 2004 to 4,723 tonnes in 2005.

Residential curbside waste is a relatively small portion (10-12%) of total domestic waste.

Figure 3: Recent Waste Growth in Whitehorse



The cause of the high rates of waste growth over the past decade and the volatility in waste volumes from year to year is likely related to a range of economic factors. Gross Domestic Product (GDP) in Yukon rose over 60% during this time period (6.2% per year on average) while by comparison Canada's GDP rose just 42% (Statistics Canada, 2010).

[2] Source: Population statistics obtained from the Yukon Bureau of Statistics 2009 Population Report

4.1.2 Disposal Quantities with Enhanced Diversion

This analysis provides an estimate of the amount of waste that would need to be disposed of at the Son of War Eagle Landfill assuming enhanced diversion, projected to 2060. It assumes for simplicity that 50% of waste would be diverted from landfill by 2015 and that this diversion rate could be maintained in spite of waste growth through increased population growth and economic activity. Wastes are broken down by domestic waste (residential, commercial and institutional sources), C&D waste (construction and demolition sources and generally of a different nature than domestic waste), and waste coming from outside communities, which is assumed to be only domestic.

Waste projections are shown in Figure 4 and Table 1. As can be seen from the figure, there is a sharp decrease of waste in 2015 when aggressive diversion programs are assumed to be implemented. After that time, volumes continue to increase in step with population growth. In reality, the transition will likely be more gradual and waste diversion is ultimately expected to exceed 50% as higher local awareness sets in and higher levels of government implement more rigorous product stewardship programs. Since these cannot be predicted at this time, the simplified model has been used for this study. However, a sensitivity analysis has been incorporated into the business case analysis assuming implementation of the diversion target is phased in between 2013 and 2020.

Figure 4: Projected landfill quantities under enhanced diversion

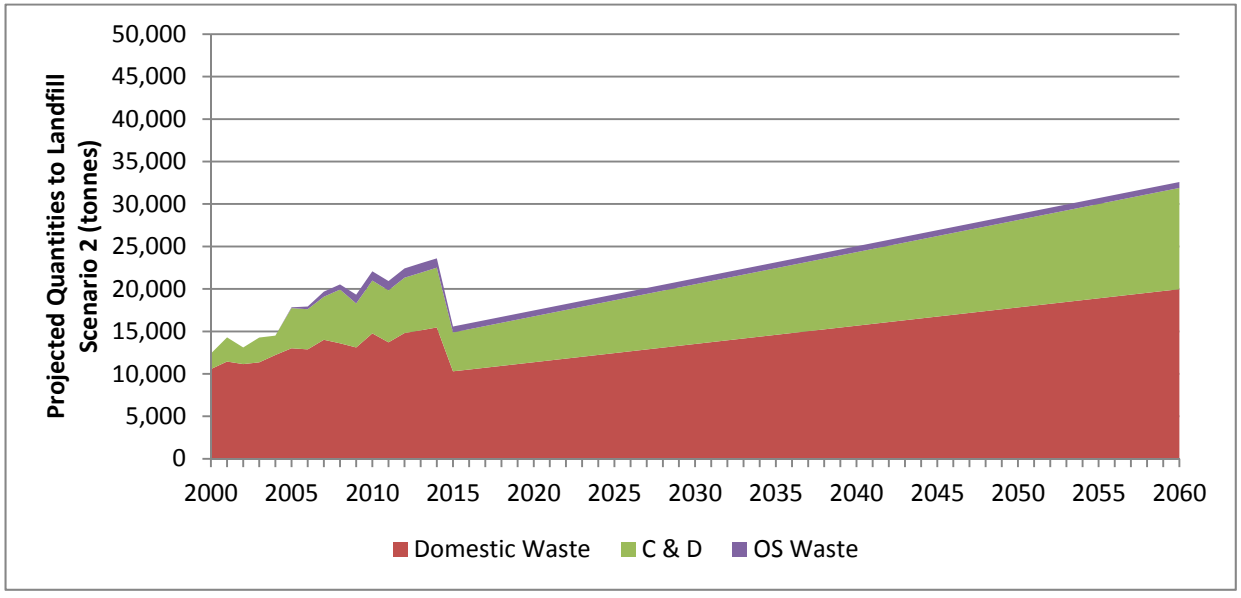


Table 1: Waste quantity projections based on enhanced diversion rate (tonnes)

	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
OS MSW	1,099	693	693	693	693	693	693	693	693	693	693
C & D	6,219	4,582	5,398	6,214	7,030	7,846	8,662	9,478	10,294	11,110	11,926
Domestic MSW	14,766	10,296	11,370	12,445	13,519	14,594	15,668	16,743	17,817	18,892	19,966
Total	**22,083**	**15,571**	**17,462**	**19,352**	**21,243**	**23,133**	**25,024**	**26,914**	**28,805**	**30,695**	**32,586**

4.1.3 Waste to Energy Facility Sizing

The residual feedstock available for waste to energy is calculated based on a 50% waste diversion target from the landfill being initiated in 2013 and achieved by 2015. This is a very aggressive schedule and as a sensitivity calculation, a more gradual phase-in of diversion programs from 2013 to 2020 was also considered (in the sensitivity analysis).

It is known from previous studies that there is a large variation in waste generation between summer (high) and winter (low) and that the peak summer monthly generation rate can be more than double of the monthly average for the year. Sizing of the WTE facility attempts to make the greatest use of the resource, while providing constant power and heat output. This is the rationale for choosing to supplement MSW with biomass when required: to capture as much of the MSW energy as reasonably possible.

Based on the enhanced diversion rate, the monthly average waste available in 2015 would be about 1,300 tonnes per year. For capacity selection, this has been increased by 50% to capture the higher waste volumes available in the summer months, without catering to the peak monthly generation (which is 100% higher than the average). During those months (e.g. in the winter) when there is insufficient MSW, biomass will be used to keep the facility operating at capacity.

For this analysis, a nominal design capacity WTE facility of 25,000 tonnes per year has been chosen. The actual annual throughput would be 95% of the total design capacity or 23,750 tonnes year. The projected loading of the WTE plant over time is shown in Figure 5 and Table 2. The biomass portion that needs to be used as fuel diminishes as MSW increases due to population and economic activity increases (while achieving 50% diversion). By 2035 the WTE facility would be using only MSW as feedstock.

Figure 5: Waste to Energy Feedstock Quantities

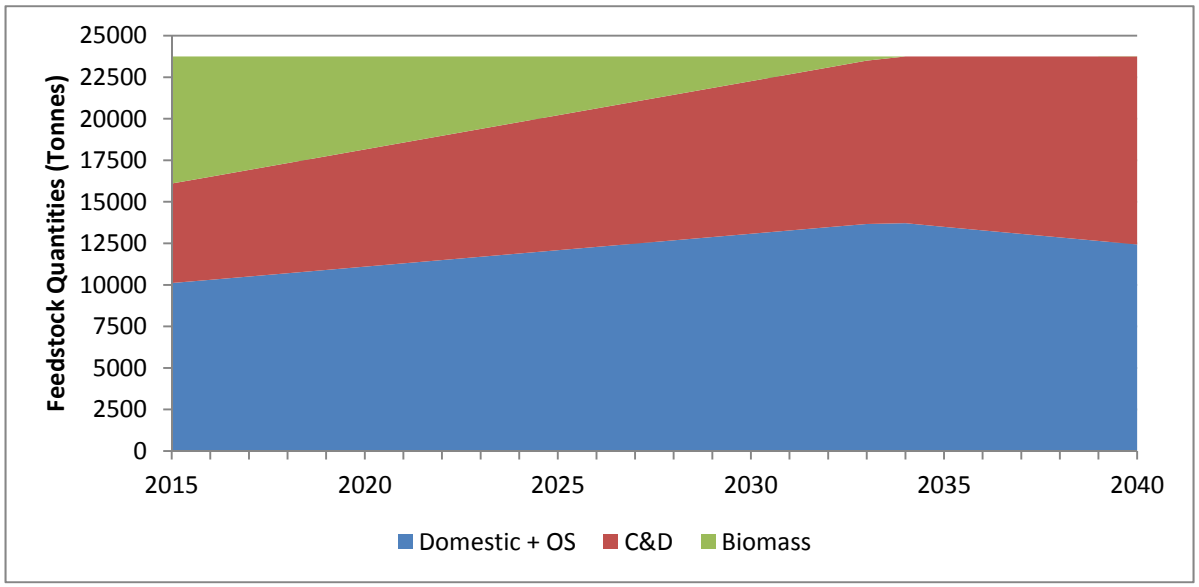


Table 2: Total Feedstock Quantities and Biomass Requirements (Tonnes)

	2015	2020	2025	2030	2035	2040
Domestic + OS	10,110	11,098	12,087	13,075	13,284	12,431
C&D	5,988	7,054	8,121	9,187	10,466	11,319
Biomass	7,652	5,598	3,543	1,488	0	0

4.1.4 Impact on Landfill with Enhanced Diversion and WTE

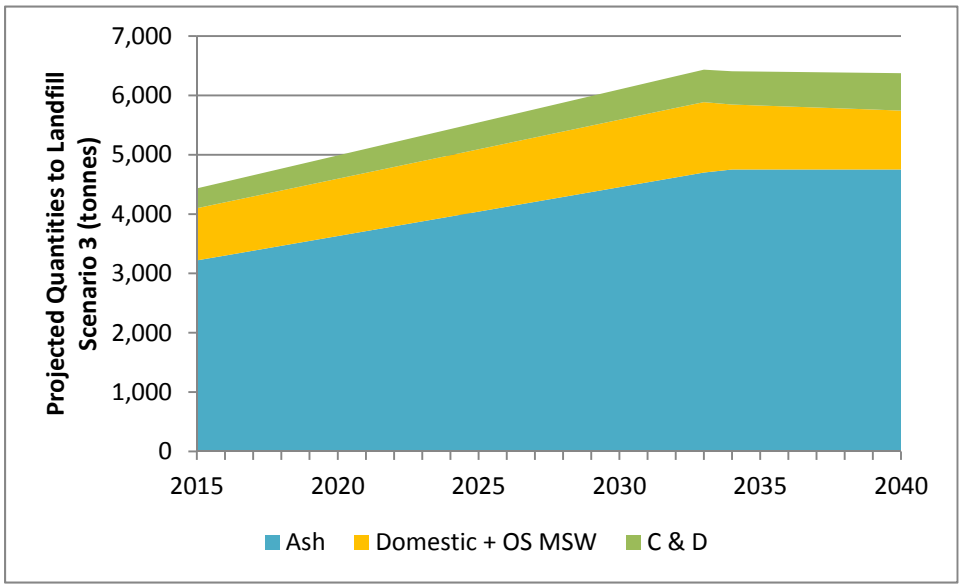
This analysis assumes that a Waste to Energy facility is constructed and commissioned by 2015. The design basis of the WTE facility maximizes utilization of remaining municipal solid waste after waste diversion (recycling and composting). It is assumed that the City achieves an enhanced waste diversion target of 50% by 2015. This is a simplification, as described above, but is used for modeling purposes.

It is assumed that solid waste growth beyond the WTE plant's capacity (which could use all of the MSW by 2035) would be accommodated through additional diversion programs. Using this assumption and projected waste growth rates, a total waste diversion rate of 57% would be required by 2040

The operating life of the WTE facility is assumed to be 25 years (to year 2040). It is likely that the WTE facility will operate longer (if there is waste still available), and the landfill will continue to accept waste/ash past 2040. Projecting waste quantities to the end of the landfill life is not considered practical for this analysis, since a WTE facility would extend the life of the current landfill well into the next century.

Projected waste and ash quantities going to the landfill until 2040 (25 year life of WTE plant) are shown in Figure 6. Wastes directed to landfill under this scenario would be primarily non-hazardous and stabilized ash resulting from the WTE process, plus some non-combustible C&D waste plus domestic waste when the WTE plant is undergoing maintenance.

Figure 6: Waste and Ash to Landfill



4.1.5 Biomass

As proposed in the preliminary business case analysis (Morrison Hershfield 2011), biomass, or wood waste, would be used as a supplementary fuel for the WTE facility if and when there is insufficient municipal waste available (e.g. during winter when waste generation rates are lower). Wood biomass therefore provides the flexibility to operate the facility at 100% capacity regardless of the available amounts of MSW.

Estimated annual biomass requirements are shown in Table 2. Initially, approximately 7,650 tonnes would be required with demand decreasing with waste growth.

The WTE facility could accept wood from multiple sources, which are discussed below. The cost of an on-site chipper and covered storage are incorporated in the facility cost estimates.

Potential sources investigated are:

1. Wood waste from mill residues;
2. Harvested spruce beetle kill and fire kill timber from Haines Junction;
3. Clearing and grubbing waste from construction activity within Whitehorse;

4. FireSmart wildfire management program;
5. Chipped wood waste from communities outside of Whitehorse;
6. Yukon Energy Right Of Way clearing; and,
7. Woody biomass from Yukon Highway maintenance.

4.1.5.1 Wood waste from mill residues

The closest source of mill residues to Whitehorse is the Dimok Timber mill in Haines Junction. Discussions with Dimok Timber determined that the estimated annual available mill residue is approximately 3000 oven dried tonnes (ODT) or approximately 3,500 green tonnes. Currently, there are no uses for the residues which are stockpiled and burned. Dimok Tiber provided Morrison Hershfield a quote for the delivered cost of the mill residues of $124/green tonne based on a maximum moisture content of 20% (Clunies-Ross, 2011). The quote includes costs for equipment to process, handle, store, and deliver biomass fuel. The most significant investment is a walking floor trailer which allows for self-unloading of the wood chips. Walking floor trailers are available in capacities ranging between 18 and 27 tonnes of biomass. This would result in between 111 and 167 loads annually depending on the trailer used.

According to Dimok Timber, the relatively low quantities provide a relatively low economy of scale and potential reductions in biomass volume requirements reduces the period in which capital costs can be amortized. The additional capital cost of the processing and handling equipment, and walking floor trailer over shipping raw logs means that utilization of mill residues results in no cost savings over using harvested timber.

4.1.5.2 Harvested spruce beetle kill and fire kill timber from Haines Junction

Spruce beetle killed wood is currently being harvested in the Haines Junction area, some of which is being shipped to Whitehorse primarily for use as firewood. Approximately 25,000 m3 of wood is currently allocated for firewood and forestry mill operations annually. The current annual allowable cut (ACC) is 100,000 m^3 or 45,000 tonnes per year, which could potentially yield a biomass supply that significantly exceeds the requirement for the WTE facility. The current price for delivered raw beetle kill logs from Haines Junction to Whitehorse at a commercial scale is approximately $115 per green tonne ($135 per ODT)[3].

[3] Based on $140 per cord of beetle kill spruce delivered to Whitehorse on a commercial scale, personal communication Clunie-Ross, Dimok Timber.

4.1.5.3 Clearing and grubbing waste from construction activity within Whitehorse

Historically, a significant portion of wood waste from land clearing for land development in Whitehorse was sent to the Son of War Eagle Landfill. In most cases this consists of non-merchantable timber, slashing, branches, and roots with intermingled topsoil.

Figure 7 indicates annual volumes between the year 2000 and 2005 were between 1,127 and 2,980 tonnes. The generation rates of clearing and grubbing waste is tied to land development activity in Whitehorse resulting in significant fluctuations over the years. In 2006 tipping fees for clearing and grubbing waste increased to $150 per tonne resulting in a sharp and sustained reduction in the volumes being sent to the landfill. As a result, clearing and grubbing waste over the last five years has been diverted primarily to landfill areas at MacLean Lake Road, near Copper Ridge subdivision off of Sandpiper Drive, and in smaller quantities on private lots that are close to job sites.

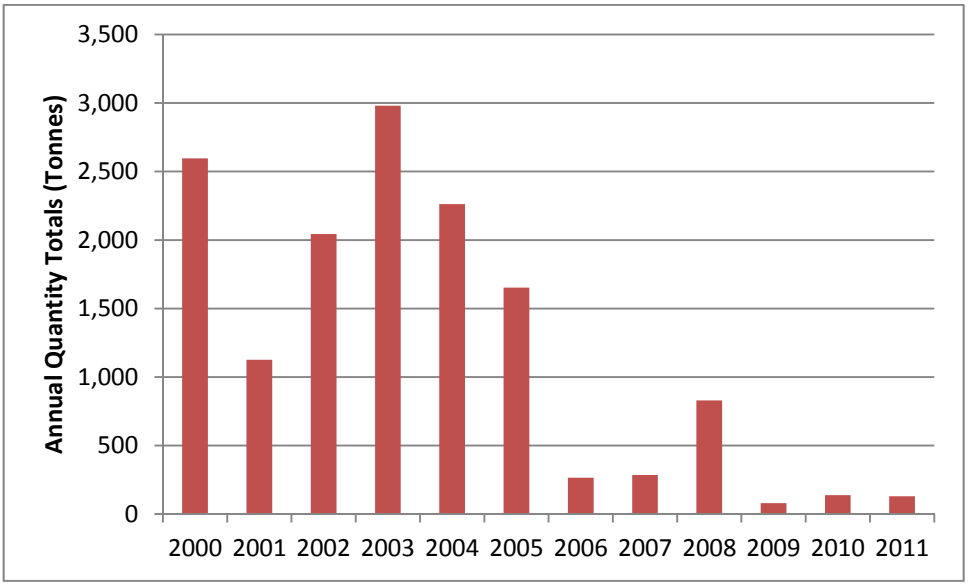
In absence of records of volumes that are currently being sent to site it is difficult to determine how much material exists in the stockpiles. Furthermore, loading and transportation costs and the likely contamination with topsoil and rocks would make extracting from existing stockpiles uneconomical.

The MacLean Lake Road site is an active site that is managed by the Yukon Contractors Association. Currently there is no charge to send waste to the site; however, introducing a $20 – $30 per load fee is currently being contemplated.

The hauling and disposal of clearing and grubbing waste is currently an onerous cost for contractors. This provides an opportunity for the WTE facility to obtain a potentially free to low cost biomass source provided careful loading and sorting of clearing and grubbing waste is undertaken to reduce soil contamination.

Based on the historical information available, it is difficult to predict what future clearing and grubbing biomass generation rates and what proportion of total material generated in Whitehorse could be obtained by a WTE facility. However, for preliminary estimation purposes, an assumption of 1000 tonnes is used. A modest financial incentive (such as $25) per tonne could be provided to capture a greater share of available clearing and grubbing waste and to encourage more careful separation of wood waste from contaminants such as soil and rocks in the waste brought to site. Separation would provide more efficient processing, reduce wear on the equipment and reduce the quantity of contaminants that would eventually have to be landfilled.

Figure 7: Historical Landfill Clearing and Grubbing Quantities disposed at City landfill



4.1.5.4 FireSmart Wildfire Management Program

The FireSmart program in the Yukon clears the equivalent of approximately 120 ha of land per year to reduce the wildfire exposure risk for Yukon Communities (pers comm. Jan, 2012 Fred Jennings, FireSmart Manager, YTG). Approximately half of the FireSmart work occurs in the Southern Lakes region which would result in a total volume of approximately 820 tonnes (680 ODT) of biomass annually[4]. Currently, most of the wood from the FireSmart program is taken by local people for firewood as costs are too high and volumes are too low to justify loading and hauling the material from a commercial perspective.

According to the FireSmart manager, there is the potential for a larger 1000 ha of fuel control work required in the Whitehorse area; however, no budget or timeframe has been established to implement such a program.

Based on the above information, current FireSmart volumes do not appear to be able to provide an economically significant and reliable supply of biomass.

4.1.5.5 Chipped wood waste from communities outside of Whitehorse

Wood construction and brush waste from outside communities is currently being chipped primarily in the spring to fall months at four sites located in Carcross, Tagish,

[4] 120 ha per season, approximately 25m^3 of wood available per ha, 2.2 m^3 per oven-dried tonne, assuming 20% moisture content.

Marsh Lake and Deep Creek. On average, there are 8 – 10 small gravel truckloads of wood chips being chipped at each site monthly for approximately 5 months of the year (pers. Comm. Jan 2012, Wes Wirth, Director, Operations and Programs Community Services Government of Yukon and Brian Buchannan, Contractor to YTG.) [5] As a result, it is estimated that approximately 650 tonnes of wood chips could be available per year from all four sites. With the cost of dump trucks between $120 and $130 per hour, the delivered cost of wood chips to Whitehorse is assumed to be approximately $25 per tonne.

4.1.5.6 Yukon Energy Right Of Way clearing

Power line right of way clearing is generally conducted by mowing with one hydro axe and a crew of two hand brushers. The material generally consists of poplar and willow and is left in the right of way. Encroachment of larger tree species such as spruce is generally not an issue in the right of way. However, where significant overgrowth exists it is typically in areas that are difficult to access and therefore would be difficult to export. Merchantable wood from new ROW development is used by the forestry sector while non-merchantable wood is left for salvage as firewood. There are no new major transmission lines planned in the near term.

Yukon Energy completed a vegetation audit in 2010 which provides an indication of the timing of when brush clearing is required to maintain right of ways. The schedule shows that between 140 and 240 ha per year would need to be maintained over the next ten years. The location of the clearing activities within a particular year would determine the feasibility of collecting and shipping the biomass to Whitehorse.

Biomass from power line right of way clearing cannot be relied upon as a reliable source of biomass; however, should vegetation control near Whitehorse be collected, it could potentially provide a supplemental source of biomass to costlier sources.

4.1.5.7 Woody biomass from Yukon Highway maintenance

Information from Yukon Government's Vegetation Control Program from 2008 to 2011 was provided from the Yukon Government Transportation Maintenance branch. Currently highway vegetation control consists of three types of clearing:

1. Type A: ROW full width brushing covers the area from shoulder to old growth is between 10 and 30 m and primarily used to improve sightlines. This type of material could include trees and brush. Significant Type A work has occurred near Whitehorse in the past few years (between Teslin and Haines Junction has already been thinned) and new areas generally being worked on are increasingly further from Whitehorse (beyond Stewart Crossing.) Between 2008 and 2011, 60 to 300 km were covered. In 2011, 200 piles approximately 10 m wide by 3 m high were generated and burned.

[5] Assumed density of woodchips to be 400 kg/m3, volume of truck load 12 cubic yards or 9.17m^3 resulting in 3.6 t per truck.

2. Type B: Shoulder brushing / mowing covers the area of up to 5 – 6 m from edge of shoulder and generally consists of patchy areas of willows and small brush which provide marginal heating value. Areas are maintained every 6 to 8 years. Historically, the distance covered annually for shoulder brushing has been between 168 and 500 km.
3. Type C: Shoulder mowing usually covers a distance of 2.5 – 4 m from edge of shoulder and generally consists of willow, clover and grass which provide very low heating value. Between 250 and 300 km are mowed annually.

Based on the above information it appears that the only suitable sources of biomass would be from Type A maintenance activities; however, no new major maintenance works are planned for the Whitehorse area which makes availability to this source cost-prohibitive.

4.1.5.1 Wood biomass source summary

Numerous potential sources of biomass exist, although consistent availability and accessibility of many of those sources is difficult to predict and rely upon. For a source to provide a significant and sustained supply of biomass, both collection and delivery costs must be more competitive than alternatives such as spruce beetle kill wood from Haines Junction.

Table 3 summarizes potential biomass sources along with their estimated present and future costs.

Based on the above discussion, the main reliable sources of biomass could be from mill residues, spruce beetle kill wood from Haines Junction, and clearing and grubbing waste from land development within Whitehorse. Other minor sources such as wood waste from outside communities, FireSmart, and ROW clearing could be accepted as is at the WTE facility site at a modest financial incentive such as $25 per green tonne.

Table 3: Biomass Sources, Anticipated Annual Availability and Delivered Cost.

Source	Quantity (green t)	Cost ($ per tonne)[6]				
		2012 $	2015 $	2020 $	2025 $	2030 $
Mill Residues	3,500 tonnes	$124	$136	$157	$182	$211
Beetle Kill Wood Delivered from Haines Junction	10,000+ tonnes	$115	$126	$146	$169	$196
Clearing and Grubbing Waste from Whitehorse	1000 tonnes	-	$25	$29	$34	$39
Wood chips from outside communities	650 tonnes	$25	$29	$34	$39	$45
Other (ROW Clearing, FireSmart, Other)	Minor and variable	-	$25	$29	$34	$39

Whole logs delivered from Haines Junction appear to be more cost-effective for the relatively small scale biomass demand than mill residues because mill residues require the purchase of a wood chipper in Haines Junction and vehicles such as a walking floor trailer to transport the wood chips. On-site chipping, handling and processing facilities are accounted for in the WTE facility cost estimates. It is anticipated that as biomass requirements decrease, reliance would be shifted toward less expensive sources.

Table 4 shows the blended average biomass price including inflation[7] based on the quantity requirements. Initially, the average biomass cost is estimated at $104 per tonne with the majority of biomass sources from beetle kill wood from Haines Junction.

[6] Annual costs are escalated assuming 3% inflation to account for higher escalation transportation fuel costs.
[7] Inflation for delivered biomass costs is assumed to increase at a higher rate than the actual inflation rate due to reliance and to reflect a greater escalation in fuel costs. Thus, a 3% annual inflation rate is assumed.

Table 4: Annual Biomass Feedstock Requirements and Average Price

	2015	2020	2025	2030
Annual Biomass Requirements	7,600	5,600	3,500	1,500
Source Quantities (green tonnes)				
Beetle Kill Wood from Haines Junction	5,950 @ $126	3,950 @ $146	1,850 @ $169	0
Clearing and Grubbing Waste from Whitehorse	1,000 @ $25	1,000 @ $29	1,000 @ $34	1,000 @ $39
Wood Chips from Outside Communities	650 @ $29	650 @ $34	650 @ $39	500 @ $45
COST				
Average Biomass Price ($ / green tonne)	$104	$112	$106	$34

4.1.6 Capacity Summary

- A WTE design capacity of 25,000 tonnes per year has been selected for the updated business case analysis. The facility will be capable of burning biomass (waste wood) as well as MSW, so that any shortfall in waste feedstock can be made up with biomass.
- It is estimated that the WTE plant will be burning MSW without need for biomass by 2035 based on current projections (assuming 50% waste diversion is maintained from 2015 onwards). This is for calculation and comparative analysis only. The actual ratio of waste to biomass will be dictated by the amount of recycling and diversion that can be achieved and the actual rate of MSW growth.
- A WTE life of 25 years is projected, after which time a decision will have to be made on whether to upgrade the facility and continue operations or to decommission the facility for lack of feedstock or because newer, more effective technologies are available to replace it.
- The current lifespan of the Son of War Eagle landfill based on the existing Landfill Management Plan (Gartner Lee, 2003), is until 2057 based on 50% waste diversion implemented in 2015. If waste diversion and WTE are in place, the capacity of the landfill would extend well into the next century. According to the City of Whitehorse, there is additional land available at the landfill for future expansion, if needed.
- Biomass is available from a variety of sources. There is adequate biomass available from reliable sources at a cost of $115 to $124 per green tonne delivered. Additional sources of biomass are less reliable but can help to

offset the cost of biomass whenever these sources are available. The cost of biomass from other sources is low, since there is a saving in disposal costs and usually only transportation and some handling expenses need to be covered.

4.2 Process Technology

In the preliminary business case analysis (Morrison Hershfield Ltd. 2011), it was determined that controlled air conventional combustion, close coupled gasification and small scale mass burn met the necessary criteria for implementation at this time. The criteria for technology selection included ability to handle the small volumes of waste and biomass available at Whitehorse, capacity to produce both heat and electrical power, and commercially viable operating facilities of a similar size that could be visited and viewed.

The September 2011 business case was based on cost and performance data of smaller systems that are available in the literature and are in the public domain. Since there are very few smaller systems operating in North America, it was decided to enhance the confidence levels in the constant performance estimates by asking vendors to submit an expression of interest (EOI) in the project. Vendors (it was open to all who wished to respond) were given a detailed project scope and description, and a series of questionnaires to fill out. The original questionnaire was made available on November 8th, 2011. A copy of the questionnaire is in Appendix C.

Responses were received on 8 January 2012 from the following vendors:

- Aquilini Renewable Energy Ltd.
- EcoWaste Solutions Ltd
- EnEco Systems Inc
- Ketza Pacific Construction Ltd.
- Novo Energy LLC
- OE Gasification
- TPF Basse Sambre

Responses were reviewed, additional clarifications requested, and final information received February 8th, 2012.

Novo Energy and Ketza offered a small scale mass burn system, EcoWaste Solutions a conventional two-stage combustion system, EnEco,TPF and OE offered different forms of close coupled gasification and Aquilini was teaming up with EnEco.

Based on the submissions, the process technology that was proposed in the original September 2011 study was confirmed. Even though the EOI process was open to newer technologies, all respondents offered conventional technologies (close coupled gasification for the purposes of this study is considered similar to conventional combustion, except the process is separated into two or more closely connected physical components). The business case analysis will therefore proceed based on performance that can be reasonably expected from using conventional combustion technologies.

This was not a technology selection exercise for implementation but rather a choosing of appropriate technologies and performance data for business case evaluation purposes. Actual technology selection, should the project proceed, is expected to take place on a competitive basis. It is possible that advanced technologies could meet requirements in the future.

4.3 Technology performance

The key measurements of performance and those that have the most impact on the business model are net production of electricity and heat per tonne of feedstock. As expected, there was a trade-off between lower capital costs and energy production efficiency (for example higher steam conditions requiring better materials and equipment resulted in better efficiencies but also higher costs). There were also varying approaches to the recovery of heat and power, from using upfront steam extraction for heat with a condensing turbine for electricity, to using an extraction turbine for the most flexible system, to using a back-pressure turbine for steady-state heat output.

The information that was received from the vendors in response to the EOI was evaluated and compared. For electricity only production, net outputs ranged from 600 kWh/tonne to 650 kWh/tonne. With CHP electricity output ranges from 200 kWh/tonne to 420 kWh/tonne while providing 4 MW of heat.

The value chosen for the base case analysis is 420 kWh per tonne of waste, which represents about a 10% electrical efficiency and is typical for smaller CHP systems. This is consistent with the number quoted by one of the vendors that provided a fairly complete and credible submission. It includes the ability to provide up to 4MW of heat for district energy.

All of the vendors claimed to be able to meet the most stringent emission standards (Ontario A7 or the EU standards), therefore there was no difference or issue with emissions.

Staffing levels quoted varied between 14 and 26, but most of the vendors indicated 17 to 18 staff would be required. The business case analysis assumes a staffing level of 18 is required for the facility.

5. SITING, ENVIRONMENTAL & APPROVALS CONSIDERATIONS

5.1 Site Considerations

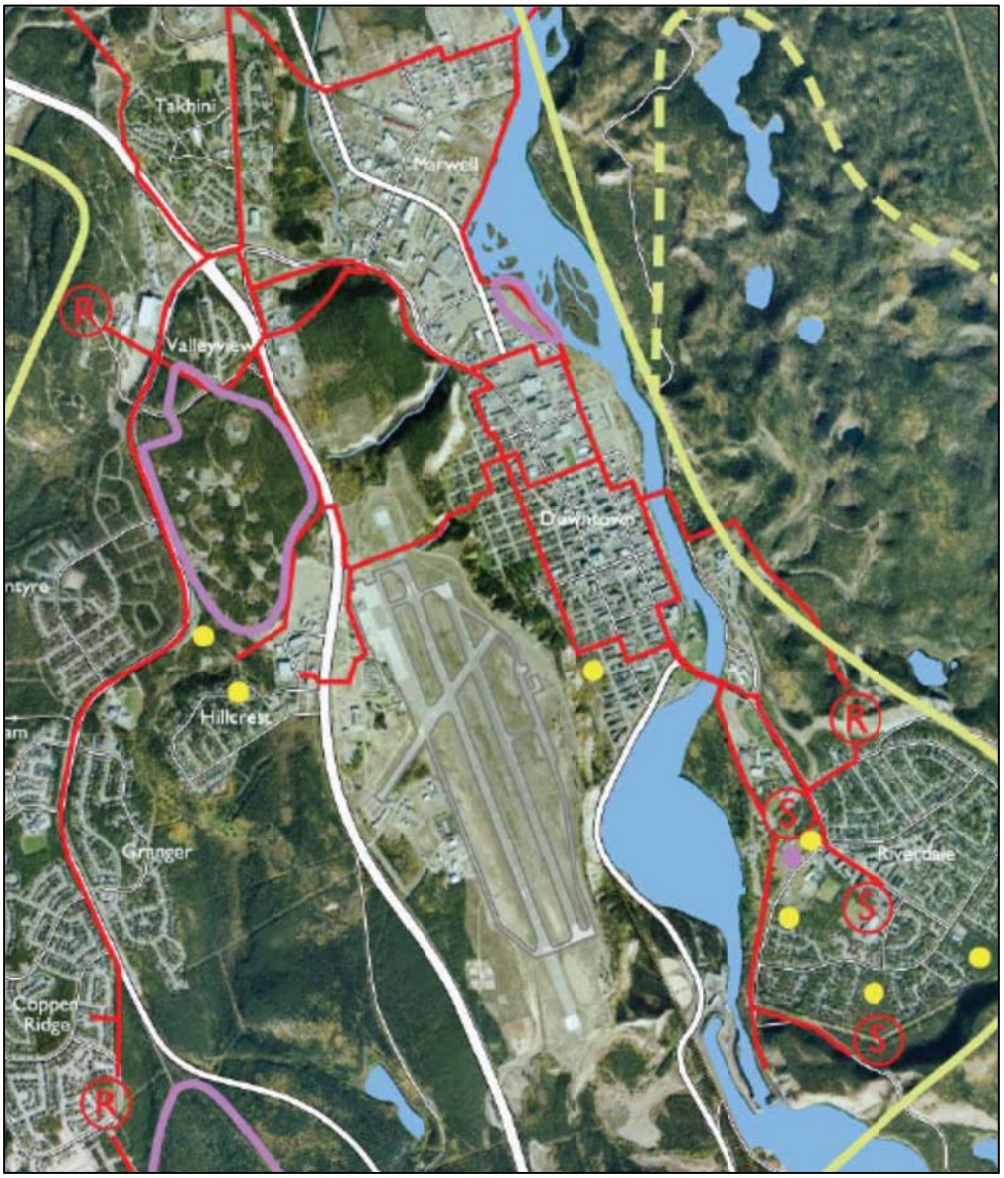
This section describes the site requirements for a Waste to Energy facility, potential economic, social and environmental impacts, and provides an assessment of two potential site areas.

5.1.1 Site and Infrastructure Requirements

A 25,000 tonne per year (70 tonnes per day) facility would require a site approximately 2 hectares in size that is relatively flat. The developed site would include buildings for the waste to energy plant, internal roads for truck access with room to turn around, scale, on-site storage of biomass and C&D waste, and a substation. The anticipated height of the stack would depend on the facility design and air dispersion requirements; however, 20 m – 30 m stack heights are common for smaller scale waste to energy facilities.

The site would require full servicing of electrical, water and sewer infrastructure. Electrical servicing will require access to a transmission line and the construction of a substation on site. Adequate water and sewer infrastructure would be required for the facility. Annual water demand of approximately 14,500,000 litres and 4,500,000 litres of wastewater are anticipated. Water demand can vary depending on the type of air pollution control systems used (dry or wet scrubbers), the cooling process employed in generating electricity and water recycling within the plant design. Figure 8 shows the location of major water and sewer lines in the City of Whitehorse. Generally, most developed areas of Whitehorse have access to sewer and water infrastructure. The area south of downtown near Yukon Energy's office and generation facilities is not serviced by municipal water or sewer. Yukon Energy is currently serviced by well water and uses a sewage holding tank where the effluent is pumped from and sent for treatment.

Figure 8: Major Water/Sewer Lines in Whitehorse



Source: City of Whitehorse OCP 2010 Map 5.

Zoning Bylaws

City of Whitehorse Zoning Bylaw 2006-01 permits public utilities in any zone under Section 1.6, Section 12.5 also applies to public utilities.

Key relevant aspects of Section 12.5 are the development regulations for siting that prescribe maximum building height of 20.0 m, minimum setbacks of 6 m, 3 m and 6 m for front yard, side yard and rear yard, respectively. Additionally, the design, siting, landscaping, screening, and buffering shall minimize and compensate for any objectionable aspects or potential incompatibility with development in abutting zones.

Development near the Whitehorse Airport could be subject to Regulations under Section 11.1 including:

> "No public utility or secondary use shall be permitted that attracts fauna or avifauna, generates electrical current or vibration that may affect the safe operation of aviation activities" and,
>
> "A development within the vicinity of the airport is subject to the obstacle clearance and electronic zoning requirements outlined in the Whitehorse Airport Zoning Plan."

Other development regulations that may apply but are unlikely to influence site selection include Section 5 (yards, projection into yards, accessory development, landscaping and screening); the parking regulations of Section 7; and the sign regulations of Section 8.

If rezoning is required, the process can take approximately 1.5 to 3 months and involves:[8]

- Determination if rezoning is required with the Planner/Development officer
- Submission of a complete rezoning application form plus supporting letters and documents and application fee of $900;
- Application is reviewed by the development review committee and recommendations are made to City Council;
- Introduction of the rezoning application to council;
- Public hearing process which includes public notification within 1 km of the site and notification in the newspaper and the development of a public hearing report;
- 2nd and 3rd reading by council.

Traffic Impacts

Based on the facility design capacity, 8 – 9 truckloads of waste per day would be transported to the facility assuming current capacity vehicles[9]. Truck traffic is only anticipated during daytime hours on waste collection days. Ash removal to the landfill from the waste to energy facility would likely result in one truckload every one or two days depending on the waste composition (ash content and inert materials of the waste stream); however, it would be possible to backhaul the ash on the incoming waste collection trucks resulting in no additional traffic impacts.

[8] Your Guide to the Rezoning Approval Process
http://ww3.whitehorse.ca/Planning/guides/rezoning%20approval%20process.pdf
[9] Assuming 2009 International Model SF62500 7400 SBA 6X4(Tandem) with GVWR 56000lbs and GAWR 20000lbs, payload of 8.6 tonnes.

District Energy Considerations

The utilization of waste heat from a WTE facility in a future DES would significantly improve the overall energy efficiency of the process and add an important additional revenue stream to the business case. Locating the WTE facility as near as possible to the heating demand reduces DES infrastructure costs and system energy losses.

A detailed district energy study is currently underway for the City of Whitehorse (described in Section 2). Preliminary study results indicate that the most cost-effective district energy scenario would supply heat to both the downtown and hospital district.

5.1.2 Air Quality Considerations

The prevailing wind in the downtown area is from the south-southwest, following the topography of the Yukon River Valley. Although air quality in the Whitehorse downtown area is generally very good, poor air quality periods can occur particularly on cold winter days when the winds are calm and dispersion is limited. Under such conditions a temperature inversion occurs trapping the colder air to the ground allowing for the temporary buildup of gaseous pollutants and fine particles in the air. Wood burning stoves, heating of commercial buildings and vehicle emissions have been identified as the primary contributors to periodic poor air quality in Whitehorse.

A CHP WTE facility would likely result in an overall improvement in air quality in the downtown area because multiple ground level point sources such as oil burning furnaces and diesel generators would be replaced with a centralized combustion facility equipped with stringent pollution controls and a stack that would elevate the emissions above the valley bottom. Further evaluation of air emissions is provided in Section 5.2.

Atmospheric dispersion modelling of facility air emissions is typically conducted after a site is selected and preliminary facility design conditions have been specified.

5.1.3 Access to Electrical Transmission System

Electrical power generated for export at the WTE facility would require an on-site substation and a 34.5 kV transmission line to connect to the existing substations in Whitehorse and the distribution system. In addition to the capital costs of constructing transmission lines and on-site substations, related considerations that would need to be confirmed and could have an impact on costs are:

- Space at existing substations for new equipment;
- Land easement;
- Permitting; and,

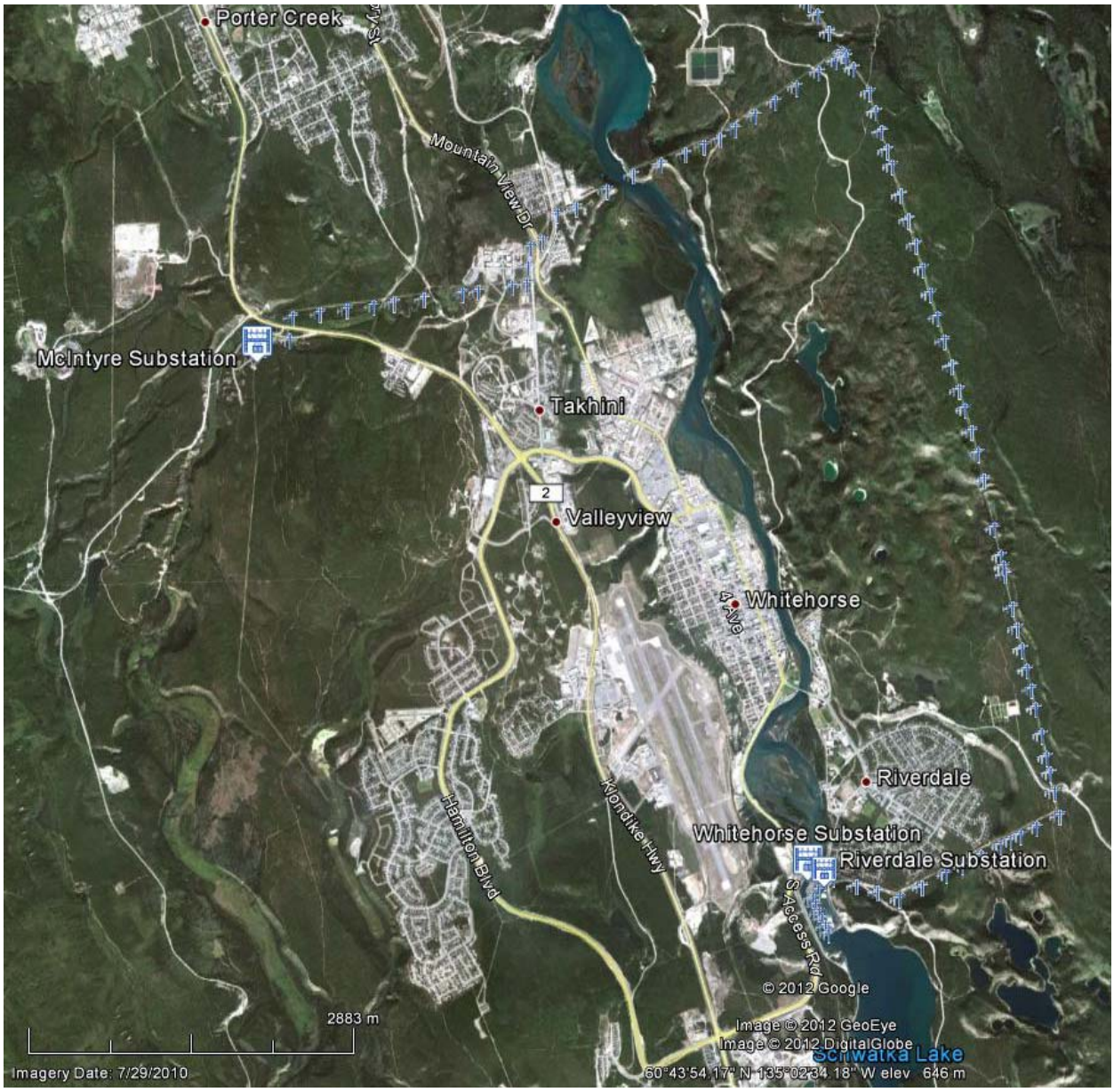
- Shut down of the bus for connecting the new supply.[10]

Four substations are currently located in Whitehorse, three of which are located within 5 km of the downtown area, as shown in Figure 9. The Whitehorse Substation on the west shore of the Yukon River and the Riverside Substation on the east shore of the Yukon River are located at the Whitehorse Hydro generation facility approximately 2.0 km southwest of the downtown along Robert Service Way. The McIntyre Substation is located approximately 5.0 km northwest of downtown Whitehorse off the Alaska Highway. The Takhini substation (not shown on the figure) is located 22 km north of the downtown on the Klondike Highway.

Major transmission lines originate at the Whitehorse Substation and border the southern end of Riverdale, then head north offset approximately 2 km along the eastern shore of the Yukon River (L172). This line is joined by a transmission line (L169) that connects to the McIntyre Substation approximately 3 km north of downtown Whitehorse near Range Road and Mountainview Drive.

[10] Person. Comm. Marc-Andre Lavigne, YEC, via. e-mail Feb 28, 2012.

Figure 9: Electrical infrastructure near downtown Whitehorse



Source: Google Earth

Noise, Odour, and Nuisance Considerations

Noise generation from the operations of a waste to energy facility could be an issue depending on its location. Sources of noise include trucks to bring waste to the facility, plant operations and fans. Assuming the facility is located in a commercial or industrial area, noise impacts associated from the anticipated truck volume and plant operations would be relatively minor.

The waste to energy facility would store any perishable waste within the facility which is under negative pressure preventing the migration of odours. The air is typically drawn from the waste receiving area into the combustion processes where high combustion temperatures eliminate any odours and dust associated with the waste.

Air emissions from a waste to energy facility depend on the pollution control system employed and the standards it is required to meet. Air emissions standards for waste to energy facilities are among the most stringent of all types of combustion processes and generally achieve lower emissions than the burning of wood or heating oil. The European Union, United States, and provinces such as Ontario and British Columbia have adopted best available technology standards which ensure that the standards achieved by the best performing similar facilities are adopted. Generally, emissions from WTE facilities are not visible except perhaps for a water vapour plume on cold days. Air pollution equipment can be configured to remove contaminants to well below the most stringent standards currently in use in Canada and Europe.

It is anticipated that Yukon would adopt WTE specific standards from either BC or Ontario.

5.1.4 Preliminary screening of siting options

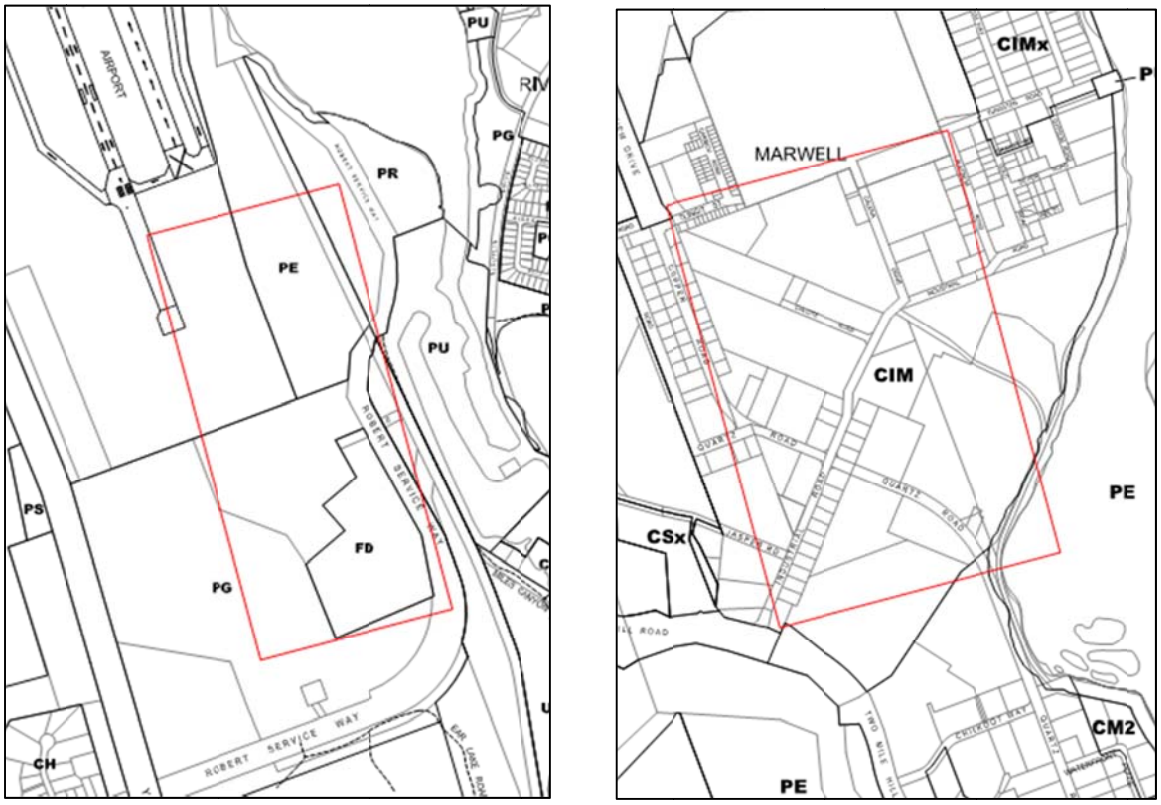
Site selection can have an important impact on project costs, additional revenue opportunities from district energy, environmental and nuisance impacts, and public acceptance. Proximity to district energy heat customers and compatibility with adjacent land uses have been used to screen potential site areas for further analysis.

The preliminary WTE business case analysis (Morrison Hershfield , 2011) indicated that heat sales to a future DES were critical to project feasibility. Accordingly, it is assumed that a future WTE plant must be sited in reasonable proximity to DES heat customers. As discussed in Section 2, preliminary results from the Whitehorse DES Feasibility Study indicate that the most promising DES option is one that serves the hospital and downtown core area.

Compatibility with adjacent land uses is critical to ensure that nuisance issues and traffic impacts are minimized. Based on land use compatibility, proximity to a future DES, and discussions with City of Whitehorse and Yukon Energy staff, two potential areas for siting a WTE facility have been identified. Those areas (illustrated in Figure 10) are:

1. South of downtown along Robert Service Way near Yukon Energy Headquarters;
2. Marwell Industrial Park, north of downtown area.

Figure 10: Siting areas Robert Service Way (Left) and Marwell Industrial Park (Right).



Robert Service Way South of Downtown

The area south of downtown near Yukon Energy head office includes several parcels of undeveloped land with good truck and electrical grid access that would easily meet the size requirements for a waste to energy facility. The haul distance to the Whitehorse landfill is approximately 16 km or 20 minutes. Depending on the parcel location, airport zoning restrictions may apply that could limit building heights and discharge of exhaust or steam from the facility that could affect air traffic. Since there is no residential development in this area and its proximity to the airport approach zone, noise and nuisance impacts to neighbouring sites would be very low. Air quality impacts however, may be of concern because of the location being upwind of downtown and the primarily residential Riverdale area which could be within 500 m of the site. Land in this area is currently zoned as either PG – Protected Green Space or PE – Environmental Protection, though based on the zoning by-law these designations may not prevent utility development, public concern may exist to development in those areas.

The close proximity to the Whitehorse substation means that electrical transmission line costs would be minimal; however, an on-site substation at the plant would still be required at an estimated capital cost of $1.5 million.[11]

A significant limiting factor to this area is the lack of water and sewer infrastructure. Currently, the City is contemplating the development of a 15 ha parcel for a new Municipal Services Building that fronts Robert Service Way and abuts the airport to the north (see figure 3). Such a development could bring water and sewer services to the area as well as a large heat consumer. As shown in Figure 8, currently the closest waste and sewer connections would be approximately 3 km from downtown. Based on the anticipated annual demand, a well could be developed to provide water to the site. Wastewater however, would require connection to the existing system. Water and sewer servicing costs are estimated to be $1.5 to $2.0 million.

Connection to a downtown DES would be between 2.0 and 3.0 km along Robert Service Way depending on the chosen site location. Current land use and topographical constraints along Robert Service Way appear to provide little opportunities for additional development for future connection along the district energy transmission route to downtown thus, constraining additional value that could be gained from the capital cost spent on district energy transmission pipe and water and sewer servicing. However, the WTE business case could improve significantly should the City construct their new Municipal Services Building at the parcel across from Yukon Energy and if further industrial and commercial development takes place in this area. This would provide new heat customers for the facility.

Marwell Industrial Park North of Downtown

Several large parcels of underutilized land (large areas exist that are only being used for surface storage of equipment) are located in Marwell area that would be of suitable size for a waste to energy facility. Marwell is well serviced with water and sewer infrastructure and has good truck access. The haul distance to the Whitehorse landfill is approximately 7 km or 10 minutes. The most accessible substation near Marwell is the McIntyre substation via transmission line L169 to the north. A substation would be required at the facility and a 34.5 KV transmission line to connect to L169 would be between 1.0 and 1.5 km in length depending on site location. The connection and substation costs are estimated to be $1.6 million[7].

Existing zoning CIM – Mixed Use Commercial/Industrial could be compatible with a Waste to Energy facility whose overall noise and nuisance impact would be no greater than other industries with such a designation. It is known that potentially contaminated lands exist in the Marwell area[12]. These sites may be suitable for a WTE facility since remediation requirements would likely be less stringent than for other land uses. Air quality impacts could be less than the location south of the downtown as a result of being downwind of the central downtown area.

Connection to the downtown DES based on the current distribution system layout would require transmission piping between 1.5 and 2.0 km in length depending on

[11] Person. Comm. Marc-Andre Lavigne, YEC, via. e-mail Feb 27, 2012
[12] Person Comm. Pat Hogan YTG Feb 27, 2012

the site location. The transmission piping could provide opportunities for additional customers to be connected to the DES along the route. A WTE location in this area could also support a future extension of the DES to potential customers in the Range Road area.

5.1.5 Preliminary assessment overview

Siting a WTE facility in either the Marwell area or south of downtown along Robert Service Way appears to be technically feasible. Table 5 provides a comparative summary of the two siting options, highlighting relative advantages and disadvantages of each site area. On most criteria, the Marwell Industrial is preferable to the Robert Service Way location. The Robert Service Way location has the advantage of lower electrical tie-in costs; however, this cost advantage is reversed when the costs of water and sewer servicing are considered. While there would be few immediate neighbours to a facility located in the Robert Service Way area, the proximity to the airport could affect the facility design and operations.

For the purpose of updating the WTE business case analysis (Section 6) it is assumed that the WTE facility would be located in the Marwell Industrial area. A more detailed siting analysis, environmental assessment, and associated public consultation will be required before a final siting decision is made.

Table 5: Comparison of siting options

	Area 1: Robert Service Way South of Downtown	Area 2: Marwell Industrial Park North of Downtown
Land Availability	Yes	Potentially; however, no specific sites identified. Siting on contaminated land could result in lower land costs.
Distance to Landfill	Longer haul distance,16 km or 20 minutes	Shorter Haul distance, 7 km or 10 minutes
Compatibility with existing land uses and designations	Some restrictions, airport height and zoning restrictions and existing city zoning would need to be modified. Can be mitigated.	Yes
Access to water and sewer infrastructure	No, potentially mitigated if infrastructure is extended from Riverdale or MSB is constructed. Costs estimated between $1.5 and $2.0 million.	Yes
Access to electrical infrastructure	Yes – On-site substation still required, $1.5 million	No, may require connection to transmission line up to 1.5 km away and/or substation, $1.7 million
Connection to expanded DES in future	Limited, unless the City's new MSB (or other new commercial/industrial facilities) is constructed in this area.	Good potential for expanding DES into Range Road area.

	Area 1: Robert Service Way South of Downtown	Area 2: Marwell Industrial Park North of Downtown
Air quality limitations	Some limitations; need to ensure steam from the facility does not impact airport, close proximity to residential area and upwind of downtown. Detailed air study should determine if significant impacts exist.	Limited limitations, site location is in industrial/commercial area and downwind of downtown. Detailed air study should determine if significant impacts exist.
Noise and nuisance impacts	Minimal, site is located in an isolated area, truck traffic and operations should not have a significant impact to neighbouring properties. Nuisance impacts to Riverdale may be identified.	Minimal, site is located in a more central area, truck traffic and operations could have some impact to neighbouring properties; however, impacts could be mitigated and are minimal since operations are largely compatible with existing land use designations.

5.2 Air Emissions

Comparison of Air Quality Parameters

Waste to energy facilities, just like landfills and all combustion based energy sources, emit air pollutants. In the Whitehorse context, the net air emissions resulting from WTE include emissions associated with the combustion of waste minus avoided air emissions associated with landfilling of waste, displaced diesel-generated electricity, and displaced heating oil used in boilers (assuming implementation of a DES).

The air emissions from a WTE facility are dependent on the waste composition, the thermal conversion technology employed, combustion conditions, and the design of air pollution control system. Standards such as Ontario and BC's maximum achievable technology standards specific to municipal thermal waste treatment facilities are continuously becoming more stringent to ensure emissions are as low as technically feasible. Table 6 illustrates a comparison between the Ontario Guideline A-7: Combustion and Air Pollution Control Requirement for New Municipal Waste Incinerators and the average air emissions from the "top ten" Waste to Energy Research and Technology Council 2006 Industrial award finalists. (Psomopoulos, C.S., 2009). For all parameters, facilities demonstrated an ability to achieve significantly lower levels of emissions than the Ontario standards.

Table 6: Comparison of air emissions from WTE combustion technologies and Ontario Guideline A-7 Standard.

All concentrations are compared at 11% O_2

	Average of 10 Finalists	Ontario Guideline A-7 Standard 2010
Smog Precursors		
Total Particulate Matter (PM) mg/Rm3	3.1	14
Acid Gases		
Nitrogen Oxides (NOx) mg/Rm3	112	198
Hydrogen Chloride (HCL) mg/Rm3	8.5	27
Carbon Monoxide (CO) mg/Rm3	24	40
Total Organic Content (TOC) mg/Rm3	1.02	33
Sulphur Dioxide (SO2) mg/Rm3	2.96	21
Trace Air Contaminants		
Mercury (Hg) ug/Rm3	10	20
Dioxins (TEQ) ng/m3	0.02	0.08
Cadmium (Cd) ug/Rm3	4.9[13]	7
Lead (Pb) ug/Rm3	44.51	60

The government of Ontario conducted a detailed assessment[14] of the human health and ecological risks of a modern well run incinerator that complied with the A-7 Standard in conjunction with a similar study on their landfill standards. The study concluded that:

- No significant human health effects (those being cancer, lung disease, nerve damage or reproductive effects) are likely in a typical suburban community located near an incinerator or a landfill, however both cancer risks and non-cancer risks from incinerators were lower than those associated with landfill emissions[15];

[13] Source: (Psomopoulos, C.S., 2009)

[14] Environmental Risks of Municipal Non-Hazardous Waste Landfilling and Incineration (Ontario MoE, 1999)

[15] Total lifetime incremental cancer risk for a maximally exposed individual from long-term exposure to incinerator emissions range from 4.7x10-8 to 2.3X10-7 versus total combined cancer risk from long-term exposure to landfill emissions containing volatile chlorinated chemicals range from 4.0x10-6 to 1.0x10-5 for landfill emissions. (Ontario MoE, 1999)

- An ecological risk assessment predicts that water and sediment quality near an incinerator or landfill will meet Ministry guidelines for the protection of aquatic life;
- Direct or indirect impacts to the terrestrial environment, vegetation or wildlife resulting from incinerator or landfill emissions are not anticipated to be significant.

Similar conclusions from other comparative studies are summarized by Moy (2005). Most recently, an independent study commissioned by the Commissioner and Medical Officer of Health for Region of Durham, Ontario, determined that there is no conclusive evidence indicating negative impacts of modern incinerators on the health of people living in the vicinity, based on the epidemiologic literature from 2000 – 2007 (Smith, 2007).

Energy from the WTE facility is expected to displace approximately 10,200 MWh diesel generated power and 23,700 MWh of heat derived from burning 3,383,000 litres of heating oil annually. Table 7 illustrates air emissions for these energy sources per unit of energy generated.

Table 7: Comparison of air emission intensities from energy sources in Whitehorse with WTE

	Heating Oil[16] (kg/MWh)	Diesel Generator[17] (kg/MWh)	WTE (kg/MWh)[18]
Total Particulate Matter (PM)	0.042	0.183	0.0228
Nitrogen Oxides (NOx)	0.416	8.82	0.82
Carbon Monoxide (CO)	0.104	0.516	0.176
Sulphur Dioxide (SOx)	1.66e-7	0.014	0.022

Table 8 illustrates the total air emissions based on the anticipated WTE energy output and the emissions of heating oil and diesel that could be displaced as a result of a WTE facility. The results indicate that WTE would result in overall emission reductions of total particulate matter, nitrogen oxides and carbon monoxide and an increase in sulphur dioxide. It should be noted that the WTE emission estimate is based on an average of operating facilities. If the need was established to reduce sulphur dioxide emissions in the Whitehorse area,

[16] Source: Heating oil calculations adapted from emissions calculator by Illinois Environmental Protection Agency for #1 and #2 Fuel Oil http://www.epa.state.il.us/air/aer/calculate/boiler_oil.html . Sulphur content of oil supplied in Whitehorse is Ultra Low Sulphur Platinum 0.0005 ppm. Annual seasonal boiler efficiency is assumed to be 65% according to DES study by FVB Energy.
[17] Source: Diesel emissions data from Yukon Energy

[18] Source: Calculated based on air emissions from average 10 WTE finalists, 9,975 MWh electricity and 23,700 MWh of heat generated.

additional air emission controls limiting sulphur dioxide stack emissions are technically feasible.

Table 8: Total annual air emissions displaced by WTE

	Heating Oil (kg)	Diesel Generator (kg)	WTE (kg)	Air Emissions Displaced (kg)
Total Particulate Matter (PM)	985	1,825	767	(2,044)
Nitrogen Oxides (NOx)	9,854	88,019	27,720	(70,153)
Carbon Monoxide (CO)	2,464	5,147	5,940	(1,671)
Sulphur Dioxide	0.00394	140	733	593

Dioxins and furan compounds can be formed by a wide variety of combustion sources including cars, trucks, diesel generators, wood burning fireplaces and WTE facilities. The implementation of stringent air pollution standards and controls for WTE facilities over the previous decades has dramatically reduced dioxin and furan emissions. The German Ministry of Environment now considers dioxins and furans coming from WTE to be insignificant, since they make up less than 1% of the loading in Germany, even though 35% of the municipal waste in Germany is treated using WTE[19]. In Canada, we have Canada-Wide Standards for dioxins and furans which are the most stringent in the world.

Metals contained within MSW commonly include iron, copper, lead, zinc, cadmium and mercury. Within a WTE facility, most metals remain inert and appear in the bottom ash following combustion. Volatile metals however, particularly mercury and lead will be partially or fully volatized at high temperatures.

The emission of mercury and lead from WTE facilities is a function of the presence of these elements in the waste stream and the capabilities of the air pollution control system. The diversion of hazardous materials from disposal, such as thermostats, barometers and manometers, lighting and electrical appliances, major appliances, electronic waste, and batteries, can eliminate the source while air pollution control systems have been proven to be able to reduce volatile metal emissions to well below environmental regulations. Mercury emissions measured from the top ten North American WTE facilities are now less than 50% of the Ontario standard (see Table 6 above) while lead emissions are also consistently below the Ontario standard for these facilities. According to a German Ministry of Environment publication, lead and mercury emissions from incineration of household waste are no longer significant sources for human exposure to toxic substances, and emissions from all other sources are over 1,000 times greater than the emissions produced by WTE facilities (BMU, 2005).

[19] Germany, Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (2005). *Waste Incineration – A Potential Danger? Bidding Farewell to Dioxin Sprouting*. Accessed October 26, 2008. http://www.bmu.de/files/pdfs/allgemein/application/pdf/muellverbrennung_dioxin_en.pdf

Ultrafine particles (also referred to as “nano-particles”) are the subject of recent research and growing public interest. Ultrafine particles are generated directly by combustion from stationary sources (power plants, heating furnaces, WTE facilities) and mobile sources such as cars, trucks and industrial mobile equipment burning diesel, gas or gasoline. In order to put ultrafine sources into perspective, one study[20] in the literature compared the ultrafine emissions from vehicles with those coming from a WTE facility. Converted to the proposed size for the WTE plant in Whitehorse, about 100 vehicles traveling 3km would release about the same amount of ultrafine particles as a WTE facility in an hour. There is also recent evidence (briefly described below) that suggests that stringent air pollution control requirements for WTE facilities result in significantly fewer ultrafine particle emissions than from other combustion sources. One study conducted by a university in Switzerland on different types of pollution control equipment at WTE facilities found that a certain combination of scrubbers actually reduced ultrafine loadings from the stack to levels lower than in the ambient rural air (UMTEC, 2001). Further study and verification is required and would be addressed in an environmental assessment.

This section provided an overview of WTE air emissions in the context of emissions from displaced energy sources (diesel and furnace oil) and other emission sources. More detailed air quality analysis, including plume dispersion modelling is recommended once a potential site, process technology and air pollution controls have been specified.

5.3 Environmental Approvals and Permitting

Project-specific regulatory issues and requirements should be well understood as early in the life of a project as possible. A well thought out program for meeting these requirements that includes early engagement of relevant regulatory agencies, key stakeholders, and public can greatly reduce the risk of lengthy and costly project delays.

This section provides a brief summary of the expected federal, territorial and municipal regulatory requirements associated with the construction and operation of a WTE facility in Whitehorse, including undertaking an environmental assessment of the project, as well as obtaining all required permits and licenses as per territorial regulations and municipal by-laws. More details on the anticipated environmental assessment process are provided in ***Appendix D***.

5.3.1 Yukon Environmental and Socio-Economic Assessment Act Process Overview

It is anticipated that the construction of a WTE facility in Whitehorse will trigger the requirement to obtain approval under the *Yukon Environmental and Socio-Economic Assessment Act (*YESAA). Based on the type of facility proposed it is expected the assessment will involve a Designated Office evaluation (process used for the majority of assessments conducted in Yukon).

[20] *Buonanno, G., Ficco, G., & Stabile, L. (2009). Size distribution and number concentration of particles at the stack of a municipal waste incinerator.* Journal of Waste Management, *29, 749-755*

An assessment is initiated when a proponent submits a project proposal to the Yukon Environmental and Socio-economic Assessment Board. Project proposals typically contain environmental and socioeconomic information describing baseline conditions, potential project impacts, and mitigation strategies in some or all of the following areas:

- Air Quality
- Geology and Soil
- Water and Water Quality
- Fish and Fish Habitat
- Wildlife and Wildlife Habitat
- Vegetation Age, Composition, and Structure
- Cultural/Heritage Resources
- Recreation
- Health
- Employment
- Education/Knowledge
- Families

Following submission of the project proposal by the Proponent, a review process is coordinated (in this case) by the Designation Office. Following the evaluation phase, the Designated Office prepares a recommendation to applicable Decision Body(s)[21].

5.3.2 Territorial and Municipal Permitting & Licensing Requirements

A WTE facility in the Yukon will trigger permitting and licensing requirements at the territorial and municipal level. Project-specific issues linked to approvals requirements include air emissions, ash disposal, land acquisition needs, socio-economic implications, surface water / groundwater extraction and use, and potential for contaminant spills, amongst others. Table 9 lists the regulatory permits, leases and licenses likely to be associated with a WTE facility, along with information that should be included in environmental permit and approval applications.

Territorial permits and approvals can be issued by relevant regulatory agencies only after release of the YESAB Final Report recommendations and (if undue delay is to be avoided) only after each Decision Body has issued a Decision Document accepting the YESAB recommendations. However, permit application materials can be filed with relevant regulatory agencies prior to the issuance of a Decision Document to help expedite this process. Assuming no major issues arise during the review period, approvals could then be obtained shortly after the Decision Document is issued.

[21] A Decision Body is the federal government, territorial government or First Nation that responds to recommendations made to them by Designated Offices, the Executive Committee of YESAB or a Panel of the Board, and has the authority to determine whether a project may proceed.

Development activities in the Yukon often require additional federal permits or authorizations. Triggers for such permits include impacts to fish or fish habitat, or to navigable waters. It is assumed that no watercourses will be impacted as a result of construction of the WTE facility; as a result, an Authorization as per the *Fisheries Act* or Permit as per the *Navigable Waters Act* will not be required.

Table 9: Overview of Approvals Requirements for a Whitehorse Waste to Energy facility

Project Activity	Approval Requirement	Applicable Act / Regulation / By-Law	Information Requirements for Obtaining Approval (i.e. permit, license or lease)
Territorial Permit / Licensing Requirements			
Operation of incinerators capable of burning more than 5 kilograms of solid waste per day.	Air Emissions Permit	*Environment Act* / Air Emissions Regulations	▪ A description of the source of the contaminants that may be released into the air; ▪ The type and quantity of the contaminants that may be released into the air; ▪ One set of plans and drawings clearly showing the layout of the facility, location of individual equipment, and points of discharge, building dimensions and stack heights; ▪ A description of air quality control devices, including efficiency and other design criteria and photocopies of the manufacturer's specifications for the air quality control devices establishing that the equipment is capable of complying with applicable emission criteria in the permit; ▪ A map or aerial photograph, on a scale of 1:50,000 detailing the location of the facility, homes, buildings, roads and other adjacent facilities within a five kilometre radius of the facility; ▪ Specifications for any equipment, including incinerators, that may be used and a description of the mitigative measures planned to control air emissions and the disposal and handling of all types of ash; and, ▪ A description of any equipment or devices the applicant intends to use to monitor the release of contaminants into the air.
Constructing and operating a waste disposal facility	Permit for the Facility	*Environment Act* / Solid Waste Regulations	▪ The location and size of the proposed waste disposal facility or dump and a description of the type of solid waste to be handled or disposed of the site;
Disposal or handling of special waste[22]	Special Waste Permit	*Environment Act* / Special Waste Regulations	▪ The types of special waste and operations for which the application is made; ▪ Location of any proposed handling or disposal of special waste; ▪ The rate at which special waste will be generated; and

[22] Commonly known as hazardous waste.

Project Activity	Approval Requirement	Applicable Act / Regulation / By-Law	Information Requirements for Obtaining Approval (i.e. permit, license or lease)
			▪ Method of treatment or disposal.
Storage and handling of petroleum products	Storage Tank Systems Permit	*Environment Act* / Storage Tank Regulations	▪ Any plans related to the activity to be undertaken, including storage tank system design plans, safety and inspection plans and closure and reclamation plans; ▪ Identification of on-site and adjacent groundwater and surface water sources; and ▪ The proposed dates and timing of work to be undertaken in relation to the permitted activity.
Establishment of a solid waste disposal facility; **Fuel caches of more than 4000L or any single container of more than 2000L on Commissioner's Land**	Land Lease and Land Use Permit	*Territorial Lands (Yukon) Act, Lands Act* / Land Use Regulations	▪ A preliminary plan showing the lands proposed to be used and an estimate of their area, and the approximate location of all of the following: – existing lines, trails, rights-of-way, and cleared areas proposed to be used in the land use operation; – new lines, trails, rights-of-way, and cleared areas proposed to be used in the land use operation; – buildings, campsites, air landing strips, air navigation aids, fuel and supply storage sites, waste disposal sites, excavations, and other works and places proposed to be constructed or used during the land use operation; and – bridges, dams, ditches, railroads, highways and roads, transmission lines, pipelines, survey lines and monuments, air landing strips, streams, and all other features, structures or works that, in the opinion of the applicant, may be affected by the land use operation.
Water use or the potential deposition of waste materials in water	Water License	*Waters Act*	▪ Where the water is proposed to be used for an industrial, placer mining, or quartz mining undertaking, a description of the undertaking and of all wastes produced and chemicals used in the operation of the undertaking; and ▪ Where the proposed undertaking involves the handling or storage of petroleum products or hazardous materials, a plan for their safe handling, storage, and disposal, and a contingency plan for their containment and for cleaning them up in the event of a spill; and ▪ Plans for the abandonment, or any temporary closing, of the proposed undertaking.

Project Activity	Approval Requirement	Applicable Act / Regulation / By-Law	Information Requirements for Obtaining Approval (i.e. permit, license or lease)
Relevant Municipal Requirements			
Disposal of solid waste	Permit to Dispose of Solid Waste	Solid Waste By-Law	▪ Conditions that may be placed on the permit may include the requirement to provide information on the origin, type and amount of solid waste from outside the city, or laboratory analysis of the concentration of contaminants in the contaminated soil.
Release of waste water, storm water, subsurface water or clear-water waste into the sewer or drainage systems	Permit to Discharge	Sewer and Water By-Law	Information requirements associated with a permit to discharge not explicitly stated in the sewer and water by-law.
Establishment of a solid waste disposal facility	Development Permit	Zoning By-Law	▪ legal description and property address; ▪ statement of the current, proposed use and occupancy of all parts of the lot and buildings; ▪ description of the size of the proposed development with respect to gross floor area, lot coverage, building or structure height, amount and location of parking and loading areas; ▪ be accompanied by a site plan in duplicate, at an appropriate metric scale containing – a north arrow; – the legal property description; – lot dimensions and other reference features such as the location of easements, existing buildings, fences relative to property lines, and existing and proposed grades; – the location of all existing and proposed improvements on the lot including site access and egress, front, side and rear yard dimensions, location and size of required parking, loading and garbage collection areas; – the location of any trees, shrubbery or natural features to be retained; – the location of public sidewalks, hydro poles, light standards, boulevard trees, fire hydrants and other related features; – floor plans and elevation drawings of all proposed buildings, and

Project Activity	Approval Requirement	Applicable Act / Regulation / By-Law	Information Requirements for Obtaining Approval (i.e. permit, license or lease)
			structures including any additions; – the location, size, and placement of signs and future signs in all commercial, institutional and industrial zones; – the location of all existing and proposed services on the property; and – the location of all proposed structures to manage drainage including connections to existing storm mains, ditches, rock sumps and/or storm sewer interceptors for areas with high contamination potential.

5.3.3 Public Utilities Board Requirements

All energy projects proposed for development in the Yukon require an Energy Project Certificate (EPC) prior to construction. As per the *Public Utilities Act*, an energy project includes "… a facility for the generation of electricity from the motion of wind or water, or the combustion of natural gas, oil, petroleum products, coal, or plant products or geothermal energy".

The following is an outline of information that it is expected to be required in an EPC Application, primarily based on the information supplied in the YEC Application for the Mayo Hydro Enhancement Project (2009):

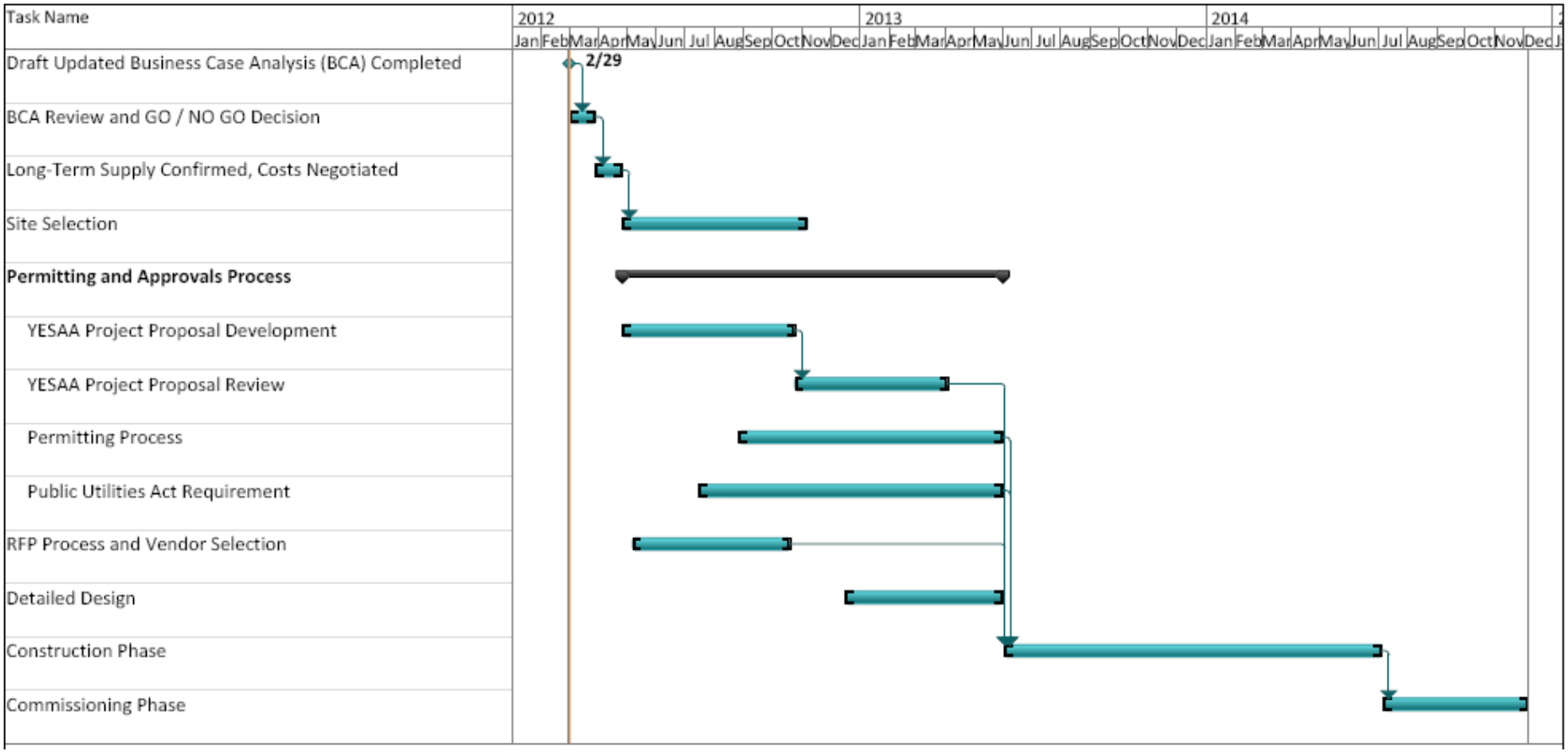
- Introduction and Applicant Information;
- Project Description, including a summary of anticipated environmental and socio-economic impacts;
- Project Justification, including project need, risks and effect on rate payers;
- Consultation Undertaken to Date; and
- Description of other Permitting Applications and Approvals.

5.3.4 Project Scheduling Implications

Figure 11 provides a preliminary schedule for getting a WTE project through the environmental assessment, permitting and approvals phase. The schedule incorporates regulated times associated with the adequacy, evaluation and recommendation stages of YESAA. However, the YESAA timelines have been intentionally structured to incorporate a great deal of flexibility such that both small-scale and large-scale projects can be accommodated. This results in some uncertainty for any particular project in exactly how long the approvals phase will take. To deal with this issue as well as other project uncertainties such as timing of when proposal development will begin, the schedule presented in Figure 11 incorporates the following assumptions:

- Decision whether to proceed with project based on updated Business Case Analysis made by end of March 2012.
- Project Energy Certificate Application and Permit Applications developed in parallel with YESAA Project Proposal Development and Review, requiring little additional time for regulatory decisions to be made (by the Yukon Utilities Board and territorial regulators such as the Yukon Ministry of Environment) following YESAA Decision Body approval.
- Six to 12 month commissioning phase.
- Detailed design phase completed in parallel with permitting review and approval phase.
- A relatively straightforward consultation process, with moderate public interest and few major issues and concerns identified, requiring 1 month for Seeking Views & Information, and an additional 2 weeks to respond to information requests

Figure 11: Preliminary Schedule for a Waste to Energy Project in the Yukon.



6. UPDATED BUSINESS CASE ANALYSIS

6.1 Approach and Key Assumptions

This analysis builds on the preliminary business case analysis, completed in September, 2011 (Morrison Hershfield, September 2011), and determines costs to produce additional power by utilizing municipal solid waste and biomass (wood) as fuel sources.

Research and analysis since the September 2011 study have resulted in the selection of a single scenario based on the most recent waste diversion initiatives and supported by research into residual waste availability, biomass supply, district energy heat needs and costs, technology types and costs (via an EOI) and other research as required. Key parameters and assumptions are presented in Table 10.

Table 10: Business Case Parameters and Assumptions

Business Case Parameter	Assumption	Comments
Nominal capacity of WTE plant	25,000 Tonnes Per Year	
Technology used	Conventional combustion	Two stage combustion, close coupled gasification or mass burn
Actual plant throughput at 95% availability	23,750 tonnes per year	
Feedstock used in in 2015	16,100 tonnes MSW 7,650 tonnes biomass	Based on 50% MSW diversion
Feedstock used in 2035	23,750 tonnes MSW	Based on expected population and waste growth
Tipping fee for waste received	$108 per tonne	Based on what it would cost to otherwise landfill that material
Tipping fee paid for ash disposed	$185 per tonne	Based on what it would cost to operate a smaller ash landfill
Average cost of biomass supply	$104 per tonne	As received wet wood
Net electricity production	9,975 MWh	Based on 470 kWh per tonne of waste
Net heat produced and sold	23,700 MWh	Based on supplying 79% of the heat for a future Whitehorse DES
Value of heat sold	$81/MWh	From separate district energy study
Minimum site size	2 ha	
Waste to energy facility life	25 years	With potential to extend
Remaining landfill capacity with expanded diversion (and no WTE)	Until 2057	Landfill expansion is possible
Remaining landfill capacity with expanded diversion and WTE	Well into next century	Landfill expansion likely not required
Contingency	10%	On capital and operating costs

6.2 Feedstock costs and revenues

6.2.1 Municipal solid waste

Revenues from tipping fees for the acceptance of MSW at the WTE facility are based on an analysis of the life cycle costs of operating the Whitehorse Landfill, Appendix B. The tipping fee will need to be discussed and confirmed with the City when this project moves forward.

The WTE tipping fees used in this analysis are the lifecycle costs of operating the Son of War Eagle Landfill assuming waste volumes are reduced/diverted from landfilling by a total of 50%. In this analysis, it is assumed that the residual waste would be taken to the WTE facility instead of the Son of War Eagle Landfill. The tipping fees paid to the WTE operator would be the same as the City's deferred cost to landfill the waste.

Costs of ash disposal, disposal of some non-burnable waste and small amounts of MSW when the WTE plant is being serviced were also assessed based on what it would cost the City to keep the landfill in operation for the lower volumes with WTE. While overall landfill costs go down when mostly ash is disposed, the unit costs per tonne actually go up because of the much lower volumes (units). For this analysis, it has been assumed that the WTE facility operator would pay the City the true cost of disposal for ash residue. This is substantially higher than the unit fee per tonne that would be paid to the WTE plant operator for acceptance of MSW.

Fly ash would require stabilization treatment prior to disposal into the landfill. An allowance of $30 per tonne has been included for ash stabilization.

6.2.2 Wood biomass

Wood biomass costs are dependent on the annual requirements and quantities available. Cheaper biomass source would be prioritized ahead of more expensive sources. Based on an assessment of the biomass availability near Whitehorse the initial cost is estimated at $104 per wet tonne delivered to the WTE facility. This is an average cost and may be less if greater quantities of cheaper sources of biomass become available. Since the volumes of MSW will increase along with population growth and commercial activity in the Yukon, the amount of biomass required should decrease to zero by about 2035 (more or less, depending on actual growth and actual recycling). Capital and operating cost estimates include provisions for biomass storage, handling and chipping.

6.2.3 Heat Revenues

The waste to energy facility would be able to provide a heat baseload of 23,700 MWh to a district heating system supplying the downtown and hospital district. When

taking into consideration the additional capital and operating costs associated with the district energy, the potential net revenue from heat sales would be $81/MWh[23].

6.2.4 Metal Recycling

Recovered metals are expected to consist of 3% of the annual waste throughput. Revenues from recycled metals will fluctuate with world market demand for scrap. A value of $100 per tonne is used at this time to reflect an expected long term average.

6.3 Facility Capital and Operating costs

6.3.1 Scope included and excluded

At this stage of the project, where the technology has been defined, but a vendor not yet selected, and a site area defined, but a specific site not yet selected, there are some items that can be firmly defined and some that are accounted for with a cost allowance (for confirmation as the project develops).

Capital costs

Included in the capital cost estimates, which are supported by information received through the EOI and supplemented through other research and studies are:

- Purchased equipment to receive, process, combust waste;
- Equipment to recover energy in the form of heat and electricity;
- Air pollution control equipment;
- Ash removal and ash treatment as required;
- Biomass receiving, storage, processing/chipping and feeding;
- Buildings;
- Site work;
- Permits and approvals;
- Cost of land;
- Electrical tie-in and substations; and,
- Utility connections for water and sewer.

Interest during construction is not included.

[23] Calculations by FVB Energy for Whitehorse District Energy feasibility study provided by Robert Doyle February 29, 2012

Operating Costs

Operating costs include:

- labour costs;
- variable operating costs;
- maintenance costs;
- biomass processing;
- bottom ash disposal; and,
- fly ash treatment.

6.3.2 Estimated Costs

Capital costs were estimated using supporting information from vendor submissions, existing data from previous work, and new information from recent studies into the true cost of landfilling and into DESs. Vendor submissions provided a range of capital costs from $19.9 million to $42.8 million, with an average from 5 submissions calculated at about $31 million. The capital cost used in the business case analysis including 10% contingency was $34.6 million.

Operating costs, excluding feedstock costs and revenues, range from $3.3 million per year to $4.6 million per year based on vendor submissions. The higher number was for a technology from Europe, where prices are generally much higher than in North America. The other vendors' operating costs were within 20% of the lowest figure. The estimated operating costs for the business case analysis assume a staff requirement of 18 persons (vendors suggested between 7 and 39), variable operating costs supported by vendor submitted data, ash disposal costs derived from the landfill cost analysis, and an allowance for biomass processing and fly ash stabilization. Including a 10% contingency, the operating costs are estimated at $3.3 million per year and are within the range of operating costs provided by vendors in the EOI process.

A sensitivity analysis was used to account for the potential variability of some key costs.

6.4 Financial Analysis Base Case

Table 11: Base Case WTE Cost Model

MAXIMUM PRODUCTION OF ELECTRICITY (MSW and Biomass)

Combined Heat and Power, 1.6 MW (Electricity)

Base Case

Plant design capacity		25,000	Tonnes per year
Plant feedstock usage		16,098	Tonnes per year MSW
		7,652	Tonnes per year biomass
Complete facility installed and commissioned	$25,500,000	1,020	$ per tonne of installed annual capacity
Additional costs for wood handing, storage & chipping	$ 1,000,000		
Land Costs	$ 1,000,000		
Site work	$ 2,000,000		
AC Connection Costs	$ 1,600,000		
Permits and approvals	$ 50,000		
Total capital cost	***$31,450,000***		
Contingency	*$ 3,145,000*	10%	
Total capital cost + Contingency	***$34,595,000***		
Assumed average cost of capital		5.5	% annual interest rate
Amortization period		25	Years
Annual capital costs	***$ 2,611,923***	$ 110	capital expense per tonne of feedstock
Annual labor costs	$ 1,440,000	18	Assume average staff cost of $80k per year
Variable operation and maintenance costs	$ 900,000	$ 36	$ per tonne of installed annual capacity
Biomass Processing	$ 45,914	$ 6	$per tonne allowance
Bottom ash disposal (17% of MSW, 1% of biomass)	$ 519,113	$ 185	$ per tonne to landfill
Fly ash treatment and disposal (3% of feedstock	$ 145,730	$ 205	$ per tonne to treat and landfill
Total Operating Costs	**$ 3,050,757**		
Contingency	*$ 305,076*	*10%*	
Total Heat Sales		*23,700*	*MWh*
Net Revenue from DE	($1,914,960)	*$ 81*	*$ per MWh heat sold*
Cost of wood supply	$ 795,846	$ 104	$ per wet tonne
Revenue from tipping fees	($1,736,356)	$ 108	$ per tonne of MSW received
Revenue from sale of recyclables (3% of MSW)	($ 48,293)	$ 100	$ per tonne
Net annual cost	***$ 3,063,992***		
Total electricity produced in MWh	9,975	420	kWh per tonne of MSW and tonne biomass
Cost per kWh of electricity generated	**$ 0.31**		

The costs per kWh of electricity generated are higher than in the Preliminary Business Case Analysis (Morrison Hershfield, 2011) of $0.16 - $0.18 per kWh. The changes in the business case include the following:

- Capital costs are lower by about 10% due to a small reduction in capacity, more precise vendor information, and a reduction in contingency. Actual scope of capital items increased and now includes electrical substation and land cost allowances.
- Non-feedstock related operating costs are higher by about 15%. This is due to higher estimated ash disposal costs (arising from the landfill cost assessment) and a better understanding of some of the operating components through vendor input.
- Electricity production is 30% less than originally indicated due to electricity generation efficiency losses resulting from the amount of heat that will be removed for the DES (as indicated by vendors in EOI process). It is expected that vendors would optimize their CHP systems in a competitive bidding situation and may be able to improve on the electricity generation efficiencies quoted under the EOI.
- The amount of biomass required to augment the MSW feedstock in the near-term is substantially higher since we have assumed a 50% MSW diversion target is achieved in 2015. The additional biomass requirements and reduction in MSW tipping fee revenues significantly increase operating costs.

The base case analysis is appropriately conservative for the current stage of project evaluation. The impacts of varying key project variables are discussed in the sensitivity analysis section below.

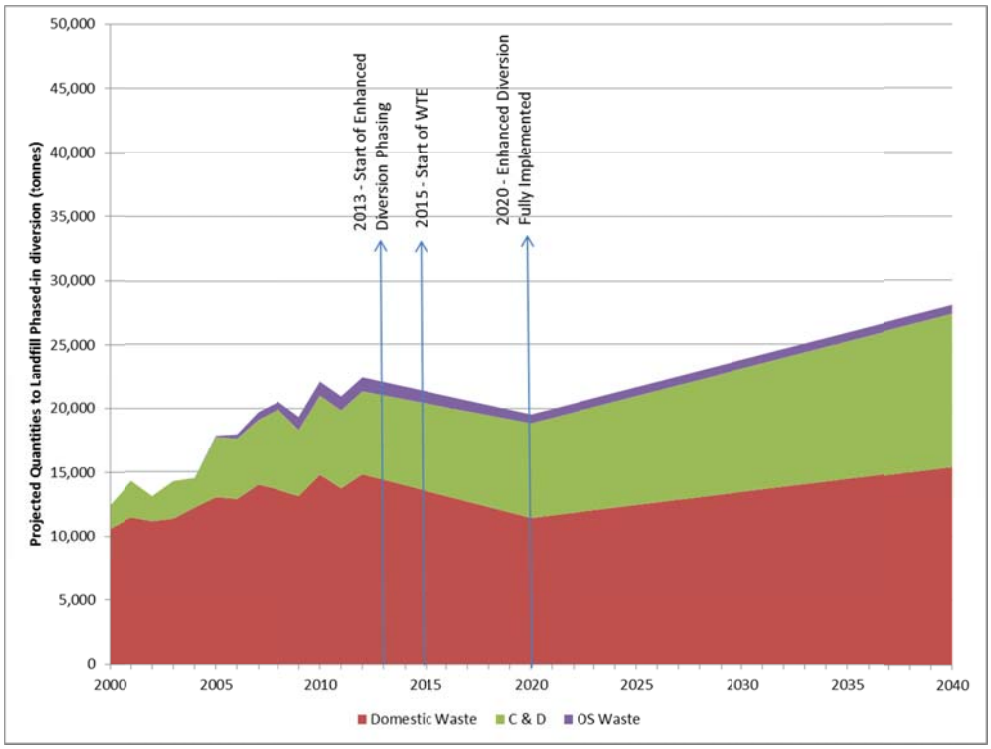
6.5 Sensitivity Analysis

The base case has a higher level of confidence than the preliminary business case analysis completed in September 2011. However, several key areas of uncertainty remain that can have a major bearing on project feasibility. A sensitivity analysis of the business case has been conducted for these key project variables and is described in the sections below.

6.5.1 Sensitivity #1 - Potential for Phased-in Waste Diversion

The base analysis assumes an almost immediate drop in waste generation due to very aggressive recycling efforts. This sensitivity looks at the economics of the WTE facility if the diversion programs are phased in between 2013 and 2020, achieving a diversion of 50% by 2020. The impacts on MSW residual waste volumes are illustrated in Figure 12.

Figure 12: Phased-In Enhanced Diversion Sensitivity



Assuming the 50% waste diversion measures are phased in between 2013 and 2020, additional MSW would be available initially. Waste quantities would continue to increase due to population growth and economic activity while progress was being made towards the 50% diversion goal. With this sensitivity, the cost to produce electricity using WTE is $0.21 per kWh in 2015.

6.5.2 Sensitivity #2 - Federal Grant Funding under the ECO II NRCan program

An application for federal grant funding toward capital costs has been made under the NRCan ECO II program, ***Appendix E***. Since the result of this funding application is not yet known, this funding is not reflected in the base case analysis. Should the grant application be successful, the total capital funds required would be reduced to $21.7 million improving the business case. This case was evaluated based on two scenarios:

- Sensitivity #2a, assumes that the ECO II funding is granted and 50% waste diversion is achieved in 2015. This results in a cost to produce electricity using WTE of $0.21 per kWh in 2015.

- Sensitivity #2b, assumes that the ECO II funding is granted and 50% waste diversion is phase-in as described in sensitivity #1. This results in a cost to produce electricity using WTE of $0.11 per kWh in 2015

6.5.3 Sensitivity #3 - Reduction in landfill costs.

With this sensitivity, the possibility of reduced landfill costs is explored. Should the City of Whitehorse find that estimated costs to operate the landfill can be reduced by, say 20%, then this could reduce the tipping fee revenue for accepting waste at the WTE facility by 20% and also reduce the cost to dispose of ash by 20%. In this case, the cost to produce electricity would rise to $0.34 per kWh because of reduced tipping fee revenues.

6.5.4 Sensitivity #4 - Electricity only

This sensitivity analysis examines the impact of designing the WTE facility for highest electrical generation efficiency and with no possibility of excess heat being available for district energy in any substantial amount. Even though the electricity generation would increase to 625 kWh for each tonne of feedstock consumed, the total energy that can be sold is lower, thus cost to produce electricity would rise to $0.34 per kWh.

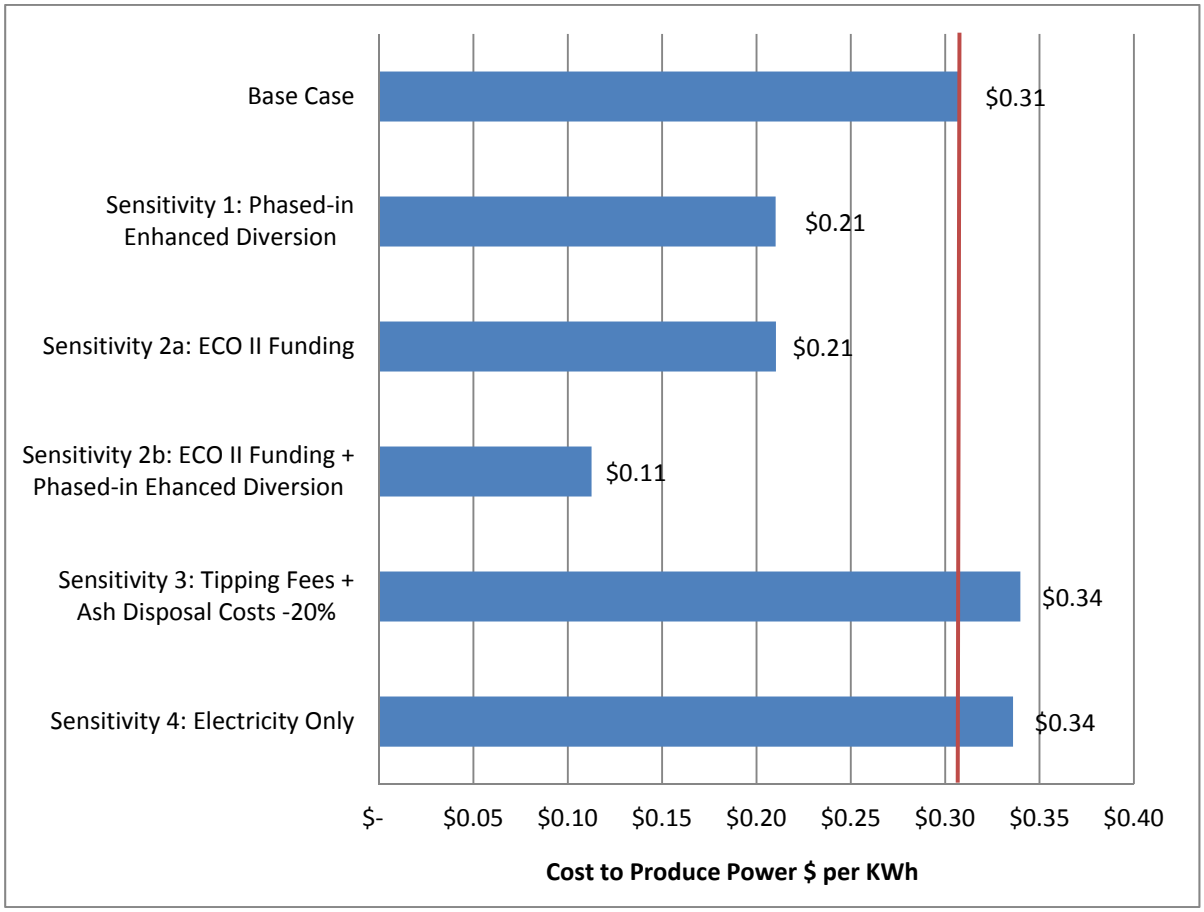
6.5.5 Sensitivity Analysis Summary

A summary of the sensitivity analyses is provided in Table 12. Figure 13 provides a graphical illustration of the electricity production cost for the base case and each sensitivity analysis.

Table 12: Sensitivity Analysis Summary

	Total Capital Cost $	Electrical Capacity MW	Annual Net Electricity Produced MWh/yr	Annual Heat Sales MWh/yr	Cost of Electricity Generated $/kWh
Base Case	34,595,000	1.6	9,975	23,700	0.31
Sensitivity #1 – Phased-in Diversion	34,595,000	1.6	9,975	23,700	0.21
Sensitivity #2a – ECOII Funding	21,700,000	1.6	9,975	23,700	0.21
Sensitivity #2b – ECOII Funding + Phased-in Diversion	21,700,000	1.6	9,975	23,700	0.11
Sensitivity #3 – Reduced Tipping Fees & Ash Disposal Costs	34,595,000	1.6	9,975	23,700	0.34
Sensitivity #4 - Electricity Only	34,595,000	2.0	14,844	0	0.34

Figure 13: Cost of Electricity Production Comparison



7. CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

Several meetings and discussions have been held between Yukon Energy, their consultant team, and key stakeholders including City of Whitehorse, Government of Yukon Community Services Department, Raven Recycling, P&M Recycling, and the Yukon Conservation Society. Yukon Energy organized a half-day workshop and public meeting on October 18, 2011 for the purpose of identifying issues and opportunities and outlining a plan for moving forward. A key theme identified at the workshop and public meeting was support for locally derived energy sources. There was a strong desire expressed to ensure that WTE is part of an integrated waste management system and does not compete with recycling. There was also strong support for increased diversion of materials away from landfill and future WTE, with discussion of the territory and City potentially establishing a 50% waste diversion target.

A WTE design capacity of 25,000 tonnes per year has been selected for the updated business case analysis. This capacity has been reduced from an earlier analysis in response to the desire of key stakeholders to aggressively pursue a 50% waste diversion target. The facility will be capable of burning biomass (waste wood) as well as MSW, so that any shortfall in waste feedstock can be made up with biomass. There is adequate biomass available from reliable sources for the foreseeable future. It is estimated that the WTE plant will be burning MSW without need for biomass by 2035 based on current projections.

A WTE life of 25 years is projected, after which time a decision will have to be made on whether to upgrade the facility and continue operations or to decommission the facility for lack of feedstock or because newer, more effective technologies are available to replace it.

An expression of interest was issued to vendors of WTE equipment in November 2011 and 7 vendors responded in January 2012. All of the vendors offered information on conventional combustion or close-coupled gasification. Technical, performance, operational and cost information provided by the vendors was used to increase confidence in estimates for the business case analysis.

A preliminary siting assessment, informed by the results obtained from a separate Whitehorse District Energy feasibility study, identified potential site locations in the Marwell Industrial area and along Robert Service Way south of the downtown area. While a more detailed siting assessment and consultations will be required prior to final site selection, the business case analysis assumes siting in the Marwell area because of proximity to potential heat customers, access to municipal services and compatibility with adjacent land uses.

Air emissions have been estimated for a WTE facility and compared to emissions from diesel combustion in electrical generators and furnace oil combustion in space heating applications. Assuming the electricity produced from WTE displaces diesel-generated electricity, and waste heat is utilized in a district energy system displacing furnace oil, WTE is expected to result in a net reduction of nitrogen oxide, particulate matter and carbon monoxide emissions and a net increase in sulphur dioxide emissions.

A single business case was reviewed. Cost and revenue estimate uncertainty has been reduced due to separate studies that have been conducted into landfill life cycle costs,

district energy requirements and costs, and biomass supply and costs. Greater certainty in WTE facility capital and operating costs and energy recovery efficiencies have been obtained through submissions received from technology vendors in an EOI process.

The estimated cost to produce electricity from MSW and biomass in the "base case" is $0.31 per kWh. This estimate is similar to the cost of diesel-generated electricity and does not provide a clear incentive to pursue a WTE project. This cost estimate is higher than reported in the September 2011 preliminary business case analysis ($0.16 per kWh) largely as a result of two key factors: (1) requirements for additional biomass (higher cost) feedstock during initial operations, assuming that the waste diversion target of 50% is achieved in 2015; and (2) reduced electricity generation efficiencies reported by vendors when operating in a CHP mode, while meeting the heat quality requirements specified in the separate District Energy study.

Evaluation of the business case identified several areas where there is still considerable uncertainty associated with "base case" assumptions and potential changes in circumstances could beneficially affect the viability of WTE. These areas of uncertainty were investigated using a sensitivity analysis. The following have the potential to significantly improve project economics:

- An application for federal grant funding has been made under the NRCan ECO II program. If awarded, the grant amount that could reduce the required plant capital costs to $21.7 million. Under this scenario the cost to generate electricity would be reduced to between $0.11/kWh and $0.21/kWh.
- The base case analysis assumes an almost immediate drop (by 2015) in residual waste volumes due to very aggressive recycling efforts. A sensitivity calculation examined the economics of the WTE facility if the diversion programs are phased in over 7 years instead of two years, achieving a diversion of 50% by 2020. With a phased-in diversion, there would be a need to manage more residual (non-recycled) MSW initially and until the diversion program is fully implemented. In the meantime, waste quantities continue to increase due to population growth and economic activity. With this sensitivity, the cost to produce electricity using WTE is $0.21 per kWh in 2015.

7.2 Recommendations and Next Steps

Based on the analysis in this report, it is recommended that the following two key project uncertainties be examined further to determine if the project feasibility can be improved:

1. Capital funding grants: Defer any final decisions on feasibility of WTE until the results of the NRCan ECO II application are known. The potential grant has the ability to substantially improve project economics.

2. Waste diversion implementation: The rate of waste diversion implementation is unknown and has a large bearing on project economics. Most aggressive diversion projects require extensive planning and funding, and there is a reasonable chance that achievement of a 50% diversion target would occur sometime after 2015 (potential commissioning date of a WTE facility). It is recommended that Yukon Energy initiate discussions with the City of Whitehorse and Yukon Government to understand diversion strategy implementation plans and schedule. Revise base case business case analysis taking into account waste diversion strategy implementation plans.

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APPENDIX A: YUKON ENERGY WASTE TO ENERGY WORKSHOP REPORT

APPENDIX B: LANDFILL FULL COST ACCOUNTING REPORT (DRAFT)

APPENDIX C: EOI QUESTIONNAIRE

APPENDIX D: ENVIRONMENTAL ASSESSMENT PROCESS

APPENDIX E: NRCAN ECOII FUNDING APPLICATION

Appendix 5.15
Thermal Energy Plan Development Study (Stantec 2016)

2016-007 – Thermal Energy Plant Development Study – Rev. 1

Conceptual planning and design for a 5 MWe, 10 MWe, and 20 MWe LNG and diesel thermal station in the Whitehorse area

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Revision 1

November 21, 2016

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Table of Contents

1.0 INTRODUCTION 1.1

2.0 PLANT SITING 2.1
2.1 SITE SELECTION 2.2
2.1.1 Site 1: City of Whitehorse Landfill 2.2
2.1.2 Site 3: Mayo Road Substation - Lot Enlargement 2.4

3.0 CONCEPTUAL DESIGN 3.1
3.1 BASIS OF DESIGN 3.1
3.2 PRIME MOVERS 3.1
3.3 CONCEPTUAL SITE LAYOUTS 3.2
3.4 ENGINE WASTE HEAT RECOVERY, HEAT RATE AND LOAD PICK-UP CAPABILITY 3.3
3.4.1 Engine Waste Heat Recovery 3.3
3.4.2 Heat Rate 3.4
3.4.3 Load Pick-Up Capability 3.4
3.5 OPINION OF PROBABLE COST 3.5
3.6 OPINION OF PROBABLE O&M COST 3.6
3.7 IMPLEMENTATION SCHEDULE 3.8
3.8 YEC PERFORMANCE ATTRIBUTES 3.9

4.0 RISK IDENTIFICATION 4.1

5.0 APPENDICES 5.1

LIST OF TABLES

Table 1 Selected Criteria and Level of Importance 2.1
Table 2 Selection Criteria - Landfill 2.2
Table 3 Selection Criteria – Takhini Substation 2.5
Table 4 Summary of Opinion of Probable Capital Cost 3.1
Table 5 Summary of Opinion of Probable Capital Cost 3.6
Table 6 Opinion of Probable Reciprocating Engine O&M Costs (Excluding Fuel) 3.8
Table 7 Implementation Schedule 3.8
Table 8 Performance Attributes by Option 3.9
Table 9 Project Development Risks 4.1

LIST OF FIGURES

Figure 1 Conceptual Map of Potential Site Location (Landfill) 2.3
Figure 2 Photo of Potential Plant Location at Landfill 2.4
Figure 3 Conceptual Map of Potential Site Location (Takhini) 2.6
Figure 4 Photo of Potential Plant Location at Takhini 2.6
Figure 5 Site Layout Sample for Landfill, 20 MW, LNG (Plant) 3.2
Figure 6 Site Layout Sample for Landfill, 20 MW, LNG (Satellite) 3.3
Figure 7 Sample Engine's Maximum Load Step at Varying Loads 3.5

1.0 INTRODUCTION

Stantec Consulting Ltd. (Stantec) was retained by Yukon Energy Corporation (YEC) to conduct a desktop conceptual planning and design exercise to support their resource planning activities relative to thermal generation. The objective of this study is to determine a potential site within the Whitehorse and surrounding area for the new facility, and to complete conceptual designs for a power generation plant in size increments of 5 MW_e, 10 MW_e, and 20 MW_e output. In all cases, the plant is to use LNG or diesel as its primary fuel.

The study was conducted in a series of finite tasks, building methodically toward the solutions outlined herein. Siting was conducted in two phases. The first phase identified attributes and characteristics desired for the potential site, with the second phase applying the criteria to the candidate sites, leading to selection of a recommended site. Results for this aspect of the study are outlined in Chapter 2 – Plant Siting.

In parallel to the siting exercise, conceptual designs for the three plant capacities using LNG and diesel fuel were developed. This design process included securing budgetary quotations from major equipment vendors for reciprocating engines and fuel handling equipment. Preliminary site layouts were generated for each option, along with AACE Class 5 opinions of probable capital cost, in order to support YEC planning activities. The engineering effort also included a preliminary implementation schedule, as expected performance of the plant, and commentary on other plant attributes. Results for this effort are covered in Chapter 3 – Conceptual Design.

2.0 PLANT SITING

The plant siting selection was executed as a mainly desktop study. Stantec carried out site visits for some of the sites and had preliminary conversations with City of Whitehorse and Yukon Government officials concerning planning and zoning regulations as well as land tenure and disposition. Mandatory criteria and desired criteria were confirmed with YEC prior to the selection of sites (Appendix A). These criteria were assembled to create a 'level of importance matrix' for site criteria, which is presented in Table 1.

Table 1 Selected Criteria and Level of Importance

	Low	Medium	High
Greenfield –undisturbed land	X		
Brownfield – previously developed land			X
Proximity to existing YEC generating facilities in Whitehorse		X	
Connected to city services (water and sewer)		X	
Inside city limits	x		
Ease of constructability (laydown area, security, heavy equipment access)		X	
Proximity to residential areas (noise, smell, spill containment)			X
Proximity to YEC transmission/substation			X
Proximity to AEY distribution/substation			X
Opportunity to connect to District Energy System	X		
Accessible directly off Alaska Hwy/Klondike Hwy			X
Commissioner's Land		X	

OCP and Zoning Review City of Whitehorse

The City of Whitehorse has advised that any thermal generation plant must be located on land designated 'Public Utilities' in the Official Community Plan (OCP). It must also be within a PU (Public Utilities) zone in the Zoning Bylaw. Because all existing PU land use and zoning designations are on lands that have existing utility uses, the City has advised that both an OCP and zoning amendment will be required to permit the use of a thermal generation plant on a new site. This is not unexpected as new uses require public input and consideration. The City of Whitehorse is carrying out an OCP review in 2017 and it is our recommendation that YEC engage with the City early to identify and plan for future needs.

PLANT SITING
November 21, 2016

Whitehorse Periphery Area Development Regulations

The Yukon Government administers the zoning of lands in the Whitehorse periphery. Similar to Whitehorse's planning and zoning regulations there are no large sites that are currently identified for thermal energy generation. Public Utilities are a permitted use in most zones and are defined as '*the use of land for a sewerage, water, telecommunications, electricity or transportation systems'.*

2.1 SITE SELECTION

Stantec applied the siting criteria and level importance as determined by YEC and identified four (4) sites for consideration: two (2) within the City of Whitehorse, and two (2) just north of the City of Whitehorse boundaries. A site selection memo was prepared to support YEC's decision on a site for the study. See Appendix B for these documents. Following review of the site selection memo, YEC indicated they would like to further investigate two sites, Site 1 – Whitehorse Landfill and Site 3 – Mayo Road Substation (Takhini S164).

2.1.1 Site 1: City of Whitehorse Landfill

This is a land parcel that is owned by the City of Whitehorse and is located within the area of their existing landfill. The land is appropriately zoned and would not require a public planning process. Information on the potential site is outlined below, with the selection criteria in Table 2, and site photos in Figures 1 and 2.

Owner: City of Whitehorse

Size: A 4 hectare parcel would need to be surveyed out of the larger City of Whitehorse War Eagle Landfill

Tenure opportunity: Long term lease from the City of Whitehorse

OCP Designation: Public Utilities

Zoning: PU - Public Utilities

Table 2 Selection Criteria - Landfill

Criteria	Yes	No
Greenfield – undisturbed land		✓
Brownfield – previously developed land	✓	
Proximity to existing YEC generating facility on Robert Service Way, Whitehorse	8500 m	
Connected to city services (water and sewer)	345 m	✓

2016-007 – THERMAL ENERGY PLANT DEVELOPMENT STUDY – REV. 1

PLANT SITING
November 21, 2016

Criteria	Yes	No
Inside city limits	✓	
Ease of constructability (laydown area, security, heavy equipment access)	✓	
Proximity to residential areas (noise, smell, spill containment)	1400 m	
Proximity to YEC transmission/substation	2500 m	
Proximity to AEY distribution/substation	2500 m	
Opportunity to connect to a DES	✓	910 m
Accessible directly off Alaska Hwy	✓	500 m
Commissioner's Land		✓

Figure 1 Conceptual Map of Potential Site Location (Landfill)

Figure 2 Photo of Potential Plant Location at Landfill

2.1.2 Site 3: Mayo Road Substation - Lot Enlargement

This is a parcel of Vacant Commissioner's land adjacent to the existing Yukon Energy Corporation substation on the Mayo Road, and is within the Mayo Road Area Development Regulations. Information on the potential site is outlined below, with the selection criteria in Table 3, and site photos in Figures 3 and 4.

Owner: Commissioner of Yukon

Size: The existing substation property is not large enough to accommodate the thermal energy plant. However, carving a 4.0 hectare parcel from the Commissioner's land to add to the existing parcel seems to be a reasonable expectation. This additional land is required to maintain a buffer to separate the Agriculture zoned parcel to the north and First Nation Land Use (TKC C-36B) zoned parcel to the south.

Tenure opportunity: Purchase and consolidate with existing parcel

Local Area Planning Zoning Designation: H – Hinterland (Uses include public utilities)

Table 3 Selection Criteria – Takhini Substation

Criteria – Level of Importance in Site Selection	Yes	No
Greenfield – undisturbed land	✓	
Brownfield – previously developed land		✓
Proximity to existing YEC generating facility on Robert Service Way, Whitehorse	21,660 m	
Connected to city services (water and sewer)		✓
Inside city limits		✓
Ease of constructability (laydown area, security, heavy equipment access)	✓	
Proximity to residential areas (noise, smell, spill containment)	260 m	
Proximity to YEC transmission/substation	110 m	
Proximity to AEY distribution/substation	110 m	
Opportunity to connect to a DES		✓
Accessible directly off Alaska Hwy/Klondike Hwy	✓	200 m
Commissioner's Land	✓	

Figure 3 Conceptual Map of Potential Site Location (Takhini)

Figure 4 Photo of Potential Plant Location at Takhini

3.0 CONCEPTUAL DESIGN

Using the two selected sites, Stantec was tasked with the development of conceptual designs for the multiple options desired by YEC. The following sub-sections cover each topic of interest to YEC, and present the results.

3.1 BASIS OF DESIGN

In order to drive the conceptual design and document the assumptions made, a Basis of Design (BOD) document was generated. The BOD considers both sites, both technologies, and three (3) unit capacities, resulting in the twelve (12) options. The BOD is a standalone document containing the site layout drawings and opinions of probable capital costs. Please refer to Appendix D for the full BOD document and supplemental information.

3.2 PRIME MOVERS

A budgetary request for quotation was issued to several prominent engine suppliers in order to validate performance and establish lead times and costing for the units required for the YEC plant configurations. Packages were received, but due to the quick turnaround required, they were not complete and did not address all unit sizes requested. Because of the budgetary nature of the request, detailed price break-outs for specific equipment options of interest were not available. For example, half of the units quoted were supplied with enclosures for outdoor installation. Vendor responses have been provided for YEC to future reference.

Similar to the scope of supply, the unit pricing also varied significantly depending on options included and on the extent of construction and commissioning support embedded in the quotation. Therefore, Stantec relied on in-house data and professional judgement as well as the budgetary quotations to arrive at an appropriate Class 5 opinion of probable cost (OPC). Using the following scope of supply, engine equipment costs utilized are presented in Table 4.

Table 4 Summary of Opinion of Probable Capital Cost

Scope of Supply:	Unit / Fuel Type	Unit Cost (CAD)
Prime Mover	2.5 MW_e / NG	$2.0 M
Generator and Auxiliaries	5.0 MW_e / NG	$4.0 M
Mechanical Auxiliaries (circulating pumps / radiator)	2.5 MW_e / Diesel	$1.5 M
Electrical Control Equipment	5.0 MW_e / Diesel	$3.5 M
Heat Recovery / Rejection		
Engineering / Project Management / Drawings		
Sound Attenuation		

3.3 CONCEPTUAL SITE LAYOUTS

Building on the design characteristics outlined in the BOD in Appendix C, site layout drawings were prepared for each option. To appreciate land requirements, a tentative layout of the generating halls and switchyards, as well as fuel storage requirements have been provided. The site layout drawing is embedded within the BOD document in Appendix D and are presented in two forms for each option. The site layout (or general arrangement) is presented on its own to facilitate review and an understanding of the site itself (see sample in Figure 5) as well as on a second sheet with a satellite image in the background to appreciate its impact to the selected site (see Figure 6). Both drawings we used during the course of the study to finalize design considerations in the BOD as well as complete each options' OPC.

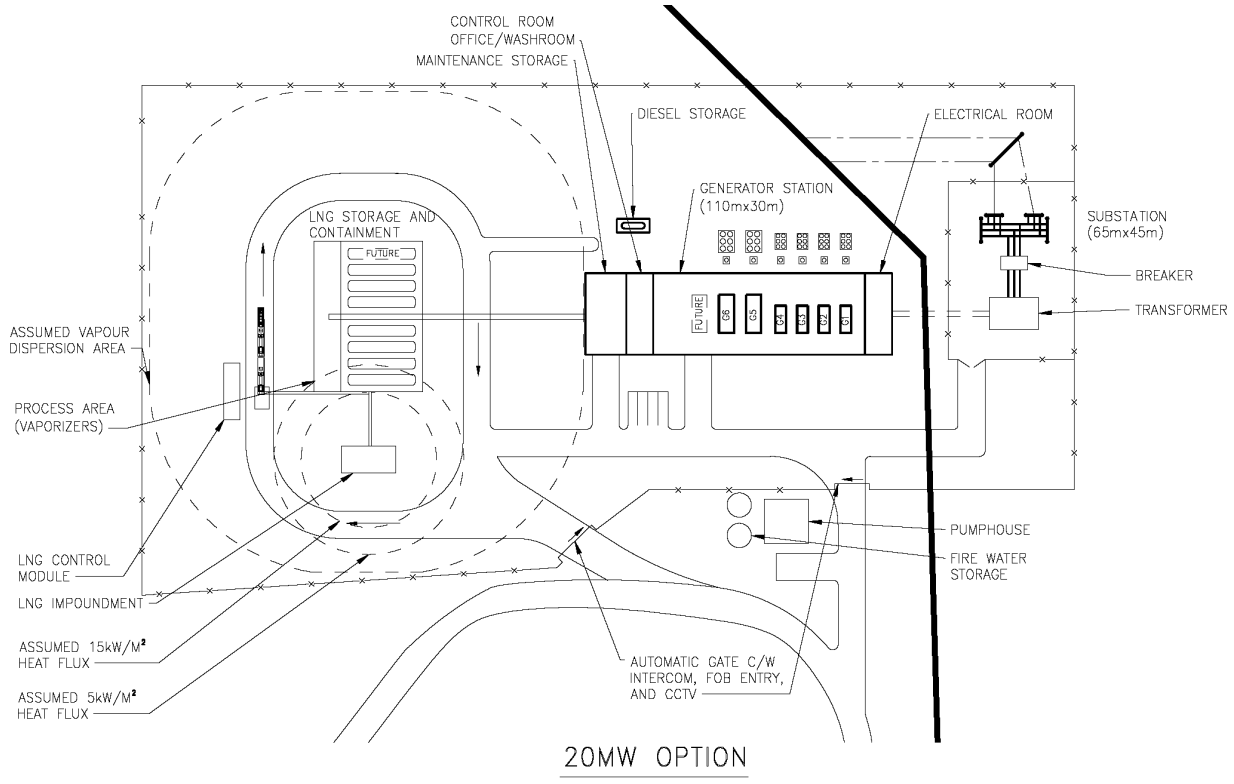

Figure 5 Site Layout Sample for Landfill, 20 MW, LNG (Plant)

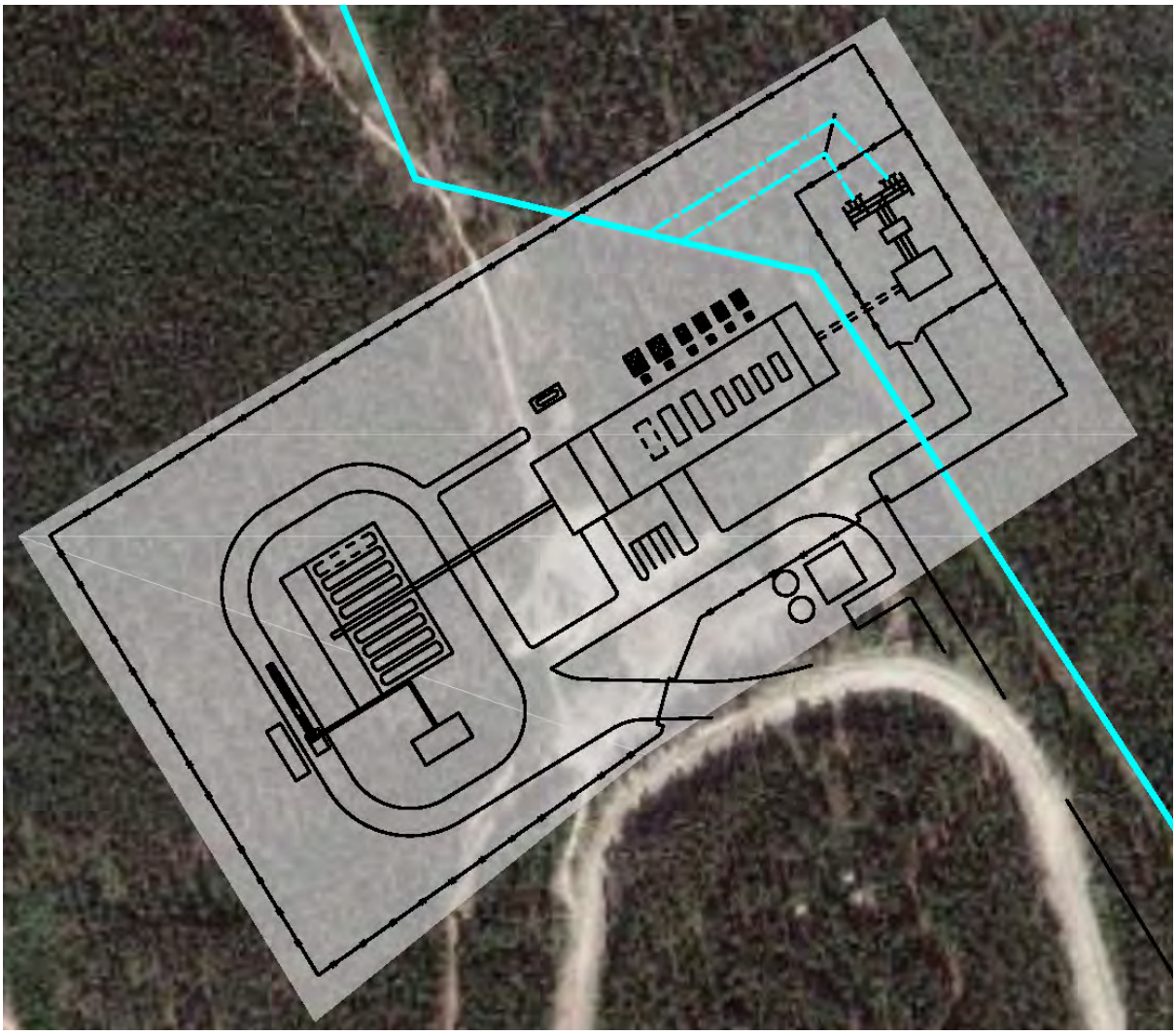

Figure 6 Site Layout Sample for Landfill, 20 MW, LNG (Satellite)

3.4 ENGINE WASTE HEAT RECOVERY, HEAT RATE AND LOAD PICK-UP CAPABILITY

3.4.1 Engine Waste Heat Recovery

A typical reciprocating engine, whether diesel or natural gas, will have a fuel-to-power conversion efficiency based on fuel lower heating value (LHV) and ISO conditions of between 41-48%. The remainder of the fuel energy is rejected as heat in the engine cooling system and the engine exhaust. Most of this 'waste heat' can be recovered and may be sold to heat buildings or provide industrial process heat. Therefore, waste heat recovery should be considered if any significant commercial/industrial heating load is expected near the plant.

Based on the potential site locations selected for the study, there are no existing potential heat customers nearby. Recovered heat can also be transported for use at more distant locations, including for winter site fire water heating. However, this 'district heating' piping is not inexpensive, and an evaluation of district heating network economics is not part of the study.

3.4.2 Heat Rate

Fuel purchases are based on Higher Heating Values (HHV). The difference between the two values is the heat of vaporization of the exhausted water vapor (which is formed during combustion). The ratio of LHV to HHV for natural gas is typically 0.90; and for light or distillate oils is typically 0.93.

Representative heat rates for both diesel and NG reciprocating engines (as provided by Wartsila) are based on Lower Heating Values (LHV) of the fuels. So, suggested heat rates for YEC's financial model are as follows:

For Natural Gas:	7634 Btu/kWh (LHV)/0.90	=	**8842 Btu/Kwh (HHV)**
For Diesel:	7876 Btu/kWh (LHV)/0.93	=	**8469 Btu/kWh (HHV)**

3.4.3 Load Pick-Up Capability

The thermal energy plant would be required to back up existing generation, so would be required to operate continuously in the event of low water (drought) conditions, or intermittently in the event of an outage of a critical unit (n-1), and during a post outage restoration.

As discussed with YEC, diesel and natural gas generators accommodate load fluctuations differently. In general, diesel engines respond better to load changes and are better able to respond to quick electrical load addition.

The performance variation can be depicted in a load application graph as shown in Figure 7 for a sample 'dual-fuel' reciprocating engine. A dual-fuel generator's performance was used to clearly illustrate load step performance based solely on the fuel used, performance will vary by model. The diesel's maximum tolerable instant load step increase is equal or better than the gas engine up to 90% of rated generator load.

Furthermore, considering time step, during operation, the ramp rate on gas would be greater than 50% per minute, but on liquid fuel the operational ramp rate could exceed 100% per minute.

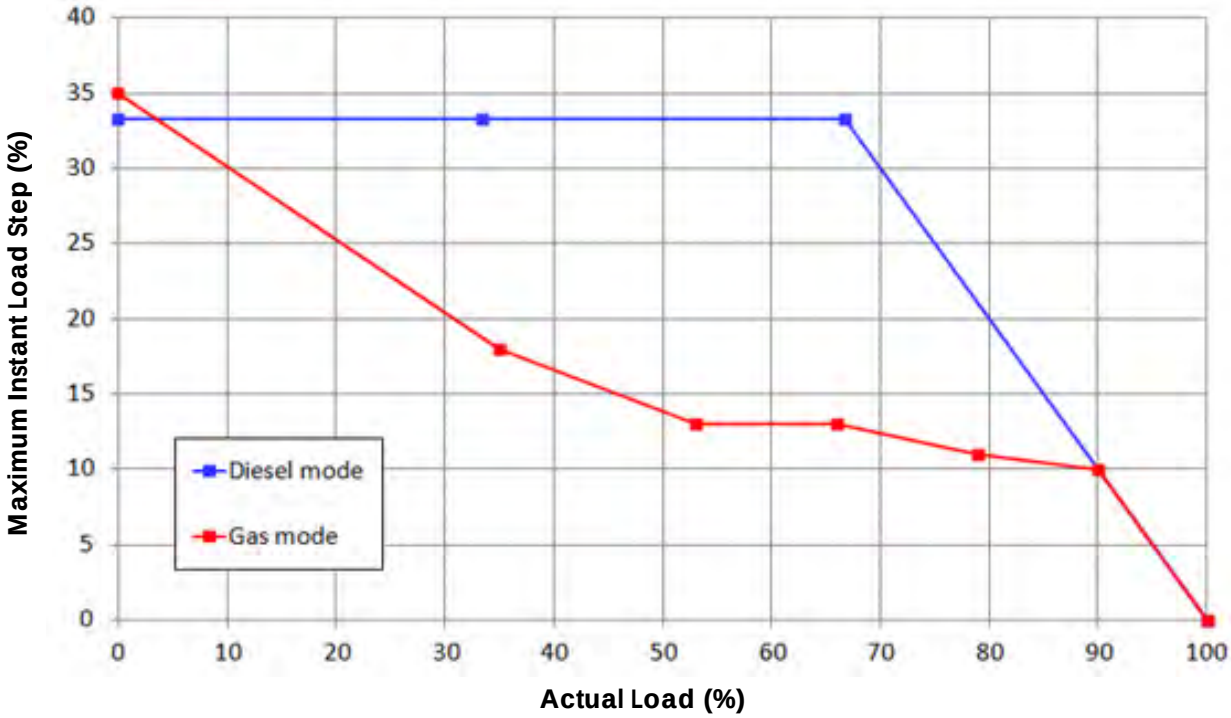

Figure 7 Sample Engine's Maximum Load Step at Varying Loads

3.5 OPINION OF PROBABLE COST

The opinions of probable capital costs (OPC) for the multiple options are outlined in Appendix C as part of the Basis of Design document. A summary of the results of the study are presented in Table 5 for easy reference.

Table 5 Summary of Opinion of Probable Capital Cost

Option #	Fuel Type Natural Gas or Diesel	Site Landfill or Takhini	Plant Capacities 5 MW_e, 10 MW_e, 20 MW_e	Opinion of Probable Capital Cost (OPC)
NG-LF-05	Natural Gas	Landfill	5 MW_e (2x 2.5 MW_e)	$48.6 M
NG-LF-10	Natural Gas	Landfill	10 MW_e (4x 2.5 MW_e)	$66.9 M
NG-LF-20	Natural Gas	Landfill	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$100.1 M
NG-TK-05	Natural Gas	Takhini	5 MW_e (2x 2.5 MW_e)	$48.5 M
NG-TK-10	Natural Gas	Takhini	10 MW_e (4x 2.5 MW_e)	$66.8 M
NG-TK-20	Natural Gas	Takhini	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$100.0 M
DL-LF-05	Diesel	Landfill	5 MW_e (2x 2.5 MW_e)	$32.0 M
DL-LF-10	Diesel	Landfill	10 MW_e (4x 2.5 MW_e)	$42.2 M
DL-LF-20	Diesel	Landfill	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$62.5 M
DL-TK-05	Diesel	Takhini	5 MW_e (2x 2.5 MW_e)	$31.7 M
DL-TK-10	Diesel	Takhini	10 MW_e (4x 2.5 MW_e)	$41.9 M
DL-TK-20	Diesel	Takhini	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$62.2 M

Note that the 10 MW_e Natural Gas options presented result in an OPC of $66.8M - $66.9M ($6.7/MW_e), which compares with a YEC recent LNG plant installed in Whitehorse which was roughly $42M, for 8.8 MW_e ($4.8M/MW_e) using two engines. The existing installation was less costly because existing utilities infrastructure was available at the site and because the generators were installed in weatherproof enclosures instead of in a building.

In detailed design of an LNG plant, attention should be paid to the requirement for a flare stack for commissioning, boil-off gas management and emergencies. There may also be additional O & M costs related to instrumentation, tank and process equipment maintenance.

3.6 OPINION OF PROBABLE O&M COST

Plant operating costs are addressed in discreet categories described below:

Labor - The labor component, excluding fuel cost, is typically the largest cost in an O&M budget. It consists of the salaries and benefits for the plant manager; licensed operators; maintenance staff (mechanical; electrical; and instrumentation techs); plant engineering; and administration staff including safety; purchasing; accounting; etc. The size of the staff can vary significantly depending on the size and complexity of the plant.

For this reciprocating engine plant because of its proximity to other YEC operations in Whitehorse, staff will not be dedicated solely to this plant. Labor costs are therefore expected to be approximately ½ of what they might otherwise be for a standalone plant.

Maintenance and Materials - The cost for maintenance and materials reflects normal daily, weekly, monthly costs for regular plant maintenance.

Environmental Testing - Most environmental operating permits require annual testing for any air, water or waste water discharges from a plant to verify compliance with the permit conditions.

Consumables, Chemicals, & Misc. - The cost of lubricants, oils, chemicals and miscellaneous consumables used during normal plant operation is included in this line item. It also covers the general administrative cost of running the power plant: phones, office supplies, computers, etc.

Major Equipment Repair Reserve Fund - The major equipment in a reciprocating engine plant needs to be overhauled and repaired on a regular basis in accordance with the vendor's recommended procedures. An engine typically has a service life of 100,000 or more operating hours. Wear components such as valves, piston rings and bearings are normally replaced about every three (3) years and a more thorough engine overhaul is carried out two (2) or three (3) times during the life of the engine. During these, the pistons, cylinder heads, piston liners, connecting rods and turbocharger rotors are replaced or overhauled. This reserve fund is primarily associated with the reciprocating engines but could also include other major pieces of equipment. A reserve fund is established so that money is available to cover the significant costs of the equipment overhaul several years in the future.

In lieu of planning and reserving for major equipment overhauls and inspections, owners sometime establish a Long-Term Service Agreement (LTSA) with the reciprocating engine vendor. The LTSA provides annual performance guarantees from the generator supplier as well as responsibility for all reciprocating engine repairs and overhauls. The term of the LTSA can vary from 10 to 20 years (or can be based on operating hours). Note this approach was not taken for this O&M estimate – cost of the packages depend on option/coverage selected and vary significantly by vendor and offering.

The following Table 6 is a summary of estimated O&M costs for an Owner operated reciprocating engine power plant:

Table 6 Opinion of Probable Reciprocating Engine O&M Costs (Excluding Fuel)

Description	5 MW_e	10 MW_e	20 MW_e
Labor	$300,000	$400,000	$500,000
Maintenance & Materials	$80,000	$100,000	$125,000
Major Equipment Repair Fund	$200,000	$300,000	$400,000
Environmental Testing	$40,000	$70,000	$90,000
Consumables, Chemicals, Misc.	$55,000	$65,000	$75,000
Total O&M Estimated Cost*	**$675,000**	**$935,000**	**$1,190,000**

*The estimated cost for O&M reflects the estimated average annual cost. It does not include cost normally incurred by the owner. These costs include insurance; property taxes or asset management fees. It also does not include fees if the O&M is subcontracted out.

3.7 IMPLEMENTATION SCHEDULE

Development of either option on a greenfield site depending on several factors outside YEC's control. Initial planning activities and preliminary engineering need to be further developed to finalize site selection (see implementation schedule in Table 7). With a short-list of sites selected, land negotiations, as well as commencement of the YESAA process will drive the project timeline. Permitting for diesel fuel is expected to be less involved than a new LNG facility, but with the recent LNG installation at the Whitehorse Generating Station, precedence exists for LNG storage and permitting in the Territory. Detailed engineering will need to commence following approval of preliminary engineering activities and YEC go-decision for the project. Engineer will support YESAA activities as well as prepare technical drawings and specifications to support project tendering and/procurement of major equipment. Reciprocating engine lead times require approximately 8 -12 months from receipt of order to delivery to site. Construction and commissioning activities will vary slightly depending on the size of the plant and site accessibility.

Table 7 Implementation Schedule

Task Description	YR1	YR2	YR3	YR4
Planning and Preliminary Engineering				
Environmental Permitting (YESAA) and Site Selection				
Detailed Engineering and Procurement				
Construction				
Start-up & Commissioning				

3.8 YEC PERFORMANCE ATTRIBUTES

A summary table of the performance attributes of the options is presented in Table 8 below. Data provided indicates the high availability and generation capabilities of the technology. YEC is to reconcile final plant capacities to the expected load forecast, in order to determine a true capacity factor for the plant and expected annual energy generation.

The Levelized Cost of Capital (LCOC) for each option has been shown. Financial analysis sheets for each option are included in Appendix C.

Table 8 Performance Attributes by Option

Option #	Installed Capacity [MW_e]	Availability Factor [%]	Maximum Annual Energy [GWh]	Project Life [years]	Opinion of Probable Capital Cost (OPC)	Levelized Cost of Capital (LCOC)
NG-LF-05	5	>95	41.6	20 yr / 60,000 hrs	$48.6 M	$679/kW
NG-LF-10	10	>95	83.2	20 yr / 60,000 hrs	$66.9 M	$467/kW
NG-LF-20	20	>95	166.4	20 yr / 60,000 hrs	$100.1 M	$350/kW
NG-TK-05	5	>95	41.6	20 yr / 60,000 hrs	$48.5 M	$678/kW
NG-TK-10	10	>95	83.2	20 yr / 60,000 hrs	$66.8 M	$466/kW
NG-TK-20	20	>95	166.4	20 yr / 60,000 hrs	$100.0 M	$349/kW
DL-LF-05	5	>95	41,6	20 yr / 60,000 hrs	$32.0 M	$447/kW
DL-LF-10	10	>95	83.2	20 yr / 60,000 hrs	$42.2 M	$295/kW
DL-LF-20	20	>95	166.4	20 yr / 60,000 hrs	$62.5 M	$218/kW
DL-TK-05	5	>95	41,6	20 yr / 60,000 hrs	$31.7 M	$443/kW
DL-TK-10	10	>95	83.2	20 yr / 60,000 hrs	$41.9 M	$293/kW
DL-TK-20	20	>95	166.4	20 yr / 60,000 hrs	$62.2 M	$217/kW

4.0 RISK IDENTIFICATION

As this study was only a desktop effort resulting in a concept design, a series of project risks exist that must be mitigated should any option for a thermal generating station be considered in the future. These initial risks are presented in Table 9 for YEC's consideration.

Table 9 Project Development Risks

Site 1: City of Whitehorse Landfill

No.	Risk Description	Potential Impact
1	Land Tenure	Yukon Energy Corporation currently has no tenure. YEC will need to enter into a long term lease with the City of Whitehorse (City). The City's land disposition process is public and invites comments. Public processes that solicit input always have some risk of local opposition to the project.
2	Access	Yukon Government Highways and Public Works will need to approve access off Alaska Highway. Entrance to the landfill is a fairly steep incline but should not pose a significant issue. The City identified a site behind the landfill as an alternative to the one used in the study for the plant. Increase in truck traffic can be mitigated by securing the site closer to the highway and the existing transmission line.
3	Mineral Claims	There are quartz mining claims on both sites. The subsurface rights are encumbered but should not affect the ability to develop on the surface. Engagement with the claim holder is recommended.

Site 3: Mayo Road Substation - Lot Enlargement

No.	Risk Description	Potential Impact
4	Land Tenure	The site is vacant Commissioners Land. Yukon Energy Corporation currently has no tenure. YEC will need to enter into a long term lease or purchase with Yukon Government. The Yukon Government's land disposition process will trigger a YESAB application which is public and invites

		comments. Public processes that solicit input always have some risk.
5	Adjacent Land Uses	This parcel of land would be situated between a Ta'an Kwäch'än Council (TKC) owned vacant parcel and privately owned agricultural piece of land. TKC future development plans may not be compatible with a thermal generating facility.
6	Land Use and Zoning Designation	The parcel is designated in the Mayo Road Development Area Regulations as Hinterland (H) which allows public utility uses. The existing substation is designated Public Use and Institutional (PI). An argument may be made that a zoning amendment is required. Interpretation of the regulation is a risk.

Fuel Storage and Usage

No.	Risk Description	Potential Impact
7	Diesel fuel option	YEC will need to consider approach to diesel storage, number of tanks, containment, and volume. Study assumed double walled tanks to reduce containment requirements and real estate.
8	LNG fuel option	YEC has recent firsthand experience with the design and permitting constraints associated with LNG. As the site is a greenfield, YEC will have the ability to better arrange tankage to avoid the need for expensive vapour barriers and restriction on road layouts. This should reduce costs and operational issues experienced with the existing plant but will need to be kept at the forefront of design to minimize these impacts while meeting code requirements.
9	Dual fuel	Dual fuel units were not used in the study but provide YEC with an avenue to avoid the issues associated with NG engines poorer load pick-up performance. Fuel blending is also an option. Although operations flexibility would be gained, YEC would have to review fuel storage requirements to have both fuels on site while maintaining code separation requirements.

RISK IDENTIFICATION
November 21, 2016

10	Fuel Procurement	While outside the scope of this study, fuel pricing and security, price hedging, and supply contracts will all impact the project business case and require YEC due diligence. Fuel delivery issues due to weather are also a factor.

Prime Movers

No.	Risk Description	Potential Impact
11	Technology	Reciprocating engines running on either NG or diesel are a mature technology used throughout the continent. Technology risk is minimal. Similarly, auxiliary equipment and infrastructure to support the engines also carry minimal technology risk (transformer, switchgear, controls).
12	Procurement	Procurement processes, cost and schedule control, and ensuring options selected meet the project requirements are main risks with the prime movers. These risks are mitigated with proper planning and engineering to ensure the units selected are fit for purpose and represent the best value for YEC. The project delivery method needs to be determined. Responsibility for project implementation risk can be more easily assigned to 3rd parties under some delivery methods. Whether YEC intends to procure the engine and free-issue to a contractor, or equipment procurement and installation are in a common tender (DB/EPC), remains to be decided, each with their own pros/cons.
13	Enclosures	The study assumes that any option would be executed with a new generating hall to house the units. Alternatively, the project can use stand-alone engine enclosures similar to the existing LNG plant. Future study is needed to properly compare the two options, with input from YEC operations.

General Site

2016-007 – THERMAL ENERGY PLANT DEVELOPMENT STUDY – REV. 1

RISK IDENTIFICATION
November 21, 2016

No.	Risk Description	Potential Impact
14	Safety and Security	Fire protection, fuel system alarms and procedures, site fencing and access, telecom and security, etc. are all critical areas require future study and refinement. Risk in these areas is mitigated with proper planning, assessment, and engineering.

Appendices
November 21, 2016

5.0 APPENDICES

Appendix A Siting Criteria Memo

Appendix B Site Identification and Evaluation Memo

Appendix C Financial Analysis

Appendix D Basis of Design

2016-007 – THERMAL ENERGY PLANT DEVELOPMENT STUDY – REV. 1

November 21, 2016

APPENDIX A

Siting Criteria Memo

Stantec

Memo

To:	Marc-Andre Lavigne Yukon Energy Corporation	From:	Lesley Cabott RPP Stantec
File:	Thermal Energy Plant Development Study: 133547248_21_8	Date:	April 21, 2016

Reference: Thermal Generation Siting Criteria

This memo has been prepared to support the site selection of Yukon Energy Corporation's (YEC) resource planning study of a future thermal generation plant in and/or around Whitehorse. There are some criteria that are mandatory and other criteria that will be preferred by YEC. This memo identifies those items that are mandatory as well as the criteria that YEC may wish to consider. It is the intent of this memo to confirm mandatory criteria and receive direction as to the importance of the other criteria. The feedback we receive will inform the site selection for conceptual design purposes.

OCP AND ZONING REVIEW CITY OF WHITEHORSE

The City of Whitehorse has advised that a thermal generation plant will need to be located on land designated Public Utilities (PU) in the Official Community Plan (OCP) and within a PU zone in the Zoning Bylaw. The existing PU land use and zoning designations are on lands that have existing utility infrastructure – no undeveloped PU land existing today. The City has advised that both an OCP and zoning amendment will be required to permit the use of a thermal generation plant. This is not unexpected as new uses require public input and consideration. The City is carrying out an OCP review in 2017 and it is our recommendation YEC engage with the City early to identify and plan for future needs if a decision is made to pursue a new thermal plant.

WHITEHORSE PERIPHERY AREA DEVELOPMENT REGULATIONS

The Yukon Government administers the zoning of lands in the Whitehorse periphery. Similar to the City planning and zoning regulations, there are no large sites that are currently identified for a thermal generation plant. A rezoning process would also need to be undertaken in the periphery.

SITE CRITERIA THAT WILL BE CONSISTENT FOR ALL SITES (MANDATORY):

As discussed and excluded from our scope of work, any environmental (heritage, archaeology, biophysical, wildlife, water sources/quality, etc.) and socio-economic impact are not included. Our assessment will touch on topics of noise, air quality, and wildlife protected areas as they relate to engine performance and are publically available data but an in-depth site assessment is not included.

DESIRED CRITERIA

In addition to mandatory criteria, several site selection preferences (design criteria) may exist at YEC based on past/recent generation development experience, operational requirements, and current utility needs. Please review the mandatory criteria and confirm and advise as to the importance associated with the desired criteria.

Stantec

April 21, 2016
Marc-Andre Lavigne

Reference: Thermal Generation Siting Criteria

Criteria – level of importance in site selection	Low	Medium	High
Greenfield –undisturbed land			
Brownfield – previously developed land			
Proximity to existing YEC generating facilities in Whitehorse			
Connected to city services (water and sewer)			
Inside City limits			
Ease of constructability (laydown area, security, heavy equipment access, rail siding)			
Proximity to residential areas (noise, smell, spill containment)			
Proximity to YEC transmission/substation			
Proximity to AEY distribution/substation			
Opportunity to connect to a DES			
Accessible directly off Alaska Hwy/Klondike Hwy			
Commissioner's Land			

We are available to discuss and look forward to receiving your direction as soon as possible.

Best regards

STANTEC CONSULTING LTD.

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c. Lee Fleming, Chris van Driel

2016-007 – THERMAL ENERGY PLANT DEVELOPMENT STUDY – REV. 1

November 21, 2016

APPENDIX B

Site Identification and Evaluation Memo

Stantec

Memo

To:	Marc-Andre Lavigne Yukon Energy Corporation	From:	Lesley Cabott, RPP Stantec
File:	Thermal Energy Plant Development Study: 13354728	Date:	May 4, 2016

Reference: Thermal Generation – Site Identification and Evaluation

This memo has been prepared to support the site selection of a future thermal generation plant in and/or around Whitehorse for Yukon Energy Corporation's (YEC) resource planning study, and builds upon the background work and siting criteria outline in Stantec's memo of April 21, 2016. Stantec has reviewed the City of Whitehorse Planning and Zoning bylaws and have met with the Managers of Planning and Engineering to discuss potential sites within the City. We have also reviewed the Whitehorse Periphery Planning and Zoning Regulations including: Mayo Road, Ibex, Hotsprings Road, Golden Horn and Mount Lorne. We met with a representative of the Lands Department at Yukon Government and carried out site visits to sites 1, 3, and 4.

The four sites are discussed below. The feedback we receive from YEC will help us identify the "preferred site" that will be used for conceptual design purposes.

The criteria and their associated level of importance were determined as follows in consultation with YEC:

Criteria – level of importance in site selection	Low	Medium	High
Greenfield –undisturbed land	X		
Brownfield – previously developed land			X
Proximity to existing YEC generating facilities in Whitehorse		X	
Connected to city services (water and sewer)		X	
Inside City limits		X	
Ease of constructability (laydown area, security, heavy equipment access)		X	
Proximity to residential areas (noise, smell, spill containment)			X
Proximity to YEC transmission/substation			X
Proximity to AEY distribution/substation			X
Opportunity to connect to District Energy System	X		
Accessible directly off Alaska Hwy/Klondike Hwy			X
Commissioner's Land		X	

Stantec

Reference: Thermal Generation – Site Identification and Evaluation

SITE 1: CITY OF WHITEHORSE LANDFILL

The City of Whitehorse identified the opportunity to lease a portion of land that is within the area of their existing landfill. The land is appropriately zoned and would not require a public planning process.

Owner: City of Whitehorse

Size: A 4 hectare parcel would need to be surveyed out of the larger City of Whitehorse War Eagle Landfill

Tenure opportunity: Long term lease from the City of Whitehorse

OCP Designation: Public Utilities

Zoning: PU - Public Utilities

Criteria	Yes	No
Greenfield – undisturbed land		✓
Brownfield – previously developed land	✓	
Proximity to existing YEC generating facility on Robert Service Way, Whitehorse	8500 m	
Connected to city services (water and sewer)	345 m	✓
Inside City limits	✓	
Ease of constructability (laydown area, security, heavy equipment access, rail siding)	✓	
Proximity to residential areas (noise, smell, spill containment)	1400 m	
Proximity to YEC transmission/substation	7300 m	
Proximity to AEY distribution/substation	1890 m	
Opportunity to connect to a DES	910 m	
Accessible directly off Alaska Hwy/Klondike Hwy	✓	2200 m (Alaska Hwy)
Commissioner's Land		✓

This site offers opportunities for synergies with waste to energy with waste from Whitehorse landfill.

Stantec

May 4, 2016
Marc-Andre Lavigne

Reference: Thermal Generation – Site Identification and Evaluation

Figure 1: Landfill Potential Site

Figure 2: Landfill Access Road

Stantec

Reference: Thermal Generation – Site Identification and Evaluation

SITE 2: CITY OF WHITEHORSE LIVINGSTONE TRAIL LAGOONS

The City of Whitehorse identified the opportunity to lease a portion of land that is within the area of the Livingstone Trail Environmental Control Facility (sewage lagoon). The land is appropriately zoned and would not require a public planning process.

Owner: City of Whitehorse

Size: A 4 hectare parcel would need to be surveyed out of the lagoon lands

Tenure opportunity: Long term lease from the City of Whitehorse

OCP Designation: Public Utilities

Zoning: PU - Public Utilities

Criteria – level of importance in site selection	Yes	No
Greenfield – undisturbed land	✓	
Brownfield – previously developed land		✓
Proximity to existing YEC generating facility on Robert Service Way, Whitehorse	7,660 m	
Connected to city services (water and sewer)		✓
Inside City limits	✓	
Ease of constructability (laydown area, security, heavy equipment access, rail siding)	✓	
Proximity to residential areas (noise, smell, spill containment)	1,630 m	
Proximity to YEC transmission/substation	1,120 m	
Proximity to AEY distribution/substation	3,800 m	
Opportunity to connect to a DES	12,250 m	
Accessible directly off Alaska Hwy/Klondike Hwy		✓
Commissioner's Land		✓

This site currently has challenges with access. The City is currently doing a planning study that is looking at the timing of development on the east side of the Yukon River and construction of a second crossing. Currently access to the site would be along the Long Lake Road and the Livingstone Trail Road.

Stantec

Reference: Thermal Generation – Site Identification and Evaluation

SITE 3: MAYO ROAD SUBSTATION - LOT ENLARGEMENT

This is a parcel of Vacant Commissioner's land adjacent to the existing Yukon Energy Corporation substation on the Mayo Road within the Mayo Road Area Development Regulations.

Owner: Commissioner of Yukon

Size: There is sufficient area to survey a 4.0 hectare parcel of land from the Commissioner's land to add to the existing parcel and to maintain a buffer to separate the Agriculture zoned parcel to the north and First Nation Land Use (KDFN C- 135B) zoned parcel to the south.

Tenure opportunity: Purchase and consolidate with existing parcel

Local Area Planning Zoning Designation: H – Hinterland (Uses include public utilities)

Criteria – level of importance in site selection	Yes	No
Greenfield – undisturbed land	✓	
Brownfield – previously developed land		✓
Proximity to existing YEC generating facility on Robert Service Way, Whitehorse	21,660 m	
Connected to city services (water and sewer)		✓
Inside City limits		✓
Ease of constructability (laydown area, security, heavy equipment access)	✓	
Proximity to residential areas (noise, smell, spill containment)	260 m	
Proximity to YEC transmission/substation	110 m	
Proximity to AEY distribution/substation	15,090 m	
Opportunity to connect to a DES	N/A	
Accessible directly off Alaska Hwy/Klondike Hwy	✓	200 m off
Commissioner's Land	✓	

The Yukon Government Land application process is a public process and includes First Nation and public consultation which can take up to six months. Spot land applications are not accepted for this area; however this can be considered a lot enlargement. This land will not require rezoning. Definition from Area Development Regulations: *'public utility' means the use of land for sewerage, water, telecommunications, electricity, or transportation systems.*

Reference: Thermal Generation – Site Identification and Evaluation

Figure 3: Takhini Substation Potential Site

Figure 4: Takhini Substation Access Road

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Reference: Thermal Generation – Site Identification and Evaluation

SITE 4: COPPER MINE SITE – CITY OF WHITEHORSE

This is a parcel of Commissioner's land currently within the City of Whitehorse, between the Mt. Sima Road and the Copper Haul Road.

Owner: Commissioner of Yukon

Size: There is sufficient area to survey a 4.0 hectare parcel of land from the Commissioner's land

Tenure opportunity: Purchase/lease

OCP Designation: IH – Industrial Heavy

Zoning: FP – Future Planning

Criteria – level of importance in site selection	Yes	No
Greenfield – undisturbed land	✓	
Brownfield – previously developed land		✓
Proximity to existing YEC generating facility on Robert Service Way, Whitehorse	6,400 m	
Connected to city services (water and sewer)		✓
Inside City limits		✓
Ease of constructability (laydown area, security, heavy equipment access)	✓	
Proximity to residential areas (noise, smell, spill containment)	1,640 m	
Proximity to YEC transmission/substation	6,400 m	
Proximity to AEY distribution/substation	2,790 m	
Opportunity to connect to a DES	N/A	
Accessible directly off Alaska Hwy/Klondike Hwy	✓	2,720 m (Alaska Hwy)
Commissioner's Land	✓	

There are quartz mining claims on the parcel which is consistent with many areas of Whitehorse. The Yukon Government Lands Department advised the subsurface claims should not affect the development of the generating facility; some consultation with claim holders may be required. The Manager of Planning with the City has indicated that an OCP amendment to PU may not be required.

Stantec

May 4, 2016
Marc-Andre Lavigne

Reference: Thermal Generation – Site Identification and Evaluation

Figure 5: Whitehorse Copper Potential Site 1

Figure 6: Whitehorse Copper Potential Site 2

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Reference: Thermal Generation – Site Identification and Evaluation

Figure 7: Whitehorse Copper Access Road (off Mt. Sima Road)

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Reference: Thermal Generation – Site Identification and Evaluation

SUMMARY OF RESULTS

The results from the preliminary site assessments are summarized in the table below:

Criteria	Priority	Site 1: Landfill	Site 2: Lagoon	Site 3: Takhini Substation	Site 4: Whitehorse Copper
Greenfield	L	No	No	Yes	Yes
Brownfield	H	Yes	Yes	No	No
Proximity to YEC Generation Plant	M	8.5 km	7.7 km	> 2 km	6.4 km
Serviced by City	M	No	No	No	No
Inside City limits	M	Yes	Yes	No	Yes
Constructability (laydown area, security, access)	M	Excellent	Good	Good	Excellent
Proximity to residence	H	None	> 1.5 km	~ 300 m	> 1.5 km
Proximity to YEC transmission line	H	7.3 km	1.1 km	110 m	6.4 km
Proximity to AEY distribution line	H	1.9 km	3.8 km	15 km	2.8 km
Opportunities for DES	L	1 km	None	None	None
Access to Alaska/Klondike Hwy	H	Good	Poor	Excellent	Excellent
Commissioner's Land	M	No	No	Yes	Yes
Mining Claims	L	Yes	No	No	Yes
Correct Zoning	M	Yes	Yes	Yes	No

Please review the potential sites and let us know YEC's preferred option. We are available to discuss and look forward to receiving your direction.

STANTEC CONSULTING LTD.

Lesley Cabott RPP
Senior Planner
Phone: (709) 576-1458
Fax: (709) 576-2126
Lesley.Cabott@stantec.com

Attachment: Conceptual Options Map

YEC THERMAL SITING STUDY
CONCEPTUAL LOCATIONS

April 6, 2018

Stantec

A-2913

2016-007 – THERMAL ENERGY PLANT DEVELOPMENT STUDY – REV. 1

November 21, 2016

APPENDIX C

Financial Analysis

Financial Analysis **Option # NG-LF-05**

			MW	Winter MW
Capital ($000)	2016	$48,600	5.0	5.0
Capital ($000)	2020	$52,606		
Energy		41.6 GWh/yr		
Capacity Factor		(95%CF)		
Fuel	2016			
O&M (Fixed)	2016	675.0 $000/yr		
O&M (Variable)	2016	0.0 $/MWh		

Load Growth	0.0%
	41.6 GW.h

Life	20 years
Salvage cost	0%

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, Option # NG-LF-05

Life Cycle Cost (2016$000's)	60,435
Depreciation & Return Cost (2016$000's)	50,411
Project LCOE ($/kWh)	$0.098
Project LCOC ($/MW)	$678,898
Project LCOC ($/kW)	$678.90

Year	Option # NG-LF-05					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	49,976	2,630	2,795	731	6,156	15
2021	47,346	2,630	2,652	745	6,028	14
2022	44,715	2,630	2,509	760	5,899	14
2023	42,085	2,630	2,365	775	5,771	14
2024	39,455	2,630	2,222	791	5,643	14
2025	36,824	2,630	2,079	807	5,516	13
2026	34,194	2,630	1,935	823	5,388	13
2027	31,564	2,630	1,792	839	5,261	13
2028	28,933	2,630	1,649	856	5,135	12
2029	26,303	2,630	1,505	873	5,009	12
2030	23,673	2,630	1,362	891	4,883	12
2031	21,042	2,630	1,218	908	4,757	11
2032	18,412	2,630	1,075	927	4,632	11
2033	15,782	2,630	932	945	4,507	11
2034	13,152	2,630	788	964	4,383	11
2035	10,521	2,630	645	983	4,259	10
2036	7,891	2,630	502	1,003	4,135	10
2037	5,261	2,630	358	1,023	4,012	10
2038	2,630	2,630	215	1,044	3,889	9
2039	0	2,630	72	1,064	3,766	9
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2064						
PV		33,284	21,282	10,851	65,417	
$2015PV		30,750	19,661	10,024	60,435	
					99,029	

Year from In-service	Annual Energy GW.h, Option # NG-LF-05	Annual Winter Capacity MW, Option # NG-LF-05
1	41.61	5.00
2	41.61	5.00
3	41.61	5.00
4	41.61	5.00
5	41.61	5.00
6	41.61	5.00
7	41.61	5.00
8	41.61	5.00
9	41.61	5.00
10	41.61	5.00
11	41.61	5.00
12	41.61	5.00
13	41.61	5.00
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Net Present Value	527	
Total energy	832	
Avg Annual energy	42	

Financial Analysis **Option # NG-LF-10**

			MW	Winter MW
Capital ($000)	2016	**$66,900**	**10.0**	**10.0**
Capital ($000)	2020	**$72,415**		
Energy		**83.2**	GWh/yr	
Capacity Factor		**(95%CF)**		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	**935.0**	$000/yr	**83.2** GW.h
O&M (Variable)	2016	**0.0**	$/MWh	

Life	**20** years
Salvage cost	0%

Weighted Average Cost of Capital	**5.45%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.38%**

LCOE and LCOC with 5.45% WACC, Option # NG-LF-10

Life Cycle Cost (2016$000's)	**83,278**
Depreciation & Return Cost (2016$000's)	**69,393**
Project LCOE ($/kWh)	**$0.067**
Project LCOC ($/MW)	**$467,266**
Project LCOC ($/kW)	**$467.27**

Year	Option # NG-LF-10					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	68,794	3,621	3,848	1,012	8,481	10
2021	65,173	3,621	3,651	1,032	8,304	10
2022	61,553	3,621	3,453	1,053	8,127	10
2023	57,932	3,621	3,256	1,074	7,951	10
2024	54,311	3,621	3,059	1,096	7,775	9
2025	50,690	3,621	2,861	1,117	7,599	9
2026	47,070	3,621	2,664	1,140	7,424	9
2027	43,449	3,621	2,467	1,163	7,250	9
2028	39,828	3,621	2,269	1,186	7,076	9
2029	36,207	3,621	2,072	1,210	6,902	8
2030	32,587	3,621	1,875	1,234	6,729	8
2031	28,966	3,621	1,677	1,258	6,556	8
2032	25,345	3,621	1,480	1,284	6,384	8
2033	21,724	3,621	1,283	1,309	6,213	7
2034	18,104	3,621	1,085	1,335	6,041	7
2035	14,483	3,621	888	1,362	5,871	7
2036	10,862	3,621	691	1,389	5,701	7
2037	7,241	3,621	493	1,417	5,531	7
2038	3,621	3,621	296	1,445	5,362	6
2039	0	3,621	99	1,474	5,194	6
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PV		45,817	29,296	15,030	90,143	
$2015PV		42,328	27,065	13,885	83,278	
					136,471	

Year from In-service	Annual Energy GW.h, Option # NG-LF-10	Annual Winter Capacity MW, Option # NG-LF-10
1	83.22	10.00
2	83.22	10.00
3	83.22	10.00
4	83.22	10.00
5	83.22	10.00
6	83.22	10.00
7	83.22	10.00
8	83.22	10.00
9	83.22	10.00
10	83.22	10.00
11	83.22	10.00
12	83.22	10.00
13	83.22	10.00
14	83.22	10.00
15	83.22	10.00
16	83.22	10.00
17	83.22	10.00
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Net Present Value	1,053	
Total energy	1,664	
Avg Annual energy	83	

Financial Analysis **Option # NG-LF-20**

			MW	Winter MW
Capital ($000)	2016	**$100,100**	**20.0**	**20.0**
Capital ($000)	2020	**$108,351**		
Energy		**166.4**	GWh/yr	
Capacity Factor		**(95%CF)**		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	**1190.0**	$000/yr	**166.4** GW.h
O&M (Variable)	2016	**0.0**	$/MWh	

Life	**20** years
Salvage cost	0%

Weighted Average Cost of Capital	**5.45%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.38%**

LCOE and LCOC with 5.45% WACC, Option # NG-LF-20

Life Cycle Cost (2016$000's)	**121,502**
Depreciation & Return Cost (2016$000's)	**103,830**
Project LCOE ($/kWh)	**$0.049**
Project LCOC ($/MW)	**$349,577**
Project LCOC ($/kW)	**$349.58**

Year	Option # NG-LF-20					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	102,934	5,418	5,758	1,288	12,463	7
2021	97,516	5,418	5,462	1,314	12,194	7
2022	92,099	5,418	5,167	1,340	11,925	7
2023	86,681	5,418	4,872	1,367	11,656	7
2024	81,264	5,418	4,576	1,394	11,388	7
2025	75,846	5,418	4,281	1,422	11,121	7
2026	70,428	5,418	3,986	1,451	10,854	7
2027	65,011	5,418	3,691	1,480	10,588	6
2028	59,593	5,418	3,395	1,509	10,322	6
2029	54,176	5,418	3,100	1,539	10,057	6
2030	48,758	5,418	2,805	1,570	9,793	6
2031	43,341	5,418	2,510	1,602	9,529	6
2032	37,923	5,418	2,214	1,634	9,266	6
2033	32,505	5,418	1,919	1,666	9,003	5
2034	27,088	5,418	1,624	1,700	8,741	5
2035	21,670	5,418	1,329	1,734	8,480	5
2036	16,253	5,418	1,033	1,768	8,219	5
2037	10,835	5,418	738	1,804	7,959	5
2038	5,418	5,418	443	1,840	7,700	5
2039	0	5,418	148	1,877	7,442	4
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PV		68,555	43,834	19,129	131,518	
$2015PV		63,334	40,496	17,672	121,502	
					198,700	

Year from In-service	Annual Energy GW.h, Option # NG-LF-20	Annual Winter Capacity MW, Option # NG-LF-20
1	166.44	20.00
2	166.44	20.00
3	166.44	20.00
4	166.44	20.00
5	166.44	20.00
6	166.44	20.00
7	166.44	20.00
8	166.44	20.00
9	166.44	20.00
10	166.44	20.00
11	166.44	20.00
12	166.44	20.00
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Net Present Value	2,106	
Total energy	3,329	
Avg Annual energy	166	

Financial Analysis **Option # NG-TK-05**

			MW	Winter MW
Capital ($000)	2016	$48,500	5.0	5.0
Capital ($000)	2020	$52,498		
Energy		41.6	GWh/yr	
Capacity Factor		(95%CF)		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	675.0	$000/yr	**41.6** GW.h
O&M (Variable)	2016	0.0	$/MWh	

Life	20 years
Salvage cost	0%

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, Option # NG-TK-05

Life Cycle Cost (2016$000's)	60,331
Depreciation & Return Cost (2016$000's)	50,307
Project LCOE ($/kWh)	$0.098
Project LCOC ($/MW)	$677,501
Project LCOC ($/kW)	$677.50

Year	Option # NG-TK-05					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	49,873	2,625	2,790	731	6,145	15
2021	47,248	2,625	2,647	745	6,017	14
2022	44,623	2,625	2,503	760	5,889	14
2023	41,998	2,625	2,360	775	5,761	14
2024	39,373	2,625	2,217	791	5,633	14
2025	36,749	2,625	2,074	807	5,506	13
2026	34,124	2,625	1,931	823	5,379	13
2027	31,499	2,625	1,788	839	5,252	13
2028	28,874	2,625	1,645	856	5,126	12
2029	26,249	2,625	1,502	873	5,000	12
2030	23,624	2,625	1,359	891	4,875	12
2031	20,999	2,625	1,216	908	4,749	11
2032	18,374	2,625	1,073	927	4,624	11
2033	15,749	2,625	930	945	4,500	11
2034	13,124	2,625	787	964	4,376	11
2035	10,500	2,625	644	983	4,252	10
2036	7,875	2,625	501	1,003	4,129	10
2037	5,250	2,625	358	1,023	4,006	10
2038	2,625	2,625	215	1,044	3,883	9
2039	0	2,625	72	1,064	3,761	9
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PV		33,216	21,238	10,851	65,305	
$2015PV		30,686	19,621	10,024	60,331	
					98,862	

Year from In-service	Annual Energy GW.h, Option # NG-TK-05	Annual Winter Capacity MW, Option # NG-TK-05
1	41.61	5.00
2	41.61	5.00
3	41.61	5.00
4	41.61	5.00
5	41.61	5.00
6	41.61	5.00
7	41.61	5.00
8	41.61	5.00
9	41.61	5.00
10	41.61	5.00
11	41.61	5.00
12	41.61	5.00
13	41.61	5.00
14	41.61	5.00
15	41.61	5.00
16	41.61	5.00
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Net Present Value	527	
Total energy	832	
Avg Annual energy	42	

Financial Analysis **Option # NG-TK-10**

			MW	Winter MW
Capital ($000)	2016	**$66,800**	**10.0**	**10.0**
Capital ($000)	2020	**$72,306**		
Energy		**83.2**	GWh/yr	
Capacity Factor		**(95%CF)**		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	**935.0**	$000/yr	**83.2** GW.h
O&M (Variable)	2016	**0.0**	$/MWh	

Life	**20** years
Salvage cost	0%

Weighted Average Cost of Capital	**5.45%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.38%**

LCOE and LCOC with 5.45% WACC, Option # NG-TK-10

Life Cycle Cost (2016$000's)	**83,174**
Depreciation & Return Cost (2016$000's)	**69,289**
Project LCOE ($/kWh)	**$0.067**
Project LCOC ($/MW)	**$466,568**
Project LCOC ($/kW)	**$466.57**

Year	Option # NG-TK-10					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	68,691	3,615	3,842	1,012	8,470	10
2021	65,076	3,615	3,645	1,032	8,293	10
2022	61,460	3,615	3,448	1,053	8,116	10
2023	57,845	3,615	3,251	1,074	7,940	10
2024	54,230	3,615	3,054	1,096	7,765	9
2025	50,615	3,615	2,857	1,117	7,590	9
2026	46,999	3,615	2,660	1,140	7,415	9
2027	43,384	3,615	2,463	1,163	7,241	9
2028	39,769	3,615	2,266	1,186	7,067	8
2029	36,153	3,615	2,069	1,210	6,894	8
2030	32,538	3,615	1,872	1,234	6,721	8
2031	28,923	3,615	1,675	1,258	6,549	8
2032	25,307	3,615	1,478	1,284	6,377	8
2033	21,692	3,615	1,281	1,309	6,205	7
2034	18,077	3,615	1,084	1,335	6,034	7
2035	14,461	3,615	887	1,362	5,864	7
2036	10,846	3,615	690	1,389	5,694	7
2037	7,231	3,615	493	1,417	5,525	7
2038	3,615	3,615	296	1,445	5,356	6
2039	0	3,615	99	1,474	5,188	6
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PV		45,749	29,252	15,030	90,031	
$2015PV		42,265	27,024	13,885	83,174	
					136,304	

Year from In-service	Annual Energy GW.h, Option # NG-TK-10	Annual Winter Capacity MW, Option # NG-TK-10
1	83.22	10.00
2	83.22	10.00
3	83.22	10.00
4	83.22	10.00
5	83.22	10.00
6	83.22	10.00
7	83.22	10.00
8	83.22	10.00
9	83.22	10.00
10	83.22	10.00
11	83.22	10.00
12	83.22	10.00
13	83.22	10.00
14	83.22	10.00
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16	83.22	10.00
17	83.22	10.00
18	83.22	10.00
19	83.22	10.00
20	83.22	10.00
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Net Present Value	1,053	
Total energy	1,664	
Avg Annual energy	83	

Financial Analysis **Option # NG-TK-20**

			MW	Winter MW
Capital ($000)	2016	**$100,000**	**20.0**	**20.0**
Capital ($000)	2020	**$108,243**		
Energy		**166.4**	GWh/yr	
Capacity Factor		**(95%CF)**		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	**1190.0**	$000/yr	**166.4** GW.h
O&M (Variable)	2016	**0.0**	$/MWh	

Life	**20** years
Salvage cost	0%

Weighted Average Cost of Capital	**5.45%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.38%**

LCOE and LCOC with 5.45% WACC, Option # NG-TK-20

Life Cycle Cost (2016$000's)	**121,398**
Depreciation & Return Cost (2016$000's)	**103,726**
Project LCOE ($/kWh)	**$0.049**
Project LCOC ($/MW)	**$349,227**
Project LCOC ($/kW)	**$349.23**

Year	Option # NG-TK-20					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	102,831	5,412	5,752	1,288	12,452	7
2021	97,419	5,412	5,457	1,314	12,183	7
2022	92,007	5,412	5,162	1,340	11,914	7
2023	86,595	5,412	4,867	1,367	11,646	7
2024	81,182	5,412	4,572	1,394	11,378	7
2025	75,770	5,412	4,277	1,422	11,111	7
2026	70,358	5,412	3,982	1,451	10,845	7
2027	64,946	5,412	3,687	1,480	10,579	6
2028	59,534	5,412	3,392	1,509	10,313	6
2029	54,122	5,412	3,097	1,539	10,049	6
2030	48,709	5,412	2,802	1,570	9,784	6
2031	43,297	5,412	2,507	1,602	9,521	6
2032	37,885	5,412	2,212	1,634	9,258	6
2033	32,473	5,412	1,917	1,666	8,996	5
2034	27,061	5,412	1,622	1,700	8,734	5
2035	21,649	5,412	1,327	1,734	8,473	5
2036	16,236	5,412	1,032	1,768	8,213	5
2037	10,824	5,412	737	1,804	7,953	5
2038	5,412	5,412	442	1,840	7,694	5
2039	0	5,412	147	1,877	7,436	4
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PV		68,486	43,790	19,129	131,405	
$2015PV		63,271	40,455	17,672	121,398	
					198,533	

Year from In-service	Annual Energy GW.h, Option # NG-TK-20	Annual Winter Capacity MW, Option # NG-TK-20
1	166.44	20.00
2	166.44	20.00
3	166.44	20.00
4	166.44	20.00
5	166.44	20.00
6	166.44	20.00
7	166.44	20.00
8	166.44	20.00
9	166.44	20.00
10	166.44	20.00
11	166.44	20.00
12	166.44	20.00
13	166.44	20.00
14	166.44	20.00
15	166.44	20.00
16	166.44	20.00
17	166.44	20.00
18	166.44	20.00
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Net Present Value	2,106	
Total energy	3,329	
Avg Annual energy	166	

Financial Analysis **Option # DL-LF-05**

			MW	Winter MW
Capital ($000)	2016	**$32,000**	**5.0**	**5.0**
Capital ($000)	2020	**$34,638**		
Energy		**41.6**	GWh/yr	
Capacity Factor		**(95%CF)**		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	**675.0**	$000/yr	**41.6** GW.h
O&M (Variable)	2016	**0.0**	$/MWh	

Life	**20** years
Salvage cost	0%

Weighted Average Cost of Capital	**5.45%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.38%**

LCOE and LCOC with 5.45% WACC, Option # DL-LF-05

Life Cycle Cost (2016$000's)	**43,217**
Depreciation & Return Cost (2016$000's)	**33,192**
Project LCOE ($/kWh)	**$0.070**
Project LCOC ($/MW)	**$447,011**
Project LCOC ($/kW)	**$447.01**

Year	Option # DL-LF-05					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	32,906	1,732	1,841	731	4,303	10
2021	31,174	1,732	1,746	745	4,223	10
2022	29,442	1,732	1,652	760	4,144	10
2023	27,710	1,732	1,557	775	4,065	10
2024	25,978	1,732	1,463	791	3,986	10
2025	24,246	1,732	1,369	807	3,907	9
2026	22,515	1,732	1,274	823	3,829	9
2027	20,783	1,732	1,180	839	3,751	9
2028	19,051	1,732	1,085	856	3,673	9
2029	17,319	1,732	991	873	3,596	9
2030	15,587	1,732	897	891	3,519	8
2031	13,855	1,732	802	908	3,443	8
2032	12,123	1,732	708	927	3,366	8
2033	10,391	1,732	614	945	3,291	8
2034	8,659	1,732	519	964	3,215	8
2035	6,928	1,732	425	983	3,140	8
2036	5,196	1,732	330	1,003	3,065	7
2037	3,464	1,732	236	1,023	2,991	7
2038	1,732	1,732	142	1,044	2,917	7
2039	0	1,732	47	1,064	2,843	7
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2064						
PV		21,916	14,013	10,851	46,779	
$2015PV		20,247	12,946	10,024	43,217	
					71,268	

Year from In-service	Annual Energy GW.h, Option # DL-LF-05	Annual Winter Capacity MW, Option # DL-LF-05
1	41.61	5.00
2	41.61	5.00
3	41.61	5.00
4	41.61	5.00
5	41.61	5.00
6	41.61	5.00
7	41.61	5.00
8	41.61	5.00
9	41.61	5.00
10	41.61	5.00
11	41.61	5.00
12	41.61	5.00
13	41.61	5.00
14	41.61	5.00
15	41.61	5.00
16	41.61	5.00
17	41.61	5.00
18	41.61	5.00
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Net Present Value	527	
Total energy	832	
Avg Annual energy	42	

Financial Analysis **Option # DL-LF-10**

			MW	Winter MW
Capital ($000)	2016	$42,200	10.0	10.0
Capital ($000)	2020	$45,679		
Energy		83.2	GWh/yr	
Capacity Factor		(95%CF)		
Fuel	2016			
O&M (Fixed)	2016	935.0	$000/yr	
O&M (Variable)	2016	0.0	$/MWh	
Life		20	years	
Salvage cost		0%		

Load Growth 0.0%

83.2 GW.h

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, Option # DL-LF-10

Life Cycle Cost (2016$000's)	57,658
Depreciation & Return Cost (2016$000's)	43,772
Project LCOE ($/kWh)	$0.047
Project LCOC ($/MW)	$294,748
Project LCOC ($/kW)	$294.75

Year	Option # DL-LF-10					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	43,395	2,284	2,427	1,012	5,723	7
2021	41,111	2,284	2,303	1,032	5,619	7
2022	38,827	2,284	2,178	1,053	5,515	7
2023	36,543	2,284	2,054	1,074	5,412	7
2024	34,259	2,284	1,929	1,096	5,309	6
2025	31,975	2,284	1,805	1,117	5,206	6
2026	29,691	2,284	1,680	1,140	5,104	6
2027	27,407	2,284	1,556	1,163	5,002	6
2028	25,123	2,284	1,431	1,186	4,901	6
2029	22,839	2,284	1,307	1,210	4,800	6
2030	20,555	2,284	1,183	1,234	4,700	6
2031	18,271	2,284	1,058	1,258	4,600	6
2032	15,988	2,284	934	1,284	4,501	5
2033	13,704	2,284	809	1,309	4,402	5
2034	11,420	2,284	685	1,335	4,304	5
2035	9,136	2,284	560	1,362	4,206	5
2036	6,852	2,284	436	1,389	4,109	5
2037	4,568	2,284	311	1,417	4,012	5
2038	2,284	2,284	187	1,445	3,916	5
2039	0	2,284	62	1,474	3,821	5
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PV		28,901	18,479	15,030	62,411	
$2015PV		26,700	17,072	13,885	57,658	
					95,164	

Year from In-service	Annual Energy GW.h, Option # DL-LF-10	Annual Winter Capacity MW, Option # DL-LF-10
1	83.22	10.00
2	83.22	10.00
3	83.22	10.00
4	83.22	10.00
5	83.22	10.00
6	83.22	10.00
7	83.22	10.00
8	83.22	10.00
9	83.22	10.00
10	83.22	10.00
11	83.22	10.00
12	83.22	10.00
13	83.22	10.00
14	83.22	10.00
15	83.22	10.00
16	83.22	10.00
17	83.22	10.00
18	83.22	10.00
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Net Present Value	1,053	
Total energy	1,664	
Avg Annual energy	83	

Financial Analysis **Option # DL-LF-20**

			MW	Winter MW
Capital ($000)	2016	$62,500	20.0	20.0
Capital ($000)	2020	$67,652		
Energy		166.4	GWh/yr	
Capacity Factor		(95%CF)		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	1190.0	$000/yr	**166.4** GW.h
O&M (Variable)	2016	0.0	$/MWh	

Life	20 years
Salvage cost	0%

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, Option # DL-LF-20

Life Cycle Cost (2016$000's)	82,501
Depreciation & Return Cost (2016$000's)	64,829
Project LCOE ($/kWh)	$0.033
Project LCOC ($/MW)	$218,267
Project LCOC ($/kW)	$218.27

Year	Option # DL-LF-20					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	64,269	3,383	3,595	1,288	8,266	5
2021	60,887	3,383	3,411	1,314	8,107	5
2022	57,504	3,383	3,226	1,340	7,949	5
2023	54,122	3,383	3,042	1,367	7,791	5
2024	50,739	3,383	2,857	1,394	7,634	5
2025	47,356	3,383	2,673	1,422	7,478	4
2026	43,974	3,383	2,489	1,451	7,322	4
2027	40,591	3,383	2,304	1,480	7,167	4
2028	37,209	3,383	2,120	1,509	7,012	4
2029	33,826	3,383	1,936	1,539	6,858	4
2030	30,443	3,383	1,751	1,570	6,704	4
2031	27,061	3,383	1,567	1,602	6,551	4
2032	23,678	3,383	1,383	1,634	6,399	4
2033	20,296	3,383	1,198	1,666	6,247	4
2034	16,913	3,383	1,014	1,700	6,096	4
2035	13,530	3,383	830	1,734	5,946	4
2036	10,148	3,383	645	1,768	5,796	3
2037	6,765	3,383	461	1,804	5,647	3
2038	3,383	3,383	277	1,840	5,499	3
2039	0	3,383	92	1,877	5,351	3
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PV		42,804	27,369	19,129	89,302	
$2015PV		39,544	25,285	17,672	82,501	
					135,820	

Year from In-service	Annual Energy GW.h, Option # DL-LF-20	Annual Winter Capacity MW, Option # DL-LF-20
1	166.44	20.00
2	166.44	20.00
3	166.44	20.00
4	166.44	20.00
5	166.44	20.00
6	166.44	20.00
7	166.44	20.00
8	166.44	20.00
9	166.44	20.00
10	166.44	20.00
11	166.44	20.00
12	166.44	20.00
13	166.44	20.00
14	166.44	20.00
15	166.44	20.00
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Net Present Value	2,106	
Total energy	3,329	
Avg Annual energy	166	

Financial Analysis **Option # DL-TK-05**

			MW	Winter MW
Capital ($000)	2016	**$31,700**	**5.0**	**5.0**
Capital ($000)	2020	**$34,313**		
Energy		**41.6**	GWh/yr	
Capacity Factor		**(95%CF)**		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	**675.0**	$000/yr	**41.6** GW.h
O&M (Variable)	2016	**0.0**	$/MWh	

Life	**20** years
Salvage cost	0%

Weighted Average Cost of Capital	**5.45%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.38%**

LCOE and LCOC with 5.45% WACC, Option # DL-TK-05

Life Cycle Cost (2016$000's)	**42,905**
Depreciation & Return Cost (2016$000's)	**32,881**
Project LCOE ($/kWh)	**$0.069**
Project LCOC ($/MW)	**$442,820**
Project LCOC ($/kW)	**$442.82**

Year	Option # DL-TK-05					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	32,597	1,716	1,823	731	4,270	10
2021	30,882	1,716	1,730	745	4,191	10
2022	29,166	1,716	1,636	760	4,112	10
2023	27,450	1,716	1,543	775	4,034	10
2024	25,735	1,716	1,449	791	3,956	10
2025	24,019	1,716	1,356	807	3,878	9
2026	22,304	1,716	1,262	823	3,801	9
2027	20,588	1,716	1,169	839	3,724	9
2028	18,872	1,716	1,075	856	3,647	9
2029	17,157	1,716	982	873	3,571	9
2030	15,441	1,716	888	891	3,495	8
2031	13,725	1,716	795	908	3,419	8
2032	12,010	1,716	701	927	3,344	8
2033	10,294	1,716	608	945	3,269	8
2034	8,578	1,716	514	964	3,194	8
2035	6,863	1,716	421	983	3,120	7
2036	5,147	1,716	327	1,003	3,046	7
2037	3,431	1,716	234	1,023	2,972	7
2038	1,716	1,716	140	1,044	2,899	7
2039	0	1,716	47	1,064	2,827	7
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PV		21,710	13,881	10,851	46,442	
$2015PV		20,057	12,824	10,024	42,905	
					70,766	

Year from In-service	Annual Energy GW.h, Option # DL-TK-05	Annual Winter Capacity MW, Option # DL-TK-05
1	41.61	5.00
2	41.61	5.00
3	41.61	5.00
4	41.61	5.00
5	41.61	5.00
6	41.61	5.00
7	41.61	5.00
8	41.61	5.00
9	41.61	5.00
10	41.61	5.00
11	41.61	5.00
12	41.61	5.00
13	41.61	5.00
14	41.61	5.00
15	41.61	5.00
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Net Present Value	527	
Total energy	832	
Avg Annual energy	42	

Financial Analysis **Option # DL-TK-10**

			MW	Winter MW
Capital ($000)	2016	**$41,900**	**10.0**	**10.0**
Capital ($000)	2020	**$45,354**		
Energy		**83.2**	GWh/yr	
Capacity Factor		**(95%CF)**		**Load Growth**
Fuel	2016			0.0%
O&M (Fixed)	2016	**935.0**	$000/yr	**83.2** GW.h
O&M (Variable)	2016	**0.0**	$/MWh	

Life	**20** years
Salvage cost	0%

Weighted Average Cost of Capital	**5.45%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.38%**

LCOE and LCOC with 5.45% WACC, Option # DL-TK-10

Life Cycle Cost (2016$000's)	**57,347**
Depreciation & Return Cost (2016$000's)	**43,461**
Project LCOE ($/kWh)	**$0.046**
Project LCOC ($/MW)	**$292,653**
Project LCOC ($/kW)	**$292.65**

Year	Option # DL-TK-10					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	43,086	2,268	2,410	1,012	5,690	7
2021	40,819	2,268	2,286	1,032	5,586	7
2022	38,551	2,268	2,163	1,053	5,483	7
2023	36,283	2,268	2,039	1,074	5,381	6
2024	34,015	2,268	1,916	1,096	5,279	6
2025	31,748	2,268	1,792	1,117	5,177	6
2026	29,480	2,268	1,668	1,140	5,076	6
2027	27,212	2,268	1,545	1,163	4,975	6
2028	24,945	2,268	1,421	1,186	4,875	6
2029	22,677	2,268	1,298	1,210	4,775	6
2030	20,409	2,268	1,174	1,234	4,676	6
2031	18,142	2,268	1,051	1,258	4,577	5
2032	15,874	2,268	927	1,284	4,478	5
2033	13,606	2,268	803	1,309	4,380	5
2034	11,338	2,268	680	1,335	4,283	5
2035	9,071	2,268	556	1,362	4,186	5
2036	6,803	2,268	433	1,389	4,090	5
2037	4,535	2,268	309	1,417	3,994	5
2038	2,268	2,268	185	1,445	3,899	5
2039	0	2,268	62	1,474	3,804	5
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2064						
PV		28,696	18,348	15,030	62,074	
$2015PV		26,510	16,951	13,885	57,347	
					94,663	

Year from In-service	Annual Energy GW.h, Option # DL-TK-10	Annual Winter Capacity MW, Option # DL-TK-10
1	83.22	10.00
2	83.22	10.00
3	83.22	10.00
4	83.22	10.00
5	83.22	10.00
6	83.22	10.00
7	83.22	10.00
8	83.22	10.00
9	83.22	10.00
10	83.22	10.00
11	83.22	10.00
12	83.22	10.00
13	83.22	10.00
14	83.22	10.00
15	83.22	10.00
16	83.22	10.00
17	83.22	10.00
18	83.22	10.00
19	83.22	10.00
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Net Present Value	1,053	
Total energy	1,664	
Avg Annual energy	83	

Financial Analysis **Option # DL-TK-20**

			MW	Winter MW
Capital ($000)	2016	$62,200	20.0	20.0
Capital ($000)	2020	$67,327		
Energy		166.4	GWh/yr	
Capacity Factor		(95%CF)		
Fuel	2016			
O&M (Fixed)	2016	1190.0	$000/yr	
O&M (Variable)	2016	0.0	$/MWh	

Load Growth	0.0%
	166.4 GW.h

Life	20 years
Salvage cost	0%

Weighted Average Cost of Capital	5.45%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.38%

LCOE and LCOC with 5.45% WACC, Option # DL-TK-20

Life Cycle Cost (2016$000's)	82,190
Depreciation & Return Cost (2016$000's)	64,517
Project LCOE ($/kWh)	$0.033
Project LCOC ($/MW)	$217,219
Project LCOC ($/kW)	$217.22

Year	Option # DL-TK-20					
	Year-End Balance $000	Depr $000	Return $000	O&M $000	Total $000	cents/ kW.h
2020	63,961	3,366	3,578	1,288	8,232	5
2021	60,595	3,366	3,394	1,314	8,074	5
2022	57,228	3,366	3,211	1,340	7,917	5
2023	53,862	3,366	3,027	1,367	7,761	5
2024	50,495	3,366	2,844	1,394	7,604	5
2025	47,129	3,366	2,660	1,422	7,449	4
2026	43,763	3,366	2,477	1,451	7,294	4
2027	40,396	3,366	2,293	1,480	7,139	4
2028	37,030	3,366	2,110	1,509	6,985	4
2029	33,664	3,366	1,926	1,539	6,832	4
2030	30,297	3,366	1,743	1,570	6,679	4
2031	26,931	3,366	1,559	1,602	6,527	4
2032	23,565	3,366	1,376	1,634	6,376	4
2033	20,198	3,366	1,193	1,666	6,225	4
2034	16,832	3,366	1,009	1,700	6,075	4
2035	13,465	3,366	826	1,734	5,926	4
2036	10,099	3,366	642	1,768	5,777	3
2037	6,733	3,366	459	1,804	5,629	3
2038	3,366	3,366	275	1,840	5,481	3
2039	0	3,366	92	1,877	5,335	3
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2063						
2064						
PV		42,598	27,237	19,129	88,965	
$2015PV		39,354	25,163	17,672	82,190	
					135,318	

Year from In-service	Annual Energy GW.h, Option # DL-TK-20	Annual Winter Capacity MW, Option # DL-TK-20
1	166.44	20.00
2	166.44	20.00
3	166.44	20.00
4	166.44	20.00
5	166.44	20.00
6	166.44	20.00
7	166.44	20.00
8	166.44	20.00
9	166.44	20.00
10	166.44	20.00
11	166.44	20.00
12	166.44	20.00
13	166.44	20.00
14	166.44	20.00
15	166.44	20.00
16	166.44	20.00
17	166.44	20.00
18	166.44	20.00
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Net Present Value	2,106	
Total energy	3,329	
Avg Annual energy	166	

2016-007 – THERMAL ENERGY PLANT DEVELOPMENT STUDY – REV. 1

November 21, 2016

APPENDIX D

Basis of Design

Basis of Design (BOD)
Thermal Energy Plant Study

Prepared for:
Yukon Energy Corporation
Whitehorse, Yukon

Prepared by:
Stantec Consulting Ltd.
845 Prospect Street
Fredericton, NB E3B 2T7

Project File: 133547248_6_2

August 5, 2016

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BASIS OF DESIGN (BOD)
THERMAL ENERGY PLANT STUDY

Table of Contents

Section Page

1.0 INTRODUCTION 1.1

2.0 DETAILED PROJECT SCOPE DEFINITION 2.1
2.1 CIVIL / STRUCTURAL 2.1
2.2 MECHANICAL / MAJOR EQUIPMENT 2.2
2.3 ELECTRICAL 2.4
2.4 MISCELLANEOUS CONSTRUCTION DIRECTS 2.5

3.0 DETAILED BASIS OF ESTIMATE 3.1
3.1 ENGINEERING 3.1
3.2 PROCUREMENT 3.1
3.3 PRODUCTIVITY FACTORS 3.1
3.4 CONSTRUCTION 3.2
3.5 INDIRECT CONSTRUCTION COSTS 3.2
3.5.1 Construction Staff & Consultants 3.2
3.5.2 Commissioning Costs 3.2
3.5.3 Escalation Costs 3.2
3.5.4 Capital Spares 3.2
3.5.5 Indirects Specifically Not Included 3.2

4.0 OPINION OF PROBABLE CAPITAL COST 4.1
4.1 CAPITAL COST RISK ANALYSIS 4.1

5.0 APPENDICES 5.1

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BASIS OF DESIGN (BOD)
THERMAL ENERGY PLANT STUDY

1.0 Introduction

Design scope for this study effort was broken down by major discipline to support design decisions and discussions to-date. The following document is considered the Basis of Design (BOD) for the study and provides the overall conceptual considerations given to the multiple options and sites.

In general, the plant was to be a stand-alone, greenfield installation adjacent to brownfield sites, but not to be supported by any current YEC infrastructure (i.e., near existing Whitehorse Generating Station). It was desired to site the plant within the Whitehorse area or within a 25 km boundary outside city limits, as well as near suitable infrastructure for interconnection (i.e., existing substations/T&D lines).

The study considered plant options and sites as outlined in Table 1.0 to provide YEC with multiple scenarios for consideration during its resource planning exercise. This resulted in twelve (12) independent options for consideration and AACE Class 5 opinions of probable capital costs.

Table 1.0 – Summary Options and Sites

Fuel Type	Site	Plant Capacities		
Natural Gas or Diesel	**Whitehorse Landfill or Takhini Substation (S164)**	**5 MW_e** (2x 2.5 MW_e)	**10 MW_e** (4x 2.5 MW_e)	**20 MW_e** (4x 2.5 MW_e, 2x 5 MW_e)

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THERMAL ENERGY PLANT STUDY

2.0 Detailed Project Scope Definition

2.1 CIVIL / STRUCTURAL

The civil/structural scope includes:

- Greenfield site (YEC – April 12, 2016 (Kick-off)):
  - Plant will be new, not located near to the existing Whitehorse plant (brownfield sites adjacent to assumed plant locations).
  - Concept layouts completed to allow for up to 20 MW_e plant, allowing for smaller plants to be easily incorporated.
  - Concept design assumed reciprocating engines will be installed inside a generating hall (YEC – April 20, 2016). It is recognized that containerized/enclosures are a possibility to be evaluated in future engineering design efforts (similar to existing YEC LNG plant).
- Site Work including:
  - Clearing and grubbing overall site.
  - Site grading including road and parking preparation.
  - Site drainage and culverts.
  - Base, sub-base, and asphalt for site roads and parking areas, including improvements to access roads from main highway (i.e., upgrading Takhini gated entrance and new road to plant, widening and strengthening landfill access road/hill).
  - Foundation excavation and preparation for structures and slabs.
  - New septic system for plant washrooms and facilities.
  - Site fencing and security - motorized vehicle gates (two gates), separate substation fenced area. Fencing assumes YEC standard 8 ft. chain linked fence with angular barb wire. As per plant layouts, fencing extends beyond assumed vapour dispersion area of the LNG plant to avoid use of vapour fencing. Future study is required to confirm extent of vapour cloud. The current 60 m allowance around impoundment areas is based on a worst case scenario from existing LNG plant modeling. Fencing for diesel options provides at least a 15 m buffer from plant equipment.
- Concrete Work:
  - LNG fuel storage area to meet CSA Z276-15:
    - LNG tank, process area, and truck unloading containment pads.
    - Open trenching to impoundment area.
    - Impoundment sized in excess of 110% of largest tank + 10% (or 50 cm) for snow/rain collection.
    - LNG tankage located outside 15 kW/m^2 assumed heat flux zone. Radii used for heat flux zones based on worse case scenarios from existing LNG plant modelling. New plant will vary based on site specific characteristics.

- Thickened slabs for generator foundations.
- Equipment foundations for: stack and silencers, radiators, transformers, breaker, and steel structures.
- LNG cases include aboveground pipe bridge from LNG process area to generating station. Diesel options use underground double walled pipes connecting the tank farm pump house to the generating station.

- Pre-engineered building unit costs are based on previous work in Whitehorse area and territory. Unit price includes: Building steel, insulated walls, insulated roof, doors, slab and concrete footings. Equipment within the building or building services are not included in the unit cost.
- Allowance for building Internals including Interior rooms & sanitary (washroom).
- Fire protection loop is based on using water storage for site wide protection. Options exist for wells instead of storage, and for a potential hybrid system, which can be investigated in future studies. Current water storage for fire protection system incorporates:
  - Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal).
  - Fire water pump house (electric and diesel driven fire pumps, building).
  - Fire Loop (allowance) & Recirculation Pumps.
  - Fire Hydrants.

Civil/structural assessment will be based on: area/unit factors, recent Whitehorse projects, and parametric techniques.

2.2 MECHANICAL / MAJOR EQUIPMENT

The mechanical/process as well as major equipment scope includes:

- The generating stations are designed for the dedicated use of one fuel supply. Plants were either LNG/NG or diesel. Blending or dual fuel units were not to be considered, though some vendor's engines are dual fuel capable.
  Desired plant capacities:
  - 5 MW_e nominal:
    - 2 small engines (~2.5 MW_e).
  - 10 MW_e nominal:
    - 4 small engines (~2.5 MW_e).
  - 20 MW_e nominal:
    - 4 small engines (~2.5 MW_e).
    - 2 larger engines (~5 MW_e).
  - Standard vendor submissions included the following as a minimum. Most submissions received did not provide sufficient breakdown in cost, and typically included enclosures, stack heat recovery, site services, testing, and commissioning:
    - Prime Mover.
    - Generator and Auxiliaries.
    - Mechanical Auxiliaries (circulating pumps / radiator).
    - Electrical and Control Equipment.
    - Heat Recovery / Rejection.

    - Engineering / Project Management / Drawings.
    - Sound Attenuation.
- Fuel Delivery and Storage:
    - YEC requested Stantec to allow for 7-days of fuel storage on-site using horizontal tanks.
    - For LNG cases, the following equipment was scaled from YEC's previous LNG project since LNG vendors did not respond to RFQs:
        - LNG storage tanks: 1x 150 m^3 (usable) vacuum jacketed, horizontal storage tank (number of tanks depending on plant capacity).
        - Vaporizers.
        - LNG storage infrastructure, truck unloading station, piping, and infrastructure.
        - Transportation.
    - For diesel cases, pricing for common tank sizes were used and incorporates double wall containment to mitigate the need for dykes or berms. Future study into the desired approach for a diesel tank farm should consider custom sized double wall tanks, single wall tanks with secondary containment, larger single tank instead of horizontal tankage. OPC includes:
        - Diesel storage tanks: Double Walled (100% secondary containment, standard 75,000 L design).
        - Diesel truck unloading and pump house, underground containment tank, sump and lines.
        - Transportation.
- General mechanical and process equipment were based on fuel type and plant capacity (number of units). Allowances were made for larger system to support the overall pricing. Internal fire protection would tie into new fire water loop and include building sprinklers and local protection equipment. Mechanical scope of work includes:
    - Fuel System Piping (from fuel storage, building internal).
    - Glycol Heating System (including unit heaters, electric & diesel boiler).
    - Generating Station HVAC (electric unit heaters, building and combustion ventilation).
    - Allowance for Building Services / Plumbing.
    - Allowance for Lube / Waste Oil System.
    - Continuous Emissions Monitoring System.
    - Instrument and Plant Compressed Air Systems.
    - Generating Station Sprinkler System, extinguisher, fire protection equipment.

Mechanical/process assessment will be based on: area/unit factors, recent Whitehorse projects, and parametric techniques.

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THERMAL ENERGY PLANT STUDY

2.3 ELECTRICAL

The EI&C scope of work includes:

- Pole line brought to the local substation or nearest distribution line at 34.5 kV (Site 1 – S170 McIntyre, Site 3 – S164 Takhini) (YEC – May 16, 2016). Two circuits 10 MW_e circuits assumed for each 20 MW_e site at 10 MW_e each, otherwise one circuit assumed.
- Major equipment:
  - New engines to generate at 4,160V (YEC – April 21, 16).
  - Generator Step up Transformer - 34.5 kV high side, generator bus voltage on low side, +/- 5% off load taps.
  - 34.5 kV incoming breaker.
  - 34.5 kV vertical break, vertical mounted disconnect switch.
  - Medium voltage cable between generator step up transformer and generator switchgear.
  - Bus work / Dead end structure at substation at thermal plant.
  - VTs/surge arrestor and station service transformers.
- Generator Substation:
  - Ground Grid.
  - Substation Fence.
  - Cable and conduit.
  - Cable trench.
- Inside Generator Building Electrical Room:
  - Transformer protection and control panel.
  - 34.5 kV line protection panel.
  - Metering panel.
  - 125 VDC Station service battery.
- The plant control system will be a distributed control system (DCS), with local PLC control for various systems as appropriate.
- Allowance for station service transformer and associated equipment (MCC, etc.).
- Allowance for site wide grounding grid.
- Allowances for plant communication and security, including:
  - Roadway / Site Lighting.
  - CCTV Security and Integration to System Control Centre.
  - Fire and Gas Alarm Systems.
  - Communications (fibre, CAT5, telephone).
- Allowance for Uninterruptible Power Supply (UPS) system and black start genset.
- 34.5 kV Interconnection - poles, conductor, hardware, deadends.
- Allowances will be made for building services, lighting, fire alarms, receptacles, etc.

EI&C assessment will be based on: area/unit factors, recent Whitehorse projects, and parametric techniques.

2.4 MISCELLANEOUS CONSTRUCTION DIRECTS

Most construction directs will be accounted for in a blended labor rate. This would include small tools and consumables. Allowances for required equipment rentals used as part of a normal installation are included in the blended labor rate. Supervision, crew trailer, meals & accommodations for out of territory staff, and personal PPE are also included.

Freight is included in the material and equipment pricing, unless otherwise noted.

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3.0 Detailed Basis of Estimate

The following sub-sections outline assumptions related to direct and indirect costs for the project as it is understood today. These will be carried forward into the Opinion of Capital Cost (OPC) and presented in the draft study report.

3.1 ENGINEERING

A preliminary engineering allowance of $400,000 was carried which would include generating a feasibility study design and Class 3 OPC for project appropriations (option to conduct study in two phases also exists, with pre-feasibility study for a Class 4 OPC). A detailed engineering allowance is 8% of capital will be included to cover detailed engineering, schedule and cost control.

3.2 PROCUREMENT

Major equipment is assumed to be purchased by YEC and supplied to the installation contractor on site. In this particular study, that would include the reciprocating engines, auxiliaries, switchgear, the step-up transformer, transfer switches, and other vendor supplied equipment. This approach is advantageous in that:

- It ensures adherence to the utility standards for equipment where many options and additions are commonly available.
- It does not delegate away the responsibility of expediting these items to site. By maintaining responsibility, the Owner can exercise greater control of delivery on these critical items.
- It avoids the standard contractor markup of 10-15% (or more) being added to large value line items.

All other items, including piping, cable, cable tray, and all other commodity items required for the installation shall be supplied by the contractor(s) as part of their lump sum installation pricing. This eliminates the need for utility engineers, managers, or consultants to be responsible or concerned with inventory levels of items that are extremely hard to track on a busy construction site.

3.3 PRODUCTIVITY FACTORS

Labour factor adjustments were be applied to the OPC based on the following:

- Work in Whitehorse as it applies to accessing supplies and skilled labour.
- Estimated inventory levels at local supply houses.
- Working outdoors or in non-serviced building in Whitehorse, Yukon weather.

- Productivity was applied as a factor to labour or embedded in allowance made depending on the line item.

3.4 CONSTRUCTION

This OPC is based on the following sources of data for labor and materials:

- In-house databases built from historical or manufacturer's listed prices.
- Direct contact with vendors for indicative pricing of reciprocating engine and auxiliaries (including fuel tankage).
- NECA (National Electrical Contractors Association) Manual of Labor Units for specific items covered by that publication.
- Historical labor costs for other items not specifically listed or requiring special consideration.

3.5 INDIRECT CONSTRUCTION COSTS

At this stage of study and classification of the OPC, indirect costs are assigned as a percentage of expected direct costs based on previous experience, industry norms, and Stantec professional judgement.

3.5.1 Construction Staff & Consultants

An allowance of 2.5% of capital will be carried for an on-site construction manager. An allowance of 1% of capital will be carried for site engineering services to support construction.

3.5.2 Commissioning Costs

Commissioning costs will be carried as 1.5% of capital. This includes allowances to bring vendor representatives to site.

3.5.3 Escalation Costs

An escalation allowance of 3.5% will be allowed based on lead time required before construction begins.

3.5.4 Capital Spares

A capital spares allowance of 2% of the major equipment cost will be included.

3.5.5 Indirects Specifically Not Included

The indirect costs associated with the following are typically not considered and are assumed to be supplied by Owner. At YEC's request, an 18% factor of direct costs will be assigned to these services based on recent utility experience:

- Security.

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- Lock-out tag-out (LOTO) coordination.
- Waste removal.
- Snow removal.
- Warehousing and utilities including temporary power supply.
- Temporary construction lighting.
- Taxes.
- Interest charges during construction.
- Land acquisition and zoning.
- Environmental studies, YESAB assessment and all permitting.
- Owner's administration costs, including:
  - Legal fees.
  - Insurance.
  - Salaries & expenses of Owner's project staff.
  - Allowance for operators hours & fuel costs during training, commissioning, and start up.
  - Special costs to dispose from site construction waste.

4.0 Opinion of Probable Capital Cost

The Opinion of Probable Capital Cost (OPC) for the study is in line with an AACE Class 5 estimate, following a level of engineering project definition of 0 – 2%. From AACE, "Class 5 estimates are prepared for any number of strategic business planning purposes...typical accuracy ranges for Class 5 estimates are - 20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination". Given the expected level of effort for this study, an order of magnitude estimate of +50%/-30% is expected. Full line item OPCs are attached in Appendix A.

Table 2.0 – Summary of Opinion of Probable Capital Cost

Option #	Fuel Type Natural Gas or Diesel	Site Landfill or Takhini	Plant Capacities 5 MW_e, 10 MW_e, 20 MW_e	Opinion of Probable Capital Cost (OPC)
NG-LF-05	Natural Gas	Landfill	5 MW_e (2x 2.5 MW_e)	$48.6 M
NG-LF-10	Natural Gas	Landfill	10 MW_e (4x 2.5 MW_e)	$66.9 M
NG-LF-20	Natural Gas	Landfill	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$100.1 M
NG-TK-05	Natural Gas	Takhini	5 MW_e (2x 2.5 MW_e)	$48.5 M
NG-TK-10	Natural Gas	Takhini	10 MW_e (4x 2.5 MW_e)	$66.8 M
NG-TK-20	Natural Gas	Takhini	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$100.0 M
DL-LF-05	Diesel	Landfill	5 MW_e (2x 2.5 MW_e)	$32.0 M
DL-LF-10	Diesel	Landfill	10 MW_e (4x 2.5 MW_e)	$42.2 M
DL-LF-20	Diesel	Landfill	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$62.5 M
DL-TK-05	Diesel	Takhini	5 MW_e (2x 2.5 MW_e)	$31.7 M
DL-TK-10	Diesel	Takhini	10 MW_e (4x 2.5 MW_e)	$41.9 M
DL-TK-20	Diesel	Takhini	20 MW_e (4x 2.5 MW_e, 2x 5 MW_e)	$62.2 M

4.1 CAPITAL COST RISK ANALYSIS

No detailed risk analysis (Monte Carlo) is planned for the OPC. A contingency of 20% will be allocated.

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5.0 Appendices

Appendix A Opinions of Probable Capital Cost

Appendix B Concept Layouts

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APPENDIX A

Opinions of Probable Capital Cost

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
NG-LF-05: LNG - Landfill - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**15,628 hrs**	**$1,868,080**	**$7,374,763**	**$17,061,163**	**$4,400,750**	**$48,592,020**
-	1	-	Major Equipment	6,448 hrs	$709,280	$673,000	$13,460,000	$150,000	$14,992,280
-	2	-	General Civil	00 hrs	$0	$3,370,450	$807,500	$0	$4,177,950
-	3	-	Buildings and Structures	00 hrs	$0	$1,478,913	$0	$4,200,000	$5,678,913
-	4	-	Mechanical and Process	4,143 hrs	$455,693	$112,500	$1,413,750	$0	$1,981,943
-	5	-	Electrical, Instrumentation & Controls	5,037 hrs	$604,089	$1,739,900	$1,110,713	$0	$3,454,702
-	**6**	-	**Sub Total Directs**	15,628 hrs	**$1,769,063**	**$7,374,763**	**$16,791,963**	**$4,350,000**	**$30,285,788**
-	7	-	Preliminary Engineering for Budget Approval (Class 3)	-	-	-	-	-	$400,000
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$2,422,863
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$1,060,003
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$454,287
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$99,017	-	-	$50,750	$149,767
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$269,200	-	$269,200
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$5,451,442
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$99,017**	**$0**	**$269,200**	**$50,750**	**$10,207,562**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$8,098,670

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
NG-LF-05: LNG - Landfill - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**6,448**		**709,280**		**673,000**		**13,460,000**		**150,000**	**14,992,280**
	1			**Generating Station**					0		0		0		0		0	0
	2			NG fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	100,000	200,000	2,000,000	4,000,000		0	4,566,080
	3			Transportation	2	ea			0		0		0		0	75,000	150,000	150,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**LNG Tank Farm**					0		0		0		0		0	0
	13			LNG storage tanks: 1x 150 m3 (usable) vacuum jacketed, horizontal storage tank	2	ea	240	1.30	624	110.00	68,640	37,500	75,000	750,000	1,500,000		0	1,643,640
	13			Storage Infrastructure	1	ea	480	1.30	624	110.00	68,640	43,250	43,250	865,000	865,000		0	976,890
	14			Vaporizers	2	ea	480	1.30	1,248	110.00	137,280	95,750	191,500	1,915,000	3,830,000		0	4,158,780
	15			LNG truck unloading station, piping, and infrastructure	1	ea	480	1.30	624	110.00	68,640	163,250	163,250	3,265,000	3,265,000		0	3,496,890
	16			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
NG-LF-05: LNG - Landfill - 5 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,370,450**		**807,500**		**0**	**4,177,950**
	1			Clearing & Grubbing	6.5	ha			0		0	$30,000	195,000		0		0	195,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	6,500	m^3			0		0	$15	97,500		0		0	97,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	4,950	tonne			0		0	$35	173,250		0		0	173,250
	8			Granular Sub-Base - 300mm	9,900	tonne			0		0	$18	178,200		0		0	178,200
	9			Asphalt - (Base and Seal)	3,150	tonne			0		0	$150	472,500		0		0	472,500
	10			Fencing (8ft, angular razor wire)	1,100	m			0		0	$300	330,000		0		0	330,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			**FIRE WATER**					**0**		**0**		**1,350,000**		**807,500**		**0**	**2,157,500**
	16			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	17			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	18			Fire Loop (allowance) & Recirc Pumps	1,500	m			0		0	$300	450,000		50,000		0	500,000
	19			Fire Hydrants	15	ea.			0		0		0	10,500	157,500		0	157,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
NG-LF-05: LNG - Landfill - 5 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**1,478,913**		**0**		**4,200,000**	**5,678,913**
	1			**FUEL STORAGE**					**0**		**0**		**759,600**		**0**		**0**	**759,600**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 8 m x 10 m x 0.3 m	24	m^3			0		0	1,500	36,000		0		0	36,000
	4			Containment Sump					0		0		0		0		0	0
	5			Base 10 m x 20 m x 0.3 m	60	m^3			0		0	1,500	90,000		0		0	90,000
	6			Walls 60 m x 2 m x 0.3 m	36	m^3			0		0	1,500	54,000		0		0	54,000
	7			LNG Control Module					0		0		0		0		0	0
	8			Base 6 m x 22 m x 0.3 m	40	m^3			0		0	1,500	59,400		0		0	59,400
	9			Tank Containment					0		0		0		0		0	0
	10			Concrete pad 25 m x 40 m x 0.3 m	300	m^3			0		0	1,500	450,000		0		0	450,000
	11			Containment Curb 130 m x 0.3 m x 0.2 m	8	m^3			0		0	1,500	11,700		0		0	11,700
	12			Concrete Trenching					0		0		0		0		0	0
	13			Base 60 m x 0.5 m x 0.3 m	9	m^3			0		0	1,500	13,500		0		0	13,500
	14			Walls 120 m x 1 m x 0.25 m	30	m^3			0		0	1,500	45,000		0		0	45,000
	15			**GENERATOR HALL**					**0**		**0**		**114,225**		**0**		**4,200,000**	**4,314,225**
	16			Pre-engineered Building					0		0		0		0		0	0
	17			Building Size 25 m x 70 m	1,750	m^2			0		0		0		0	2,400	4,200,000	4,200,000
	18			Generator Foundation					0		0		0		0		0	0
	19			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 2	40	m^3			0		0	1,500	60,000		0		0	60,000
	20			Generator Stack Foundation					0		0		0		0		0	0
	21			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 2	4	m^3			0		0	1,500	5,625		0		0	5,625
	22			Diesel Storage Tank					0		0		0		0		0	0
	23			Base 5 m x 12 m x 0.3 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	24			Radiator Foundation					0		0		0		0		0	0
	25			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 2	14	m^3			0		0	1,500	21,600		0		0	21,600
	26			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	27			Transformer					0		0		0		0		0	0
	28			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	29			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	30			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	31			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	32			Breaker					0		0		0		0		0	0
	33			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500
	34			**OTHER**					**0**		**0**		**236,088**		**0**		**0**	**236,088**
	35			Pipe Bridge 115 m Long					0		0		0		0		0	0
	36			Weight of Steel per Meter 72 kg	8,280	kg			0		0	15	124,200		0		0	124,200
	37			Pipe Bridge Foundation (14 total)					0		0		0		0		0	0
	38			Footing 4 m x 3 m x 0.3 m @ 14 locations	50	m^3			0		0	1,500	75,600		0		0	75,600
	39			Pier 0.6 m x 0.6 m x 2.4 m @ 28 locations	24	m^3			0		0	1,500	36,288		0		0	36,288

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
NG-LF-05: LNG - Landfill - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,143**		**455,693**		**112,500**		**1,413,750**		**0**	**1,981,943**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	2	lot	107	1.30	277	110.00	30,507	5,000	10,000	75,000	150,000		0	190,507
	3			Glycol Heating System (incl LNG vaporizers, unit heaters, electric & diesel/NG boiler)	2	lot	107	1.30	277	110.00	30,507	7,500	15,000	150,000	300,000		0	345,507
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	40,000	40,000	400,000	400,000		0	623,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	110,000	110,000		0	193,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	80,000	80,000		0	135,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	15,000	15,000	175,000	175,000		0	241,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	5,000	7,500	50,000	50,000		0	103,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	1,750	m^2			0		0		0	85	148,750		0	148,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
NG-LF-05: LNG - Landfill - 5 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,037**		**604,089**		**1,739,900**		**1,110,713**		**0**	**3,454,702**
	1			**STATION ELECTRICAL**					**2,457**		**270,270**		**840,000**		**345,000**		**0**	**1,455,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	50,000	50,000		0		0	78,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 10 Sections)	10	sect	10	1.30	130	110.00	14,300		0	8,500	85,000		0	99,300
	9			BOP PLC and Instrumentation (100 Points, $1000 per Point)	1	ls			0		0		0	100,000	100,000		0	100,000
	10			Medium/Low Voltage Cable	3,000	ft	0.15	1.30	585	110.00	64,350	30	90,000		0		0	154,350
	11			Cable Tray and Cables from Unit Output to Electrical Room	3,000	ft	0.30	1.30	1,170	110.00	128,700	45	135,000		0		0	263,700
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	50,000	50,000		0		0	50,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**110,000**		**43,000**		**0**	**184,460**
	16			Station Service Transformer 300KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	25,000	25,000		0	28,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	95,000	95,000		0		0	95,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,294**		**252,359**		**39,900**		**722,713**		**0**	**1,014,972**
	23			Transformer - 5MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	12,000	12,000	255,000	255,000		0	292,740
	24			Breaker - 34.5 kV, 650 kV BIL, 600A, 31.5 kA (min) outdoor dead tank c/w multi-ratio CTs	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 1/0 AWG, XLPE insulation, aluminum conductor, 100% insulation	240	M	0.5	1.30	140	110.00	15,444	0	0	79	18,900		0	34,344
	29			Conductor - Bare, 336.4 kcmil AAC (Tulip)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	12	ea	7	1.30	105	110.00	11,583	450	5,400	0	0		0	16,983
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**375,000**		**0**		**0**	**425,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire and Gas Alarm Systems	1	ls			0		0	150,000	150,000		0		0	150,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**375,000**		**0**		**0**	**375,000**
	40			Engine, fuel, and auxiliaries controls installation	300	pt			0		0	750	225,000		0		0	225,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
NG-LF-05: LNG - Landfill - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**5,451,442**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	5,451,442
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
NG-LF-10: LNG - Landfill - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**21,030 hrs**	**$2,497,220**	**$8,336,088**	**$25,808,263**	**$5,766,500**	**$66,911,946**
-	1	-	Major Equipment	10,400 hrs	$1,144,000	$1,068,500	$21,370,000	$300,000	$23,882,500
-	2	-	General Civil	00 hrs	$0	$3,370,450	$807,500	$0	$4,177,950
-	3	-	Buildings and Structures	00 hrs	$0	$1,838,838	$0	$5,400,000	$7,238,838
-	4	-	Mechanical and Process	4,697 hrs	$516,707	$152,500	$1,928,750	$0	$2,597,957
-	5	-	Electrical, Instrumentation & Controls	5,933 hrs	$702,616	$1,905,800	$1,274,613	$0	$3,883,029
-	**6**	-	**Sub Total Directs**	21,030 hrs	**$2,363,323**	**$8,336,088**	**$25,380,863**	**$5,700,000**	**$41,780,273**
-	7	-	Preliminary Engineering for Budget Approval (Class 3)	-	-	-	-	-	$400,000
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$3,342,422
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$1,462,310
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$626,704
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$133,897	-	-	$66,500	$200,397
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$427,400	-	$427,400
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$7,520,449
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$133,897**	**$0**	**$427,400**	**$66,500**	**$13,979,682**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$11,151,991

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
NG-LF-10: LNG - Landfill - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**10,400**		**1,144,000**		**1,068,500**		**21,370,000**		**300,000**	**23,882,500**
	1			**Generating Station**					0		0		0		0		0	0
	2			NG fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	100,000	400,000	2,000,000	8,000,000		0	9,132,160
	3			Transportation	4	ea			0		0		0		0	75,000	300,000	300,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**LNG Tank Farm**					0		0		0		0		0	0
	13			LNG storage tanks: 1x 150 m3 (usable) vacuum jacketed, horizontal storage tank	4	ea	240	1.30	1,248	110.00	137,280	37,500	150,000	750,000	3,000,000		0	3,287,280
	13			Storage Infrastructure	1	ea	480	1.30	624	110.00	68,640	86,750	86,750	1,735,000	1,735,000		0	1,890,390
	14			Vaporizers	2	ea	480	1.30	1,248	110.00	137,280	134,250	268,500	2,685,000	5,370,000		0	5,775,780
	15			LNG truck unloading station, piping, and infrastructure	1	ea	480	1.30	624	110.00	68,640	163,250	163,250	3,265,000	3,265,000		0	3,496,890
	16			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
NG-LF-10: LNG - Landfill - 10 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,370,450**		**807,500**		**0**	**4,177,950**
	1			Clearing & Grubbing	6.5	ha			0		0	$30,000	195,000		0		0	195,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	6,500	m^3			0		0	$15	97,500		0		0	97,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	4,950	tonne			0		0	$35	173,250		0		0	173,250
	8			Granular Sub-Base - 300mm	9,900	tonne			0		0	$18	178,200		0		0	178,200
	9			Asphalt - (Base and Seal)	3,150	tonne			0		0	$150	472,500		0		0	472,500
	10			Fencing (8ft, angular razor wire)	1,100	m			0		0	$300	330,000		0		0	330,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			**FIRE WATER**					**0**		**0**		**1,350,000**		**807,500**		**0**	**2,157,500**
	16			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	17			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	18			Fire Loop (allowance) & Recirc Pumps	1,500	m			0		0	$300	450,000		50,000		0	500,000
	19			Fire Hydrants	15	ea.			0		0		0	10,500	157,500		0	157,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
NG-LF-10: LNG - Landfill - 10 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**1,838,838**		**0**		**5,400,000**	**7,238,838**
	1			**FUEL STORAGE**					**0**		**0**		**1,032,300**		**0**		**0**	**1,032,300**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 8 m x 10 m x 0.3 m	24	m^3			0		0	1,500	36,000		0		0	36,000
	4			Containment Sump					0		0		0		0		0	0
	5			Base 10 m x 20 m x 0.3 m	60	m^3			0		0	1,500	90,000		0		0	90,000
	6			Walls 60 m x 2 m x 0.3 m	36	m^3			0		0	1,500	54,000		0		0	54,000
	7			LNG Control Module					0		0		0		0		0	0
	8			Base 6 m x 22 m x 0.3 m	40	m^3			0		0	1,500	59,400		0		0	59,400
	9			Tank Containment					0		0		0		0		0	0
	10			Concrete pad 40 m x 40 m x 0.3 m	480	m^3			0		0	1,500	720,000		0		0	720,000
	11			Containment Curb 160 m x 0.3 m x 0.2 m	10	m^3			0		0	1,500	14,400		0		0	14,400
	12			Concrete Trenching					0		0		0		0		0	0
	13			Base 60 m x 0.5 m x 0.3 m	9	m^3			0		0	1,500	13,500		0		0	13,500
	14			Walls 120 m x 1 m x 0.25 m	30	m^3			0		0	1,500	45,000		0		0	45,000
	15			**GENERATOR HALL**					**0**		**0**		**201,450**		**0**		**5,400,000**	**5,601,450**
	16			Pre-engineered Building					0		0		0		0		0	0
	17			Building Size 25 m x 90 m	2,250	m^2			0		0		0		0	2,400	5,400,000	5,400,000
	18			Generator Foundation					0		0		0		0		0	0
	19			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	20			Generator Stack Foundation					0		0		0		0		0	0
	21			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 4	8	m^3			0		0	1,500	11,250		0		0	11,250
	22			Diesel Storage Tank					0		0		0		0		0	0
	23			Base 5 m x 12 m x 0.3 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	24			Radiator Foundation					0		0		0		0		0	0
	25			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	26			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	27			Transformer					0		0		0		0		0	0
	28			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	29			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	30			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	31			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	32			Breaker					0		0		0		0		0	0
	33			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500
	34			**OTHER**					**0**		**0**		**236,088**		**0**		**0**	**236,088**
	35			Pipe Bridge 115 m Long					0		0		0		0		0	0
	36			Weight of Steel per Meter 72 kg	8,280	kg			0		0	15	124,200		0		0	124,200
	37			Pipe Bridge Foundation (14 total)					0		0		0		0		0	0
	38			Footing 4 m x 3 m x 0.3 m @ 14 locations	50	m^3			0		0	1,500	75,600		0		0	75,600
	39			Pier 0.6 m x 0.6 m x 2.4 m @ 28 locations	24	m^3			0		0	1,500	36,288		0		0	36,288

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
NG-LF-10: LNG - Landfill - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,697**		**516,707**		**152,500**		**1,928,750**		**0**	**2,597,957**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	4	lot	107	1.30	555	110.00	61,013	5,000	20,000	60,000	240,000		0	321,013
	3			Glycol Heating System (incl LNG vaporizers, unit heaters, electric & diesel/NG boiler)	4	lot	107	1.30	555	110.00	61,013	7,500	30,000	125,000	500,000		0	591,013
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	50,000	50,000	500,000	500,000		0	733,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	135,000	135,000		0	218,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	90,000	90,000		0	145,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	220,000	220,000		0	291,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	5,000	7,500	75,000	75,000		0	128,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	2,250	m^2			0		0		0	75	168,750		0	168,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
NG-LF-10: LNG - Landfill - 10 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,933**		**702,616**		**1,905,800**		**1,274,613**		**0**	**3,883,029**
	1			**STATION ELECTRICAL**					**3,107**		**341,770**		**940,000**		**412,500**		**0**	**1,694,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	60,000	60,000		0		0	88,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 15 Sections)	15	sect	10	1.30	195	110.00	21,450		0	8,500	127,500		0	148,950
	9			BOP PLC and Instrumentation (125 Points, $1000 per Point)	1	ls			0		0		0	125,000	125,000		0	125,000
	10			Medium/Low Voltage Cable	4,000	ft	0.15	1.30	780	110.00	85,800	30	120,000		0		0	205,800
	11			Cable Tray and Cables from Unit Output to Electrical Room	4,000	ft	0.30	1.30	1,560	110.00	171,600	45	180,000		0		0	351,600
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	65,000	65,000		0		0	65,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**130,000**		**45,500**		**0**	**206,960**
	16			Station Service Transformer 400KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	27,500	27,500		0	31,075
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	115,000	115,000		0		0	115,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,540**		**279,386**		**48,300**		**816,613**		**0**	**1,144,299**
	23			Transformer - 10 MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	15,000	15,000	330,000	330,000		0	370,740
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	480	M	0.5	1.30	281	110.00	30,888	0	0	79	37,800		0	68,688
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	24	ea	7	1.30	211	110.00	23,166	450	10,800	0	0		0	33,966
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**375,000**		**0**		**0**	**425,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire and Gas Alarm Systems	1	ls			0		0	150,000	150,000		0		0	150,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**412,500**		**0**		**0**	**412,500**
	40			Engine, fuel, and auxiliaries controls installation	350	pt			0		0	750	262,500		0		0	262,500
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
NG-LF-10: LNG - Landfill - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**7,520,449**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	7,520,449
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
NG-LF-20: LNG - Landfill - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**27,069 hrs**	**$3,210,212**	**$9,747,413**	**$42,201,250**	**$8,467,650**	**$100,124,167**
-	1	-	Major Equipment	14,664 hrs	$1,613,040	$1,831,000	$36,620,000	$450,000	$40,514,040
-	2	-	General Civil	00 hrs	$0	$3,370,450	$807,500	$0	$4,177,950
-	3	-	Buildings and Structures	00 hrs	$0	$2,275,863	$0	$7,920,000	$10,195,863
-	4	-	Mechanical and Process	5,252 hrs	$577,720	$187,500	$2,322,500	$0	$3,087,720
-	5	-	Electrical, Instrumentation & Controls	7,153 hrs	$836,786	$2,082,600	$1,718,850	$0	$4,638,236
-	**6**	-	**Sub Total Directs**	27,069 hrs	**$3,027,546**	**$9,747,413**	**$41,468,850**	**$8,370,000**	**$62,613,809**
-	7	-	Preliminary Engineering for Budget Approval (Class 3)	-	-	-	-	-	$400,000
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$5,009,105
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$2,191,483
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$939,207
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$182,666	-	-	$97,650	$280,316
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$732,400	-	$732,400
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$11,270,486
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$182,666**	**$0**	**$732,400**	**$97,650**	**$20,822,997**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$16,687,361

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
NG-LF-20: LNG - Landfill - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**14,664**		**1,613,040**		**1,831,000**		**36,620,000**		**450,000**	**40,514,040**
	1			**Generating Station**					0		0		0		0		0	0
	2			NG fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	100,000	400,000	2,000,000	8,000,000		0	9,132,160
	3			NG fired Reciprocating Engine - 5.0 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	200,000	400,000	4,000,000	8,000,000		0	8,766,080
	3			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**LNG Tank Farm**					0		0		0		0		0	0
	13			LNG storage tanks: 1x 150 m3 (usable) vacuum jacketed, horizontal storage tank	7	ea	240	1.30	2,184	110.00	240,240	37,500	262,500	750,000	5,250,000		0	5,752,740
	13			Storage Infrastructure	1	ea	480	1.30	624	110.00	68,640	151,750	151,750	3,035,000	3,035,000		0	3,255,390
	14			Vaporizers	2	ea	480	1.30	1,248	110.00	137,280	191,750	383,500	3,835,000	7,670,000		0	8,190,780
	15			LNG truck unloading station, piping, and infrastructure	1	ea	480	1.30	624	110.00	68,640	233,250	233,250	4,665,000	4,665,000		0	4,966,890
	16			Transportation	9	ea			0		0		0		0	75,000	675,000	675,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
NG-LF-20: LNG - Landfill - 20 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,370,450**		**807,500**		**0**	**4,177,950**
	1			Clearing & Grubbing	6.5	ha			0		0	$30,000	195,000		0		0	195,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	6,500	m^3			0		0	$15	97,500		0		0	97,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	4,950	tonne			0		0	$35	173,250		0		0	173,250
	8			Granular Sub-Base - 300mm	9,900	tonne			0		0	$18	178,200		0		0	178,200
	9			Asphalt - (Base and Seal)	3,150	tonne			0		0	$150	472,500		0		0	472,500
	10			Fencing (8ft, angular razor wire)	1,100	m			0		0	$300	330,000		0		0	330,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			**FIRE WATER**					**0**		**0**		**1,350,000**		**807,500**		**0**	**2,157,500**
	16			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	17			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	18			Fire Loop (allowance) & Recirc Pumps	1,500	m			0		0	$300	450,000		50,000		0	500,000
	19			Fire Hydrants	15	ea.			0		0		0	10,500	157,500		0	157,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
NG-LF-20: LNG - Landfill - 20 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**2,275,863**		**0**		**7,920,000**	**10,195,863**
	1			**FUEL STORAGE**					**0**		**0**		**1,305,000**		**0**		**0**	**1,305,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 8 m x 10 m x 0.3 m	24	m^3			0		0	1,500	36,000		0		0	36,000
	4			Containment Sump					0		0		0		0		0	0
	5			Base 10 m x 20 m x 0.3 m	60	m^3			0		0	1,500	90,000		0		0	90,000
	6			Walls 60 m x 2 m x 0.3 m	36	m^3			0		0	1,500	54,000		0		0	54,000
	7			LNG Control Module					0		0		0		0		0	0
	8			Base 6 m x 22 m x 0.3 m	40	m^3			0		0	1,500	59,400		0		0	59,400
	9			Tank Containment					0		0		0		0		0	0
	10			Concrete pad 55 m x 40 m x 0.3 m	660	m^3			0		0	1,500	990,000		0		0	990,000
	11			Containment Curb 190 m x 0.3 m x 0.2 m	11	m^3			0		0	1,500	17,100		0		0	17,100
	12			Concrete Trenching					0		0		0		0		0	0
	13			Base 60 m x 0.5 m x 0.3 m	9	m^3			0		0	1,500	13,500		0		0	13,500
	14			Walls 120 m x 1 m x 0.25 m	30	m^3			0		0	1,500	45,000		0		0	45,000
	15			**GENERATOR HALL**					**0**		**0**		**365,775**		**0**		**7,920,000**	**8,285,775**
	16			Pre-engineered Building					0		0		0		0		0	0
	17			Building Size 30 m x 110 m	3,300	m^2			0		0		0		0	2,400	7,920,000	7,920,000
	18			Generator Foundation					0		0		0		0		0	0
	19			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	20			Thickened Slab 5.5 m x 14 m x 0.5 m / each quantity 2	77	m^3			0		0	1,500	115,500		0		0	115,500
	21			Generator Stack Foundation					0		0		0		0		0	0
	22			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 6	11	m^3			0		0	1,500	16,875		0		0	16,875
	23			Diesel Storage Tank					0		0		0		0		0	0
	24			Base 5 m x 12 m x 0.3 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	25			Radiator Foundation					0		0		0		0		0	0
	26			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	27			Concrete Pad 6 m x 8 m x 0.3 m / each quantity 2	29	m^3			0		0	1,500	43,200		0		0	43,200
	28			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	29			Transformer					0		0		0		0		0	0
	30			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	31			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	32			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	33			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	34			Breaker					0		0		0		0		0	0
	35			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500
	36			**OTHER**					**0**		**0**		**236,088**		**0**		**0**	**236,088**
	37			Pipe Bridge 115 m Long					0		0		0		0		0	0
	38			Weight of Steel per Meter 72 kg	8,280	kg			0		0	15	124,200		0		0	124,200
	39			Pipe Bridge Foundation (14 total)					0		0		0		0		0	0
	40			Footing 4 m x 3 m x 0.3 m @ 14 locations	50	m^3			0		0	1,500	75,600		0		0	75,600
	41			Pier 0.6 m x 0.6 m x 2.4 m @ 28 locations	24	m^3			0		0	1,500	36,288		0		0	36,288

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
NG-LF-20: LNG - Landfill - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,252**		**577,720**		**187,500**		**2,322,500**		**0**	**3,087,720**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	6	lot	107	1.30	832	110.00	91,520	5,000	30,000	50,000	300,000		0	421,520
	3			Glycol Heating System (incl LNG vaporizers, unit heaters, electric & diesel/NG boiler)	6	lot	107	1.30	832	110.00	91,520	7,500	45,000	100,000	600,000		0	736,520
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	60,000	60,000	600,000	600,000		0	843,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	150,000	150,000		0	233,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	100,000	100,000		0	155,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	250,000	250,000		0	321,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	5,000	7,500	75,000	75,000		0	128,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	3,300	m^2			0		0		0	75	247,500		0	247,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
NG-LF-20: LNG - Landfill - 20 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**7,153**		**836,786**		**2,082,600**		**1,718,850**		**0**	**4,638,236**
	1			**STATION ELECTRICAL**					**3,757**		**413,270**		**1,050,000**		**480,000**		**0**	**1,943,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	70,000	70,000		0		0	98,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 20 Sections)	20	sect	10	1.30	260	110.00	28,600		0	8,500	170,000		0	198,600
	9			BOP PLC and Instrumentation (150 Points, $1000 per Point)	1	ls			0		0		0	150,000	150,000		0	150,000
	10			Medium/Low Voltage Cable	5,000	ft	0.15	1.30	975	110.00	107,250	30	150,000		0		0	257,250
	11			Cable Tray and Cables from Unit Output to Electrical Room	5,000	ft	0.30	1.30	1,950	110.00	214,500	45	225,000		0		0	439,500
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	90,000	90,000		0		0	90,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**150,000**		**48,000**		**0**	**229,460**
	16			Station Service Transformer 500KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	30,000	30,000		0	33,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	135,000	135,000		0		0	135,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**3,110**		**342,056**		**57,600**		**1,190,850**		**0**	**1,590,506**
	23			Transformer - 20MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	22,500	22,500	525,000	525,000		0	573,240
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	2	ea	90	1.30	234	110.00	25,740	1,500	3,000	111,000	222,000		0	250,740
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	2	ea	45	1.30	117	110.00	12,870	1,500	3,000	24,000	48,000		0	63,870
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	6	ea	12	1.30	94	110.00	10,296	750	4,500	7,500	45,000		0	59,796
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	6	ea	8	1.30	59	110.00	6,435	750	4,500	825	4,950		0	15,885
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	840	M	0.3	1.30	328	110.00	36,036	0	0	53	44,100		0	80,136
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	120	M	0.5	1.30	70	110.00	7,722	0	0	15	1,800		0	9,522
	30			Cable Terminations	42	ea	5	1.30	246	110.00	27,027	300	12,600	0	0		0	39,627
	31			Misc Hardware and electrical connectors	1	lot	90	1.30	117	110.00	12,870	7,500	7,500	0	0		0	20,370
	32			Line Protection Panel	2	ea	120	1.30	312	110.00	34,320	0	0	75,000	150,000		0	184,320
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	1,000	1.30	1,300	110.00	143,000		0	150,000	150,000		0	293,000
	34			**SITE SECURITY**					**0**		**50,000**		**375,000**		**0**		**0**	**425,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire and Gas Alarm Systems	1	ls			0		0	150,000	150,000		0		0	150,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**450,000**		**0**		**0**	**450,000**
	40			Engine, fuel, and auxiliaries controls installation	400	pt			0		0	750	300,000		0		0	300,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
NG-LF-20: LNG - Landfill - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**11,270,486**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	11,270,486
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
NG-TK-05: LNG - Takhini - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**15,628 hrs**	**$1,867,977**	**$7,269,973**	**$17,082,163**	**$4,400,750**	**$48,460,179**
-	1	-	Major Equipment	6,448 hrs	$709,280	$673,000	$13,460,000	$150,000	$14,992,280
-	2	-	General Civil	00 hrs	$0	$3,265,660	$828,500	$0	$4,094,160
-	3	-	Buildings and Structures	00 hrs	$0	$1,478,913	$0	$4,200,000	$5,678,913
-	4	-	Mechanical and Process	4,143 hrs	$455,693	$112,500	$1,413,750	$0	$1,981,943
-	5	-	Electrical, Instrumentation & Controls	5,037 hrs	$604,089	$1,739,900	$1,110,713	$0	$3,454,702
-	**6**	-	**Sub Total Directs**	15,628 hrs	**$1,769,063**	**$7,269,973**	**$16,812,963**	**$4,350,000**	**$30,201,998**
-	7	-	Preliminary Engineering for Budget Approval (Class 3)	-	-	-	-	-	$400,000
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$2,416,160
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$1,057,070
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$453,030
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$98,915	-	-	$50,750	$149,665
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$269,200	-	$269,200
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$5,436,360
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$98,915**	**$0**	**$269,200**	**$50,750**	**$10,181,484**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$8,076,696

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
NG-TK-05: LNG - Takhini - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**6,448**		**709,280**		**673,000**		**13,460,000**		**150,000**	**14,992,280**
	1			**Generating Station**					0		0		0		0		0	0
	2			NG fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	100,000	200,000	2,000,000	4,000,000		0	4,566,080
	3			Transportation	2	ea			0		0		0		0	75,000	150,000	150,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**LNG Tank Farm**					0		0		0		0		0	0
	13			LNG storage tanks: 1x 150 m3 (usable) vacuum jacketed, horizontal storage tank	2	ea	240	1.30	624	110.00	68,640	37,500	75,000	750,000	1,500,000		0	1,643,640
	13			Storage Infrastructure	1	ea	480	1.30	624	110.00	68,640	43,250	43,250	865,000	865,000		0	976,890
	14			Vaporizers	2	ea	480	1.30	1,248	110.00	137,280	95,750	191,500	1,915,000	3,830,000		0	4,158,780
	15			LNG truck unloading station, piping, and infrastructure	1	ea	480	1.30	624	110.00	68,640	163,250	163,250	3,265,000	3,265,000		0	3,496,890
	16			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
NG-TK-05: LNG - Takhini - 5 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,265,660**		**828,500**		**0**	**4,094,160**
	1			Clearing & Grubbing	6.5	ha			0		0	$30,000	195,000		0		0	195,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	6,500	m^3			0		0	$15	97,500		0		0	97,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	3,960	tonne			0		0	$35	138,600		0		0	138,600
	8			Granular Sub-Base - 300mm	7,920	tonne			0		0	$18	142,560		0		0	142,560
	9			Asphalt - (Base and Seal)	2,520	tonne			0		0	$150	378,000		0		0	378,000
	10			Fencing (8ft, angular razor wire)	1,100	m			0		0	$300	330,000		0		0	330,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			**FIRE WATER**					**0**		**0**		**1,410,000**		**828,500**		**0**	**2,238,500**
	16			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	17			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	18			Fire Loop (allowance) & Recirc Pumps	1,700	m			0		0	$300	510,000		50,000		0	560,000
	19			Fire Hydrants	17	ea.			0		0		0	10,500	178,500		0	178,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

Stantec

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
NG-TK-05: LNG - Takhini - 5 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**1,478,913**		**0**		**4,200,000**	**5,678,913**
	1			**FUEL STORAGE**					**0**		**0**		**759,600**		**0**		**0**	**759,600**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 8 m x 10 m x 0.3 m	24	m^3			0		0	1,500	36,000		0		0	36,000
	4			Containment Sump					0		0		0		0		0	0
	5			Base 10 m x 20 m x 0.3 m	60	m^3			0		0	1,500	90,000		0		0	90,000
	6			Walls 60 m x 2 m x 0.3 m	36	m^3			0		0	1,500	54,000		0		0	54,000
	7			LNG Control Module					0		0		0		0		0	0
	8			Base 6 m x 22 m x 0.3 m	40	m^3			0		0	1,500	59,400		0		0	59,400
	9			Tank Containment					0		0		0		0		0	0
	10			Concrete pad 25 m x 40 m x 0.3 m	300	m^3			0		0	1,500	450,000		0		0	450,000
	11			Containment Curb 130 m x 0.3 m x 0.2 m	8	m^3			0		0	1,500	11,700		0		0	11,700
	12			Concrete Trenching					0		0		0		0		0	0
	13			Base 60 m x 0.5 m x 0.3 m	9	m^3			0		0	1,500	13,500		0		0	13,500
	14			Walls 120 m x 1 m x 0.25 m	30	m^3			0		0	1,500	45,000		0		0	45,000
	15			**GENERATOR HALL**					**0**		**0**		**114,225**		**0**		**4,200,000**	**4,314,225**
	16			Pre-engineered Building					0		0		0		0		0	0
	17			Building Size 25 m x 70 m	1,750	m^2			0		0		0		0	2,400	4,200,000	4,200,000
	18			Generator Foundation					0		0		0		0		0	0
	19			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 2	40	m^3			0		0	1,500	60,000		0		0	60,000
	20			Generator Stack Foundation					0		0		0		0		0	0
	21			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 2	4	m^3			0		0	1,500	5,625		0		0	5,625
	22			Diesel Storage Tank					0		0		0		0		0	0
	23			Base 5 m x 12 m x 0.3 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	24			Radiator Foundation					0		0		0		0		0	0
	25			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 2	14	m^3			0		0	1,500	21,600		0		0	21,600
	26			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	27			Transformer					0		0		0		0		0	0
	28			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	29			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	30			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	31			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	32			Breaker					0		0		0		0		0	0
	33			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500
	34			**OTHER**					**0**		**0**		**236,088**		**0**		**0**	**236,088**
	35			Pipe Bridge 115 m Long					0		0		0		0		0	0
	36			Weight of Steel per Meter 72 kg	8,280	kg			0		0	15	124,200		0		0	124,200
	37			Pipe Bridge Foundation (14 total)					0		0		0		0		0	0
	38			Footing 4 m x 3 m x 0.3 m @ 14 locations	50	m^3			0		0	1,500	75,600		0		0	75,600
	39			Pier 0.6 m x 0.6 m x 2.4 m @ 28 locations	24	m^3			0		0	1,500	36,288		0		0	36,288

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
NG-TK-05: LNG - Takhini - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,143**		**455,693**		**112,500**		**1,413,750**		**0**	**1,981,943**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	2	lot	107	1.30	277	110.00	30,507	5,000	10,000	75,000	150,000		0	190,507
	3			Glycol Heating System (incl LNG vaporizers, unit heaters, electric & diesel/NG boiler)	2	lot	107	1.30	277	110.00	30,507	7,500	15,000	150,000	300,000		0	345,507
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	40,000	40,000	400,000	400,000		0	623,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	110,000	110,000		0	193,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	80,000	80,000		0	135,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	15,000	15,000	175,000	175,000		0	241,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	5,000	7,500	50,000	50,000		0	103,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	1,750	m^2			0		0		0	85	148,750		0	148,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
NG-TK-05: LNG - Takhini - 5 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,037**		**604,089**		**1,739,900**		**1,110,713**		**0**	**3,454,702**
	1			**STATION ELECTRICAL**					**2,457**		**270,270**		**840,000**		**345,000**		**0**	**1,455,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	50,000	50,000		0		0	78,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 10 Sections)	10	sect	10	1.30	130	110.00	14,300		0	8,500	85,000		0	99,300
	9			BOP PLC and Instrumentation (100 Points, $1000 per Point)	1	ls			0		0		0	100,000	100,000		0	100,000
	10			Medium/Low Voltage Cable	3,000	ft	0.15	1.30	585	110.00	64,350	30	90,000		0		0	154,350
	11			Cable Tray and Cables from Unit Output to Electrical Room	3,000	ft	0.30	1.30	1,170	110.00	128,700	45	135,000		0		0	263,700
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	50,000	50,000		0		0	50,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**110,000**		**43,000**		**0**	**184,460**
	16			Station Service Transformer 300KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	25,000	25,000		0	28,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	95,000	95,000		0		0	95,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,294**		**252,359**		**39,900**		**722,713**		**0**	**1,014,972**
	23			Transformer - 5MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	12,000	12,000	255,000	255,000		0	292,740
	24			Breaker - 34.5 kV, 650 kV BIL, 600A, 31.5 kA (min) outdoor dead tank c/w multi-ratio CTs	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 1/0 AWG, XLPE insulation, aluminum conductor, 100% insulation	240	M	0.5	1.30	140	110.00	15,444	0	0	79	18,900		0	34,344
	29			Conductor - Bare, 336.4 kcmil AAC (Tulip)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	12	ea	7	1.30	105	110.00	11,583	450	5,400	0	0		0	16,983
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**375,000**		**0**		**0**	**425,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire and Gas Alarm Systems	1	ls			0		0	150,000	150,000		0		0	150,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**375,000**		**0**		**0**	**375,000**
	40			Engine, fuel, and auxiliaries controls installation	300	pt			0		0	750	225,000		0		0	225,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
NG-TK-05: LNG - Takhini - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**5,436,360**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	5,436,360
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
NG-TK-10: LNG - Takhini - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**21,030 hrs**	**$2,497,117**	**$8,231,298**	**$25,829,263**	**$5,766,500**	**$66,780,105**
-	1	-	Major Equipment	10,400 hrs	$1,144,000	$1,068,500	$21,370,000	$300,000	$23,882,500
-	2	-	General Civil	00 hrs	$0	$3,265,660	$828,500	$0	$4,094,160
-	3	-	Buildings and Structures	00 hrs	$0	$1,838,838	$0	$5,400,000	$7,238,838
-	4	-	Mechanical and Process	4,697 hrs	$516,707	$152,500	$1,928,750	$0	$2,597,957
-	5	-	Electrical, Instrumentation & Controls	5,933 hrs	$702,616	$1,905,800	$1,274,613	$0	$3,883,029
-	**6**	-	**Sub Total Directs**	21,030 hrs	**$2,363,323**	**$8,231,298**	**$25,401,863**	**$5,700,000**	**$41,696,483**
-	7	-	Preliminary Engineering for Budget Approval (Class 3)	-	-	-	-	-	$400,000
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$3,335,719
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$1,459,377
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$625,447
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$133,794	-	-	$66,500	$200,294
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$427,400	-	$427,400
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$7,505,367
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$133,794**	**$0**	**$427,400**	**$66,500**	**$13,953,604**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$11,130,018

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
NG-TK-10: LNG - Takhini - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**10,400**		**1,144,000**		**1,068,500**		**21,370,000**		**300,000**	**23,882,500**
	1			**Generating Station**					0		0		0		0		0	0
	2			NG fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	100,000	400,000	2,000,000	8,000,000		0	9,132,160
	3			Transportation	4	ea			0		0		0		0	75,000	300,000	300,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**LNG Tank Farm**					0		0		0		0		0	0
	13			LNG storage tanks: 1x 150 m3 (usable) vacuum jacketed, horizontal storage tank	4	ea	240	1.30	1,248	110.00	137,280	37,500	150,000	750,000	3,000,000		0	3,287,280
	13			Storage Infrastructure	1	ea	480	1.30	624	110.00	68,640	86,750	86,750	1,735,000	1,735,000		0	1,890,390
	14			Vaporizers	2	ea	480	1.30	1,248	110.00	137,280	134,250	268,500	2,685,000	5,370,000		0	5,775,780
	15			LNG truck unloading station, piping, and infrastructure	1	ea	480	1.30	624	110.00	68,640	163,250	163,250	3,265,000	3,265,000		0	3,496,890
	16			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
NG-TK-10: LNG - Takhini - 10 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,265,660**		**828,500**		**0**	**4,094,160**
	1			Clearing & Grubbing	6.5	ha			0		0	$30,000	195,000		0		0	195,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	6,500	m^3			0		0	$15	97,500		0		0	97,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	3,960	tonne			0		0	$35	138,600		0		0	138,600
	8			Granular Sub-Base - 300mm	7,920	tonne			0		0	$18	142,560		0		0	142,560
	9			Asphalt - (Base and Seal)	2,520	tonne			0		0	$150	378,000		0		0	378,000
	10			Fencing (8ft, angular razor wire)	1,100	m			0		0	$300	330,000		0		0	330,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			**FIRE WATER**					**0**		**0**		**1,410,000**		**828,500**		**0**	**2,238,500**
	16			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	17			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	18			Fire Loop (allowance) & Recirc Pumps	1,700	m			0		0	$300	510,000		50,000		0	560,000
	19			Fire Hydrants	17	ea.			0		0		0	10,500	178,500		0	178,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
NG-TK-10: LNG - Takhini - 10 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**1,838,838**		**0**		**5,400,000**	**7,238,838**
	1			**FUEL STORAGE**					**0**		**0**		**1,032,300**		**0**		**0**	**1,032,300**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 8 m x 10 m x 0.3 m	24	m^3			0		0	1,500	36,000		0		0	36,000
	4			Containment Sump					0		0		0		0		0	0
	5			Base 10 m x 20 m x 0.3 m	60	m^3			0		0	1,500	90,000		0		0	90,000
	6			Walls 60 m x 2 m x 0.3 m	36	m^3			0		0	1,500	54,000		0		0	54,000
	7			LNG Control Module					0		0		0		0		0	0
	8			Base 6 m x 22 m x 0.3 m	40	m^3			0		0	1,500	59,400		0		0	59,400
	9			Tank Containment					0		0		0		0		0	0
	10			Concrete pad 40 m x 40 m x 0.3 m	480	m^3			0		0	1,500	720,000		0		0	720,000
	11			Containment Curb 160 m x 0.3 m x 0.2 m	10	m^3			0		0	1,500	14,400		0		0	14,400
	12			Concrete Trenching					0		0		0		0		0	0
	13			Base 60 m x 0.5 m x 0.3 m	9	m^3			0		0	1,500	13,500		0		0	13,500
	14			Walls 120 m x 1 m x 0.25 m	30	m^3			0		0	1,500	45,000		0		0	45,000
	15			**GENERATOR HALL**					**0**		**0**		**201,450**		**0**		**5,400,000**	**5,601,450**
	16			Pre-engineered Building					0		0		0		0		0	0
	17			Building Size 25 m x 90 m	2,250	m^2			0		0		0		0	2,400	5,400,000	5,400,000
	18			Generator Foundation					0		0		0		0		0	0
	19			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	20			Generator Stack Foundation					0		0		0		0		0	0
	21			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 4	8	m^3			0		0	1,500	11,250		0		0	11,250
	22			Diesel Storage Tank					0		0		0		0		0	0
	23			Base 5 m x 12 m x 0.3 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	24			Radiator Foundation					0		0		0		0		0	0
	25			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	26			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	27			Transformer					0		0		0		0		0	0
	28			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	29			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	30			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	31			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	32			Breaker					0		0		0		0		0	0
	33			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500
	34			**OTHER**					**0**		**0**		**236,088**		**0**		**0**	**236,088**
	35			Pipe Bridge 115 m Long					0		0		0		0		0	0
	36			Weight of Steel per Meter 72 kg	8,280	kg			0		0	15	124,200		0		0	124,200
	37			Pipe Bridge Foundation (14 total)					0		0		0		0		0	0
	38			Footing 4 m x 3 m x 0.3 m @ 14 locations	50	m^3			0		0	1,500	75,600		0		0	75,600
	39			Pier 0.6 m x 0.6 m x 2.4 m @ 28 locations	24	m^3			0		0	1,500	36,288		0		0	36,288

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
NG-TK-10: LNG - Takhini - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,697**		**516,707**		**152,500**		**1,928,750**		**0**	**2,597,957**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	4	lot	107	1.30	555	110.00	61,013	5,000	20,000	60,000	240,000		0	321,013
	3			Glycol Heating System (incl LNG vaporizers, unit heaters, electric & diesel/NG boiler)	4	lot	107	1.30	555	110.00	61,013	7,500	30,000	125,000	500,000		0	591,013
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	50,000	50,000	500,000	500,000		0	733,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	135,000	135,000		0	218,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	90,000	90,000		0	145,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	220,000	220,000		0	291,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	5,000	7,500	75,000	75,000		0	128,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	2,250	m^2			0		0		0	75	168,750		0	168,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
NG-TK-10: LNG - Takhini - 10 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,933**		**702,616**		**1,905,800**		**1,274,613**		**0**	**3,883,029**
	1			**STATION ELECTRICAL**					**3,107**		**341,770**		**940,000**		**412,500**		**0**	**1,694,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	60,000	60,000		0		0	88,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 15 Sections)	15	sect	10	1.30	195	110.00	21,450		0	8,500	127,500		0	148,950
	9			BOP PLC and Instrumentation (125 Points, $1000 per Point)	1	ls			0		0		0	125,000	125,000		0	125,000
	10			Medium/Low Voltage Cable	4,000	ft	0.15	1.30	780	110.00	85,800	30	120,000		0		0	205,800
	11			Cable Tray and Cables from Unit Output to Electrical Room	4,000	ft	0.30	1.30	1,560	110.00	171,600	45	180,000		0		0	351,600
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	65,000	65,000		0		0	65,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**130,000**		**45,500**		**0**	**206,960**
	16			Station Service Transformer 400KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	27,500	27,500		0	31,075
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	115,000	115,000		0		0	115,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,540**		**279,386**		**48,300**		**816,613**		**0**	**1,144,299**
	23			Transformer - 10 MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	15,000	15,000	330,000	330,000		0	370,740
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	480	M	0.5	1.30	281	110.00	30,888	0	0	79	37,800		0	68,688
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	24	ea	7	1.30	211	110.00	23,166	450	10,800	0	0		0	33,966
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**375,000**		**0**		**0**	**425,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire and Gas Alarm Systems	1	ls			0		0	150,000	150,000		0		0	150,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**412,500**		**0**		**0**	**412,500**
	40			Engine, fuel, and auxiliaries controls installation	350	pt			0		0	750	262,500		0		0	262,500
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
NG-TK-10: LNG - Takhini - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**7,505,367**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	7,505,367
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
NG-TK-20: LNG - Takhini - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**27,069 hrs**	**$3,210,109**	**$9,642,623**	**$42,222,250**	**$8,467,650**	**$99,992,326**
-	1	-	Major Equipment	14,664 hrs	$1,613,040	$1,831,000	$36,620,000	$450,000	$40,514,040
-	2	-	General Civil	00 hrs	$0	$3,265,660	$828,500	$0	$4,094,160
-	3	-	Buildings and Structures	00 hrs	$0	$2,275,863	$0	$7,920,000	$10,195,863
-	4	-	Mechanical and Process	5,252 hrs	$577,720	$187,500	$2,322,500	$0	$3,087,720
-	5	-	Electrical, Instrumentation & Controls	7,153 hrs	$836,786	$2,082,600	$1,718,850	$0	$4,638,236
-	**6**	-	**Sub Total Directs**	27,069 hrs	**$3,027,546**	**$9,642,623**	**$41,489,850**	**$8,370,000**	**$62,530,019**
-	7	-	Preliminary Engineering for Budget Approval (Class 3)	-	-	-	-	-	$400,000
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$5,002,402
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$2,188,551
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$937,950
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$182,563	-	-	$97,650	$280,213
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$732,400	-	$732,400
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$11,255,403
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$182,563**	**$0**	**$732,400**	**$97,650**	**$20,796,919**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$16,665,388

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
NG-TK-20: LNG - Takhini - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**14,664**		**1,613,040**		**1,831,000**		**36,620,000**		**450,000**	**40,514,040**
	1			**Generating Station**					0		0		0		0		0	0
	2			NG fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	100,000	400,000	2,000,000	8,000,000		0	9,132,160
	3			NG fired Reciprocating Engine - 5.0 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	200,000	400,000	4,000,000	8,000,000		0	8,766,080
	3			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**LNG Tank Farm**					0		0		0		0		0	0
	13			LNG storage tanks: 1x 150 m3 (usable) vacuum jacketed, horizontal storage tank	7	ea	240	1.30	2,184	110.00	240,240	37,500	262,500	750,000	5,250,000		0	5,752,740
	13			Storage Infrastructure	1	ea	480	1.30	624	110.00	68,640	151,750	151,750	3,035,000	3,035,000		0	3,255,390
	14			Vaporizers	2	ea	480	1.30	1,248	110.00	137,280	191,750	383,500	3,835,000	7,670,000		0	8,190,780
	15			LNG truck unloading station, piping, and infrastructure	1	ea	480	1.30	624	110.00	68,640	233,250	233,250	4,665,000	4,665,000		0	4,966,890
	16			Transportation	9	ea			0		0		0		0	75,000	675,000	675,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
NG-TK-20: LNG - Takhini - 20 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,265,660**		**828,500**		**0**	**4,094,160**
	1			Clearing & Grubbing	6.5	ha			0		0	$30,000	195,000		0		0	195,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	6,500	m^3			0		0	$15	97,500		0		0	97,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	3,960	tonne			0		0	$35	138,600		0		0	138,600
	8			Granular Sub-Base - 300mm	7,920	tonne			0		0	$18	142,560		0		0	142,560
	9			Asphalt - (Base and Seal)	2,520	tonne			0		0	$150	378,000		0		0	378,000
	10			Fencing (8ft, angular razor wire)	1,100	m			0		0	$300	330,000		0		0	330,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			**FIRE WATER**					**0**		**0**		**1,410,000**		**828,500**		**0**	**2,238,500**
	16			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	17			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	18			Fire Loop (allowance) & Recirc Pumps	1,700	m			0		0	$300	510,000		50,000		0	560,000
	19			Fire Hydrants	17	ea.			0		0		0	10,500	178,500		0	178,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
NG-TK-20: LNG - Takhini - 20 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**2,275,863**		**0**		**7,920,000**	**10,195,863**
	1			**FUEL STORAGE**					**0**		**0**		**1,305,000**		**0**		**0**	**1,305,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 8 m x 10 m x 0.3 m	24	m^3			0		0	1,500	36,000		0		0	36,000
	4			Containment Sump					0		0		0		0		0	0
	5			Base 10 m x 20 m x 0.3 m	60	m^3			0		0	1,500	90,000		0		0	90,000
	6			Walls 60 m x 2 m x 0.3 m	36	m^3			0		0	1,500	54,000		0		0	54,000
	7			LNG Control Module					0		0		0		0		0	0
	8			Base 6 m x 22 m x 0.3 m	40	m^3			0		0	1,500	59,400		0		0	59,400
	9			Tank Containment					0		0		0		0		0	0
	10			Concrete pad 55 m x 40 m x 0.3 m	660	m^3			0		0	1,500	990,000		0		0	990,000
	11			Containment Curb 190 m x 0.3 m x 0.2 m	11	m^3			0		0	1,500	17,100		0		0	17,100
	12			Concrete Trenching					0		0		0		0		0	0
	13			Base 60 m x 0.5 m x 0.3 m	9	m^3			0		0	1,500	13,500		0		0	13,500
	14			Walls 120 m x 1 m x 0.25 m	30	m^3			0		0	1,500	45,000		0		0	45,000
	15			**GENERATOR HALL**					**0**		**0**		**365,775**		**0**		**7,920,000**	**8,285,775**
	16			Pre-engineered Building					0		0		0		0		0	0
	17			Building Size 30 m x 110 m	3,300	m^2			0		0		0		0	2,400	7,920,000	7,920,000
	18			Generator Foundation					0		0		0		0		0	0
	19			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	20			Thickened Slab 5.5 m x 14 m x 0.5 m / each quantity 2	77	m^3			0		0	1,500	115,500		0		0	115,500
	21			Generator Stack Foundation					0		0		0		0		0	0
	22			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 6	11	m^3			0		0	1,500	16,875		0		0	16,875
	23			Diesel Storage Tank					0		0		0		0		0	0
	24			Base 5 m x 12 m x 0.3 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	25			Radiator Foundation					0		0		0		0		0	0
	26			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	27			Concrete Pad 6 m x 8 m x 0.3 m / each quantity 2	29	m^3			0		0	1,500	43,200		0		0	43,200
	28			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	29			Transformer					0		0		0		0		0	0
	30			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	31			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	32			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	33			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	34			Breaker					0		0		0		0		0	0
	35			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500
	36			**OTHER**					**0**		**0**		**236,088**		**0**		**0**	**236,088**
	37			Pipe Bridge 115 m Long					0		0		0		0		0	0
	38			Weight of Steel per Meter 72 kg	8,280	kg			0		0	15	124,200		0		0	124,200
	39			Pipe Bridge Foundation (14 total)					0		0		0		0		0	0
	40			Footing 4 m x 3 m x 0.3 m @ 14 locations	50	m^3			0		0	1,500	75,600		0		0	75,600
	41			Pier 0.6 m x 0.6 m x 2.4 m @ 28 locations	24	m^3			0		0	1,500	36,288		0		0	36,288

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
NG-TK-20: LNG - Takhini - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,252**		**577,720**		**187,500**		**2,322,500**		**0**	**3,087,720**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	6	lot	107	1.30	832	110.00	91,520	5,000	30,000	50,000	300,000		0	421,520
	3			Glycol Heating System (incl LNG vaporizers, unit heaters, electric & diesel/NG boiler)	6	lot	107	1.30	832	110.00	91,520	7,500	45,000	100,000	600,000		0	736,520
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	60,000	60,000	600,000	600,000		0	843,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	150,000	150,000		0	233,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	100,000	100,000		0	155,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	250,000	250,000		0	321,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	5,000	7,500	75,000	75,000		0	128,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	3,300	m^2			0		0		0	75	247,500		0	247,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
NG-TK-20: LNG - Takhini - 20 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**7,153**		**836,786**		**2,082,600**		**1,718,850**		**0**	**4,638,236**
	1			**STATION ELECTRICAL**					**3,757**		**413,270**		**1,050,000**		**480,000**		**0**	**1,943,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	70,000	70,000		0		0	98,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 20 Sections)	20	sect	10	1.30	260	110.00	28,600		0	8,500	170,000		0	198,600
	9			BOP PLC and Instrumentation (150 Points, $1000 per Point)	1	ls			0		0		0	150,000	150,000		0	150,000
	10			Medium/Low Voltage Cable	5,000	ft	0.15	1.30	975	110.00	107,250	30	150,000		0		0	257,250
	11			Cable Tray and Cables from Unit Output to Electrical Room	5,000	ft	0.30	1.30	1,950	110.00	214,500	45	225,000		0		0	439,500
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	90,000	90,000		0		0	90,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**150,000**		**48,000**		**0**	**229,460**
	16			Station Service Transformer 500KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	30,000	30,000		0	33,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	135,000	135,000		0		0	135,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**3,110**		**342,056**		**57,600**		**1,190,850**		**0**	**1,590,506**
	23			Transformer - 20MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	22,500	22,500	525,000	525,000		0	573,240
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	2	ea	90	1.30	234	110.00	25,740	1,500	3,000	111,000	222,000		0	250,740
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	2	ea	45	1.30	117	110.00	12,870	1,500	3,000	24,000	48,000		0	63,870
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	6	ea	12	1.30	94	110.00	10,296	750	4,500	7,500	45,000		0	59,796
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	6	ea	8	1.30	59	110.00	6,435	750	4,500	825	4,950		0	15,885
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	840	M	0.3	1.30	328	110.00	36,036	0	0	53	44,100		0	80,136
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	120	M	0.5	1.30	70	110.00	7,722	0	0	15	1,800		0	9,522
	30			Cable Terminations	42	ea	5	1.30	246	110.00	27,027	300	12,600	0	0		0	39,627
	31			Misc Hardware and electrical connectors	1	lot	90	1.30	117	110.00	12,870	7,500	7,500	0	0		0	20,370
	32			Line Protection Panel	2	ea	120	1.30	312	110.00	34,320	0	0	75,000	150,000		0	184,320
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	1,000	1.30	1,300	110.00	143,000		0	150,000	150,000		0	293,000
	34			**SITE SECURITY**					**0**		**50,000**		**375,000**		**0**		**0**	**425,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire and Gas Alarm Systems	1	ls			0		0	150,000	150,000		0		0	150,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**450,000**		**0**		**0**	**450,000**
	40			Engine, fuel, and auxiliaries controls installation	400	pt			0		0	750	300,000		0		0	300,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
NG-TK-20: LNG - Takhini - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**11,255,403**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	11,255,403
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
DL-LF-05: Diesel - Landfill - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**15,420 hrs**	**$1,831,477**	**$5,771,490**	**$7,958,663**	**$4,400,750**	**$32,007,606**
-	1	-	Major Equipment	6,240 hrs	$686,400	$223,000	$4,460,000	$150,000	$5,519,400
-	2	-	General Civil	00 hrs	$0	$3,048,265	$755,000	$0	$3,803,265
-	3	-	Buildings and Structures	00 hrs	$0	$722,825	$80,000	$4,200,000	$5,002,825
-	4	-	Mechanical and Process	4,143 hrs	$455,693	$112,500	$1,463,750	$0	$2,031,943
-	5	-	Electrical, Instrumentation & Controls	5,037 hrs	$604,089	$1,664,900	$1,110,713	$0	$3,379,702
-	**6**	-	**Sub Total Directs**	15,420 hrs	**$1,746,183**	**$5,771,490**	**$7,869,463**	**$4,350,000**	**$19,737,135**
-	7	-	AFE Engineering @ 3% of Directs	-	-	-	-	-	$592,114
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$1,578,971
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$690,800
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$296,057
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$85,294	-	-	$50,750	$136,044
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$89,200	-	$89,200
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$3,552,684
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$85,294**	**$0**	**$89,200**	**$50,750**	**$6,935,870**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$5,334,601

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
DL-LF-05: Diesel - Landfill - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**6,240**		**686,400**		**223,000**		**4,460,000**		**150,000**	**5,519,400**
	1			**Generating Station**					0		0		0		0		0	0
	2			Diesel fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	75,000	150,000	1,500,000	3,000,000		0	3,516,080
	3			Transportation	2	ea			0		0		0		0	75,000	150,000	150,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**Diesel Tank Farm**					0		0		0		0		0	0
	13			Diesel storage tanks: Double Walled (100% secondary containment, standard 75,000L design)	4	ea	160	1.30	832	110.00	91,520	3,250	13,000	65,000	260,000		0	364,520
	14			Diesel truck unloading and pump house, undergound containment tank, sump and lines	1	ea	1,600	1.30	2,080	110.00	228,800	60,000	60,000	1,200,000	1,200,000		0	1,488,800
	15			Transportation	5	ea			0		0		0		0	20,000	100,000	100,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
DL-LF-05: Diesel - Landfill - 5 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,048,265**		**755,000**		**0**	**3,803,265**
	1			Clearing & Grubbing	5.5	ha			0		0	$30,000	165,000		0		0	165,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	5,500	m^3			0		0	$15	82,500		0		0	82,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	3,465	tonne			0		0	$35	121,275		0		0	121,275
	8			Granular Sub-Base - 300mm	6,930	tonne			0		0	$18	124,740		0		0	124,740
	9			Asphalt - (Base and Seal)	2,205	tonne			0		0	$150	330,750		0		0	330,750
	10			Fencing (8ft, angular razor wire)	1,000	m			0		0	$300	300,000		0		0	300,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			Double walled U/G diesel line form storage to plant	100	m			0		0	$1,500	150,000		0		0	150,000
	16			**FIRE WATER**					**0**		**0**		**1,200,000**		**755,000**		**0**	**1,955,000**
	17			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	18			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	19			Fire Loop (allowance) & Recirc Pumps	1,000	m			0		0	$300	300,000		50,000		0	350,000
	20			Fire Hydrants	10	ea.			0		0		0	10,500	105,000		0	105,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
DL-LF-05: Diesel - Landfill - 5 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**722,825**		**80,000**		**4,200,000**	**5,002,825**
	1			**FUEL STORAGE**					**0**		**0**		**245,000**		**80,000**		**0**	**325,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 10 m x 35 m x 0.3 m	105	m^3			0		0	1,500	157,500		0		0	157,500
	4			Process/Tank Containment					0		0		0		0		0	0
	5			Containment Tank / Piping	1	lot			0		0	20,000	20,000	80,000	80,000		0	100,000
	6			Concrete pad 30 m x 5 m x 0.3 m	45	m^3			0		0	1,500	67,500		0		0	67,500
	7			**GENERATOR HALL**					**0**		**0**		**108,825**		**0**		**4,200,000**	**4,308,825**
	8			Pre-engineered Building					0		0		0		0		0	0
	9			Building Size 25 m x 70 m	1,750	m^2			0		0		0		0	2,400	4,200,000	4,200,000
	10			Generator Foundation					0		0		0		0		0	0
	11			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 2	40	m^3			0		0	1,500	60,000		0		0	60,000
	12			Generator Stack Foundation					0		0		0		0		0	0
	13			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 2	4	m^3			0		0	1,500	5,625		0		0	5,625
	14			Radiator Foundation					0		0		0		0		0	0
	15			Concrete Pad 6 m x 8 m x 0.3 m / each quantity 2	29	m^3			0		0	1,500	43,200		0		0	43,200
	16			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	17			Transformer					0		0		0		0		0	0
	18			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	19			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	20			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	21			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	22			Breaker					0		0		0		0		0	0
	23			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
DL-LF-05: Diesel - Landfill - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,143**		**455,693**		**112,500**		**1,463,750**		**0**	**2,031,943**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	2	lot	107	1.30	277	110.00	30,507	5,000	10,000	75,000	150,000		0	190,507
	3			Glycol Heating System (incl unit heaters, electric & diesel boiler)	2	lot	107	1.30	277	110.00	30,507	7,500	15,000	150,000	300,000		0	345,507
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	40,000	40,000	400,000	400,000		0	623,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	110,000	110,000		0	193,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	80,000	80,000		0	135,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	15,000	15,000	175,000	175,000		0	241,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	10,000	7,500	100,000	100,000		0	153,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	1,750	m^2			0		0		0	85	148,750		0	148,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
DL-LF-05: Diesel - Landfill - 5 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,037**		**604,089**		**1,664,900**		**1,110,713**		**0**	**3,379,702**
	1			**STATION ELECTRICAL**					**2,457**		**270,270**		**840,000**		**345,000**		**0**	**1,455,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	50,000	50,000		0		0	78,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 10 Sections)	10	sect	10	1.30	130	110.00	14,300		0	8,500	85,000		0	99,300
	9			BOP PLC and Instrumentation (100 Points, $1000 per Point)	1	ls			0		0		0	100,000	100,000		0	100,000
	10			Medium/Low Voltage Cable	3,000	ft	0.15	1.30	585	110.00	64,350	30	90,000		0		0	154,350
	11			Cable Tray and Cables from Unit Output to Electrical Room	3,000	ft	0.30	1.30	1,170	110.00	128,700	45	135,000		0		0	263,700
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	50,000	50,000		0		0	50,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**110,000**		**43,000**		**0**	**184,460**
	16			Station Service Transformer 300KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	25,000	25,000		0	28,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	95,000	95,000		0		0	95,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,294**		**252,359**		**39,900**		**722,713**		**0**	**1,014,972**
	23			Transformer - 5MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	12,000	12,000	255,000	255,000		0	292,740
	24			Breaker - 34.5 kV, 650 kV BIL, 600A, 31.5 kA (min) outdoor dead tank c/w multi-ratio CTs	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 1/0 AWG, XLPE insulation, aluminum conductor, 100% insulation	240	M	0.5	1.30	140	110.00	15,444	0	0	79	18,900		0	34,344
	29			Conductor - Bare, 336.4 kcmil AAC (Tulip)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	12	ea	7	1.30	105	110.00	11,583	450	5,400	0	0		0	16,983
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**300,000**		**0**		**0**	**350,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire Alarm Systems	1	ls			0		0	75,000	75,000		0		0	75,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**375,000**		**0**		**0**	**375,000**
	40			Engine, fuel, and auxiliaries controls installation	300	pt			0		0	750	225,000		0		0	225,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
DL-LF-05: Diesel - Landfill - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**3,552,684**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	3,552,684
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
DL-LF-10: Diesel - Landfill - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**20,822 hrs**	**$2,454,188**	**$6,199,300**	**$11,896,463**	**$5,766,500**	**$42,180,847**
-	1	-	Major Equipment	10,192 hrs	$1,121,120	$382,750	$7,655,000	$300,000	$9,458,870
-	2	-	General Civil	00 hrs	$0	$3,044,800	$755,000	$0	$3,799,800
-	3	-	Buildings and Structures	00 hrs	$0	$788,450	$80,000	$5,400,000	$6,268,450
-	4	-	Mechanical and Process	4,697 hrs	$516,707	$152,500	$1,978,750	$0	$2,647,957
-	5	-	Electrical, Instrumentation & Controls	5,933 hrs	$702,616	$1,830,800	$1,274,613	$0	$3,808,029
-	**6**	-	**Sub Total Directs**	20,822 hrs	**$2,340,443**	**$6,199,300**	**$11,743,363**	**$5,700,000**	**$25,983,105**
-	7	-	AFE Engineering @ 3% of Directs	-	-	-	-	-	$779,493
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$2,078,648
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$909,409
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$389,747
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$113,745	-	-	$66,500	$180,245
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$153,100	-	$153,100
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$4,676,959
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$113,745**	**$0**	**$153,100**	**$66,500**	**$9,167,601**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$7,030,141

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
DL-LF-10: Diesel - Landfill - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**10,192**		**1,121,120**		**382,750**		**7,655,000**		**300,000**	**9,458,870**
	1			**Generating Station**					0		0		0		0		0	0
	2			Diesel fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	75,000	300,000	1,500,000	6,000,000		0	7,032,160
	3			Transportation	4	ea			0		0		0		0	75,000	300,000	300,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**Diesel Tank Farm**					0		0		0		0		0	0
	13			Diesel storage tanks: Double Walled (100% secondary containment, standard 75,000L design)	7	ea	160	1.30	1,456	110.00	160,160	3,250	22,750	65,000	455,000		0	637,910
	14			Diesel truck unloading and pump house, undergound containment tank, sump and lines	1	ea	1,600	1.30	2,080	110.00	228,800	60,000	60,000	1,200,000	1,200,000		0	1,488,800
	15			Transportation	8	ea			0		0		0		0	20,000	160,000	160,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
DL-LF-10: Diesel - Landfill - 10 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,044,800**		**755,000**		**0**	**3,799,800**
	1			Clearing & Grubbing	5.5	ha			0		0	$30,000	165,000		0		0	165,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	5,500	m^3			0		0	$15	82,500		0		0	82,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	6,930	tonne			0		0	$35	242,550		0		0	242,550
	8			Granular Sub-Base - 300mm	0	tonne			0		0	$18	0		0		0	0
	9			Asphalt - (Base and Seal)	2,205	tonne			0		0	$150	330,750		0		0	330,750
	10			Fencing (8ft, angular razor wire)	1,000	m			0		0	$300	300,000		0		0	300,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			Double walled U/G diesel line form storage to plant	100	m			0		0	$1,500	150,000		0		0	150,000
	16			**FIRE WATER**					**0**		**0**		**1,200,000**		**755,000**		**0**	**1,955,000**
	17			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	18			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	19			Fire Loop (allowance) & Recirc Pumps	1,000	m			0		0	$300	300,000		50,000		0	350,000
	20			Fire Hydrants	10	ea.			0		0		0	10,500	105,000		0	105,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
DL-LF-10: Diesel - Landfill - 10 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**788,450**		**80,000**		**5,400,000**	**6,268,450**
	1			**FUEL STORAGE**					**0**		**0**		**245,000**		**80,000**		**0**	**325,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 10 m x 35 m x 0.3 m	105	m^3			0		0	1,500	157,500		0		0	157,500
	4			Process/Tank Containment					0		0		0		0		0	0
	5			Containment Tank / Piping	1	lot			0		0	20,000	20,000	80,000	80,000		0	100,000
	6			Concrete pad 30 m x 5 m x 0.3 m	45	m^3			0		0	1,500	67,500		0		0	67,500
	7			**GENERATOR HALL**					**0**		**0**		**174,450**		**0**		**5,400,000**	**5,574,450**
	8			Pre-engineered Building					0		0		0		0		0	0
	9			Building Size 25 m x 90 m	2,250	m^2			0		0		0		0	2,400	5,400,000	5,400,000
	10			Generator Foundation					0		0		0		0		0	0
	11			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	12			Generator Stack Foundation					0		0		0		0		0	0
	13			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 4	8	m^3			0		0	1,500	11,250		0		0	11,250
	14			Radiator Foundation					0		0		0		0		0	0
	15			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	16			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	17			Transformer					0		0		0		0		0	0
	18			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	19			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	20			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	21			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	22			Breaker					0		0		0		0		0	0
	23			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
DL-LF-10: Diesel - Landfill - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,697**		**516,707**		**152,500**		**1,978,750**		**0**	**2,647,957**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	4	lot	107	1.30	555	110.00	61,013	5,000	20,000	60,000	240,000		0	321,013
	3			Glycol Heating System (incl unit heaters, electric & diesel boiler)	4	lot	107	1.30	555	110.00	61,013	7,500	30,000	125,000	500,000		0	591,013
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	50,000	50,000	500,000	500,000		0	733,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	135,000	135,000		0	218,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	90,000	90,000		0	145,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	220,000	220,000		0	291,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	12,500	7,500	125,000	125,000		0	178,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	2,250	m^2			0		0		0	75	168,750		0	168,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
DL-LF-10: Diesel - Landfill - 10 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,933**		**702,616**		**1,830,800**		**1,274,613**		**0**	**3,808,029**
	1			**STATION ELECTRICAL**					**3,107**		**341,770**		**940,000**		**412,500**		**0**	**1,694,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	60,000	60,000		0		0	88,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 15 Sections)	15	sect	10	1.30	195	110.00	21,450		0	8,500	127,500		0	148,950
	9			BOP PLC and Instrumentation (125 Points, $1000 per Point)	1	ls			0		0		0	125,000	125,000		0	125,000
	10			Medium/Low Voltage Cable	4,000	ft	0.15	1.30	780	110.00	85,800	30	120,000		0		0	205,800
	11			Cable Tray and Cables from Unit Output to Electrical Room	4,000	ft	0.30	1.30	1,560	110.00	171,600	45	180,000		0		0	351,600
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	65,000	65,000		0		0	65,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**130,000**		**45,500**		**0**	**206,960**
	16			Station Service Transformer 400KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	27,500	27,500		0	31,075
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	115,000	115,000		0		0	115,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,540**		**279,386**		**48,300**		**816,613**		**0**	**1,144,299**
	23			Transformer - 10 MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	15,000	15,000	330,000	330,000		0	370,740
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	480	M	0.5	1.30	281	110.00	30,888	0	0	79	37,800		0	68,688
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	24	ea	7	1.30	211	110.00	23,166	450	10,800	0	0		0	33,966
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**300,000**		**0**		**0**	**350,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire Alarm Systems	1	ls			0		0	75,000	75,000		0		0	75,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**412,500**		**0**		**0**	**412,500**
	40			Engine, fuel, and auxiliaries controls installation	350	pt			0		0	750	262,500		0		0	262,500
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
DL-LF-10: Diesel - Landfill - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**4,676,959**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	4,676,959
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
DL-LF-20: Diesel - Landfill - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**27,381 hrs**	**$3,216,122**	**$6,948,175**	**$20,363,550**	**$8,467,650**	**$62,478,684**
-	1	-	Major Equipment	14,976 hrs	$1,647,360	$755,500	$15,110,000	$450,000	$17,962,860
-	2	-	General Civil	00 hrs	$0	$3,044,800	$755,000	$0	$3,799,800
-	3	-	Buildings and Structures	00 hrs	$0	$952,775	$80,000	$7,920,000	$8,952,775
-	4	-	Mechanical and Process	5,252 hrs	$577,720	$187,500	$2,397,500	$0	$3,162,720
-	5	-	Electrical, Instrumentation & Controls	7,153 hrs	$836,786	$2,007,600	$1,718,850	$0	$4,563,236
-	**6**	-	**Sub Total Directs**	27,381 hrs	**$3,061,866**	**$6,948,175**	**$20,061,350**	**$8,370,000**	**$38,441,391**
-	7	-	AFE Engineering @ 3% of Directs	-	-	-	-	-	$1,153,242
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$3,075,311
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$1,345,449
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$576,621
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$154,256	-	-	$97,650	$251,906
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$302,200	-	$302,200
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$6,919,450
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$154,256**	**$0**	**$302,200**	**$97,650**	**$13,624,179**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$10,413,114

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
DL-LF-20: Diesel - Landfill - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**14,976**		**1,647,360**		**755,500**		**15,110,000**		**450,000**	**17,962,860**
	1			**Generating Station**					0		0		0		0		0	0
	2			Diesel fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	75,000	300,000	1,500,000	6,000,000		0	7,032,160
	3			Diesel fired Reciprocating Engine - 5.0 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	175,000	350,000	3,500,000	7,000,000		0	7,716,080
	3			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**Diesel Tank Farm**					0		0		0		0		0	0
	13			Diesel storage tanks: Double Walled (100% secondary containment, standard 75,000L design)	14	ea	160	1.30	2,912	110.00	320,320	3,250	45,500	65,000	910,000		0	1,275,820
	14			Diesel truck unloading and pump house, undergound containment tank, sump and lines	1	ea	1,600	1.30	2,080	110.00	228,800	60,000	60,000	1,200,000	1,200,000		0	1,488,800
	15			Transportation	16	ea			0		0		0		0	20,000	320,000	320,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
DL-LF-20: Diesel - Landfill - 20 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**3,044,800**		**755,000**		**0**	**3,799,800**
	1			Clearing & Grubbing	5.5	ha			0		0	$30,000	165,000		0		0	165,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	5,500	m^3			0		0	$15	82,500		0		0	82,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	6,930	tonne			0		0	$35	242,550		0		0	242,550
	8			Granular Sub-Base - 300mm	0	tonne			0		0	$18	0		0		0	0
	9			Asphalt - (Base and Seal)	2,205	tonne			0		0	$150	330,750		0		0	330,750
	10			Fencing (8ft, angular razor wire)	1,000	m			0		0	$300	300,000		0		0	300,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			Double walled U/G diesel line form storage to plant	100	m			0		0	$1,500	150,000		0		0	150,000
	16			**FIRE WATER**					**0**		**0**		**1,200,000**		**755,000**		**0**	**1,955,000**
	17			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	18			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	19			Fire Loop (allowance) & Recirc Pumps	1,000	m			0		0	$300	300,000		50,000		0	350,000
	20			Fire Hydrants	10	ea.			0		0		0	10,500	105,000		0	105,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
DL-LF-20: Diesel - Landfill - 20 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**952,775**		**80,000**		**7,920,000**	**8,952,775**
	1			**FUEL STORAGE**					**0**		**0**		**245,000**		**80,000**		**0**	**325,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 10 m x 35 m x 0.3 m	105	m^3			0		0	1,500	157,500		0		0	157,500
	4			Process/Tank Containment					0		0		0		0		0	0
	5			Containment Tank / Piping	1	lot			0		0	20,000	20,000	80,000	80,000		0	100,000
	6			Concrete pad 30 m x 5 m x 0.3 m	45	m^3			0		0	1,500	67,500		0		0	67,500
	7			**GENERATOR HALL**					**0**		**0**		**338,775**		**0**		**7,920,000**	**8,258,775**
	8			Pre-engineered Building					0		0		0		0		0	0
	9			Building Size 30 m x 110 m	3,300	m^2			0		0		0		0	2,400	7,920,000	7,920,000
	10			Generator Foundation					0		0		0		0		0	0
	11			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	12			Thickened Slab 5.5 m x 14 m x 0.5 m / each quantity 2	77	m^3			0		0	1,500	115,500		0		0	115,500
	13			Generator Stack Foundation					0		0		0		0		0	0
	14			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 6	11	m^3			0		0	1,500	16,875		0		0	16,875
	15			Radiator Foundation					0		0		0		0		0	0
	16			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	17			Concrete Pad 6 m x 8 m x 0.3 m / each quantity 2	29	m^3			0		0	1,500	43,200		0		0	43,200
	18			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	19			Transformer					0		0		0		0		0	0
	20			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	21			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	22			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	23			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	24			Breaker					0		0		0		0		0	0
	25			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
DL-LF-20: Diesel - Landfill - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,252**		**577,720**		**187,500**		**2,397,500**		**0**	**3,162,720**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	6	lot	107	1.30	832	110.00	91,520	5,000	30,000	50,000	300,000		0	421,520
	3			Glycol Heating System (incl unit heaters, electric & diesel boiler)	6	lot	107	1.30	832	110.00	91,520	7,500	45,000	100,000	600,000		0	736,520
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	60,000	60,000	600,000	600,000		0	843,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	150,000	150,000		0	233,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	100,000	100,000		0	155,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	250,000	250,000		0	321,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	15,000	7,500	150,000	150,000		0	203,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	3,300	m^2			0		0		0	75	247,500		0	247,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
DL-LF-20: Diesel - Landfill - 20 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**7,153**		**836,786**		**2,007,600**		**1,718,850**		**0**	**4,563,236**
	1			**STATION ELECTRICAL**					**3,757**		**413,270**		**1,050,000**		**480,000**		**0**	**1,943,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	70,000	70,000		0		0	98,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 20 Sections)	20	sect	10	1.30	260	110.00	28,600		0	8,500	170,000		0	198,600
	9			BOP PLC and Instrumentation (150 Points, $1000 per Point)	1	ls			0		0		0	150,000	150,000		0	150,000
	10			Medium/Low Voltage Cable	5,000	ft	0.15	1.30	975	110.00	107,250	30	150,000		0		0	257,250
	11			Cable Tray and Cables from Unit Output to Electrical Room	5,000	ft	0.30	1.30	1,950	110.00	214,500	45	225,000		0		0	439,500
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	90,000	90,000		0		0	90,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**150,000**		**48,000**		**0**	**229,460**
	16			Station Service Transformer 500KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	30,000	30,000		0	33,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	135,000	135,000		0		0	135,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**3,110**		**342,056**		**57,600**		**1,190,850**		**0**	**1,590,506**
	23			Transformer - 20MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	22,500	22,500	525,000	525,000		0	573,240
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	2	ea	90	1.30	234	110.00	25,740	1,500	3,000	111,000	222,000		0	250,740
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	2	ea	45	1.30	117	110.00	12,870	1,500	3,000	24,000	48,000		0	63,870
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	6	ea	12	1.30	94	110.00	10,296	750	4,500	7,500	45,000		0	59,796
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	6	ea	8	1.30	59	110.00	6,435	750	4,500	825	4,950		0	15,885
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	840	M	0.3	1.30	328	110.00	36,036	0	0	53	44,100		0	80,136
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	120	M	0.5	1.30	70	110.00	7,722	0	0	15	1,800		0	9,522
	30			Cable Terminations	42	ea	5	1.30	246	110.00	27,027	300	12,600	0	0		0	39,627
	31			Misc Hardware and electrical connectors	1	lot	90	1.30	117	110.00	12,870	7,500	7,500	0	0		0	20,370
	32			Line Protection Panel	2	ea	120	1.30	312	110.00	34,320	0	0	75,000	150,000		0	184,320
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	1,000	1.30	1,300	110.00	143,000		0	150,000	150,000		0	293,000
	34			**SITE SECURITY**					**0**		**50,000**		**300,000**		**0**		**0**	**350,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire Alarm Systems	1	ls			0		0	75,000	75,000		0		0	75,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**450,000**		**0**		**0**	**450,000**
	40			Engine, fuel, and auxiliaries controls installation	400	pt			0		0	750	300,000		0		0	300,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
DL-LF-20: Diesel - Landfill - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**6,919,450**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	6,919,450
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
DL-TK-05: Diesel - Takhini - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**15,420 hrs**	**$1,831,254**	**$5,589,165**	**$7,958,663**	**$4,400,750**	**$31,714,160**
-	1	-	Major Equipment	6,240 hrs	$686,400	$223,000	$4,460,000	$150,000	$5,519,400
-	2	-	General Civil	00 hrs	$0	$2,865,940	$755,000	$0	$3,620,940
-	3	-	Buildings and Structures	00 hrs	$0	$722,825	$80,000	$4,200,000	$5,002,825
-	4	-	Mechanical and Process	4,143 hrs	$455,693	$112,500	$1,463,750	$0	$2,031,943
-	5	-	Electrical, Instrumentation & Controls	5,037 hrs	$604,089	$1,664,900	$1,110,713	$0	$3,379,702
-	**6**	-	**Sub Total Directs**	15,420 hrs	**$1,746,183**	**$5,589,165**	**$7,869,463**	**$4,350,000**	**$19,554,810**
-	7	-	AFE Engineering @ 3% of Directs	-	-	-	-	-	$586,644
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$1,564,385
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$684,418
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$293,322
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$85,071	-	-	$50,750	$135,821
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$89,200	-	$89,200
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$3,519,866
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$85,071**	**$0**	**$89,200**	**$50,750**	**$6,873,656**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$5,285,693

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
DL-TK-05: Diesel - Takhini - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**6,240**		**686,400**		**223,000**		**4,460,000**		**150,000**	**5,519,400**
	1			**Generating Station**					0		0		0		0		0	0
	2			Diesel fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	75,000	150,000	1,500,000	3,000,000		0	3,516,080
	3			Transportation	2	ea			0		0		0		0	75,000	150,000	150,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**Diesel Tank Farm**					0		0		0		0		0	0
	13			Diesel storage tanks: Double Walled (100% secondary containment, standard 75,000L design)	4	ea	160	1.30	832	110.00	91,520	3,250	13,000	65,000	260,000		0	364,520
	14			Diesel truck unloading and pump house, underground containment tank, sump and lines	1	ea	1,600	1.30	2,080	110.00	228,800	60,000	60,000	1,200,000	1,200,000		0	1,488,800
	15			Transportation	5	ea			0		0		0		0	20,000	100,000	100,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
DL-TK-05: Diesel - Takhini - 5 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**2,865,940**		**755,000**		**0**	**3,620,940**
	1			Clearing & Grubbing	4.5	ha			0		0	$30,000	135,000		0		0	135,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	4,500	m^3			0		0	$15	67,500		0		0	67,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	2,640	tonne			0		0	$35	92,400		0		0	92,400
	8			Granular Sub-Base - 300mm	5,280	tonne			0		0	$18	95,040		0		0	95,040
	9			Asphalt - (Base and Seal)	1,680	tonne			0		0	$150	252,000		0		0	252,000
	10			Fencing (8ft, angular razor wire)	1,000	m			0		0	$300	300,000		0		0	300,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			Double walled U/G diesel line form storage to plant	100	m			0		0	$1,500	150,000		0		0	150,000
	16			**FIRE WATER**					**0**		**0**		**1,200,000**		**755,000**		**0**	**1,955,000**
	17			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	18			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	19			Fire Loop (allowance) & Recirc Pumps	1,000	m			0		0	$300	300,000		50,000		0	350,000
	20			Fire Hydrants	10	ea.			0		0		0	10,500	105,000		0	105,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
DL-TK-05: Diesel - Takhini - 5 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**722,825**		**80,000**		**4,200,000**	**5,002,825**
	1			**FUEL STORAGE**					**0**		**0**		**245,000**		**80,000**		**0**	**325,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 10 m x 35 m x 0.3 m	105	m^3			0		0	1,500	157,500		0		0	157,500
	4			Process/Tank Containment					0		0		0		0		0	0
	5			Containment Tank / Piping	1	lot			0		0	20,000	20,000	80,000	80,000		0	100,000
	6			Concrete pad 30 m x 5 m x 0.3 m	45	m^3			0		0	1,500	67,500		0		0	67,500
	7			**GENERATOR HALL**					**0**		**0**		**108,825**		**0**		**4,200,000**	**4,308,825**
	8			Pre-engineered Building					0		0		0		0		0	0
	9			Building Size 25 m x 70 m	1,750	m^2			0		0		0		0	2,400	4,200,000	4,200,000
	10			Generator Foundation					0		0		0		0		0	0
	11			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 2	40	m^3			0		0	1,500	60,000		0		0	60,000
	12			Generator Stack Foundation					0		0		0		0		0	0
	13			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 2	4	m^3			0		0	1,500	5,625		0		0	5,625
	14			Radiator Foundation					0		0		0		0		0	0
	15			Concrete Pad 6 m x 8 m x 0.3 m / each quantity 2	29	m^3			0		0	1,500	43,200		0		0	43,200
	16			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	17			Transformer					0		0		0		0		0	0
	18			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	19			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	20			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	21			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	22			Breaker					0		0		0		0		0	0
	23			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
DL-TK-05: Diesel - Takhini - 5 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,143**		**455,693**		**112,500**		**1,463,750**		**0**	**2,031,943**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	2	lot	107	1.30	277	110.00	30,507	5,000	10,000	75,000	150,000		0	190,507
	3			Glycol Heating System (incl unit heaters, electric & diesel boiler)	2	lot	107	1.30	277	110.00	30,507	7,500	15,000	150,000	300,000		0	345,507
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	40,000	40,000	400,000	400,000		0	623,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	110,000	110,000		0	193,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	80,000	80,000		0	135,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	15,000	15,000	175,000	175,000		0	241,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	10,000	7,500	100,000	100,000		0	153,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	1,750	m^2			0		0		0	85	148,750		0	148,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
DL-TK-05: Diesel - Takhini - 5 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,037**		**604,089**		**1,664,900**		**1,110,713**		**0**	**3,379,702**
	1			**STATION ELECTRICAL**					**2,457**		**270,270**		**840,000**		**345,000**		**0**	**1,455,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	50,000	50,000		0		0	78,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 10 Sections)	10	sect	10	1.30	130	110.00	14,300		0	8,500	85,000		0	99,300
	9			BOP PLC and Instrumentation (100 Points, $1000 per Point)	1	ls			0		0		0	100,000	100,000		0	100,000
	10			Medium/Low Voltage Cable	3,000	ft	0.15	1.30	585	110.00	64,350	30	90,000		0		0	154,350
	11			Cable Tray and Cables from Unit Output to Electrical Room	3,000	ft	0.30	1.30	1,170	110.00	128,700	45	135,000		0		0	263,700
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	50,000	50,000		0		0	50,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**110,000**		**43,000**		**0**	**184,460**
	16			Station Service Transformer 300KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	25,000	25,000		0	28,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	95,000	95,000		0		0	95,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,294**		**252,359**		**39,900**		**722,713**		**0**	**1,014,972**
	23			Transformer - 5MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	12,000	12,000	255,000	255,000		0	292,740
	24			Breaker - 34.5 kV, 650 kV BIL, 600A, 31.5 kA (min) outdoor dead tank c/w multi-ratio CTs	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 1/0 AWG, XLPE insulation, aluminum conductor, 100% insulation	240	M	0.5	1.30	140	110.00	15,444	0	0	79	18,900		0	34,344
	29			Conductor - Bare, 336.4 kcmil AAC (Tulip)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	12	ea	7	1.30	105	110.00	11,583	450	5,400	0	0		0	16,983
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**300,000**		**0**		**0**	**350,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire Alarm Systems	1	ls			0		0	75,000	75,000		0		0	75,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**375,000**		**0**		**0**	**375,000**
	40			Engine, fuel, and auxiliaries controls installation	300	pt			0		0	750	225,000		0		0	225,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
DL-TK-05: Diesel - Takhini - 5 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**3,519,866**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	3,519,866
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
DL-TK-10: Diesel - Takhini - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**20,822 hrs**	**$2,453,969**	**$6,020,440**	**$11,896,463**	**$5,766,500**	**$41,892,977**
-	1	-	Major Equipment	10,192 hrs	$1,121,120	$382,750	$7,655,000	$300,000	$9,458,870
-	2	-	General Civil	00 hrs	$0	$2,865,940	$755,000	$0	$3,620,940
-	3	-	Buildings and Structures	00 hrs	$0	$788,450	$80,000	$5,400,000	$6,268,450
-	4	-	Mechanical and Process	4,697 hrs	$516,707	$152,500	$1,978,750	$0	$2,647,957
-	5	-	Electrical, Instrumentation & Controls	5,933 hrs	$702,616	$1,830,800	$1,274,613	$0	$3,808,029
-	**6**	-	**Sub Total Directs**	20,822 hrs	**$2,340,443**	**$6,020,440**	**$11,743,363**	**$5,700,000**	**$25,804,245**
-	7	-	AFE Engineering @ 3% of Directs	-	-	-	-	-	$774,127
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$2,064,340
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$903,149
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$387,064
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$113,526	-	-	$66,500	$180,026
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$153,100	-	$153,100
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$4,644,764
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$113,526**	**$0**	**$153,100**	**$66,500**	**$9,106,569**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$6,982,163

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
DL-TK-10: Diesel - Takhini - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**10,192**		**1,121,120**		**382,750**		**7,655,000**		**300,000**	**9,458,870**
	1			**Generating Station**					0		0		0		0		0	0
	2			Diesel fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	75,000	300,000	1,500,000	6,000,000		0	7,032,160
	3			Transportation	4	ea			0		0		0		0	75,000	300,000	300,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**Diesel Tank Farm**					0		0		0		0		0	0
	13			Diesel storage tanks: Double Walled (100% secondary containment, standard 75,000L design)	7	ea	160	1.30	1,456	110.00	160,160	3,250	22,750	65,000	455,000		0	637,910
	14			Diesel truck unloading and pump house, undergound containment tank, sump and lines	1	ea	1,600	1.30	2,080	110.00	228,800	60,000	60,000	1,200,000	1,200,000		0	1,488,800
	15			Transportation	8	ea			0		0		0		0	20,000	160,000	160,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
DL-TK-10: Diesel - Takhini - 10 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**2,865,940**		**755,000**		**0**	**3,620,940**
	1			Clearing & Grubbing	4.5	ha			0		0	$30,000	135,000		0		0	135,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	4,500	m^3			0		0	$15	67,500		0		0	67,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	2,640	tonne			0		0	$35	92,400		0		0	92,400
	8			Granular Sub-Base - 300mm	5,280	tonne			0		0	$18	95,040		0		0	95,040
	9			Asphalt - (Base and Seal)	1,680	tonne			0		0	$150	252,000		0		0	252,000
	10			Fencing (8ft, angular razor wire)	1,000	m			0		0	$300	300,000		0		0	300,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			Double walled U/G diesel line form storage to plant	100	m			0		0	$1,500	150,000		0		0	150,000
	16			**FIRE WATER**					**0**		**0**		**1,200,000**		**755,000**		**0**	**1,955,000**
	17			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	18			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	19			Fire Loop (allowance) & Recirc Pumps	1,000	m			0		0	$300	300,000		50,000		0	350,000
	20			Fire Hydrants	10	ea.			0		0		0	10,500	105,000		0	105,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
DL-TK-10: Diesel - Takhini - 10 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**788,450**		**80,000**		**5,400,000**	**6,268,450**
	1			**FUEL STORAGE**					**0**		**0**		**245,000**		**80,000**		**0**	**325,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 10 m x 35 m x 0.3 m	105	m^3			0		0	1,500	157,500		0		0	157,500
	4			Process/Tank Containment					0		0		0		0		0	0
	5			Containment Tank / Piping	1	lot			0		0	20,000	20,000	80,000	80,000		0	100,000
	6			Concrete pad 30 m x 5 m x 0.3 m	45	m^3			0		0	1,500	67,500		0		0	67,500
	7			**GENERATOR HALL**					**0**		**0**		**174,450**		**0**		**5,400,000**	**5,574,450**
	8			Pre-engineered Building					0		0		0		0		0	0
	9			Building Size 25 m x 90 m	2,250	m^2			0		0		0		0	2,400	5,400,000	5,400,000
	10			Generator Foundation					0		0		0		0		0	0
	11			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	12			Generator Stack Foundation					0		0		0		0		0	0
	13			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 4	8	m^3			0		0	1,500	11,250		0		0	11,250
	14			Radiator Foundation					0		0		0		0		0	0
	15			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	16			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	17			Transformer					0		0		0		0		0	0
	18			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	19			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	20			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	21			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	22			Breaker					0		0		0		0		0	0
	23			Concrete Pad 5 m x 10 m x 0.3 m	15	m^3			0		0	1,500	22,500		0		0	22,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
DL-TK-10: Diesel - Takhini - 10 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**4,697**		**516,707**		**152,500**		**1,978,750**		**0**	**2,647,957**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	4	lot	107	1.30	555	110.00	61,013	5,000	20,000	60,000	240,000		0	321,013
	3			Glycol Heating System (incl unit heaters, electric & diesel boiler)	4	lot	107	1.30	555	110.00	61,013	7,500	30,000	125,000	500,000		0	591,013
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	50,000	50,000	500,000	500,000		0	733,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	135,000	135,000		0	218,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	90,000	90,000		0	145,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	220,000	220,000		0	291,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	12,500	7,500	125,000	125,000		0	178,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	2,250	m^2			0		0		0	75	168,750		0	168,750

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
DL-TK-10: Diesel - Takhini - 10 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,933**		**702,616**		**1,830,800**		**1,274,613**		**0**	**3,808,029**
	1			**STATION ELECTRICAL**					**3,107**		**341,770**		**940,000**		**412,500**		**0**	**1,694,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	60,000	60,000		0		0	88,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 15 Sections)	15	sect	10	1.30	195	110.00	21,450		0	8,500	127,500		0	148,950
	9			BOP PLC and Instrumentation (125 Points, $1000 per Point)	1	ls			0		0		0	125,000	125,000		0	125,000
	10			Medium/Low Voltage Cable	4,000	ft	0.15	1.30	780	110.00	85,800	30	120,000		0		0	205,800
	11			Cable Tray and Cables from Unit Output to Electrical Room	4,000	ft	0.30	1.30	1,560	110.00	171,600	45	180,000		0		0	351,600
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	65,000	65,000		0		0	65,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**130,000**		**45,500**		**0**	**206,960**
	16			Station Service Transformer 400KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	27,500	27,500		0	31,075
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	115,000	115,000		0		0	115,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**2,540**		**279,386**		**48,300**		**816,613**		**0**	**1,144,299**
	23			Transformer - 10 MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	15,000	15,000	330,000	330,000		0	370,740
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	1	ea	135	1.30	176	110.00	19,305	2,250	2,250	166,500	166,500		0	188,055
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	1	ea	68	1.30	88	110.00	9,653	2,250	2,250	36,000	36,000		0	47,903
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	3	ea	18	1.30	70	110.00	7,722	1,125	3,375	11,250	33,750		0	44,847
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	3	ea	11	1.30	44	110.00	4,826	1,125	3,375	1,238	3,713		0	11,914
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	480	M	0.5	1.30	281	110.00	30,888	0	0	79	37,800		0	68,688
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	60	M	0.7	1.30	53	110.00	5,792	0	0	23	1,350		0	7,142
	30			Cable Terminations	24	ea	7	1.30	211	110.00	23,166	450	10,800	0	0		0	33,966
	31			Misc Hardware and electrical connectors	1	lot	135	1.30	176	110.00	19,305	11,250	11,250	0	0		0	30,555
	32			Line Protection Panel	1	ea	180	1.30	234	110.00	25,740	0	0	112,500	112,500		0	138,240
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	750	1.30	975	110.00	107,250		0	95,000	95,000		0	202,250
	34			**SITE SECURITY**					**0**		**50,000**		**300,000**		**0**		**0**	**350,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire Alarm Systems	1	ls			0		0	75,000	75,000		0		0	75,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**412,500**		**0**		**0**	**412,500**
	40			Engine, fuel, and auxiliaries controls installation	350	pt			0		0	750	262,500		0		0	262,500
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
DL-TK-10: Diesel - Takhini - 10 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**4,644,764**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	4,644,764
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary
DL-TK-20: Diesel - Takhini - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL, BASE SCOPE**	**27,381 hrs**	**$3,215,903**	**$6,769,315**	**$20,363,550**	**$8,467,650**	**$62,190,814**
-	1	-	Major Equipment	14,976 hrs	$1,647,360	$755,500	$15,110,000	$450,000	$17,962,860
-	2	-	General Civil	00 hrs	$0	$2,865,940	$755,000	$0	$3,620,940
-	3	-	Buildings and Structures	00 hrs	$0	$952,775	$80,000	$7,920,000	$8,952,775
-	4	-	Mechanical and Process	5,252 hrs	$577,720	$187,500	$2,397,500	$0	$3,162,720
-	5	-	Electrical, Instrumentation & Controls	7,153 hrs	$836,786	$2,007,600	$1,718,850	$0	$4,563,236
-	**6**	-	**Sub Total Directs**	27,381 hrs	**$3,061,866**	**$6,769,315**	**$20,061,350**	**$8,370,000**	**$38,262,531**
-	7	-	AFE Engineering @ 3% of Directs	-	-	-	-	-	$1,147,876
-	8	-	Detail Engineering @ 8% Direct Construction Cost	-	-	-	-	-	$3,061,002
-	9	-	Construction Staff & Consultants and Construction Management Fee @3.5%	-	-	-	-	-	$1,339,189
-	10	-	Commissioning Costs - Excluding Owner's Staff @ 1.5% of Directs	-	-	-	-	-	$573,938
-	11	-	Escalation Allowance @ 3.5% Labour, 3.5% Construction Staff & Mgmt Fee, & 3.5% of 1/3 Sub-Contractor Cost	-	$154,037	-	-	$97,650	$251,687
-	12	-	Capital Spares - 2% Major Equipment	-	-	-	$302,200	-	$302,200
-	13	-	Indirect Construction Costs and Owner's Costs (See Line Item List, 18% of Directs)	-	-	-	-	-	$6,887,256
-	**14**	-	**Sub Total In-Directs**	**00 hrs**	**$154,037**	**$0**	**$302,200**	**$97,650**	**$13,563,147**
-	15	-	Contingency of 20% - AACE Class 5 Opinion of Probable Cost						$10,365,136

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Major Equipment
DL-TK-20: Diesel - Takhini - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **HC**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**14,976**		**1,647,360**		**755,500**		**15,110,000**		**450,000**	**17,962,860**
	1			**Generating Station**					0		0		0		0		0	0
	2			Diesel fired Reciprocating Engine - 2.5 MWe capacity, 4,160V	4	unit	1,280	1.30	6,656	110.00	732,160	75,000	300,000	1,500,000	6,000,000		0	7,032,160
	3			Diesel fired Reciprocating Engine - 5.0 MWe capacity, 4,160V	2	unit	1,280	1.30	3,328	110.00	366,080	175,000	350,000	3,500,000	7,000,000		0	7,716,080
	3			Transportation	6	ea			0		0		0		0	75,000	450,000	450,000
	4			Includes:					0		0		0		0		0	0
	5			Prime Mover					0		0		0		0		0	0
	6			Generator and Auxiliaries					0		0		0		0		0	0
	7			Mechanical Auxiliaries (circulating pumps / radiator)					0		0		0		0		0	0
	8			Electrical Control Equipment					0		0		0		0		0	0
	9			Heat Recovery / Rejection					0		0		0		0		0	0
	10			Engineering / Project Management / Drawings					0		0		0		0		0	0
	11			Sound Attenuation					0		0		0		0		0	0
	12			**Diesel Tank Farm**					0		0		0		0		0	0
	13			Diesel storage tanks: Double Walled (100% secondary containment, standard 75,000L design)	14	ea	160	1.30	2,912	110.00	320,320	3,250	45,500	65,000	910,000		0	1,275,820
	14			Diesel truck unloading and pump house, underground containment tank, sump and lines	1	ea	1,600	1.30	2,080	110.00	228,800	60,000	60,000	1,200,000	1,200,000		0	1,488,800
	15			Transportation	16	ea			0		0		0		0	20,000	320,000	320,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Civil
DL-TK-20: Diesel - Takhini - 20 MWe

Prepared by: **AW / RM**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **AF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**GENERAL CIVIL TOTAL**					**0**		**0**		**2,865,940**		**755,000**		**0**	**3,620,940**
	1			Clearing & Grubbing	4.5	ha			0		0	$30,000	135,000		0		0	135,000
	2			Excavation & Backfill for Structures & Slab (Allowance)	1	ea.			0		0	$225,000	225,000		0		0	225,000
	3			Site Drainage and Culverts (Allowance)	1	ea.			0		0	$125,000	125,000		0		0	125,000
	4			Site Grading - Incl. Roads and Parking Lot Preparation	4,500	m^3			0		0	$15	67,500		0		0	67,500
	5			General Landscaping	1	ea.			0		0	$60,000	60,000		0		0	60,000
	6			Water and Sewer Piping	80	m			0		0	$250	20,000		0		0	20,000
	7			Granular Base - 150mm	2,640	tonne			0		0	$35	92,400		0		0	92,400
	8			Granular Sub-Base - 300mm	5,280	tonne			0		0	$18	95,040		0		0	95,040
	9			Asphalt - (Base and Seal)	1,680	tonne			0		0	$150	252,000		0		0	252,000
	10			Fencing (8ft, angular razor wire)	1,000	m			0		0	$300	300,000		0		0	300,000
	11			Automatic Slide Gate (10m)	2	ea.			0		0	$6,000	12,000		0		0	12,000
	12			Slide Gate (10m)	1	ea.			0		0	$2,000	2,000		0		0	2,000
	13			Potable Water Well, pump, line, and HW tank.	1	ea.			0		0	$80,000	80,000		0		0	80,000
	14			Septic System	1	ea.			0		0	$50,000	50,000		0		0	50,000
	15			Double walled U/G diesel line form storage to plant	100	m			0		0	$1,500	150,000		0		0	150,000
	16			**FIRE WATER**					**0**		**0**		**1,200,000**		**755,000**		**0**	**1,955,000**
	17			Fire water heated storage (2x 30ft dia x 30ft tanks, insulated, 250,000 gal)	2	ea			0		0		0	300,000	600,000		0	600,000
	18			Fire water pump house (electric and diesel driven fire pumps, building)	1	lot			0		0	900,000	900,000		0		0	900,000
	19			Fire Loop (allowance) & Recirc Pumps	1,000	m			0		0	$300	300,000		50,000		0	350,000
	20			Fire Hydrants	10	ea.			0		0		0	10,500	105,000		0	105,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
DL-TK-20: Diesel - Takhini - 20 MWe

Prepared by: **JS**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**952,775**		**80,000**		**7,920,000**	**8,952,775**
	1			**FUEL STORAGE**					**0**		**0**		**245,000**		**80,000**		**0**	**325,000**
	2			Truck Unloading Pad					0		0		0		0		0	0
	3			Concrete Pad 10 m x 35 m x 0.3 m	105	m^3			0		0	1,500	157,500		0		0	157,500
	4			Process/Tank Containment					0		0		0		0		0	0
	5			Containment Tank / Piping	1	lot			0		0	20,000	20,000	80,000	80,000		0	100,000
	6			Concrete pad 30 m x 5 m x 0.3 m	45	m^3			0		0	1,500	67,500		0		0	67,500
	7			**GENERATOR HALL**					**0**		**0**		**338,775**		**0**		**7,920,000**	**8,258,775**
	8			Pre-engineered Building					0		0		0		0		0	0
	9			Building Size 30 m x 110 m	3,300	m^2			0		0		0		0	2,400	7,920,000	7,920,000
	10			Generator Foundation					0		0		0		0		0	0
	11			Thickened Slab 4 m x 10 m x 0.5 m / each quantity 4	80	m^3			0		0	1,500	120,000		0		0	120,000
	12			Thickened Slab 5.5 m x 14 m x 0.5 m / each quantity 2	77	m^3			0		0	1,500	115,500		0		0	115,500
	13			Generator Stack Foundation					0		0		0		0		0	0
	14			Concrete Pad 2.5 m x 2.5 m x 0.3 m / each quantity 6	11	m^3			0		0	1,500	16,875		0		0	16,875
	15			Radiator Foundation					0		0		0		0		0	0
	16			Concrete Pad 4 m x 6 m x 0.3 m / each quantity 4	29	m^3			0		0	1,500	43,200		0		0	43,200
	17			Concrete Pad 6 m x 8 m x 0.3 m / each quantity 2	29	m^3			0		0	1,500	43,200		0		0	43,200
	18			**SUBSTATION**					**0**		**0**		**369,000**		**0**		**0**	**369,000**
	19			Transformer					0		0		0		0		0	0
	20			Base 12 m x 18 m x 0.5 m	108	m^3			0		0	1,500	162,000		0		0	162,000
	21			Containment Walls 60 m x 1.2 m x 0.25 m	18	m^3			0		0	1,500	27,000		0		0	27,000
	22			Pier 11 m x 7.4 m x 1.2 m	98	m^3			0		0	1,500	146,520		0		0	146,520
	23			Steel Grating 1.5 m x 48.8 m	73	m^2			0		0	150	10,980		0		0	10,980
	24			Breaker					0		0		0		0		0	0

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical & Process
DL-TK-20: Diesel - Takhini - 20 MWe

Prepared by: **CGV**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **LF**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**5,252**		**577,720**		**187,500**		**2,397,500**		**0**	**3,162,720**
	1			Prime Movers and Fuel Storage (See Major Equipment)					0		0		0		0		0	0
	2			Fuel System Piping (from fuel storage, building internal)	6	lot	107	1.30	832	110.00	91,520	5,000	30,000	50,000	300,000		0	421,520
	3			Glycol Heating System (incl unit heaters, electric & diesel boiler)	6	lot	107	1.30	832	110.00	91,520	7,500	45,000	100,000	600,000		0	736,520
	4			Generating Station HVAC (electric unit heaters, building and combustion ventilation)	1	lot	1,280	1.30	1,664	110.00	183,040	60,000	60,000	600,000	600,000		0	843,040
	5			Allowance for Building Services / Plumbing	1	lot	480	1.30	624	110.00	68,640	15,000	15,000	150,000	150,000		0	233,640
	6			Allowance for Lube / Waste Oil System	1	lot	320	1.30	416	110.00	45,760	10,000	10,000	100,000	100,000		0	155,760
	7			Continuous Emissions Monitoring System	1	lot	360	1.30	468	110.00	51,480	20,000	20,000	250,000	250,000		0	321,480
	8			Instrument and Plant Compressed Air Systems	1	lot	320	1.30	416	110.00	45,760	15,000	7,500	150,000	150,000		0	203,260
	9			Generating Station Sprinkler System, extinguisher, fire protection equipment	3,300	m^2			0		0		0	75	247,500		0	247,500

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical, I&C
DL-TK-20: Diesel - Takhini - 20 MWe

Prepared by: **CGV / RF**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **ES**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**7,153**		**836,786**		**2,007,600**		**1,718,850**		**0**	**4,563,236**
	1			**STATION ELECTRICAL**					**3,757**		**413,270**		**1,050,000**		**480,000**		**0**	**1,943,270**
	2			Site wide Grounding Grid	1	lot	200	1.30	260	110.00	28,600	70,000	70,000		0		0	98,600
	3			Trench and conduit	1	lot	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	4			Transformer Protection Panel	1	ea	40	1.30	52	110.00	5,720		0	50,000	50,000		0	55,720
	5			Annunciator / Control / Metering Panel	1	ea	40	1.30	52	110.00	5,720		0	30,000	30,000		0	35,720
	6			SCADA / Communications	1	lot	60	1.30	78	110.00	8,580		0	50,000	50,000		0	58,580
	7			5kV, 3000A Switchgear	1	lot	40	1.30	52	110.00	5,720	120,000	120,000		0		0	125,720
	8			Station Services MCC (allow 20 Sections)	20	sect	10	1.30	260	110.00	28,600		0	8,500	170,000		0	198,600
	9			BOP PLC and Instrumentation (150 Points, $1000 per Point)	1	ls			0		0		0	150,000	150,000		0	150,000
	10			Medium/Low Voltage Cable	5,000	ft	0.15	1.30	975	110.00	107,250	30	150,000		0		0	257,250
	11			Cable Tray and Cables from Unit Output to Electrical Room	5,000	ft	0.30	1.30	1,950	110.00	214,500	45	225,000		0		0	439,500
	12			Utility Metering Allowance	1	lot	20	1.30	26	110.00	2,860	20,000	20,000		0		0	22,860
	13			Engine & Auxiliaries Instrumentation	1	lot			0		0	90,000	90,000		0		0	90,000
	14			Black Start Diesel Genset and Auxiliaries	1	lot			0		0	375,000	375,000		0		0	375,000
	15			**BUILDING SERVICES**					**286**		**31,460**		**150,000**		**48,000**		**0**	**229,460**
	16			Station Service Transformer 500KVA Dry Type Indoor (for Station Services MCC)	1	ea	25	1.30	33	110.00	3,575		0	30,000	30,000		0	33,575
	17			Station Service AC and DC distribution Panels (for transformer and breaker)	2	ea	20	1.30	52	110.00	5,720		0	4,000	8,000		0	13,720
	18			125V DC Station service battery	1	ea	40	1.30	52	110.00	5,720		0	8,000	8,000		0	13,720
	19			125V DC Station service battery charger	1	ea	15	1.30	20	110.00	2,145		0	2,000	2,000		0	4,145
	20			Building Services Allowance	1	lot			0		0	135,000	135,000		0		0	135,000
	21			Miscellaneous (tray, conduit, terminal blocks, etc.)	1	lot	100	1.30	130	110.00	14,300	15,000	15,000		0		0	29,300
	22			**SUBSTATION**					**3,110**		**342,056**		**57,600**		**1,190,850**		**0**	**1,590,506**
	23			Transformer - 20MW, 4.16 kV / 34.5 kV, +/- 5% Off Load Tap Changer and multi ratio CTs	1	ea	180	1.30	234	110.00	25,740	22,500	22,500	525,000	525,000		0	573,240
	24			Breaker - 34.5 kV, 650 kV BIL, 800A (min), 31.5 kA (min) outdoor dead tank	2	ea	90	1.30	234	110.00	25,740	1,500	3,000	111,000	222,000		0	250,740
	25			Disconnect - 34.5 kV, 600A Vertical Break, Group Operated, c/w interlocked ground switch	2	ea	45	1.30	117	110.00	12,870	1,500	3,000	24,000	48,000		0	63,870
	26			Potential Transformer - 34.5 kV, dual winding, outdoor, post type	6	ea	12	1.30	94	110.00	10,296	750	4,500	7,500	45,000		0	59,796
	27			Surge Arrestor - 24.4 kV MCOV, outdoor, station class, surge arresters	6	ea	8	1.30	59	110.00	6,435	750	4,500	825	4,950		0	15,885
	28			Cable - 5 kV, 500MCM, XLPE insulation, aluminum conductor, 100% insulation	840	M	0.3	1.30	328	110.00	36,036	0	0	53	44,100		0	80,136
	29			Conductor - Bare, 2/0 AWG AAC (Aster)	120	M	0.5	1.30	70	110.00	7,722	0	0	15	1,800		0	9,522
	30			Cable Terminations	42	ea	5	1.30	246	110.00	27,027	300	12,600	0	0		0	39,627
	31			Misc Hardware and electrical connectors	1	lot	90	1.30	117	110.00	12,870	7,500	7,500	0	0		0	20,370
	32			Line Protection Panel	2	ea	120	1.30	312	110.00	34,320	0	0	75,000	150,000		0	184,320
	33			34.5 kV Interconnection - poles, conductor, hardware, deadends	1	lot	1,000	1.30	1,300	110.00	143,000		0	150,000	150,000		0	293,000
	34			**SITE SECURITY**					**0**		**50,000**		**300,000**		**0**		**0**	**350,000**
	35			Roadway / Site Lighting	1	ls			0		50,000	100,000	100,000		0		0	150,000
	36			CCTV Security and Integration to System Control Centre	1	ls			0		0	75,000	75,000		0		0	75,000
	37			Fire Alarm Systems	1	ls			0		0	75,000	75,000		0		0	75,000
	38			Communications (fibre, CAT5, telephone)	1	ls			0		0	50,000	50,000		0		0	50,000
	39			**EI&C MISCELLANEOUS**					**0**		**0**		**450,000**		**0**		**0**	**450,000**
	40			Engine, fuel, and auxiliaries controls installation	400	pt			0		0	750	300,000		0		0	300,000
	41			Miscellaneous BOP Electrical Equipment Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	42			Miscellaneous Engine Electrical Allowance	1	ls			0		0	50,000	50,000		0		0	50,000
	43			Miscellaneous Electrical Equipment Grounding	1	ls			0		0	50,000	50,000		0		0	50,000

Client: **Yukon Energy Corporation**
Project: **Thermal Energy Plant Study**
Project No: **133547248**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Indirect and Owner's Costs
DL-TK-20: Diesel - Takhini - 20 MWe

Prepared by: **Team**
Date: **16-May-16**
Revision No.: **A**
Issue Date: **1-Jun-16**
Checked: **CGV**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	0			**TOTAL**					**0**		**0**		**0**		**0**		**0**	**6,887,256**
	1			Based on recent YEC experience, an 18% factor on direct costs is incorporated to cover:					0		0		0		0		0	6,887,256
	2			Contractor General Conditions					0		0		0		0		0	0
	3			Security					0		0		0		0		0	0
	4			Lock-out tag-out (LOTO) coordination					0		0		0		0		0	0
	5			Waste removal					0		0		0		0		0	0
	6			Snow removal					0		0		0		0		0	0
	7			Warehousing and utilities including temporary power supply					0		0		0		0		0	0
	8			Temporary construction lighting					0		0		0		0		0	0
	9			Taxes					0		0		0		0		0	0
	10			Interest charges during construction.					0		0		0		0		0	0
	11			Land acquisition and zoning					0		0		0		0		0	0
	12			Environmental studies, YESAB assessment and all permitting					0		0		0		0		0	0
	13			Owner's administration costs, including:					0		0		0		0		0	0
	14			Legal fees.					0		0		0		0		0	0
	15			Insurance.					0		0		0		0		0	0
	16			Salaries & expenses of Owner's project staff.					0		0		0		0		0	0
	17			Allowance for operators hours & fuel costs during training, commissioning, and start up.					0		0		0		0		0	0
	18			Special costs to dispose from site construction waste.					0		0		0		0		0	0
	19								0		0		0		0		0	0

Stantec

BASIS OF DESIGN (BOD)
THERMAL ENERGY PLANT STUDY

APPENDIX B

Concept Layouts

Yukon Energy Corp.
Thermal Energy Plant Development Study

File No.: 133547248/6_1_1
Date: August 5, 2016
Log ID:

Project No. 133547248

Transmittal Drawing List

Drawing No. Sheet No.	Client Drawing No.	Rev. No.	Drawing Title	Drawing By
B-0004 1 of 2		A	SITE LAYOUT - LANDFILL - MAP LNG - 5 MWE (NG-LD-5)	Stantec
B-0004 2 of 2		A	SITE LAYOUT - LANDFILL - CAD LNG - 5 MWE (NG-LD-5)	Stantec
B-0005 1 of 2		A	SITE LAYOUT - LANDFILL - MAP LNG - 10 MWE (NG-LD-10)	Stantec
B-0005 2 of 2		A	SITE LAYOUT - LANDFILL - CAD LNG - 10 MWE (NG-LD-10)	Stantec
B-0006 1 of 2		A	SITE LAYOUT - LANDFILL - MAP LNG - 20 MWE (NG-LD-20)	Stantec
B-0006 2 of 2		A	SITE LAYOUT - LANDFILL - CAD LNG - 20 MWE (NG-LD-20)	Stantec
B-0007 1 of 2		A	SITE LAYOUT - TAKHINI - MAP LNG - 5 MWE (NG-TK-5)	Stantec
B-0007 2 of 2		A	SITE LAYOUT - TAKHINI - CAD LNG - 5 MWE (NG-TK-5)	Stantec
B-0008 1 of 2		A	SITE LAYOUT - TAKHINI - MAP LNG - 10 MWE (NG-TK-10)	Stantec

Drawing No. Sheet No.	Client Drawing No.	Rev. No.	Drawing Title	Drawing By
B-0008 2 of 2		A	SITE LAYOUT - TAKHINI - CAD LNG - 10 MWE (NG-TK-10)	Stantec
B-0009 1 of 2		A	SITE LAYOUT - TAKHINI - MAP LNG - 20 MWE (NG-TK-20)	Stantec
B-0009 2 of 2		A	SITE LAYOUT - TAKHINI - CAD LNG - 20 MWE (NG-TK-20)	Stantec
B-0013 1 of 2		A	SITE LAYOUT - LANDFILL - MAP DIESEL - 5 MWE (DL-LD-5)	Stantec
B-0013 2 of 2		A	SITE LAYOUT - LANDFILL - CAD DIESEL - 5 MWE (DL-LD-5)	Stantec
B-0014 1 of 2		A	SITE LAYOUT - LANDFILL - MAP DIESEL - 10 MWE (DL-LD-10)	Stantec
B-0014 2 of 2		A	SITE LAYOUT - LANDFILL - CAD DIESEL - 10 MWE (DL-LD-10)	Stantec
B-0015 1 of 2		A	SITE LAYOUT - LANDFILL - MAP DIESEL - 20 MWE (DL-LD-20)	Stantec
B-0015 2 of 2		A	SITE LAYOUT - LANDFILL - CAD DIESEL - 20 MWE (DL-LD-20)	Stantec
B-0016 1 of 2		A	SITE LAYOUT - TAKHINI - MAP DIESEL - 5 MWE (DL-TK-5)	Stantec

Drawing No. Sheet No.	Client Drawing No.	Rev. No.	Drawing Title	Drawing By
B-0016 2 of 2		A	SITE LAYOUT - TAKHINI - CAD DIESEL - 5 MWE (DL-TK-5)	Stantec
B-0017 1 of 2		A	SITE LAYOUT - TAKHINI - MAP DIESEL - 10 MWE (DL-TK-10)	Stantec
B-0017 2 of 2		A	SITE LAYOUT - TAKHINI - CAD DIESEL - 10 MWE (DL-TK-10)	Stantec
B-0018 1 of 2		A	SITE LAYOUT - TAKHINI - MAP DIESEL - 20 MWE (DL-TK-20)	Stantec
B-0018 2 of 2		A	SITE LAYOUT - TAKHINI - CAD DIESEL - 20 MWE (DL-TK-20)	Stantec

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REV.	ISSUED TO	ISSUED FOR	REV.	DATE	BY	REVISIONS	DES	DFTG
A	JUNE 02, 2016 CLIENT	REVIEW						

Stantec

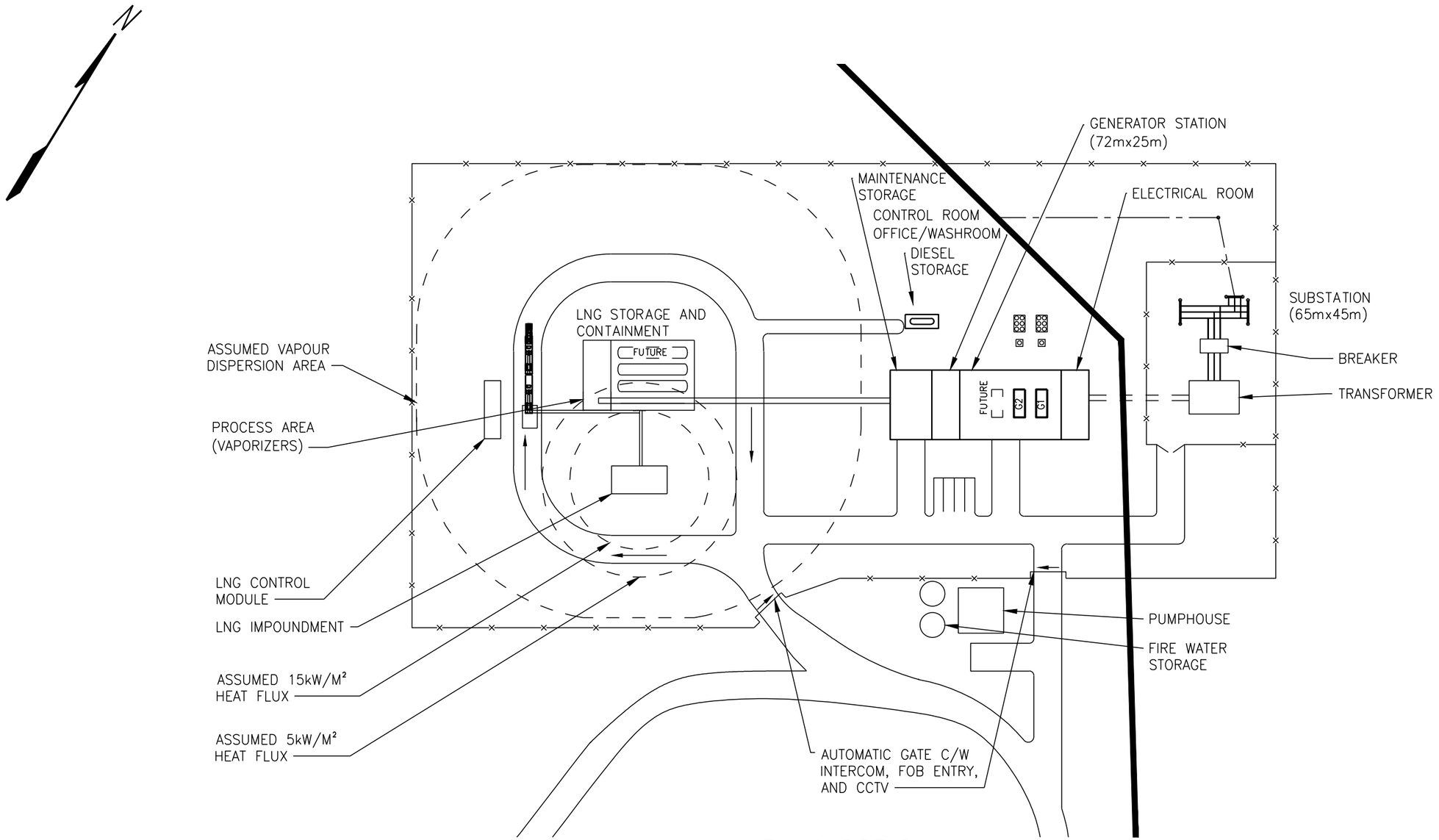
DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
		CGV	AAB	1:1500
SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – MAP
LNG – 5 MWe (NG–LD–5)

JOB No.	DWG. No.	SHEET		REV
133547248	B–0004	1 of 2		A



5MW OPTION

0 30m 60m

SCALE 1:1500

REV.	ISSUED TO	ISSUED FOR
A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – CAD
LNG – 5 MWe (NG-LD-5)

JOB No.	DWG. No.	SHEET		REV
133547248	B-0004	of	2	A

Aug 04, 2016 4:04pm abaxter \\cd1214-f02\workgroup\1335\active\133547248\21_environmental\3_drawing\133547248B0005.dwg

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A	JUNE 02, 2016 CLIENT	REVIEW						

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		CGV	AAB	1:1500
SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – MAP
LNG – 10 MWe (NG-LD-10)

JOB No.	DWG. No.	SHEET		REV
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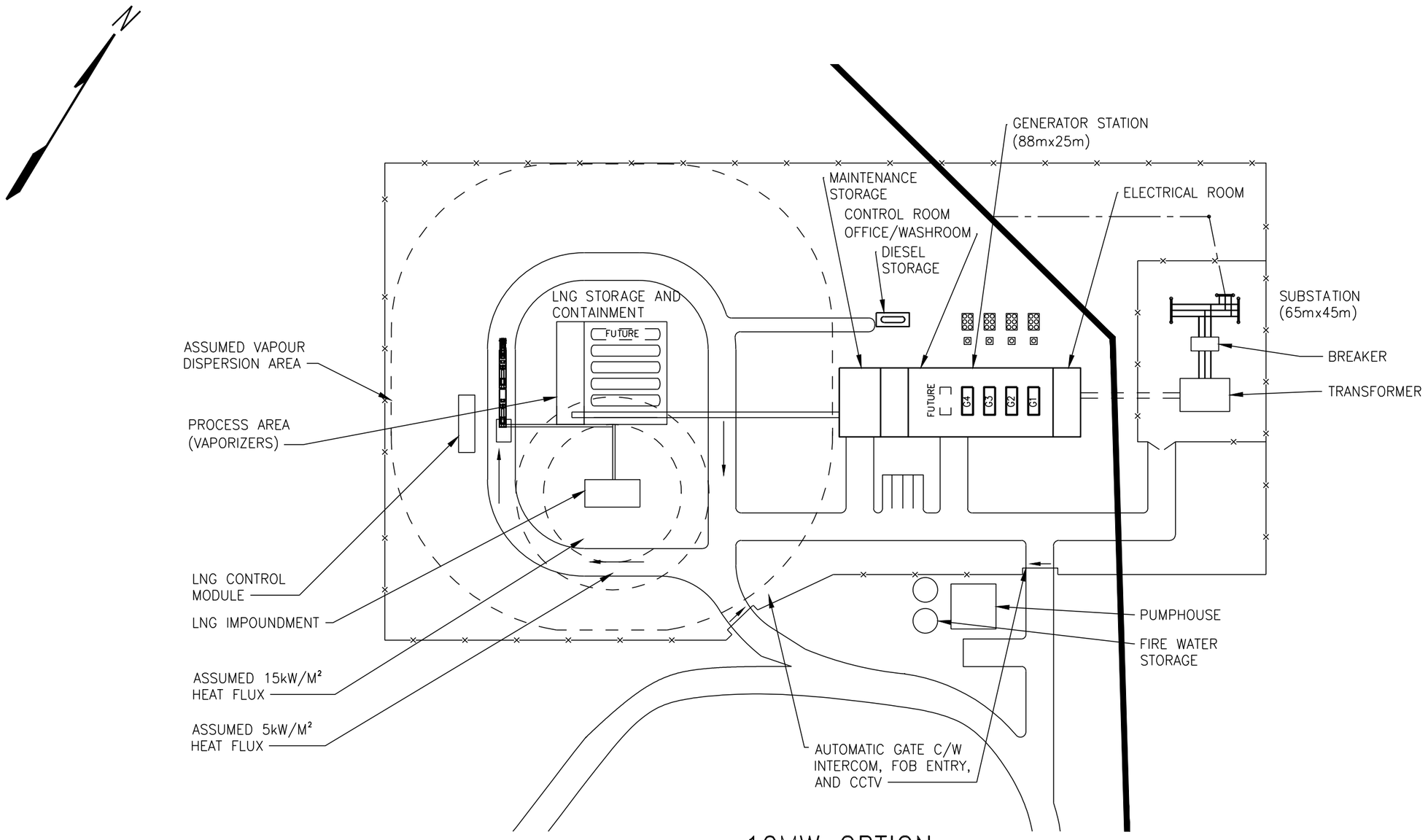

10MW OPTION

0 30m 60m

SCALE 1:1500

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A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – CAD
LNG – 10 MWe (NG-LD-10)

JOB No.	DWG. No.	SHEET		REV
133547248	B-0005	of	2	A

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A	JUNE 02, 2016 CLIENT	REVIEW						

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		CGV	AAB	1:1500
SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – MAP
LNG – 20 MWe (NG-LD-20)

JOB No.	DWG. No.	SHEET		REV
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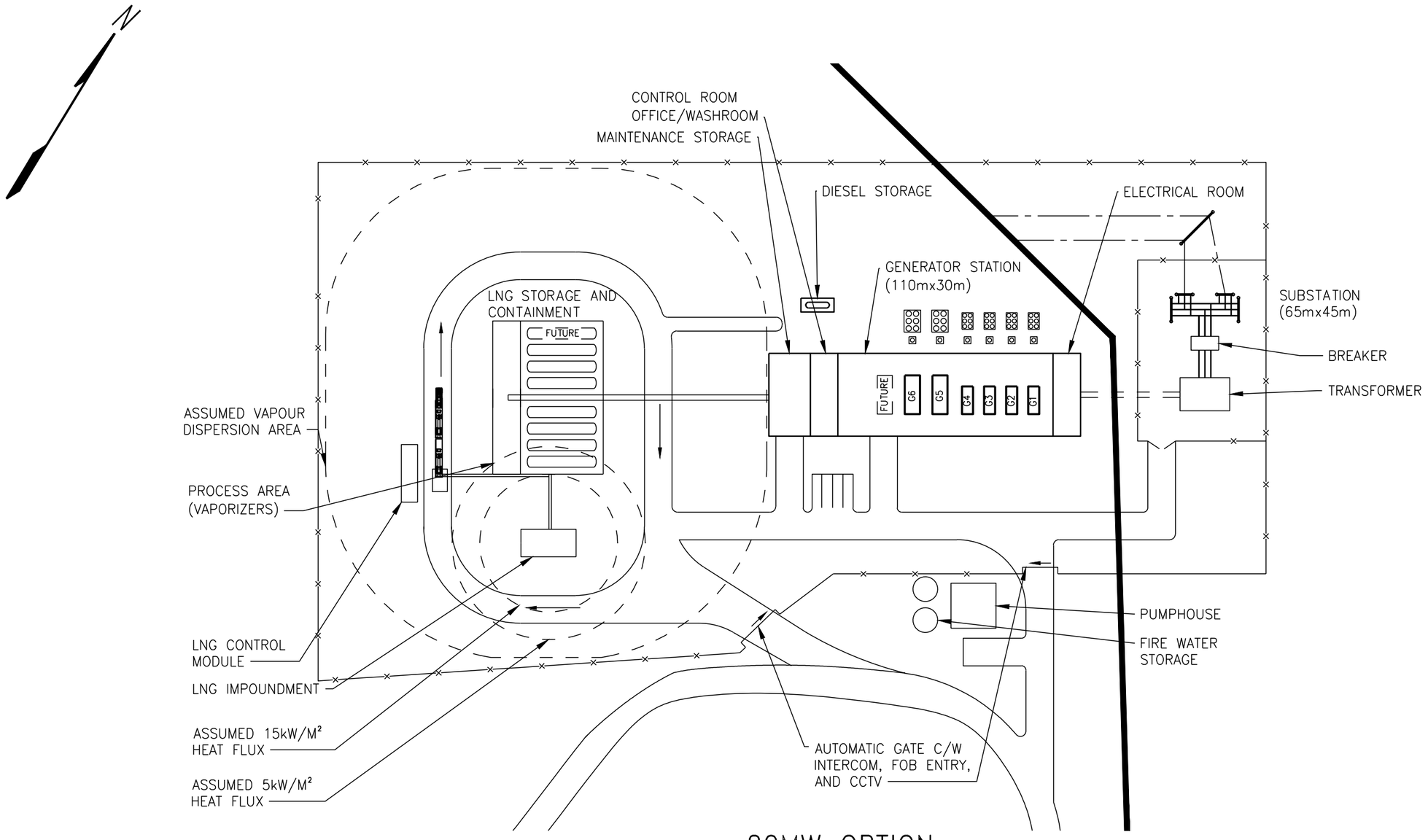

20MW OPTION

0 30m 60m

SCALE 1:1500

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A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – CAD
LNG – 20 MWe (NG-LD-20)

JOB No.	DWG. No.	SHEET		REV
133547248	B-0006	of	2	A

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A	JUNE 02, 2016 CLIENT	REVIEW						

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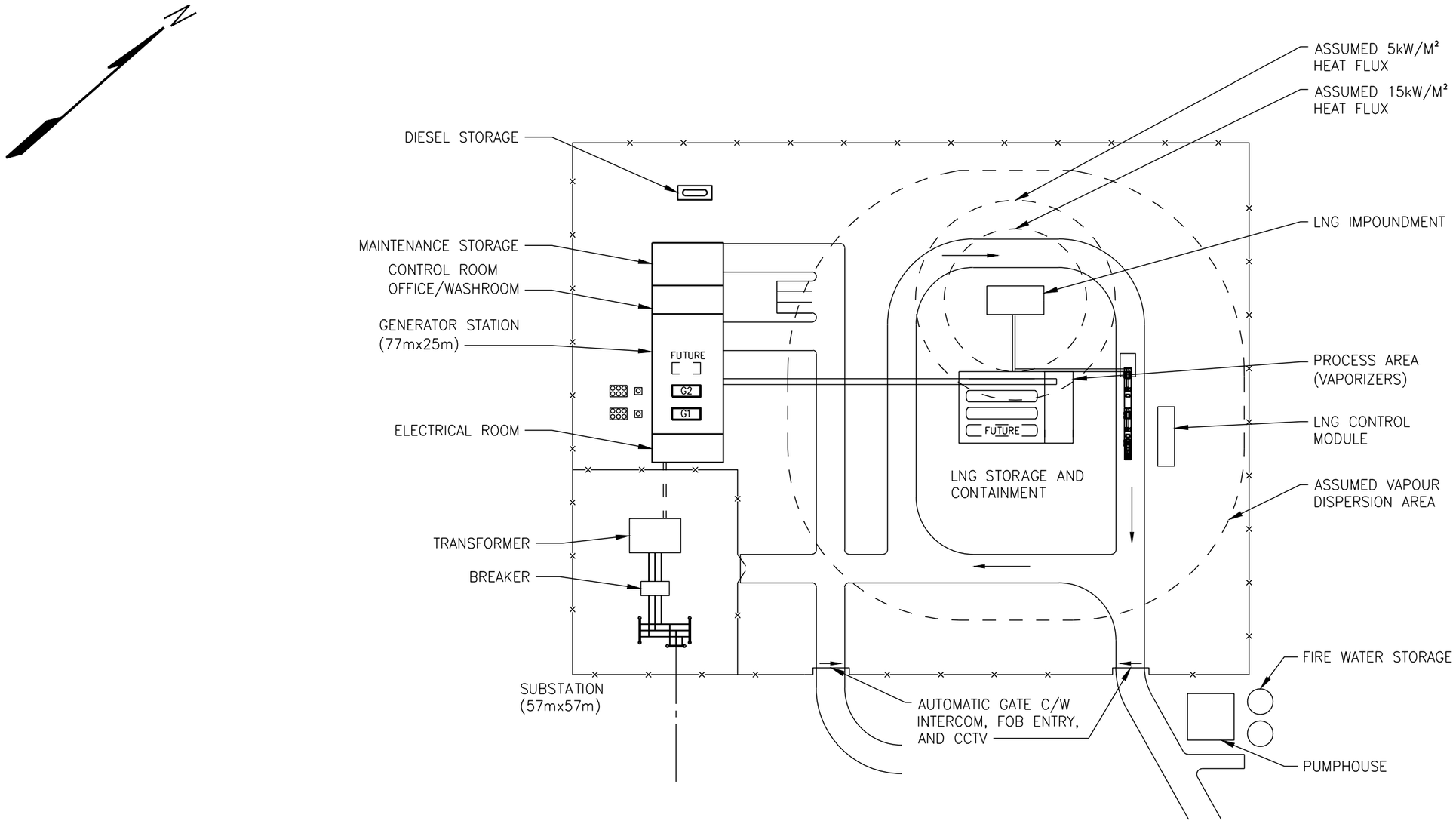
SPEC.	P.M. LF	P.T.		DATE MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – MAP
LNG – 5 MWe (NG-TK-5)

JOB No.	DWG. No.	SHEET		REV
133547248	B-0007	of	1 / 2	A



5MW OPTION

0 30m 60m

SCALE 1:1500

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A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – CAD
LNG – 5 MWe (NG-TK-5)

JOB No.	DWG. No.	SHEET	REV
133547248	B-0007	2 of 2	A

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A	JUNE 02, 2016 CLIENT	REVIEW						

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DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – MAP
LNG – 10 MWe (NG-TK-10)

JOB No.	DWG. No.	SHEET		REV
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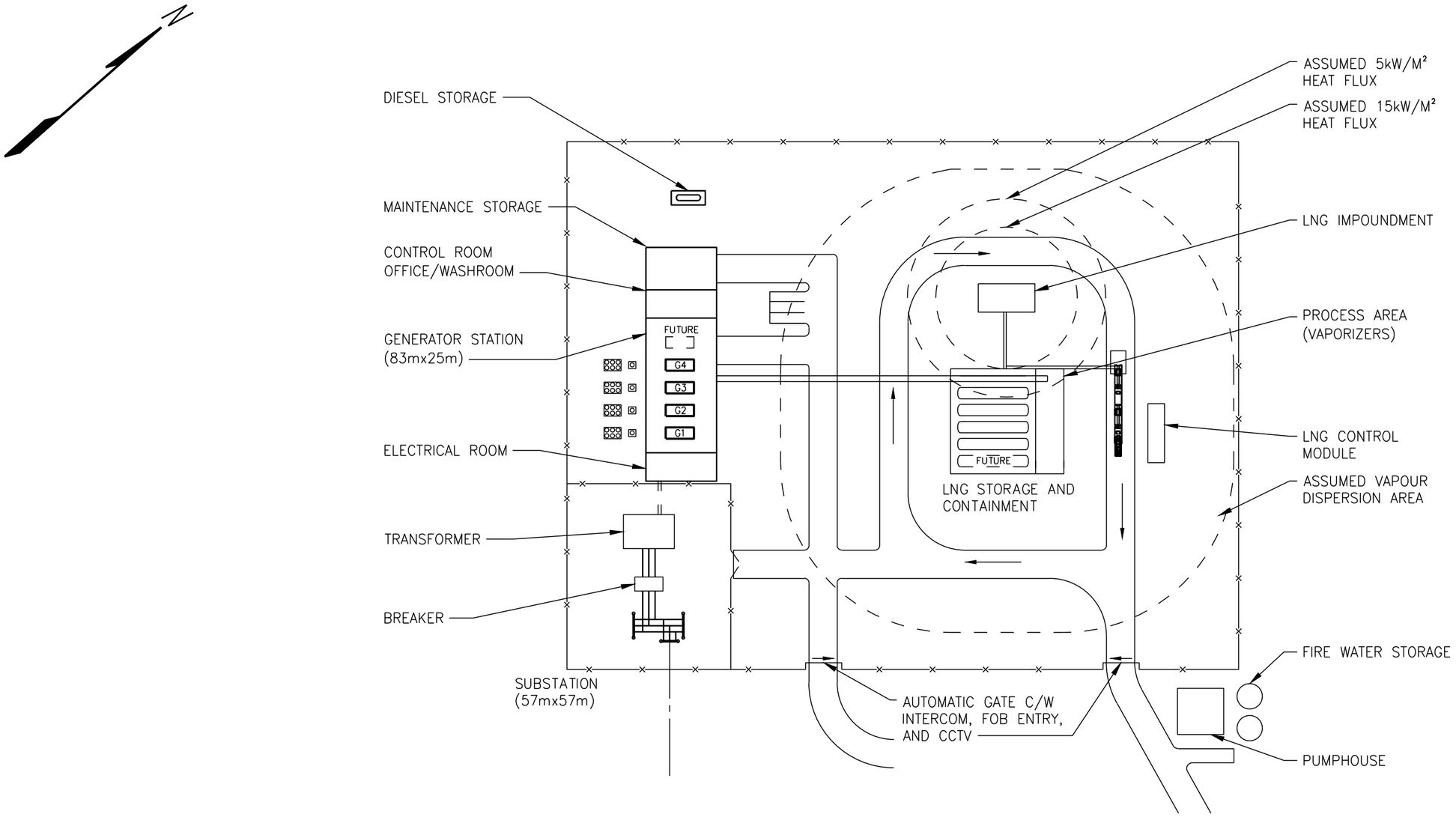
April 6, 2018



10MW OPTION

0 30m 60m

SCALE 1:1500

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A	JUNE 02 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – CAD
LNG – 10 MWe (NG-TK-10)

JOB No.	DWG. No.	SHEET	REV
133547248	B-0008	2 of 2	A

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A	JUNE 02, 2016 CLIENT	REVIEW						

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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – MAP
LNG – 20 MWe (NG-TK-20)

JOB No.	DWG. No.	SHEET		REV
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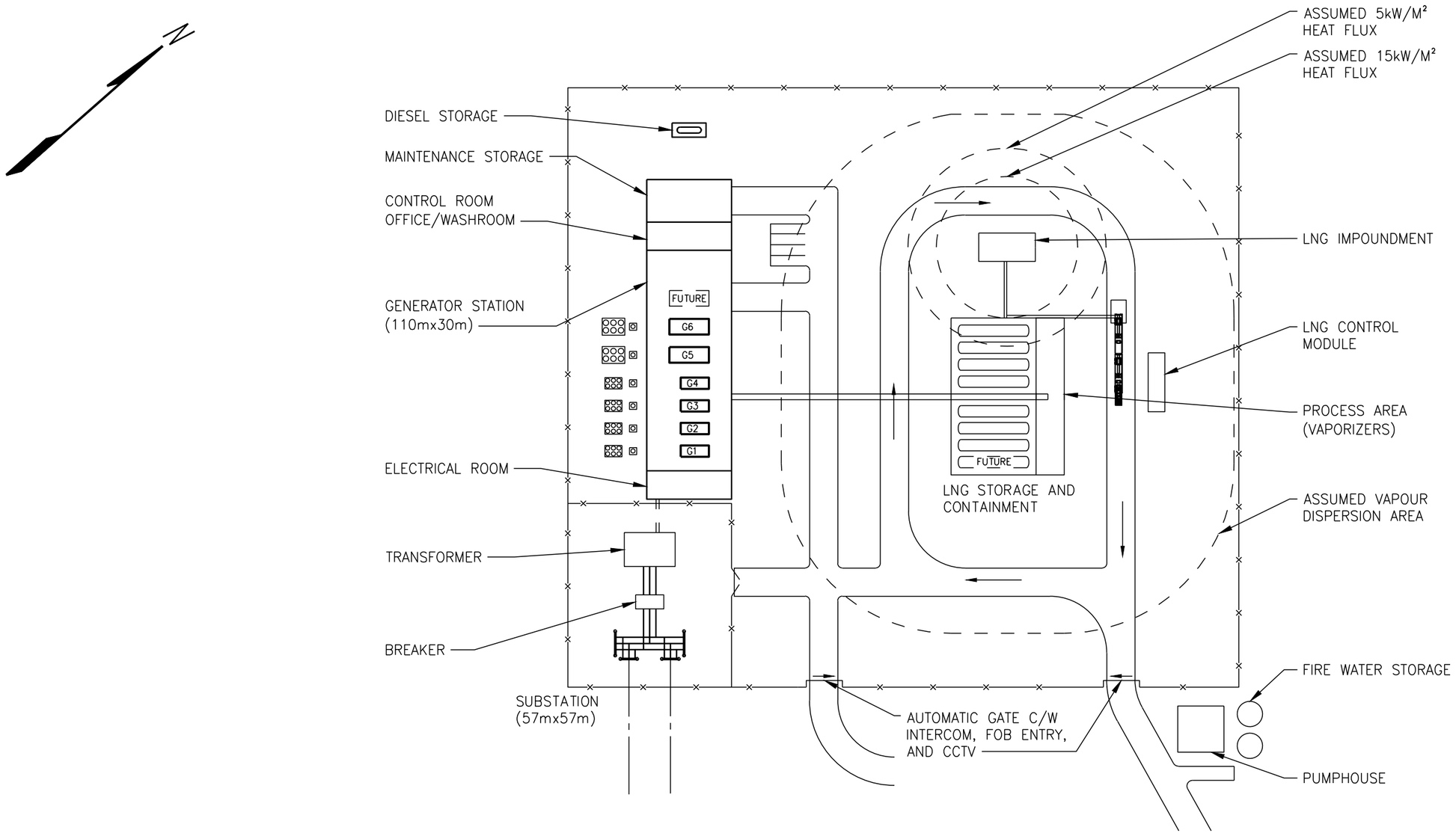

20MW OPTION

0 30m 60m

SCALE 1:1500

REV.	ISSUED TO	ISSUED FOR
A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – CAD
LNG – 20 MWe (NG-TK-20)

JOB No.	DWG. No.	SHEET		REV
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A	JUNE 02, 2016 CLIENT	REVIEW						

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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – MAP
DIESEL – 5 MWe (DL–LD–5)

JOB No.	DWG. No.	SHEET		REV
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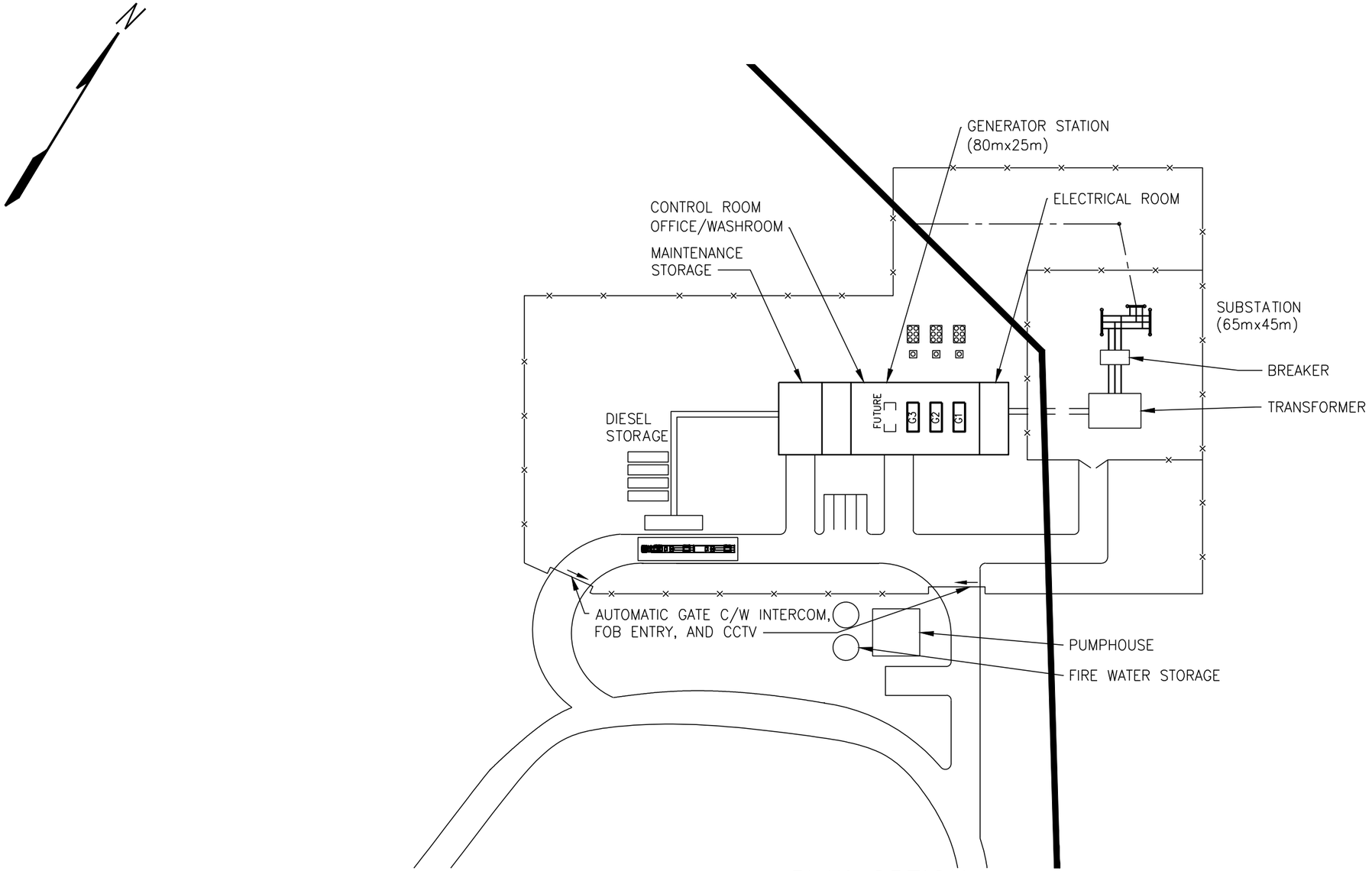

5MW OPTION

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SCALE 1:1500

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A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
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SPEC.	P.M. LF	P.T.		DATE MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – CAD
DIESEL – 5 MWe (DL–LD–5)

JOB No.	DWG. No.	SHEET	REV
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	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – MAP
DIESEL – 10 MWe (DL–LD–10)

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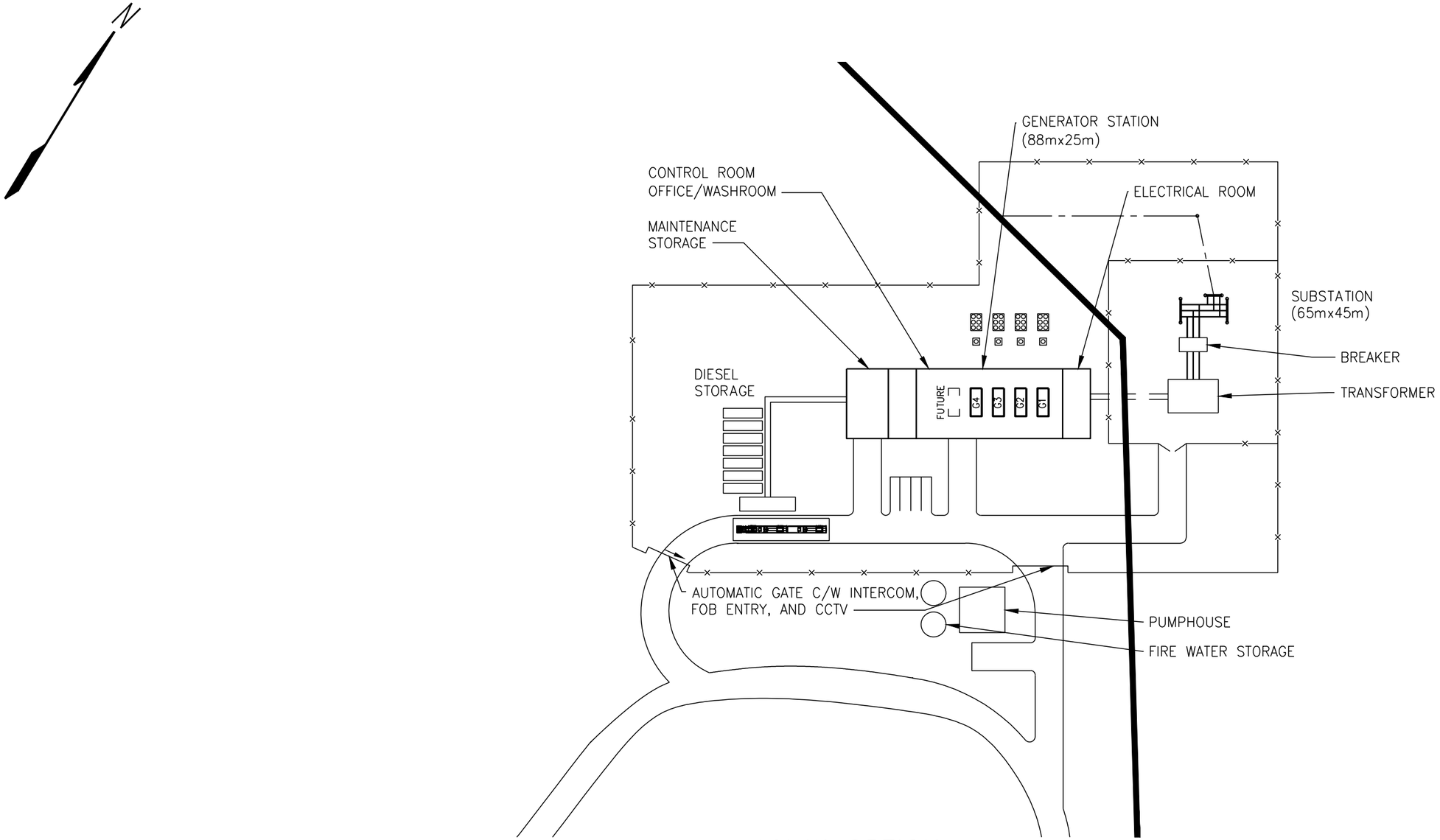

10MW OPTION

0 30m 60m
SCALE 1:1500

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A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
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SPEC.	P.M. LF	P.T.		DATE MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – CAD
DIESEL – 10 MWe (DL-LD-10)

JOB No.	DWG. No.	SHEET	REV
133547248	B-0014	2 of 2	A

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A	JUNE 02, 2016 CLIENT	REVIEW						

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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – MAP
DIESEL – 20 MWe (DL–LD–20)

JOB No.	DWG. No.	SHEET		REV
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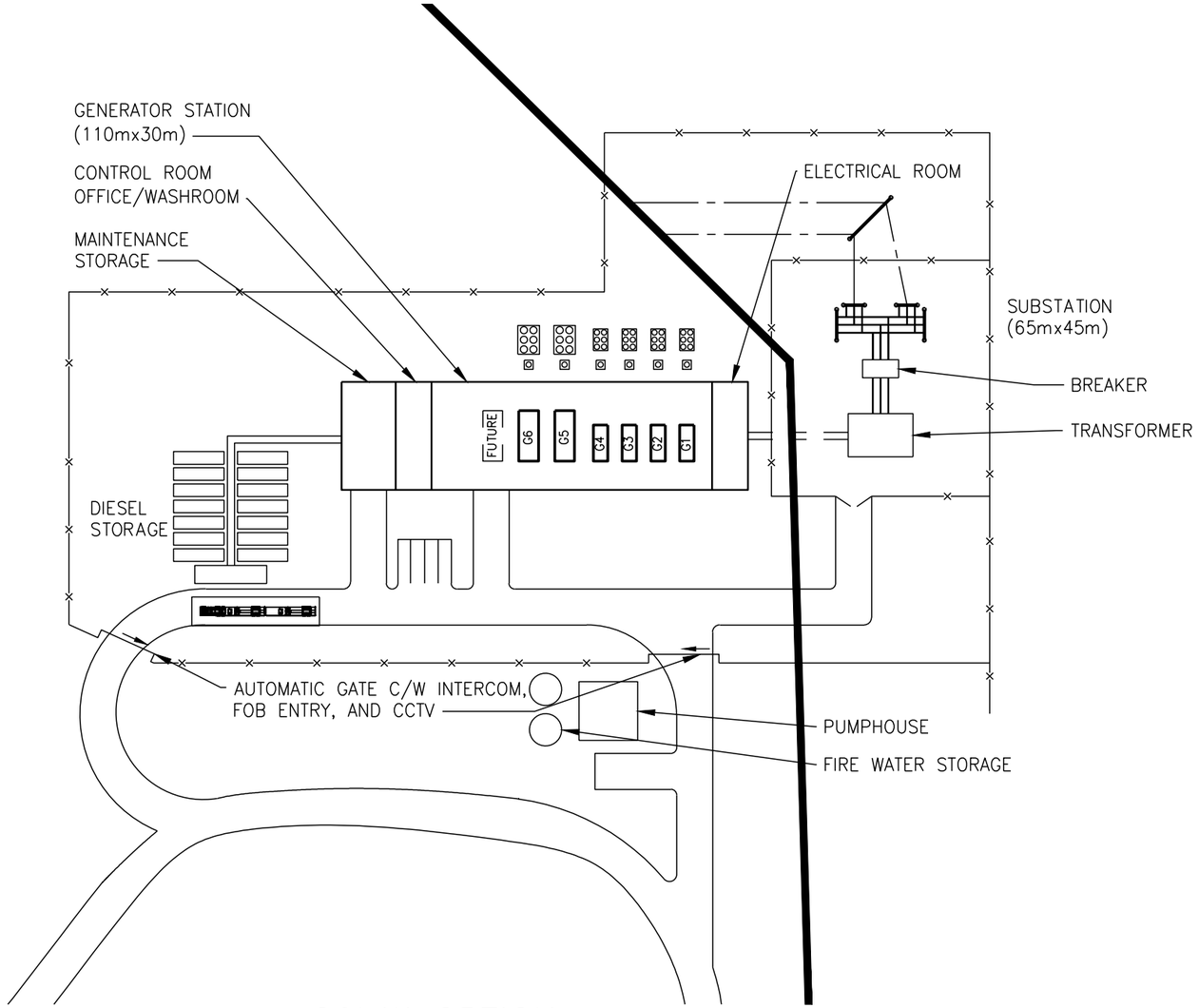

20MW OPTION

0 30m 60m

SCALE 1:1500

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A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

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SPEC.	P.M.	P.T.	DATE	
	LF		MAY 17, 2016	

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – LANDFILL – CAD
DIESEL – 20 MWe (DL–LD–20)

JOB No.	DWG. No.	SHEET	REV
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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

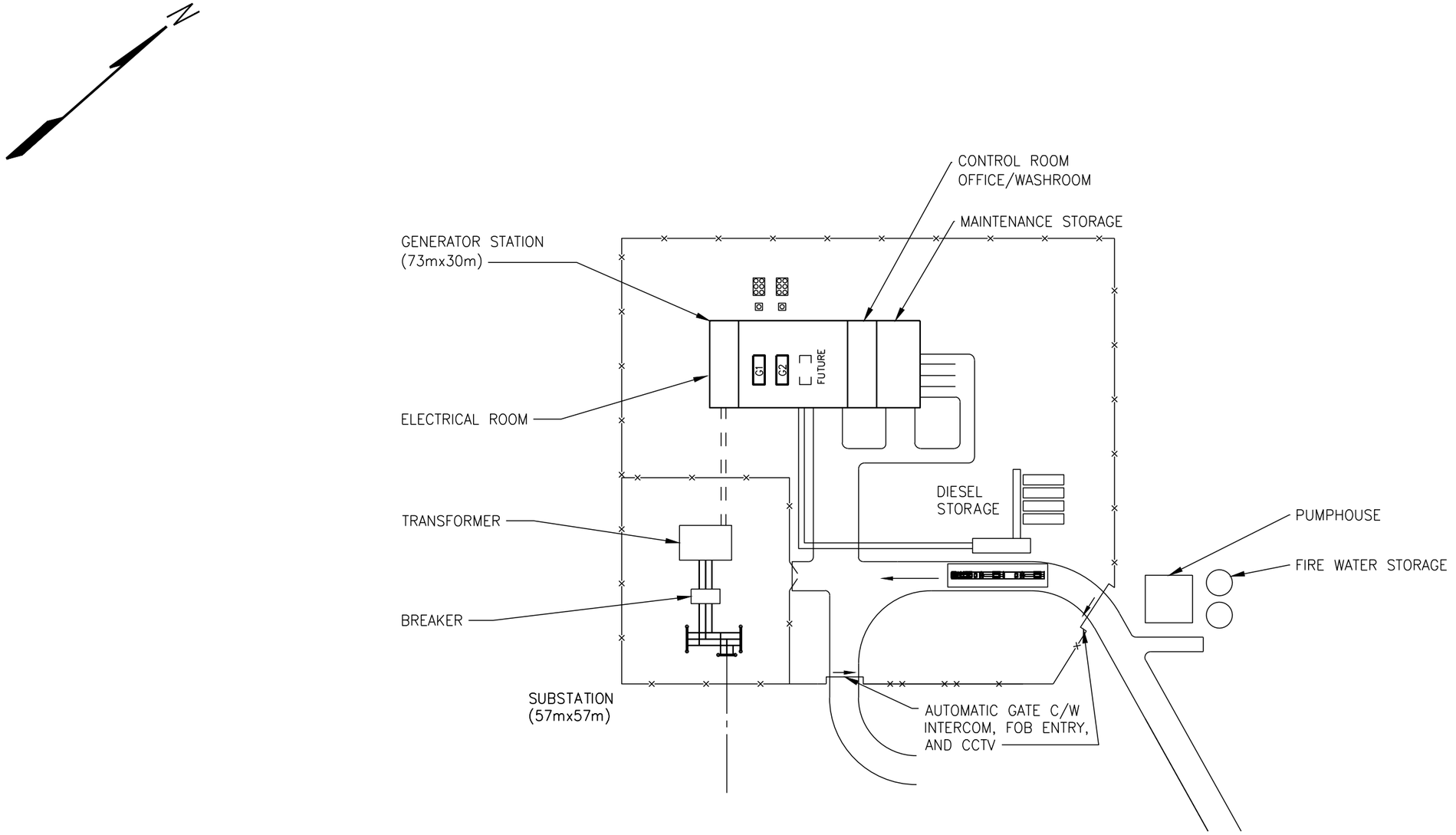
YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – MAP
DIESEL – 5 MWe (DL–TK–5)

JOB No.	DWG. No.	SHEET		REV
133547248	B–0016	of	1 / 2	A

April 6, 2018



5MW OPTION

0 30m 60m

SCALE 1:1500

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SPEC.	P.M. LF	P.T.		DATE MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – CAD
DIESEL – 5 MWe (DL-TK-5)

JOB No.	DWG. No.	SHEET	REV
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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – MAP
DIESEL – 10 MWe (DL–TK–10)

JOB No.	DWG. No.	SHEET		REV
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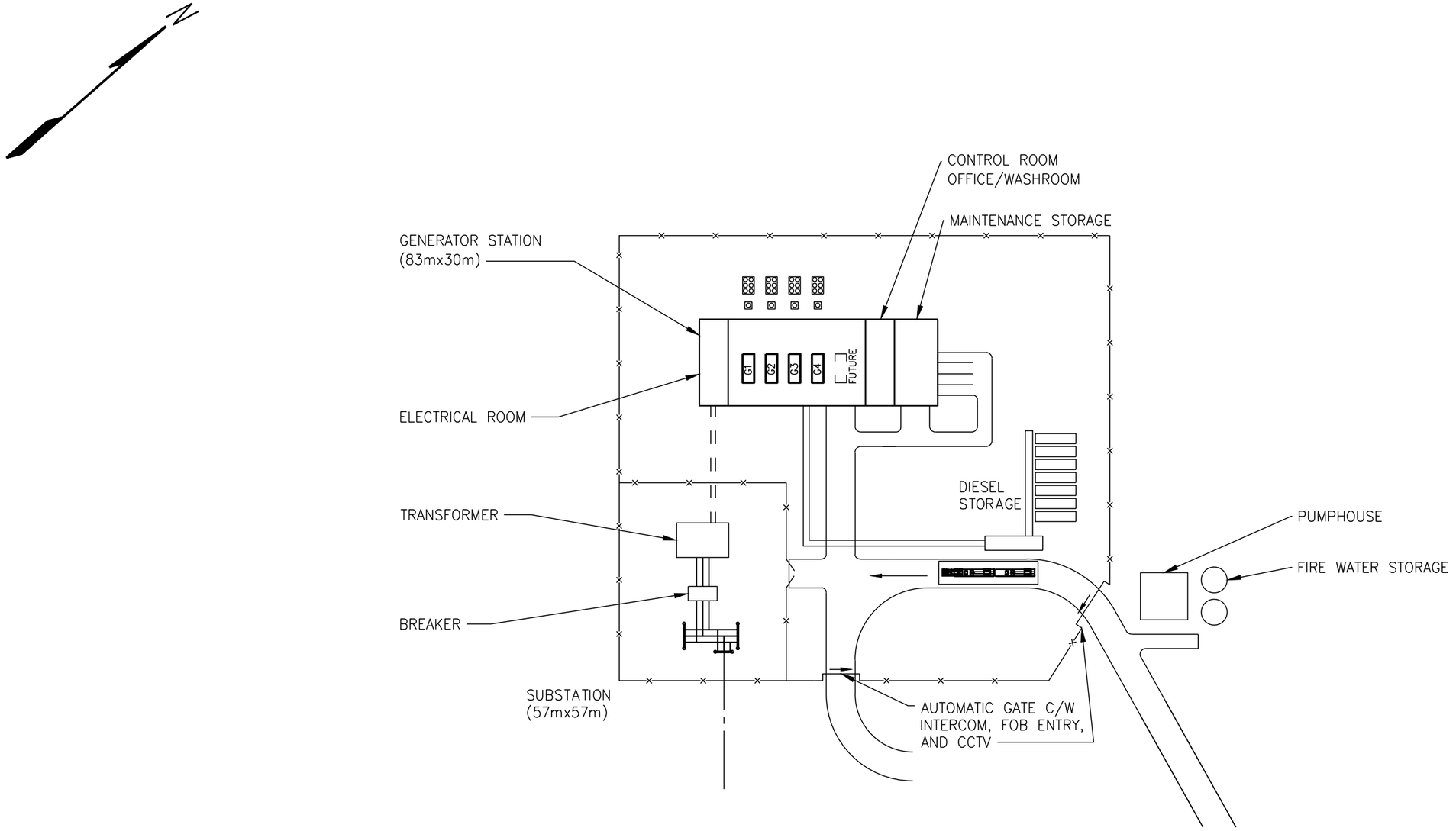

10MW OPTION

0 30m 60m

SCALE 1:1500

REV.	ISSUED TO	ISSUED FOR
A	JUNE 02, 2016 CLIENT	REVIEW

REV.	DATE	BY	REVISIONS	DES	DFTG

Stantec

DESIGN CHK	DFTG CHK	DES	DFTG	SCALE
		CGV	AAB	1:1500
SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – CAD
DIESEL – 10 MWe (DL-TK-10)

JOB No.	DWG. No.	SHEET	REV
133547248	B-0017	2 of 2	A

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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

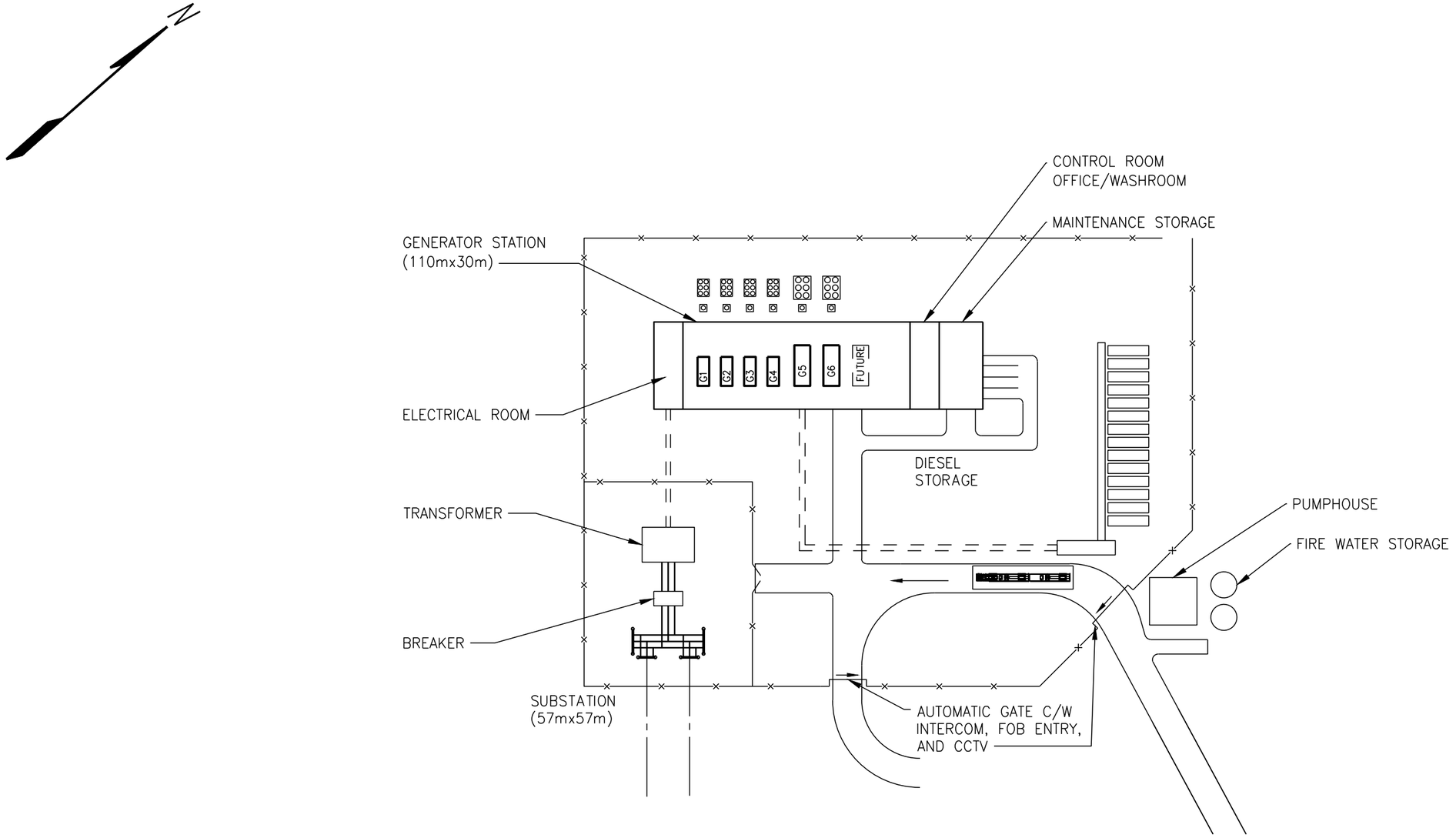
YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – MAP
DIESEL – 20 MWe (DL–TK–20)

JOB No.	DWG. No.	SHEET		REV
133547248	B–0018	of	1 / 2	A

April 6, 2018



20MW OPTION

0 30m 60m

SCALE 1:1500

REV.	ISSUED TO	ISSUED FOR	REV.	DATE	BY	REVISIONS	DES	DFTG
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Stantec

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SPEC.	P.M.	P.T.		DATE
	LF			MAY 17, 2016

YUKON ENERGY

THERMAL ENERGY PLANT DEVELOPMENT STUDY

SITE LAYOUT – TAKHINI – CAD
DIESEL – 20 MWe (DL-TK-20)

JOB No.	DWG. No.	SHEET		REV
133547248	B-0018	2 of 2		A

Appendix 5.16
Pumped Storage Assessment (Knight Piesold 2016)

YUKON ENERGY CORPORATION
PUMPED-STORAGE ASSESSMENT

PRELIMINARY ASSESSMENT

PREPARED FOR:

Yukon Energy Corporation
#2 Miles Canyon Road Box 5920
Whitehorse, Yukon
Y1A 6S7

PREPARED BY:

Knight Piésold Ltd.
Suite 1400 – 750 West Pender Street
Vancouver, BC V6C 2T8 Canada
p. +1.604.685.0543 • f. +1.604.685.0147

VA103-556/2-1
Rev 1
September 30, 2016

Knight Piésold
CONSULTING
www.knightpiesold.com

ISO 9001
ISO 14001
OHSAS 18001
FS 64925
EMS 550121
OHS 550122

YUKON ENERGY CORPORATION
PUMPED-STORAGE ASSESSMENT

PRELIMINARY ASSESSMENT
VA103-556/2-1

Rev	Description	Date
0	Issued in Final	June 30, 2016
1	Issued with Revisions	September 30, 2016

Knight Piésold Ltd.
Suite 1400
750 West Pender Street
Vancouver, British Columbia Canada V6C 2T8
Telephone: (604) 685-0543
Facsimile: (604) 685-0147
www.knightpiesold.com

Knight Piésold CONSULTING

EXECUTIVE SUMMARY

Knight Piésold (KP) has undertaken an assessment of pumped storage hydroelectric potential for Yukon Energy Corporation (YEC). The study focussed on identifying viable pumped storage facilities within a 25 km radius of existing and proposed transmission infrastructure (excluding sites located in existing parks and protected areas). The pumped-storage sites are intended to provide seasonal pumping from May through to September, along with seasonal generation from October through to April. The intention of this assessment is to determine the Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC) for pumped-storage hydro and compare these values with other potential fossil fuel and renewable generation options that may be available to YEC. The current study identified sites with the following technical constraints:

- 15 MW Capacity and 50 GWh energy storage
- 15 MW capacity and up to 100 GWh energy storage
- 25 MW capacity and 50 GWh energy storage, and
- 25 MW capacity and up to 100 GWh energy storage.

An initial screening assessment was undertaken using KP's in-house GIS and spreadsheet screening tools. This process identified 473 potential reservoir basins in the study area, and approximately 200 sites that were found to be technical viable pumped-storage sites. By ranking these sites by inferred construction cost, the top five (preferred) sites were identified for each of the 50 GWh and 100 GWh energy storage configurations. This resulted in a list of seven sites that were selected for further evaluation. These sites are as follows:

- Tutshi-Moon, near Tutshi Lake, BC
- Atlin-Black Mountain, near Atlin, BC
- Racine-Moon, near Racine Lake, BC
- Racine-Mt. Brown, near Racine Lake, BC
- Lindeman-Fraser, near Fraser, BC
- Squanga-Dalayee, between Johnson's Crossing and Jake's Corner, YT, and
- Canyon-Ittlemit, near Canyon Lake and the Aishihik Hydro Facility, YT.

Further analysis was undertaken to prepare AACE Class 5 cost estimates for the preferred sites, as well as a preliminary financial model for the proposed projects. Using YEC's assumed (real) cost of capital of 3.38%, the following results were obtained:

- 15 MW capacity and 50GWh storage configuration has a minimum $0.28/kWh LCOE and $900/kW-yr LCOC for the Tutshi-Moon facility
- 15 MW capacity and 100GWh storage configuration has a minimum $0.19/kWh LCOE and $1,300/kW-yr LCOC for the Tutshi-Moon facility
- 25 MW capacity and 50GWh storage configuration has a minimum $0.32/kWh LCOE and $650/kW-yr LCOC for the Tutshi-Moon facility, and
- 25 MW capacity and 100GWh storage configuration has a minimum $0.21/kWh LCOE and $840/kW-yr LCOC for the Tutshi-Moon facility.

In all cases, the Tutshi-Moon pumped-storage project was evaluated as the most cost-effective. The Atlin-Black Mt. and Racine-Mt. Brown facilities also have competitive cost profiles. The Racine-Moon and Lindeman-Fraser have technical constraints that make them less promising. The Squanga-Dalayee and Canyon-Ittlemit facilities are less cost effective, but have the advantage of being

relatively closer to existing YEC infrastructure. It is not known at this stage whether a viable project configuration can be found for the Canyon-Ittlemit facility that does not negatively impact the existing Aishihik hydro facility, but this should be investigated in future project stages.

The lowest LCOE ($0.19/kWh) is achieved with the 15 MW/100 GWh configuration. Conversely, the lowest LCOC ($650/kW-yr) is achieved with the 25 MW/50 GWh configuration, suggesting that there is a trade-off between cost of stored energy and capacity for pumped-storage facilities. Reducing energy storage further may provide a lower cost of capacity and would be more in line with the development trend in pumped-storage facilities worldwide (short duration storage of hours to days).

If further assessment of the pumped-storage projects is warranted by YEC, KP recommend the following next steps prior to proceeding with prefeasibility and feasibility studies:

1. Preliminary site visits to the following projects to evaluate technical viability further:
   - Tutshi-Moon
   - Atlin-Black Mt.
   - Racine-Mt. Brown
   - Squanga-Dalayee, and
   - Canyon-Ittlemit.
2. Acquisition of more detailed topographic data (such as PhotoSat) to provide better estimates of dam construction costs and reservoir storage potential.
3. Screening assessment of social and environmental permitting constraints.

TABLE OF CONTENTS

PAGE

EXECUTIVE SUMMARY I

TABLE OF CONTENTS i

1 – INTRODUCTION 1
- 1.1 BACKGROUND 1
- 1.2 PREVIOUS STUDIES 1
- 1.3 OVERVIEW OF PUMPED-STORAGE 1
- 1.4 YUKON'S ELECTRICITY SYSTEM 3
  - 1.4.1 Current Capacity 3
  - 1.4.2 Power Grid 4
  - 1.4.3 Proposed Transmission Lines 4

2 – PRELIMINARY SCREENING 5
- 2.1 SCREENING METHODOLOGY 5
  - 2.1.1 Spatial Limitations 5
  - 2.1.2 Generation and Storage Capacity 5
  - 2.1.3 Identifying Potential Reservoirs 5
  - 2.1.4 Technical Constraints 7
  - 2.1.5 Screening Assessment 8
  - 2.1.6 Preliminary Characterisation and Inferred Cost 8
- 2.2 SCREENING ASSESSMENT RESULTS 9
  - 2.2.1 Candidate Reservoir Sites 9
  - 2.2.2 Candidate Pumped-storage Facilities 9

3 – EVALUATION OF PREFERRED SITES 15
- 3.1 SELECTION OF PREFERRED SITES 15
- 3.2 HYDROLOGY 15
- 3.3 PROJECT CONFIGURATIONS 16
- 3.4 PROJECT DESCRIPTIONS 21
  - 3.4.1 Tutshi-Moon 21
  - 3.4.2 Atlin-Black Mountain 21
  - 3.4.3 Racine-Moon 24
  - 3.4.4 Racine Mt. Brown 24
  - 3.4.5 Lindeman-Fraser 27
  - 3.4.6 Squanga-Dalayee 27
  - 3.4.7 Canyon-Ittlemit 27
- 3.5 TRANSMISSION LINE CONSIDERATIONS 31
- 3.6 CAPITAL COST EVALUATION 32
- 3.7 OPERATION & MAINTENANCE COST 32
- 3.8 FINANCIAL EVALUATION 33

3.9 DEVELOPMENT SCHEDULE 36

4 – CONCLUSIONS AND RECOMMENDATIONS 38
4.1 CONCLUSIONS 38
4.2 RECOMMENDATIONS 41

5 – CERTIFICATION 42

TABLES

Table 2.1 Screening and Ranking of Potential Pumped-Storage Sites – Highest Ranked Sites - 15 MW, 50 GWh 10
Table 2.2 Screening and Ranking of Potential Pumped-Storage Sites, Highest Ranked Sites – 15 MW, 100 GWh 11
Table 2.3 Screening and Ranking of Potential Pumped Storage Sites, Highest Ranked Sites – 25 MW, 50 GWh 12
Table 2.4 Screening and Ranking of Potential Pumped Storage Sites Highest Ranked Sites – 25 MW, 100 GWh 13
Table 3.1 Project Technical Attributes - 15 MW, 50 GWh 17
Table 3.2 Project Technical Attributes - 15 MW, 100 GWh 18
Table 3.3 Project Technical Attributes - 25 MW, 50 GWh 19
Table 3.4 Project Technical Attributes - 25 MW, 100 GWh 20
Table 3.5 Cost, Energy and Financial Summary 35
Table 4.1 Project Summary - Lowest Cost Capacity 39
Table 4.2 Project Summary - Lowest Cost of Energy 40

FIGURES

Figure 1.1 Typical Components of a Pumped-Storage Hydropower System 3
Figure 1.2 Yukon Electricity Network 4
Figure 2.1 Evaluation of Pumped Storage Hydroelectric Potential – Potential Storage Reservoir Basins 6
Figure 2.2 Flow chart of the pumped-storage assessment process 9
Figure 2.3 Evaluation of Pumped Storage Hydroelectric Potential – Top – Ranked Storage Reservoir Basins 14
Figure 3.1 Evaluation of Pumped Storage Hydroelectric Potential Reservoirs - Tutshi-Moon 22
Figure 3.2 Evaluation of Pumped Storage Hydroelectric Potential Reservoirs - Atlin-Black MT 23
Figure 3.3 Evaluation of Pumped Storage Hydroelectric Potential Reservoirs - Racine-Moon 25
Figure 3.4 Evaluation of Pumped Storage Hydroelectric Potential Reservoirs - Racine-Mt. Brown 26

Figure 3.5 Evaluation of Pumped Storage Hydroelectric Potential Reservoirs - Lindeman-Fraser 28
Figure 3.6 Evaluation of Pumped Storage Hydroelectric Potential Reservoirs - Squanga-Dalayee 29
Figure 3.7 Evaluation of Pumped Storage Hydroelectric Potential Reservoirs - Canyon-Ittlemit 30
Figure 3.8 Indicative Interconnection Arrangement 31
Figure 3.9 Yukon Energy Corporation, Pumped Storage Assessment, Development Schedule – Major Tasks 37

APPENDICES

Appendix A Cost Estimate Summaries
Appendix B Financial Evaluation Summaries

1 – INTRODUCTION

1.1 BACKGROUND

Knight Piésold (KP) have undertaken this study in response to a Request for Proposals (RFP) from Yukon Energy to identify potential pumped-storage sites within a 25 km radius of existing and proposed (transmission) infrastructure. The pumped-storage sites are intended to provide seasonal pumping from May through to September, along with seasonal generation from October through to April. The intention of this assessment is to compare the cost of energy and installed capacity with other potential fossil fuel and renewable options that may be available to YEC, including conventional small hydro <20 MW, wind, diesel and natural gas-fired generation. In order to achieve this aim, the current study identified sites with the following technical constraints:

- 15 MW Capacity and 50 GWh energy storage
- 15 MW capacity and up to 100 GWh energy storage
- 25 MW capacity and 50 GWh energy storage, and
- 25 MW capacity and up to 100 GWh energy storage.

Where consideration of other combinations of installed capacity and energy storage may be beneficial, explanation has been included in this report.

1.2 PREVIOUS STUDIES

From the information provided to KP by YEC for the Pumped-Storage and Small Hydro screening assessments, the only document relating specifically to pumped-storage was the 2015 report into the proposed Moon Lake Pumped-Storage Project completed by Midgard Consultants. The report assessed the viability of the project under three possible scenarios:

1. Conventional storage with generation from November to May and a capacity of 7.5 MW.
2. Pumped-storage with a total of 48 GWh of energy storage and a capacity of 20 MW.
3. Pumped-storage with a total of 70 GWh of energy storage and a capacity of 26 MW.

The study found that the facility is limited by the available pumping energy, with more storage capacity than could be pumped during the summer months. The estimated capital costs for these projects ranged from approximately $155 million for the 7.5 MW conventional storage project to $262 million for the 70 GWh pumped-storage project. The estimated levelized cost of energy was estimated at $0.21/kWh for 48 GWh of annual generation (90% capacity factor).

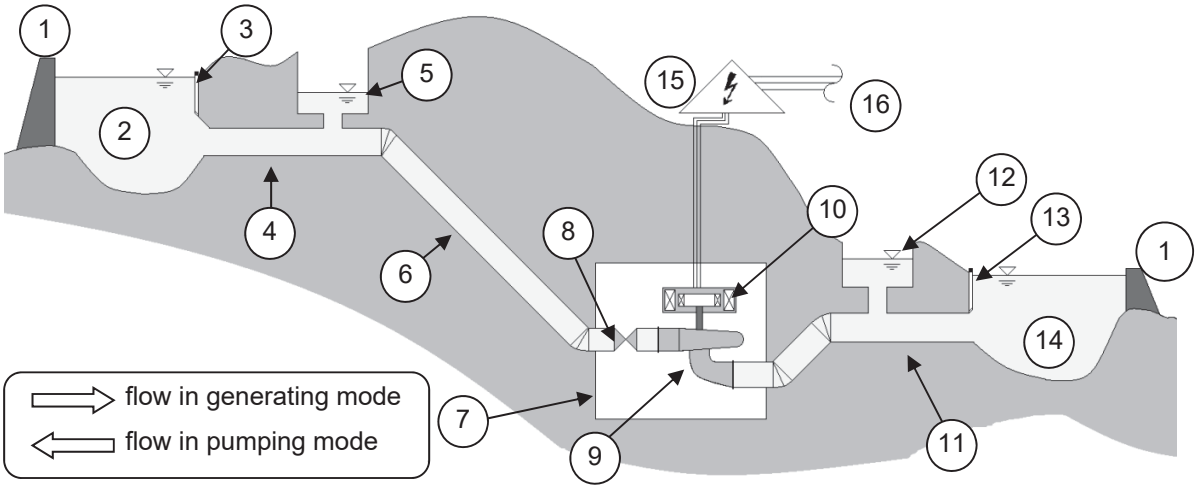
This study aims to provide a comprehensive screening assessment of pumped-storage potential in the Yukon Territory that will, among other things, determine whether there are other pumped-storage sites that might be equally or more attractive than the Moon Lake site.

1.3 OVERVIEW OF PUMPED-STORAGE

Pumped storage differs from conventional hydroelectric systems in that they operate not as a source of energy, but as a form of energy storage and reliable capacity. The conceptual arrangement of a pumped-storage facility is shown on Figure 1.1. Typical applications have included providing peak capacity in systems with a high portion of conventional thermal generating units such as coal and nuclear facilities, which are less amenable to rapid response to match load fluctuations. Increasingly in recent years pumped-storage facilities have been developed and deployed with a view to

managing the integration of intermittent renewable energy such as wind and solar. There is growing worldwide interest in the use of pumped storage to provide reliability for small, isolated grids with at least three of the Hawaiian islands in various stages of developing pumped storage. YEC are considering an alternative arrangement that is intended to shift excess hydroelectric energy available in the summer runoff and shift it to the winter to match the load. Typically, pumped storage facilities provide energy storage durations in the order of hours to days, KP is not aware of any precedents for development of pumped-storage facilities to provide long-term (seasonal) energy storage as is being proposed by YEC for the current report.

Technology for pumped-storage facilities varies depends on the site-specific conditions for a given facility. The use of reversible pump-turbines coupled with synchronous motor-generators is the most common arrangement. The units are optimised for the best round-trip efficiency, so are slightly less efficient than an equivalent conventional Francis turbine. The pumping mode is less efficient than the generating mode, and when coupled with the head losses in the water conveyance system typically result in a round-trip efficiency in the order of 70 to 80% (depending on penstock losses). The round-trip efficiency indicates the portion of pumping energy input to a pumped-storage system that can then be delivered back to the grid in generation mode, with pumped-storage facilities being overall net users of energy. Pumped-storage compares quite well with other grid-scale storage technologies, being both more efficient and more cost-effective on both a per MW capacity and per MWh stored energy basis. While pumped-storage has traditionally been used to shift a block of energy from off-peak to peak load hours, the emerging trend is for more rapid response, particularly using variable-speed units, which make a facility able to provide grid stability, frequency control, voltage regulation, spinning reserve and other grid support ancillary services.



1 Dam
2 Upper Reservoir
3 Intake (generating mode)
4 Head-race
5 Head-race surge chamber
6 Penstock
7 Powerhouse
8 Turbine inlet valve
9 Pump-turbine
10 Motor-generator
11 Tail-race
12 Tail-race surge chamber
13 Intake (pumping mode)
14 Lower reservoir
15 Substation
16 Electrical grid

Figure 1.1 Typical Components of a Pumped-Storage Hydropower System

1.4 YUKON'S ELECTRICITY SYSTEM

1.4.1 Current Capacity

YEC currently owns and operates approximately 131 MW of installed capacity, consisting of 92 MW of hydro, 0.8 MW of wind, and 37.8 MW of thermal (diesel and natural gas). Yukon Electrical Company Ltd. (YECL), owned by ATCO, supplies approximately 1.3 MW of hydroelectricity and 6.8 MW of diesel power.

YEC's hydroelectric generating capacity is comprised of:

- 37 MW Aishihik Generating Station, 150 km west of Whitehorse
- 15 MW Mayo Generating Station, 450 km north of Whitehorse
- 40 MW Whitehorse Generating Station, located on the Yukon River at Whitehorse, and
- 1.3 MW Fish Lake Generating Station (YECL).

1.4.2 Power Grid

The Yukon power grid is shown on Figure 1.2 and comprises the following major components:

- 138 kV Whitehorse / Aishihik / Faro (WAF) grid
- 69 kV Mayo / Dawson transmission line, and
- 138 kV Carmacks / Stewart transmission line, connecting the WAF grid and the Mayo / Dawson transmission line.

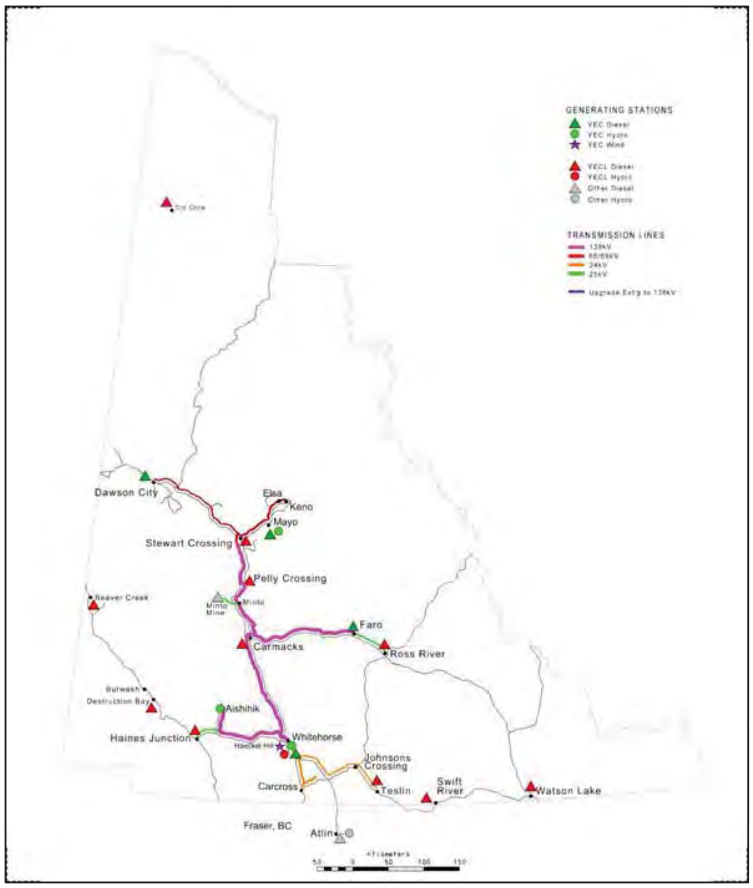


Figure 1.2 Yukon Electricity Network

The Yukon electricity network is an isolated grid, with no connection to other jurisdictions (BC, Alaska, Alberta or Northwest Territory). The Yukon grid currently services all Yukon communities except for Watson Lake, Burwash Landing/Destruction Bay, Beaver Creek, and Old Crow [YDC, 2015].

1.4.3 Proposed Transmission Lines

The following major transmission line extensions have been considered by YEC:

- Aishihik to Destruction Bay
- Skagway to Whitehorse
- Atlin to Whitehorse
- Teslin to Whitehorse, and
- Faro to Watson Lake.

2 – PRELIMINARY SCREENING

2.1 SCREENING METHODOLOGY

2.1.1 Spatial Limitations

The pumped-storage screening assessment for the Yukon was limited to a 25 km buffer from existing and planned transmission lines in the Territory. Within that area, terrestrial parks were excluded, but First Nations settlement land were included. Fish bearing habitat was not specifically excluded, but would be assessed for permitting viability in more detailed assessment phases for any identified projects. A map showing the study area is shown on Figure 2.1.

2.1.2 Generation and Storage Capacity

This study evaluates potential pumped-storage facilities that are able to provide energy generation through the winter months of October through April. This requires pumping through the summer from May through to September in order to provide the stored energy in the upper reservoir ready for the winter months. The pumping in the summer months can be supplemented through runoff through the freshet and summer, thereby reducing the total pumping energy required. Runoff was not included in the assessment at the preliminary screening stage, but was included in the assessment of the 'preferred sites'. The screening study assessed the following four combinations of power generation and energy storage capacity:

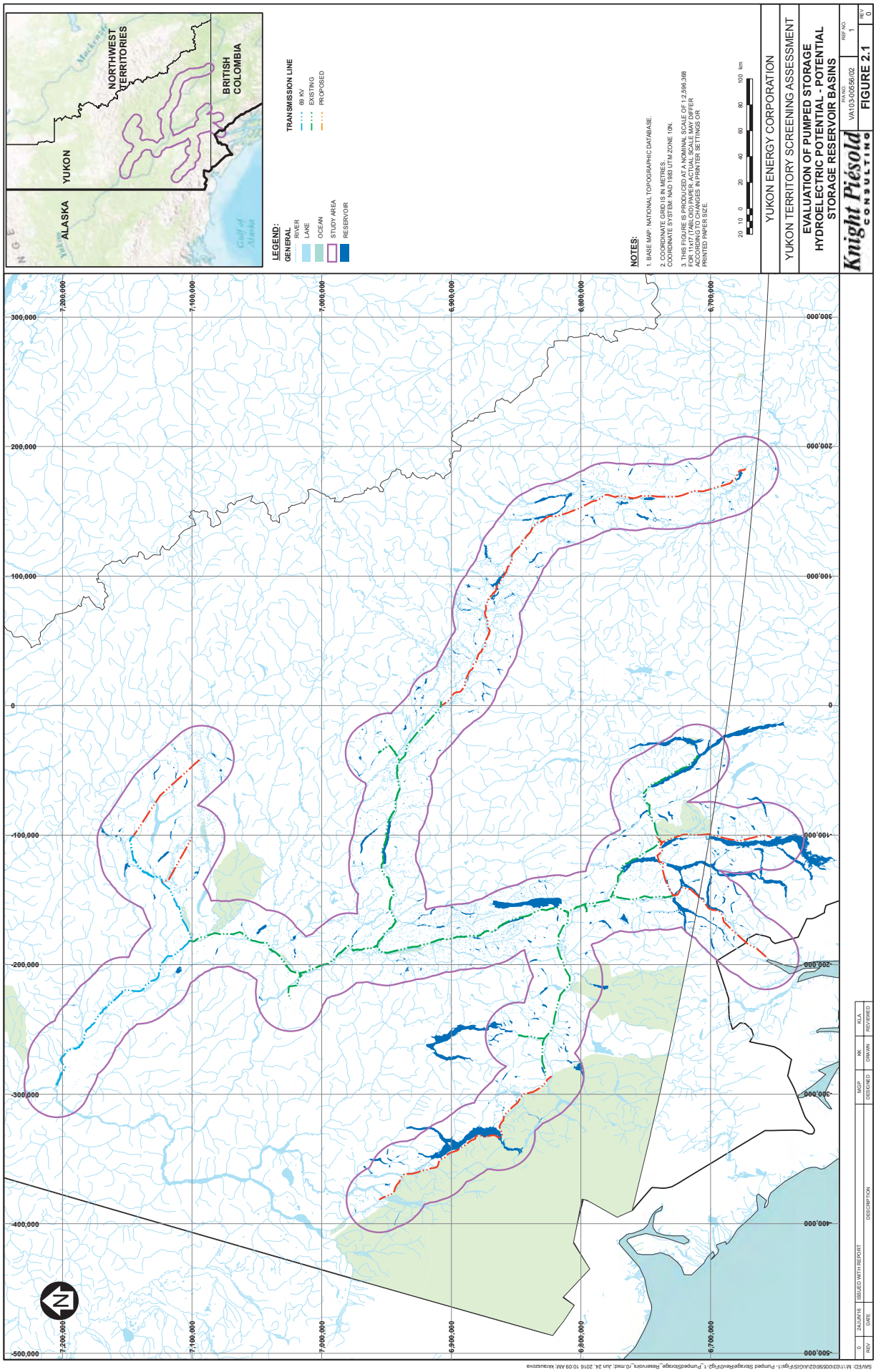
- 15 MW capacity and 50 GWh energy
- 15 MW capacity and 100 GWh energy
- 25 MW capacity and 50 GWh energy, and
- 25 MW capacity and 100 GWh energy.

In contrast to typical pumped-storage facilities, the proposed sites in the Yukon are intended for seasonal storage, whereas most applications for pumped-storage are for daily peaking operations. This will increase their overall cost, due to the increased dam size required to provide adequate water storage volume in the upper and lower reservoirs. Daily peaking facilities (with 8-10 hours of storage or less) are the most common configuration for pumped-storage facilities, and KP's prior experience shows reductions in levelized cost of capacity for facilities with shorter storage durations.

2.1.3 Identifying Potential Reservoirs

Construction of a pumped-storage facility requires use of two reservoirs at different elevations which can alternately store and discharge water as the facility moves from pumping to generating modes and vice-versa. Identifying suitable storage basins was one of the more complex portions of this study; there are potentially thousands of locations where water could be stored in such a large geographic area that was covered in this assessment.

All existing lakes within the study area greater than 50 ha in area were included as potential storage basins in the assessment. Potential dam construction locations on existing lakes were sited at the outlet of the lake. In addition, artificial reservoir locations were identified by manually assessing the study area using Google Earth to identify potential storage basins.


ALASKA
YUKON
NORTHWEST TERRITORIES
BRITISH COLUMBIA
LEGEND:
GENERAL
RIVER
LAKE
OCEAN
STUDY AREA
RESERVOIR
TRANSMISSION LINE
69 KV
EXISTING
PROPOSED
NOTES:
1. BASE MAP - NATIONAL TOPOGRAPHIC DATABASE.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 10N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:2,596,398
FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER
ACCORDING TO CHANGES IN PRINTER SETTINGS OR
PRINTED PAPER SIZE.
20 10 0 20 40 60 80 100 km
YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL - POTENTIAL STORAGE RESERVOIR BASINS
Knight Piésold CONSULTING
PA NO. VA103-00556/02
REF NO. 1
FIGURE 2.1
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SAVED: M:\1\03\00556\02\A\GIS\Figs\1 - Pumped Storage\Figs\Fig2-1_PumpedStorage_Reservoirs.mxd; Jun 24, 2016 10:09 AM; lkavanszova

Using the combination of the existing natural lakes and the artificial reservoirs, the storage potential of the reservoir basin for an approximately 30 m dam height was determined from the following:

$$S = A_L \times D + \frac{(A_R - A_L) \times D}{3}$$

Where:

$$S = A_L \times D + \frac{(A_R - A_L) \times D}{3}$$

$$A_L = Area\ of\ existing\ (natural)\ lake\ (zero\ for\ artificial\ reservoirs)$$

$$A_R = Area\ of\ reservoir\ formed\ with\ a\ 40\ m\ high\ dam$$

$$D = Dam\ height\ (30\ m)$$

The above equation assumes a prismatic shape to the reservoir storage volume. For the first phase of screening, it is sufficient to estimate the order of magnitude water storage volume potential of a particular basin based in comparison to the dam height and length, allowing identification of the most promising sites in the study area. This allowed for the development of a more efficient GIS screening tool than fully developing a depth-area-capacity (DAC) curve for all ~500 potential storage basins.

The assessment of potential reservoir basins was complicated by the low resolution of the data available to KP for completion of this study. YEC provided topographic data with 100 ft. (30 m) contours, which was insufficient to create a complete digital elevation model of the study area that could reliably determine drainage basins automatically. Some potential storage basins have likely been inadvertently excluded from this study due to the poor quality of topographic data. This also may have led to inaccuracies in estimating embankment volumes/water storage ratios. Some spurious data were generated, and most but not all was excluded manually prior to the screening assessment. Nevertheless, KP are confident that despite these data limitations the most promising pumped-storage locations have been included and correctly identified, and that only sites who have less favourable characteristics have been excluded as a result of the low resolution input topographic data.

2.1.4 Technical Constraints

While the identified facilities are smaller than typical pumped-storage facilities, some of the well-recognised hydroelectric generating equipment manufacturers (Voith, Andritz, Alstom) nevertheless have experience in manufacturing reversible pump-turbines of this capacity. Due to the level of design standardisation of generating equipment for small hydro facilities, it may be more cost-effective to adopt conventional turbines and standard pumps in place of reversible pump-turbines for a facility of this size. Determining the trade-off between the two is recommended for future project stages. For the current screening assessment, the use of reversible pump-turbines has been assumed and equipment costs have been extrapolated from published generating equipment costs for reversible pump-turbines.

For the purposes of this screening study, it is not possible to determine what form of water conveyance system (buried or surface penstock, tunnel) would be most appropriate, therefore a buried penstock is assumed for all sites, with a straight line between the upper and lower reservoirs. A maximum straight line water conveyance length of 20 km is assumed between the upper and lower reservoirs. While it is KP's experience that this exceeds the typical water conveyance length for typical hydro plants, the intention was not to unnecessarily exclude potential sites early in the screening process. A more detailed review of penstock alignment is included for the preferred sites

in the next Section of this report. Similarly, determination of the transmission lines distances assumed a straight line between the powerhouse and the nearest existing or planned transmission line was assumed for the preliminary screening and ranking of potential pumped-storage sites. A more detailed assessment of transmission line routing was undertaken for the top-ranked (preferred) sites.

Using the nominal reservoir storage volume calculated in Section 2.1.3, a relationship between dam height, dam crest length and reservoir storage volume can be determined. This allowed the screening tool to extrapolate the approximate dam size to meet a given water volume storage required as need for the screening process. It should be noted that this process is an “order of magnitude” process at best, and the dam dimensions were examined in greater detail for the preferred sites in the following Section of this report. Dams are assumed to be concrete-faced rockfill dams (CFRD). Future project studies may result in evaluations showing that alternate dam designs may be more appropriate for individual facilities, but this construction method was selected on the basis of its wide applicability. It is therefore reasonable to assume all dams are CFRD embankments for the purposes of this initial assessment.

2.1.5 Screening Assessment

From the above method, a total of just under 500 potential storage basins (473) were identified as shown on Figure 2.1. An in-house GIS screening tool developed by KP was used to select the best combinations of freshwater basins (upper and lower reservoirs) that would lead to viable pumped-storage sites. This tool identifies any two basins within 20 km, and then determines if the basins are able to store the required water volume, which is dependent on the elevation difference (head) between the two storage basins. If one or both of the two basins is unable to store the required water volume, that combination of basins is eliminated as a potential candidate pumped-storage site. To minimise the extremely high number of potential combinations, a maximum threshold of 10 Mm^3 was set for the total dam embankment construction volume between the reservoirs.

While the threshold of 20 km for the water conveyance distance and 10 Mm^3 for the embankment construction volume may both be beyond the size expected for an economical facility, the intent was not to screen out any sites prematurely, and thus to set the threshold above what would ordinarily be expected. This allows screening and ranking of the most promising sites before selection of the five preferred sites.

2.1.6 Preliminary Characterisation and Inferred Cost

Using the GIS-based screening tool, combinations of reservoir basins where a pumped-storage site could be developed were identified. A total of 250 sites were identified meeting the 50 GWh storage requirement, and 190 sites meeting the 100 GWh storage requirement. There is no suggestion that these sites are economically viable sites, simply that it is theoretically possible to construct them under the minimum thresholds of embankment construction volumes and penstock distance.

In order to identify the most economically attractive sites, data from the sites flagged using the GIS screening tool were imported to an in-house spreadsheet model that calculates inferred project costs based on overall project details (gross head, design flow, capacity), reservoir information (required storage volume, reservoir area, embankment height and length, embankment volume), and waterway parameters (length, diameter). Due to the coarse resolution of the data, the automated nature of the calculations, and the extrapolation method used to determine some of the key site

parameters (such as dam height, crest length and reservoir area) the tool is considered valid only for a broad ranking of sites and should not be considered accurate for an absolute estimation of cost.

2.2 SCREENING ASSESSMENT RESULTS

2.2.1 Candidate Reservoir Sites

Figure 2.1 shows the location of all 473 candidate reservoir sites included in the pumped-storage screening assessment. These potential storage basins vary from very large existing lakes, such as the 780 km^2 Atlin Lake on the Yukon/BC border in the south of the study area, down to small alpine cirques with no existing lake, but in which an artificial reservoir could be constructed.

2.2.2 Candidate Pumped-storage Facilities

The top 15 sites as ranked by KP's pumped-storage screening tools are included in Table 2.1 through Table 2.4. A minimum level of quality control was applied to the sites before including facilities on the Tables showing the top 15 sites, namely deletion of sites that were identified through manual inspection as overlapping a higher ranked site. It is apparent that some of the highest ranked sites appear in each of the four combinations of energy storage and installed capacity. Figure 2.3 shows the location of all sites that appear in these four Tables.

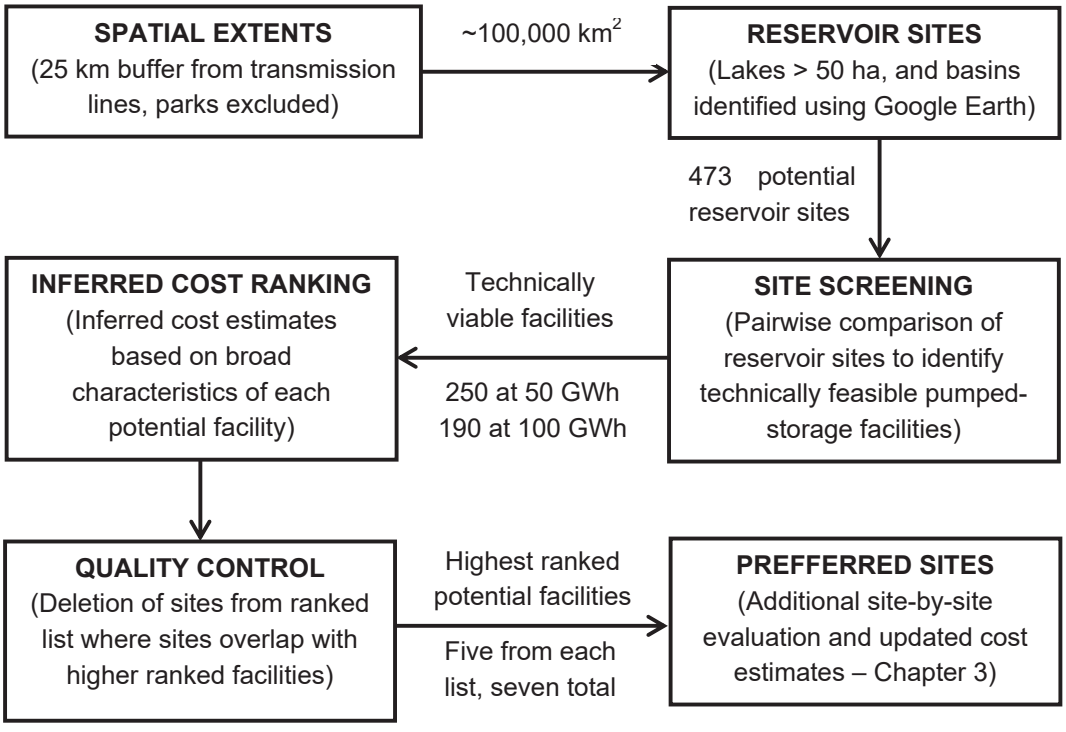

Figure 2.2 Flow chart of the pumped-storage assessment process.

Knight Piésold CONSULTING

TABLE 2.1

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

SCREENING AND RANKING OF POTENTIAL PUMPED STORAGE SITES
HIGHEST RANKED SITES - 15 MW, 50 GWh

6/28/2016 9:47

SITE ID	SITE NAME	INFERRED CAPITAL COST ($ M)	UPPER RESERVOIR			LOWER RESERVOIR		
			LATITUDE (°)	LONGITUDE (°)	ELEVATION (m)	LATITUDE (°)	LONGITUDE (°)	ELEVATION (m)
447-437	Tutshi-Moon	$220,000,000	59.84	-134.59	1109	59.86	-134.77	715
436-434	Atlin-Black Mt.	$247,000,000	59.94	-133.76	1197	59.95	-133.80	669
443-107	Racine-Mt. Brown	$300,000,000	59.82	-134.44	1511	59.76	-134.50	710
443-437	Racine-Moon	$316,000,000	59.84	-134.59	1109	59.76	-134.50	710
445-289	Lindeman-Fraser	$331,000,000	59.71	-135.10	1112	59.79	-135.07	677
384-383	Squanga-Dalayee	$337,000,000	60.38	-133.62	950	60.45	-133.60	770
6-314	Rainbow-Dezadeash	$338,000,000	60.73	-137.15	1330	60.67	-137.24	715
447-444	Tutshi-Skelly	$345,000,000	59.76	-134.77	866	59.86	-134.77	715
60-55	Granite-Moose Peak	$408,000,000	60.71	-136.88	1472	60.70	-137.06	860
445-458	Lindeman-Long Lake	$411,000,000	59.77	-135.12	866	59.79	-135.07	677
447-124	Tutshi-Jack Peak	$430,000,000	59.90	-134.63	1367	59.86	-134.77	715
454-320	Canyon-Ittlemit	$447,000,000	61.14	-137.07	1136	61.13	-137.03	892
444-437	Skelly-Moon	$480,000,000	59.84	-134.59	1109	59.76	-134.77	866
436-115	Atlin-McDonald	$508,000,000	59.70	-133.61	933	59.69	-133.75	669
60-314	Granite-Dezadeash	$530,000,000	60.73	-137.15	1330	60.70	-137.06	860

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Cost Ranking\[15 MW, 50 GWh r0.xlsx]SUMMARY

NOTES:

1. THE DATA SHOWN IN THIS TABLE HAS BEEN PRODUCED BY KP'S IN-HOUSE AUTOMATED GIS AND SPREADSHEET SCREENING TOOL.
2. QUALITY CONTROL ON THE DATA PRODUCED BY THE SCREENING TOOL HAS BEEN APPLIED BEFORE INCLUSION OF SITES ON THIS RANKED SHORT-LIST.
3. QUALITY CONTROL UNDERTAKEN ON SITES ON THIS LIST INCLUDES DELETION OF SITES THAT ARE NOT TECHNICALLY VIABLE OR THAT OVERLAP HIGHER RANKED SITES. QUALITY CONTROL ON THIS LIST DOES NOT INCLUDE MODIFICATION OF DAM ARRANGEMENT, PENSTOCK OR TRANSMISSION LINE ROUTE WHICH IS PERFORMED ONLY ON THE TOP 5 PREFERRED SITES IN A SEPARATE ANALYSIS.
4. THE TOOL RELIES ON EXTRAPOLATIONS AND SIMPLIFICATIONS TO PROVIDE INFERRED, ORDER OF MAGNITUDE COSTS FOR EACH SITE.
5. THE INDICATIVE (INFERRED) CAPITAL COSTS ARE NOT CONSIDERED RELIABLE COST ESIMATES, BUT ARE INTENDED ONLY FOR RELATIVE RANKING OF PROJECTS.
6. REFER TO SEPARATE TABLES AND COST ESTIMATES IN ASSESSMENT REPORT FOR AACE CLASS 5 COST ESTIMATES AND FINANCIAL ANALYSIS OF TOP 5 PREFFERED SITES.
7. THE GIS SCREENING TOOL FLAGGED OVER 100 SITES AS POTENTIALLY TECHNICALLY VIABLE, ONLY THE TOP 15 ARE SHOWN HERE DUE TO THE QUALITY CONTROL REQUIRED FOR INCLUDING RANKED SITES.

REV	DATE	DESCRIPTION	PREP'D	RVW'D
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TABLE 2.2

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

SCREENING AND RANKING OF POTENTIAL PUMPED STORAGE SITES
HIGHEST RANKED SITES - 15 MW, 100 GWh

6/29/2016 16:22

SITE ID	SITE NAME	INFERRED CAPITAL COST ($ M)	UPPER RESERVOIR			LOWER RESERVOIR		
			LATITUDE	LONGITUDE	ELEVATION (m)	LATITUDE	LONGITUDE	ELEVATION (m)
447-437	Tutshi-Moon	$364,000,000	59.84	-134.59	1109	59.86	-134.77	715
443-437	Racine-Moon	$519,000,000	59.84	-134.59	1109	59.76	-134.50	710
384-383	Squanga-Dalayee	$577,000,000	60.38	-133.62	950	60.45	-133.60	770
436-434	Atlin-Black Mt.	$752,000,000	59.94	-133.76	1197	59.95	-133.80	669
454-320	Canyon-Ittlemit	$801,000,000	61.14	-137.07	1136	61.13	-137.03	892
447-444	Tutshi-Skelly	$817,000,000	59.76	-134.77	866	59.86	-134.77	715
443-107	Racine-Mt. Brown	$819,000,000	59.82	-134.44	1511	59.76	-134.50	710
355-461	Little Salmon-Drury	$845,000,000	62.27	-134.50	722	62.20	-134.51	530
6-314	Rainbow-Dezadeash	$874,000,000	60.73	-137.15	1330	60.67	-137.24	715
445-289	Lindeman-Fraser	$879,000,000	59.71	-135.10	1112	59.79	-135.07	677
60-55	Granite-Moose Peak	$1,190,000,000	60.71	-136.88	1472	60.70	-137.06	860
445-458	Lindeman-Long Lake	$1,229,000,000	59.77	-135.12	866	59.79	-135.07	677
445-459	Lindeman-Homan	$1,382,000,000	59.87	-135.19	820	59.79	-135.07	677
437-107	Moon-Mt. Brown	$1,461,000,000	59.82	-134.44	1511	59.84	-134.59	1109
444-437	Skelly-Moon	$1,495,000,000	59.84	-134.59	1109	59.76	-134.77	866

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Cost Ranking\[15 MW, 100 GWh r0.xlsx]SUMMARY

NOTES:

1. THE DATA SHOWN IN THIS TABLE HAS BEEN PRODUCED BY KP'S IN-HOUSE AUTOMATED GIS AND SPREADSHEET SCREENING TOOL.
2. QUALITY CONTROL ON THE DATA PRODUCED BY THE SCREENING TOOL HAS BEEN APPLIED BEFORE INCLUSION OF SITES ON THIS RANKED SHORT-LIST.
3. QUALITY CONTROL UNDERTAKEN ON SITES ON THIS LIST INCLUDES DELETION OF SITES THAT ARE NOT TECHNICALLY VIABLE OR THAT OVERLAP HIGHER RANKED SITES. QUALITY CONTROL ON THIS LIST DOES NOT INCLUDE MODIFICATION OF DAM ARRANGEMENT, PENSTOCK OR TRANSMISSION LINE ROUTE WHICH IS PERFORMED ONLY ON THE TOP 5 PREFERRED SITES IN A SEPARATE ANALYSIS.
4. THE TOOL RELIES ON EXTRAPOLATIONS AND SIMPLIFICATIONS TO PROVIDE INFERRED, ORDER OF MAGNITUDE COSTS FOR EACH SITE.
5. THE INDICATIVE (INFERRED) CAPITAL COSTS ARE NOT CONSIDERED RELIABLE COST ESIMATES, BUT ARE INTENDED ONLY FOR RELATIVE RANKING OF PROJECTS.
6. REFER TO SEPARATE TABLES AND COST ESTIMATES IN ASSESSMENT REPORT FOR AACE CLASS 5 COST ESTIMATES AND FINANCIAL ANALYSIS OF TOP 5 PREFFERED SITES.
7. THE GIS SCREENING TOOL FLAGGED OVER 100 SITES AS POTENTIALLY TECHNICALLY VIABLE, ONLY THE TOP 15 ARE SHOWN HERE DUE TO THE QUALITY CONTROL REQUIRED FOR INCLUDING RANKED

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	28JUN'16	ISSUED WITH REPORT VA103-556/2-1	MGP	KLA

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TABLE 2.3

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

SCREENING AND RANKING OF POTENTIAL PUMPED STORAGE SITES
HIGHEST RANKED SITES - 25 MW, 50 GWh

6/29/2016 16:23

SITE ID	SITE NAME	INFERRED CAPITAL COST ($ M)	UPPER RESERVOIR			LOWER RESERVOIR		
			LATITUDE	LONGITUDE	ELEVATION (m)	LATITUDE	LONGITUDE	ELEVATION (m)
447-437	Tutshi-Moon	$250,000,000	59.84	-134.59	1109	59.86	-134.77	715
436-434	Atlin-Black Mt.	$267,000,000	59.94	-133.76	1197	59.95	-133.80	669
443-107	Racine-Mt. Brown	$322,000,000	59.82	-134.44	1511	59.76	-134.50	710
443-437	Racine-Moon	$358,000,000	59.84	-134.59	1109	59.76	-134.50	710
445-289	Lindeman-Fraser	$366,000,000	59.71	-135.10	1112	59.79	-135.07	677
6-314	Rainbow-Dezadeash	$372,000,000	60.73	-137.15	1330	60.67	-137.24	715
384-383	Squanga-Dalayee	$382,000,000	60.38	-133.62	950	60.45	-133.60	770
447-444	Tutshi-Skelly	$382,000,000	59.76	-134.77	866	59.86	-134.77	715
445-458	Lindeman-Long Lake	$434,000,000	59.77	-135.12	866	59.79	-135.07	677
60-55	Granite-Moose Peak	$442,000,000	60.71	-136.88	1472	60.70	-137.06	860
447-124	Tutshi-Jack Peak	$454,000,000	59.90	-134.63	1367	59.86	-134.77	715
454-320	Canyon-Ittlemit	$486,000,000	61.14	-137.07	1136	61.13	-137.03	892
444-437	Skelly-Moon	$513,000,000	59.84	-134.59	1109	59.76	-134.77	866
436-115	Atlin-McDonald	$547,000,000	59.70	-133.61	933	59.69	-133.75	669
60-314	Granite-Dezadesh	$555,000,000	60.73	-137.15	1330	60.70	-137.06	860

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Cost Ranking\[25 MW, 50 GWh.xlsx]SUMMARY

NOTES:

1. THE DATA SHOWN IN THIS TABLE HAS BEEN PRODUCED BY KP'S IN-HOUSE AUTOMATED GIS AND SPREADSHEET SCREENING TOOL.
2. QUALITY CONTROL ON THE DATA PRODUCED BY THE SCREENING TOOL HAS BEEN APPLIED BEFORE INCLUSION OF SITES ON THIS RANKED SHORT-LIST.
3. QUALITY CONTROL UNDERTAKEN ON SITES ON THIS LIST INCLUDES DELETION OF SITES THAT ARE NOT TECHNICALLY VIABLE OR THAT OVERLAP HIGHER RANKED SITES. QUALITY CONTROL ON THIS LIST DOES NOT INCLUDE MODIFICATION OF DAM ARRANGEMENT, PENSTOCK OR TRANSMISSION LINE ROUTE WHICH IS PERFORMED ONLY ON THE TOP 5 PREFERRED SITES IN A SEPARATE ANALYSIS.
4. THE TOOL RELIES ON EXTRAPOLATIONS AND SIMPLIFICATIONS TO PROVIDE INFERRED, ORDER OF MAGNITUDE COSTS FOR EACH SITE.
5. THE INDICATIVE (INFERRED) CAPITAL COSTS ARE NOT CONSIDERED RELIABLE COST ESIMATES, BUT ARE INTENDED ONLY FOR RELATIVE RANKING OF PROJECTS.
6. REFER TO SEPARATE TABLES AND COST ESTIMATES IN ASSESSMENT REPORT FOR AACE CLASS 5 COST ESTIMATES AND FINANCIAL ANALYSIS OF TOP 5 PREFFERED SITES.
7. THE GIS SCREENING TOOL FLAGGED OVER 100 SITES AS POTENTIALLY TECHNICALLY VIABLE, ONLY THE TOP 15 ARE SHOWN HERE DUE TO THE QUALITY CONTROL REQUIRED FOR INCLUDING RANKED SITES.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
1	28JUN'16	ISSUED WITH REPORT VA103-556/2-1	MGP	SRM

Knight Piésold CONSULTING

TABLE 2.4

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

SCREENING AND RANKING OF POTENTIAL PUMPED STORAGE SITES
HIGHEST RANKED SITES - 25 MW, 100 GWh

6/29/2016 16:24

SITE ID	SITE NAME	INFERRED CAPITAL COST ($ M)	UPPER RESERVOIR			LOWER RESERVOIR		
			LATITUDE (°)	LONGITUDE (°)	ELEVATION (m)	LATITUDE (°)	LONGITUDE (°)	ELEVATION (m)
447-437	Tutshi-Moon	$394,000,000	59.84	-134.59	1109	59.86	-134.77	715
443-437	Racine-Moon	$560,000,000	59.84	-134.59	1109	59.76	-134.50	710
384-383	Squanga-Dalayee	$621,000,000	60.38	-133.62	950	60.45	-133.60	770
436-434	Atlin-Black Mt.	$772,000,000	59.94	-133.76	1197	59.95	-133.80	669
454-320	Canyon-Ittlemit	$840,000,000	61.14	-137.07	1136	61.13	-137.03	892
443-107	Racine-Mt. Brown	$841,000,000	59.82	-134.44	1511	59.76	-134.50	710
447-444	Tutshi-Skelly	$854,000,000	59.76	-134.77	866	59.86	-134.77	715
355-461	Little Salmon-Drury	$891,000,000	62.27	-134.50	722	62.20	-134.51	530
6-314	Rainbow-Dezadeash	$907,000,000	60.73	-137.15	1330	60.67	-137.24	715
445-289	Lindeman-Fraser	$913,000,000	59.71	-135.10	1112	59.79	-135.07	677
60-55	Granite-Moose Peak	$1,224,000,000	60.71	-136.88	1472	60.70	-137.06	860
445-458	Lindeman-Long Lake	$1,251,000,000	59.77	-135.12	866	59.79	-135.07	677
445-459	Lindeman-Homan	$1,435,000,000	59.87	-135.19	820	59.79	-135.07	677
437-107	Moon-Mt. Brown	$1,497,000,000	59.82	-134.44	1511	59.84	-134.59	1109
444-437	Skelly-Moon	$1,528,000,000	59.84	-134.59	1109	59.76	-134.77	866

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Cost Ranking\[25 MW, 100 GWh r0.xlsx]SUMMARY

NOTES:

1. THE DATA SHOWN IN THIS TABLE HAS BEEN PRODUCED BY KP'S IN-HOUSE AUTOMATED GIS AND SPREADSHEET SCREENING TOOL.
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3. QUALITY CONTROL UNDERTAKEN ON SITES ON THIS LIST INCLUDES DELETION OF SITES THAT ARE NOT TECHNICALLY VIABLE OR THAT OVERLAP HIGHER RANKED SITES. QUALITY CONTROL ON THIS LIST DOES NOT INCLUDE MODIFICATION OF DAM ARRANGEMENT, PENSTOCK OR TRANSMISSION LINE ROUTE WHICH IS PERFORMED ONLY ON THE TOP 5 PREFERRED SITES IN A SEPARATE ANALYSIS.
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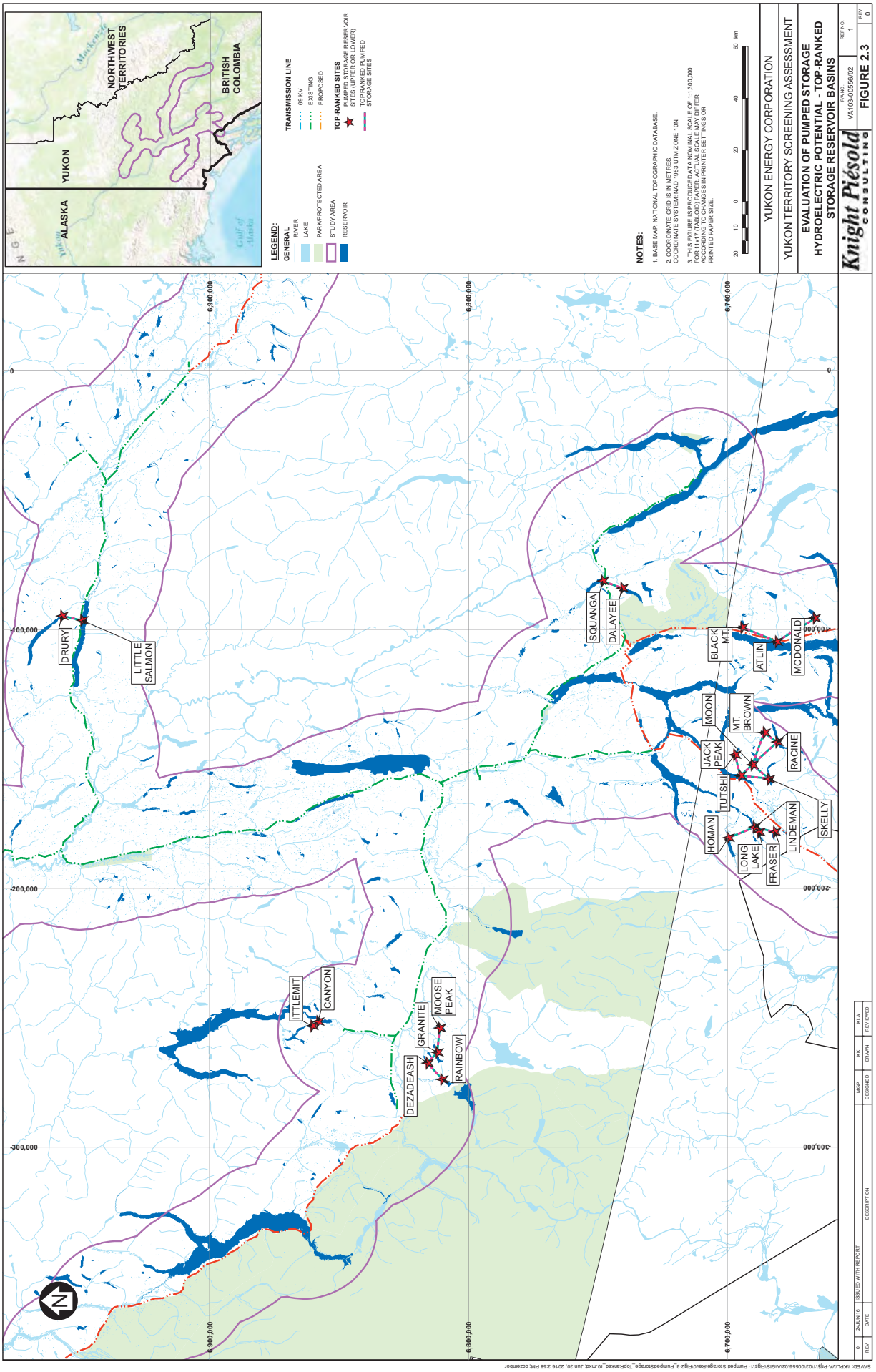
7. THE GIS SCREENING TOOL FLAGGED OVER 100 SITES AS POTENTIALLY TECHNICALLY VIABLE, ONLY THE TOP 15 ARE SHOWN HERE DUE TO THE QUALITY CONTROL REQUIRED FOR INCLUDING RANKED SIT

REV	DATE	DESCRIPTION	PREP'D	RVW'D
0	28MAR'16	ISSUED WITH REPORT VA103-556/2-1	MGP	KLA


NORTHWEST TERRITORIES
YUKON
BRITISH COLUMBIA
ALASKA
LEGEND:
GENERAL
RIVER
LAKE
PARK/PROTECTED AREA
STUDY AREA
RESERVOIR
TRANSMISSION LINE
69 KV
EXISTING
PROPOSED
TOP-RANKED SITES
ABOVE GROUND STORAGE RESERVOIR SITES (UPPER OR LOWER)
TOP RANKED PUMPED STORAGE SITES
NOTES:
1. BASE MAP: NATIONAL TOPOGRAPHIC DATABASE.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 10N.
3. THIS FIGURE IS PRODUCED DATA NOMINAL SCALE OF 1:1,300,000
FOR 11"X17" (TABLOID) PAPER. ACTUAL SCALE WILL DIFFER
ACCORDING TO CHANGES IN PAPER SIZE AND/OR
PRINTED PAPER SIZE.
20 10 0 20 40 60 km
YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL - TOP-RANKED STORAGE RESERVOIR BASINS
Knight Piésold CONSULTING
PA NO. VA103-00556/02
REF NO. 1
FIGURE 2.3
REV 0
DRURY
LITTLE SALMON
SQUANGA
DALAYEE
BLACK MT.
ATLIN
MCDONALD
MOON
MT. BROWN
JACK PEAK
RACINE
TUTSHI
HOMAN
LONG LAKE
FRASER
LINDEMAN
SKELLY
ITTLEMIT
CANYON
GRANITE
MOOSE PEAK
DEZADEASH
RAINBOW
N
6,900,000
6,800,000
6,700,000
100,000
200,000
300,000
REV
DATE
DESCRIPTION
ISSUED WITH REPORT
DESIGNED
DRAWN
REVIEWED
MGP
KK
KLA

3 – EVALUATION OF PREFERRED SITES

3.1 SELECTION OF PREFERRED SITES

By examining the top five ranked sites in each of Table 2.1 through Table 2.4, it is apparent that the following three sites appear in the top five for both the 50 GWh and 100 GWh options:

1. Tutshi-Moon
2. Atlin-Black Mt.
3. Racine-Moon

For the 50 GWh option – the following are the top five pumped-storage sites:

1. Tutshi-Moon
2. Atlin-Black Mt.
3. Racine-Moon
4. Racine-Mt. Brown (also ranked number six by a very small margin for the 25 MW, 100 GWh storage option)
5. Lindeman-Fraser

For the 100 GWh option – the following are the top five pumped-storage sites:

1. Tutshi-Moon
2. Atlin-Black Mt.
3. Racine-Moon
4. Squanga-Dalayee
5. Canyon-Ittlemit

3.2 HYDROLOGY

Hydrological characteristics are less of a consideration for pumped-storage facilities as compared to conventional hydro plants. Nevertheless, the long duration of seasonal pumping in the summer months from May through to September warranted an investigation into the likely Mean Annual Runoff to the catchments of the upper reservoirs. Any inflow to the upper reservoir at any point throughout the year can be considered water that does not need to be pumped from the lower reservoir during the summer. Note that inflow into lower reservoirs has not been evaluated. Inflow into the lower reservoirs does not reduce pumping requirements, but sufficient inflow may alleviate the need for dam construction on the lower reservoir(s). In addition, inflow may reduce the size requirement for the upper reservoir dams, and would be a useful aspect for evaluation in future.

Data from a total of 46 Water Survey of Canada (WSC) gauges with catchment areas between 10 and 7,000 km^2 were reviewed to develop an understanding of regional trends in measured runoff for catchments of varying sizes and regions. The data were used to develop estimates of Mean Annual Discharge (MAD) at the upper reservoir for all of the preferred project sites assessed here in Section 3 of this report. No analysis of the expected distribution of flow throughout the year was undertaken for the pumped-storage sites, as all inflow at any stage of the year is assumed to be captured.

Where no previous hydrology information could be obtained, KP has developed estimates on the basis of the Mean Annual Unit Discharge (MAUD) values from the WSC gauges in the region. These gauges are dispersed across the majority of the Yukon and provide a reasonable means of

assessing hydrologic patterns throughout the region. Some of the basic trends evident in the data are as follows:

- MAUD appears to decrease in a south-westerly direction along the border between the Yukon and Northwest Territories (NWT), with lower unit discharge values evident in the dry, lower relief interior zones versus the mountainous terrain along the eastern provincial border, and
- In the south-western corner of the Yukon, MAUD appears to be relatively high due to the onshore movement of moist maritime air from the Pacific Coast. The effects of this moisture influx extends slightly beyond the Coastal Mountain Range, and then drops off markedly due to a 'precipitation shadow' effect that results in a progressive reduction in MAUD moving east.

MAUD values were selected for the project sites on the basis of proximity and similarity of catchment size to the WSC stations. Commonly, there are two to three local gauge stations that provide a basis for estimating unit discharge. Where applicable, consideration was also given to the MAUD values reported for various project sites.

Additional regional considerations when determining a site's MAUD included;

- Glaciers in a watershed, which generally increase MAUD due to melt during the warm summer months
- Lakes in a watershed, which generally decrease MAUD due to greater evaporation, and
- The local relief, with higher elevation watersheds generally having higher precipitation and correspondingly higher MAUD.

3.3 PROJECT CONFIGURATIONS

Using the preliminary site information identified in Section 2 of this report, a more advanced assessment of each of the preferred sites was undertaken, including:

- Selection of a realistic penstock alignment that considers local topographic constraints and most efficient routing. These routes are longer than the straight-line distances between the upper and lower reservoir determined by the automated screening tool in Section 2
- Selection of a realistic transmission line alignment that considers local topographic constraints. These routes are longer than the straight-line distances between the powerhouse and nearest transmission line determined during the automated screening process in Section 2
- Optimisation of dam configuration (including height and length) based on the required water storage volume. This required a site by site assessment of topography and dam construction locations to supersede the dam configurations determined automatically by extrapolation during the screening process in Section 2 of this report, and
- Assessment of whether any saddle dams are required to provide the required storage.

It is apparent that the above changes will alter the anticipated cost for each project site, so the relative ranking of the top projects changes slightly with the benefit of this updated analysis. Technical attributes for all facilities are summarised in Table 3.1 through Table 3.4.

TABLE 3.1

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT TECHNICAL ATTRIBUTES - 15 MW, 50 GWh

04/07/2016 14:44

ITEM	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser
Upper Reservoir Area (ha)	500	230	210	484	190
Upper Reservoir Elevation (m)	1117	1217	1523	1117	1095
Upper Reservoir Dam Height (m)	14	26	29	16	41
Upper Reservoir Dam Crest Length (m)	470	940	320	350	940
Upper Reservoir Saddle Dam Height (m)	0	0	3	0	0
Upper Reservoir Saddle Dam Length (m)	0	0	140	0	0
Lower Reservoir Area (ha)	5400	79100	1120	1120	477
Lower Reservoir Elevation (m)	660	639	726	726	654
Lower Reservoir Dam Height (m)	3	0	5	7	0
Lower Reservoir Dam Crest Length (m)	500	0	500	870	0
Gross Head (m)	457	578	797	392	441
Design Flow - Generation (m^3/s)	3.9	3.1	2.2	4.5	4.0
Design Flow - Pumping (m^3/s)	2.7	2.1	1.6	3.2	2.8
Installed Capacity (MW)	15	15	15	15	15
Energy Storage (GWh)	50	50	50	50	50
Assumed Efficiency, Generating (%)	87	87	87	87	87
Assumed Efficiency, Pumping (%)	81	81	81	81	81
Penstock Length (km)	5.8	2.5	6.5	9.5	16.0
Transmission Line Length (km)	2.6	0.8	24.0	20.0	5.0
Reservoir Storage Volume ($x10^6$ m^3)	46.4	36.7	26.6	54.2	48.1
Upper Reservoir Catchment Area (km^2)	59	9.1	12	59	13
Upper Reservoir Approximate Unit Runoff ($l/s/km^2$)	15	5	12	15	12
Upper Reservoir Approximate Mean Annual Discharge (m^3/s)	0.879	0.046	0.144	0.879	0.156
Instream Flow Requirements, Assumed 5% of MAD (m^3/s)	0.044	0.002	0.007	0.044	0.008
Annual Generating Energy (GWh)	50.0	50.0	50.0	50.0	50.0
Annual Pumping Flow ($x10^6$ m^3)	20.0	35.3	22.3	27.8	43.5
Annual Pumping Energy (MWh)	26.7	59.5	51.8	31.8	55.8
Generation Duration to Completely Empty Reservoir (Days)	177	141	148	170	144
Pumping Duration to Completely Fill Reservoir (Days)	152	194	182	157	188

M:\1\03\00556\02\A\Report\1 - Pumped Storage\Rev 0\Tables\[Cost_Technical_Financial_15 MW, 50 GWh.xlsx]Technical Summary

NOTES:

1. TECHNICAL ATTRIBUTES ARE PRELIMINARY BASED ON A DESKTOP LEVEL SCREENING ASSESSMENT ONLY.
2. GENERATION AND PUMPING DURATIONS ASSUME MEAN ANNUAL DISCHARGE INFLOWS INTO THE RESERVOIR CONTINOUSLY WITH NO ALLOWANCE FOR SEASONAL VARIATION.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT	MGP	KLA

Knight Piésold CONSULTING

TABLE 3.2

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT TECHNICAL ATTRIBUTES - 15 MW, 100 GWh

13/04/2016 14:56

ITEM	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Squanga-Dalayee	Canyon-Ittlemit
Upper Reservoir Area (ha)	610	315	290	1300	1275
Upper Reservoir Elevation (m)	1117	1217	1523	975	1160
Upper Reservoir Dam Height (m)	22	42	43	21	33
Upper Reservoir Dam Crest Length (m)	830	1140	470	1300	970
Upper Reservoir Saddle Dam Height (m)	0	5	30	0	32
Upper Reservoir Saddle Dam Length (m)	0	800	400	0	650
Lower Reservoir Area (ha)	5600	79100	1130	1600	1538
Lower Reservoir Elevation (m)	660	639	726	792	904
Lower Reservoir Dam Height (m)	4	0	6	20	16
Lower Reservoir Dam Crest Length (m)	600	0	600	2000	1520
Gross Head (m)	457	578	797	183	256
Design Flow - Generation (m^3/s)	3.9	3.1	2.2	9.7	6.9
Design Flow - Pumping (m^3/s)	2.7	2.1	1.6	6.8	4.8
Installed Capacity (MW)	15	15	15	15	15
Energy Storage (GWh)	100	100	100	100	100
Assumed Efficiency, Generating (%)	87	87	87	87	87
Assumed Efficiency, Pumping (%)	81	81	81	81	81
Penstock Length (km)	5.8	2.5	6.5	7.8	2.0
Transmission Line Length (km)	2.6	0.8	24.0	0.8	13.9
Reservoir Storage Volume ($x10^6$ m^3)	92.8	73.4	53.2	232	165.9
Upper Reservoir Catchment Area (km^2)	59	9.1	12	68	57
Upper Reservoir Approximate Unit Runoff ($l/s/km^2$)	15	5	12	3.6	2.9
Upper Reservoir Approximate Mean Annual Discharge (m^3/s)	0.879	0.046	0.144	0.2	0.2
Instream Flow Requirements, Assumed 5% of MAD (m^3/s)	0.044	0.002	0.007	0.0	0.0
Annual Generating Energy (GWh)	100.0	100.0	100.0	100.0	100.0
Annual Pumping Flow ($x10^6$ m^3)	66.4	72.0	48.9	224.7	160.9
Annual Pumping Energy (MWh)	88.5	121.3	113.6	119.7	119.9
Generation Duration to Completely Empty Reservoir (Days)	354	282	296	285	284
Pumping Duration to Completely Fill Reservoir (Days)	303	389	365	384	384

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Preferred Sites\[Cost_Technical_Financial_15 MW, 100 GWh.xlsx]Cost Summary

NOTES:

1. TECHNICAL ATTRIBUTES ARE PRELIMINARY BASED ON A DESKTOP LEVEL SCREENING ASSESSMENT ONLY.
2. GENERATION AND PUMPING DURATIONS ASSUME MEAN ANNUAL DISCHARGE INFLOWS INTO THE RESERVOIR CONTINOUSLY WITH NO ALLOWANCE FOR SEASONAL VARIATION.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT	MGP	KLA

Knight Piésold CONSULTING

TABLE 3.3

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT TECHNICAL ATTRIBUTES - 25 MW, 50 GWh

13/04/2016 14:55

ITEM	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser
Upper Reservoir Area (ha)	500	230	210	484	190
Upper Reservoir Elevation (m)	1117	1217	1523	1117	1095
Upper Reservoir Dam Height (m)	14	26	29	16	41
Upper Reservoir Dam Crest Length (m)	470	940	320	350	940
Upper Reservoir Saddle Dam Height (m)	0	0	3	0	0
Upper Reservoir Saddle Dam Length (m)	0	0	140	0	0
Lower Reservoir Area (ha)	5400	79100	1120	1120	477
Lower Reservoir Elevation (m)	660	639	726	726	654
Lower Reservoir Dam Height (m)	3	0	5	7	0
Lower Reservoir Dam Crest Length (m)	500	0	500	870	0
Gross Head (m)	457	578	797	392	441
Design Flow - Generation (m^3/s)	6.4	5.1	3.7	7.5	6.7
Design Flow - Pumping (m^3/s)	4.5	3.6	2.6	5.3	4.7
Installed Capacity (MW)	25	25	25	25	25
Energy Storage (GWh)	50	50	50	50	50
Assumed Efficiency, Generating (%)	87	87	87	87	87
Assumed Efficiency, Pumping (%)	81	81	81	81	81
Penstock Length (km)	5.8	2.5	6.5	9.5	16.0
Transmission Line Length (km)	2.6	0.8	24.0	20.0	5.0
Reservoir Storage Volume ($x10^6$ m^3)	46.4	36.7	26.6	54.2	48.1
Upper Reservoir Catchment Area (km^2)	59	9.1	12	59	13
Upper Reservoir Approximate Unit Runoff ($l/s/km^2$)	15	5	12	15	12
Upper Reservoir Approximate Mean Annual Discharge (m^3/s)	0.879	0.046	0.144	0.879	0.156
Instream Flow Requirements, Assumed 5% of MAD (m^3/s)	0.044	0.002	0.007	0.044	0.008
Annual Generating Energy (GWh)	50.0	50.0	50.0	50.0	50.0
Annual Pumping Flow ($x10^6$ m^3)	20.0	35.3	22.3	27.8	43.5
Annual Pumping Energy (MWh)	26.7	59.5	51.8	31.8	55.8
Generation Duration to Completely Empty Reservoir (Days)	96	84	87	94	85
Pumping Duration to Completely Fill Reservoir (Days)	100	118	113	103	115

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Preferred Sites\[Cost_Technical_Financial_25 MW, 50 GWh.xlsx]Cost Summary

NOTES:

1. TECHNICAL ATTRIBUTES ARE PRELIMINARY BASED ON A DESKTOP LEVEL SCREENING ASSESSMENT ONLY.
2. GENERATION AND PUMPING DURATIONS ASSUME MEAN ANNUAL DISCHARGE INFLOWS INTO THE RESERVOIR CONTINOUSLY WITH NO ALLOWANCE FOR SEASONAL VARIATION.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT VA103-556/2-1	MGP	KLA

Knight Piésold CONSULTING

TABLE 3.4

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT TECHNICAL ATTRIBUTES - 25 MW, 100 GWh

13/04/2016 15:01

ITEM	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Squanga-Dalayee	Canyon-Ittlemit
Upper Reservoir Area (ha)	610	315	290	1300	1275
Upper Reservoir Elevation (m)	1117	1217	1523	975	1160
Upper Reservoir Dam Height (m)	22	42	43	21	33
Upper Reservoir Dam Crest Length (m)	830	1140	470	1300	970
Upper Reservoir Saddle Dam Height (m)	0	5	30	0	32
Upper Reservoir Saddle Dam Length (m)	0	800	400	0	650
Lower Reservoir Area (ha)	5600	79100	1130	1600	1538
Lower Reservoir Elevation (m)	660	639	726	792	904
Lower Reservoir Dam Height (m)	4	0	6	20	16
Lower Reservoir Dam Crest Length (m)	600	0	600	2000	1520
Gross Head (m)	457	578	797	183	256
Design Flow - Generation (m^3/s)	6.4	5.1	3.7	16.1	11.5
Design Flow - Pumping (m^3/s)	4.5	3.6	2.6	11.3	8.1
Installed Capacity (MW)	25	25	25	25	25
Energy Storage (GWh)	100	100	100	100	100
Assumed Efficiency, Generating (%)	87	87	87	87	87
Assumed Efficiency, Pumping (%)	81	81	81	81	81
Penstock Length (km)	5.8	2.5	6.5	7.8	2.0
Transmission Line Length (km)	2.6	0.8	24.0	0.8	13.9
Reservoir Storage Volume ($x10^6$ m^3)	92.8	73.4	53.2	232	165.9
Upper Reservoir Catchment Area (km^2)	59	9.1	12	68	57
Upper Reservoir Approximate Unit Runoff ($l/s/km^2$)	15	5	12	3.6	2.9
Upper Reservoir Approximate Mean Annual Discharge (m^3/s)	0.879	0.046	0.144	0.2	0.2
Instream Flow Requirements, Assumed 5% of MAD (m^3/s)	0.044	0.002	0.007	0.0	0.0
Annual Generating Energy (GWh)	100.0	100.0	100.0	100.0	100.0
Annual Pumping Flow ($x10^6$ m^3)	66.4	72.0	48.9	224.7	160.9
Annual Pumping Energy (MWh)	88.5	121.3	113.6	119.7	119.9
Generation Duration to Completely Empty Reservoir (Days)	191	168	173	169	169
Pumping Duration to Completely Fill Reservoir (Days)	201	235	226	233	234

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Preferred Sites\[Cost_Technical_Financial_25 MW, 100 GWh.xlsx]Technical Summary

NOTES:

1. TECHNICAL ATTRIBUTES ARE PRELIMINARY BASED ON A DESKTOP LEVEL SCREENING ASSESSMENT ONLY.
2. GENERATION AND PUMPING DURATIONS ASSUME MEAN ANNUAL DISCHARGE INFLOWS INTO THE RESERVOIR CONTINOUSLY WITH NO ALLOWANCE FOR SEASONAL VARIATION.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT VA103-556/2-1	MGP	KLA

3.4 PROJECT DESCRIPTIONS

3.4.1 Tutshi-Moon

This site is located between Tutshi and Moon Lakes in British Columbia. The configuration is relatively straight forward, with a dam downstream of the outlet on Moon Lake. Since inflows into the project site were not considered in sizing the upper and lower reservoir dams, our analysis indicated that a low dam would be required at the outlet of Tutshi Lake in order to ensure the required storage volume in the lake. The inflows may be sufficient to alleviate the requirement for this dam in a final project configuration.

The penstock route selected for the analysis runs along the eastern side of the valley from Moon Lake down to the powerhouse on Tutshi Lake. The transmission line then heads north across Tutshi Lake to the proposed Yukon-Skagway transmission line that will run along the north-west shore. Without construction of this line, the distance to the nearest point of interconnection increases by approximately 35 km.

This is the same site assessed by Midgard in their 2015 conceptual study report. KP's configuration and analysis for this site is useful in benchmarking KP's analysis and cost assessment for all project sites with the more detailed analysis prepared by Midgard for Moon Lake. The current analysis was completed using KP's own methods without reference to the Midgard report, but yielded similar cost results as those obtained by Midgard. This provides a level of confidence and credibility in the results of the current report, given their similarity to Midgard's estimates which were prepared using different methods and a more detailed level of information.

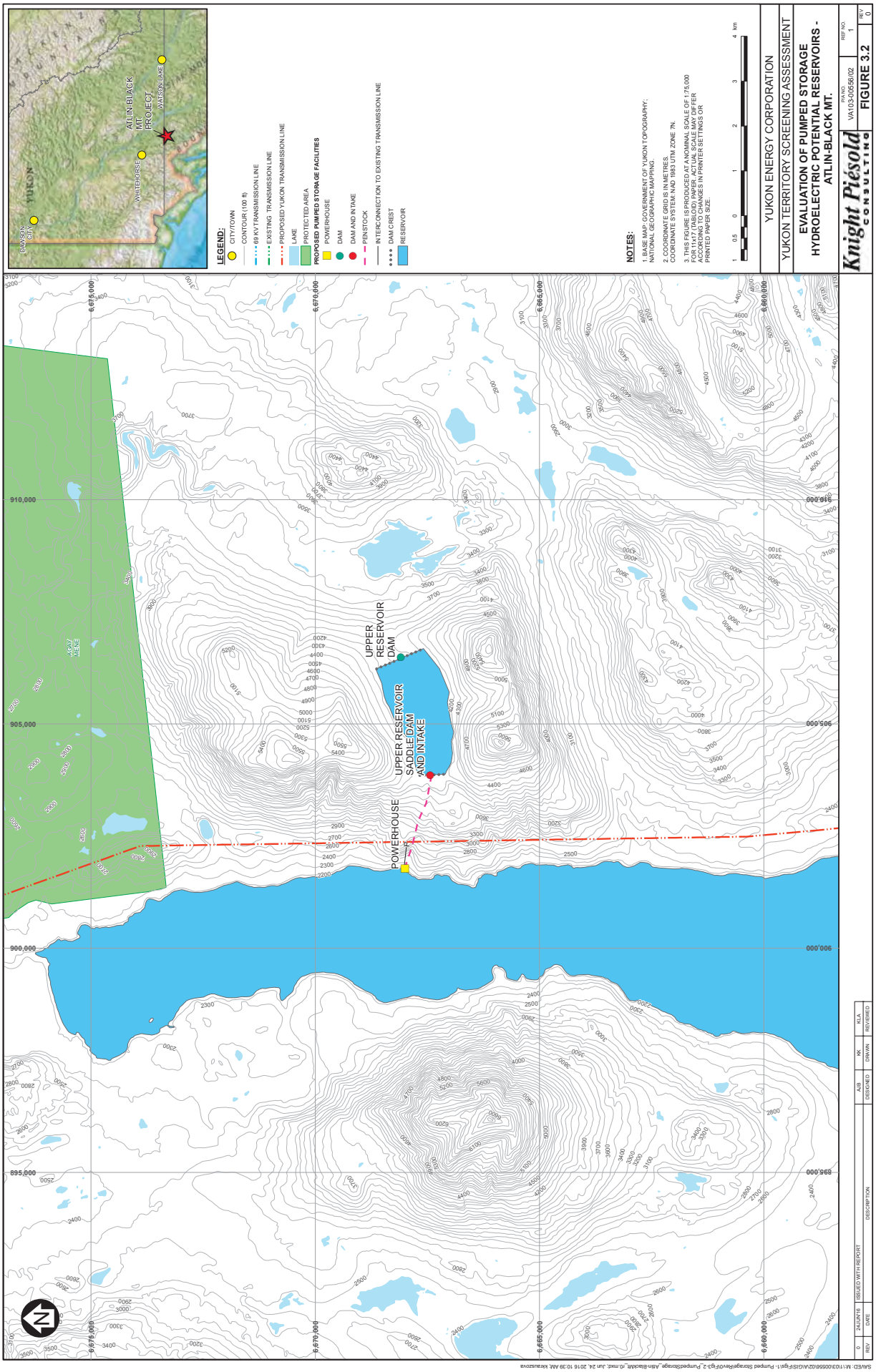
3.4.2 Atlin-Black Mountain

This project uses the very large Atlin Lake in British Columbia as a lower reservoir and a small lake perched in a hanging valley approximately 2.5 km to the east of Atlin Lake, adjacent to Black Mountain. The upper reservoir requires a saddle dam on the west side in order to achieve the 100 GWh of storage, although no saddle dam is required for the 50 GWh storage arrangement.

The natural drainage direction from the small alpine lake is to the east. The penstock route assumes a deep channel excavation on the west side of the lake in order to minimise penstock length (approximately 2.5 km length as compared to a length of over 12 km for a penstock route that follows the natural terrain to the east of the small lake). Further analysis will be required to determine the technical viability of excavating a deep trench to overcome the terrain limitation, but it appears that the project still remains "competitive" with some of the top ranked projects, even with the assumption of digging a deep channel of approximately 130 m in length to accommodate the penstock drainage. The transmission line distance for this project is short (<1 km) provided that the Atlin-Yukon transmission line is constructed as it would run immediately adjacent to the proposed powerhouse location. Without the proposed transmission line, this site would be over 40 km to the nearest point of interconnection.

No dam is required on the lower reservoir, as the entire 100 GWh energy storage volume would result in a level fluctuation in Atlin Lake of only 10 cm. Given the long duration over which the energy is both stored and discharged, this artificial fluctuation will likely be small compared to background natural fluctuations in lake level.

YUKON
DAWSON CITY
WHITEHORSE
TUTSHI-MOON PROJECT
WATSON LAKE
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
69 KV TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED YUKON TRANSMISSION LINE
LAKE
PROPOSED PUMPED STORAGE FACILITIES
POWERHOUSE
DAM AND INTAKE
PENSTOCK
INTERCONNECTION TO EXISTING TRANSMISSION LINE
DAM CREST
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES; COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:60,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDINGLY IF CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
1 0.5 0 1 2 3 km
YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL RESERVOIRS - TUTSHI-MOON
Knight Piésold CONSULTING
PIA NO. VA103-00556/02
REF NO. 1
REV. 0
FIGURE 3.1
UPPER RESERVOIR DAM AND INTAKE
POWERHOUSE
6,655,000
6,650,000
6,645,000
860,000
855,000
850,000
845,000
N
REV. DATE ISSUED WITH REPORT DESCRIP'TION AJB DESIGNED PK DRAWN KLA REVIEWED
0 24JUN'18
SAVED: M:\1\03\00556\02\A\GIS\Figs\1-Pumped Storage\rev0\Fig3-1_PumpedStorage_Tutshi-Moon_r0.mxd, Jun 24, 2018 10:11 AM kkrauszova


YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL RESERVOIRS - ATLIN-BLACK MT.
FIGURE 3.2
Knight Piésold CONSULTING
PROJECT NO. VA103-00556/02
REF NO. 1
REV 0
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
69 KV TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED YUKON TRANSMISSION LINE
LAKE
PROTECTED AREA
PROPOSED PUMPED STORAGE FACILITIES
POWERHOUSE
DAM
DAM AND INTAKE
PENSTOCK
INTERCONNECTION TO EXISTING TRANSMISSION LINE
DAM CREST
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
0 1 2 3 4 km
0 0.5 1
YUKON
DAWSON CITY
WHITEHORSE
ATLIN BLACK MTN. PROJECT
WATSON LAKE
UPPER RESERVOIR DAM
UPPER RESERVOIR SADDLE DAM AND INTAKE
POWERHOUSE
ATLIN LAKE
910,000
905,000
900,000
895,000
6,675,000
6,670,000
6,665,000
6,660,000
N
REV DATE ISSUED WITH REPORT
0 24JUN16
DESCRIPTION
DESIGNED AJB
DRAWN DK
REVIEWED KLA
SAVED: M:\1\03\00556\02\A\GIS\Figs\1-Pumped Storage\rev0\Fig3-2_PumpedStorage_AtlinBlackMt.mxd: Jun 24, 2016 10:39 AM: kteauzova

3.4.3 Racine-Moon

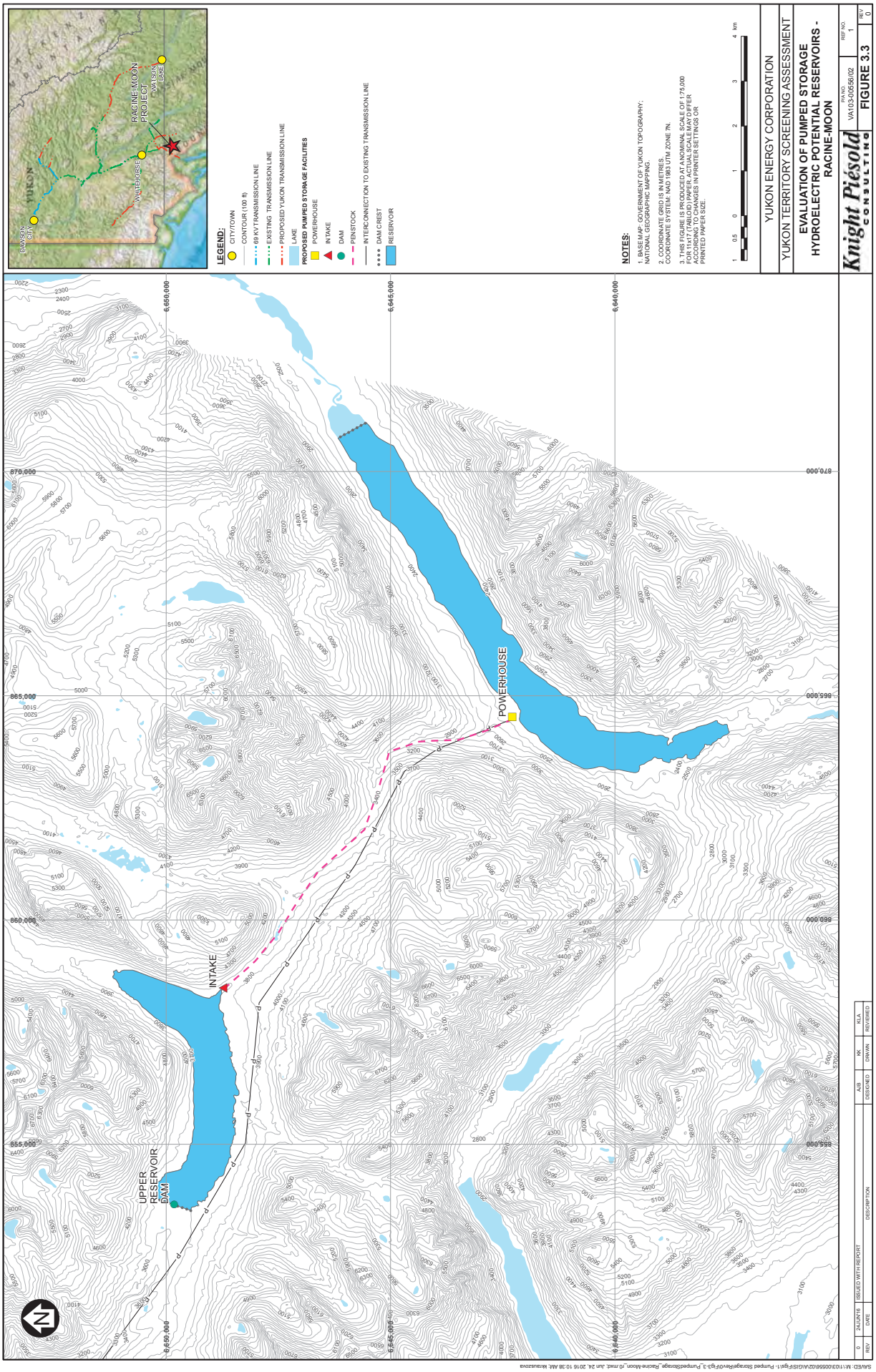
This site utilises Moon Lake as an upper reservoir, but with Racine Lake as a lower reservoir in lieu of Tutshi Lake. The proposed penstock would run along the valley which lies directly between these two lakes. The elevation of this valley lies above the upper surface level of Moon Lake. Much like for the Atlin-Black Mt. site, a section of trench would need to be excavated to maintain a constant downward slope from Moon Lake to Racine Lake. However, unlike for the Atlin-Black Mt. site, this trench section would be quite long at approximately 3,000 m, thereby making this site much less attractive than was predicted by the automated screening tool. Furthermore, it is difficult to envision a situation where this would be constructed in lieu of, or in addition to the Tutshi-Moon pumped-storage facility. This site was ranked in the top five sites for both the 50 GWh and 100 GWh storage configurations during the screening assessment in Section 2 of this report. However, the site was excluded from the 100 GWh analysis in lieu of the Racine-Mt. Brown site due to the high water conveyance system cost making it relatively unfavourable.

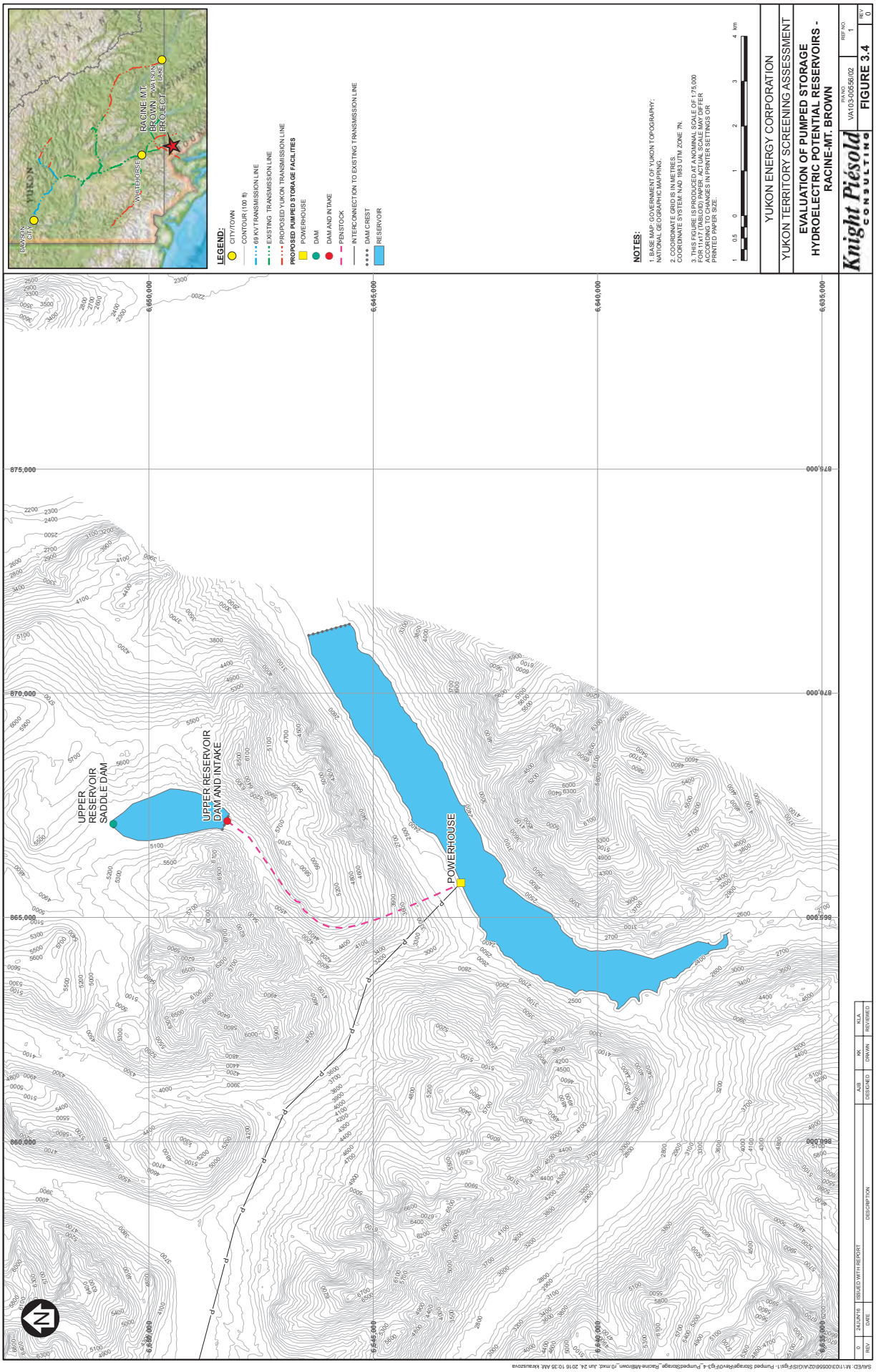
The powerhouse is located on the north shore of Racine Lake, and the transmission line would run along the valley to the north of the lake, towards Moon Lake, and then crossing Tutshi Lake. On the north-west shore of Tutshi Lake, the project's transmission line would connect to the proposed transmission line between the Yukon and Skagway, Alaska. Without construction of the proposed line, the nearest point of interconnection for this project would be a further 35 km away from the proposed facility.

3.4.4 Racine Mt. Brown

This site features a small alpine lake at high elevation to the north of Racine Lake. A penstock route would follow along the north-west slope of the ridge separating the two lakes. For the 100 GWh storage option, a saddle dam would be required to create water volume needed for the upper reservoir, while no saddle dam is needed for 50 GWh of storage.

The powerhouse is located on the north shore of Racine Lake, and the transmission line would run along the valley to the north of the lake, towards Moon Lake, and then crossing Tutshi Lake. On the north-west shore of Tutshi Lake, the project's transmission line would connect to the proposed transmission line between the Yukon and Skagway, Alaska. Without construction of the proposed line, the nearest point of interconnection for this project would be a further 35 km away from the proposed facility.


RACINE-MOON PROJECT
WHITEHORSE
VALLEY N LAKE
DAWSON CITY
YUKON
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
69 KV TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED YUKON TRANSMISSION LINE
LAKE
PROPOSED PUMPED STORAGE FACILITIES
POWERHOUSE
INTAKE
DAM
PENSTOCK
INTERCONNECTION TO EXISTING TRANSMISSION LINE
DAM CREST
RESERVOIR
NOTES:
1. BASEMAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75,000 FOR 11x17 (TABLOID) PAPER SIZE. SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
1 0 0.5 1 2 3 4 km
YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL RESERVOIRS - RACINE-MOON
Knight Piésold CONSULTING
PIA NO. VA103-00556/02
REF NO. 1
REV. 0
FIGURE 3.3
UPPER RESERVOIR DAM
INTAKE
POWERHOUSE
870,000
865,000
860,000
855,000
6,650,000
6,645,000
6,640,000
REV. DATE ISSUED WITH REPORT DESCRIPTION DESIGNED DRAWN REVIEWED
0 24JUN'18 ISSUED WITH REPORT AJB PK KLA


YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL RESERVOIRS - RACINE-MT. BROWN
Knight Piésold CONSULTING
PROJECT NO. VA103-00556/02
REF NO. 1
REV. 0
FIGURE 3.4
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
69 KV TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED YUKON TRANSMISSION LINE
PROPOSED PUMPED STORAGE FACILITIES
POWERHOUSE
DAM
DAM AND INTAKE
PENSTOCK
INTERCONNECTION TO EXISTING TRANSMISSION LINE
DAM CREST
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
1 0 0.5 1 2 3 4 km
UPPER RESERVOIR SADDLE DAM
UPPER RESERVOIR DAM AND INTAKE
POWERHOUSE
RACINE-MT. BROWN PROJECT
DAWSON CITY
WHITEHORSE
YUKON
ALASKA
BRITISH COLUMBIA
NORTHWEST TERRITORIES
SASKATCHEWAN
ALBERTA
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
COLORADO
WYOMING
UTAH
NEVADA
IDAHO
OREGON
WASHINGTON
CALIFORNIA
MINNESOTA
IOWA
KANSAS
MISSOURI
ARIZONA
NEW MEXICO
TEXAS
OKLAHOMA
ARKANSAS
LOUISIANA
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
TENNESSEE
KENTUCKY
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
MAINE
VERMONT
NEW HAMPSHIRE
MASSACHUSETTS
RHODE ISLAND
CONNECTICUT
NEW JERSEY
DELAWARE
MARYLAND
6,650,000
6,645,000
6,640,000
6,635,000
875,000
870,000
865,000
860,000
N
REV. 0 DATE: JAN/16 ISSUED WITH REPORT DESCRIPTION DESIGNED: AJB DRAWN: PK REVIEWED: KLA
SAVED: M:\1\03\00556\02\A\GIS\Figs\1-Pumped Storage\Rev0\Fig 3.4_PumpedStorage_RacineMtBrown_r0.mxd, Jun 24, 2016 10:35 AM, kkwaszova

3.4.5 Lindeman-Fraser

This site consists of Lindeman Lake as a lower reservoir, with the upper reservoir formed in an alpine valley to the west of the town of Fraser. The penstock route is long, and follows to the east of a mountain that separates the two lakes, while the transmission line runs in a south-easterly direction to connect with the proposed new transmission line to Skagway, Alaska. Without the construction of this proposed line, the required transmission line distance would be approximately 50 km to the nearest point of interconnection.

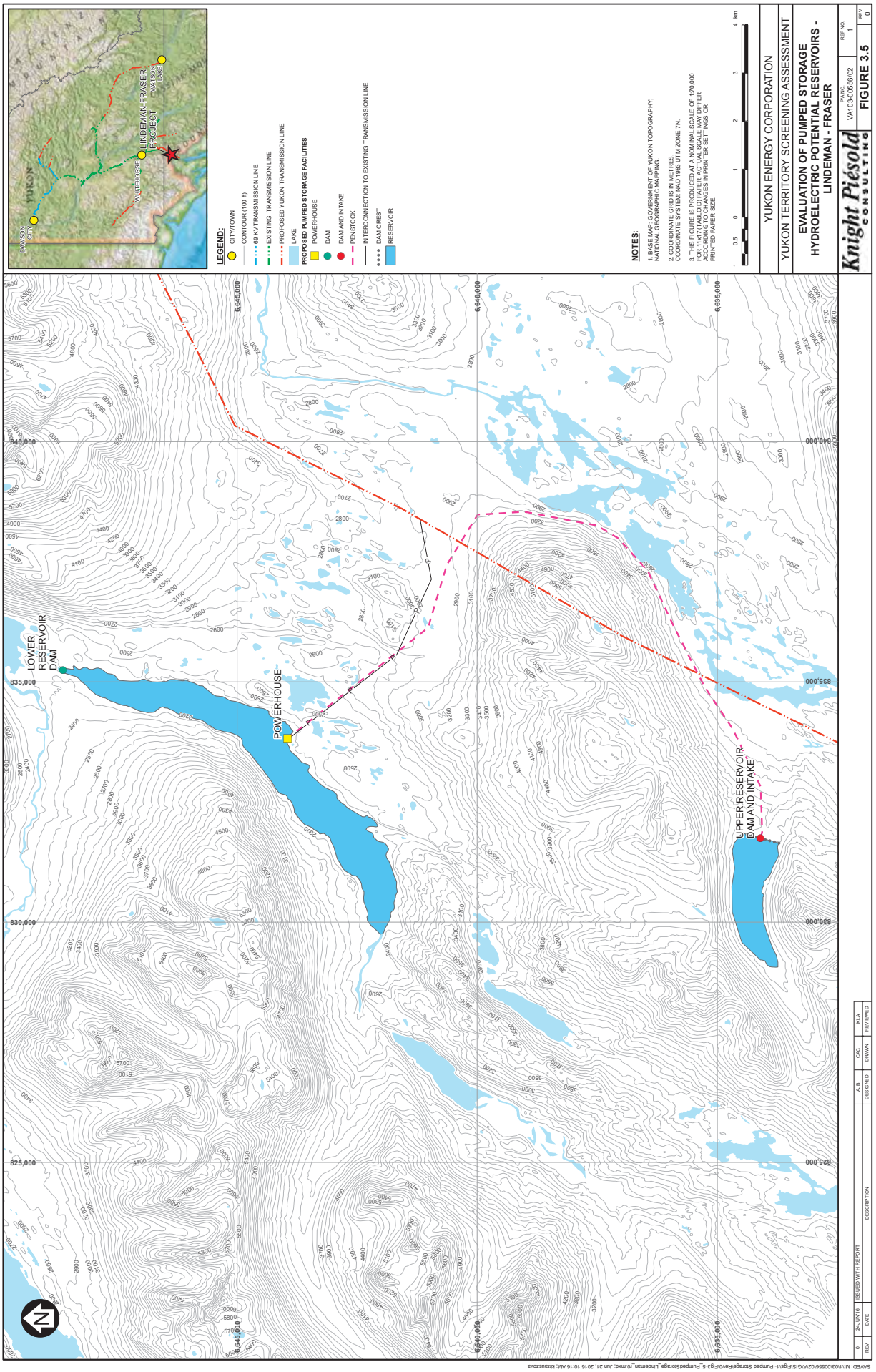
The long penstock route and the large dam required on the upper reservoir both put this site at a disadvantage. KP briefly assessed whether a tunnel through the mountain to the north of the upper reservoir may reduce overall costs by shortening the water conveyance distance. However, due to the minimum size required for tunnel construction, the small project capacity would result in a tunnel much larger than would otherwise be needed, and construction of a tunnel may actually increase, rather than decrease construction costs.

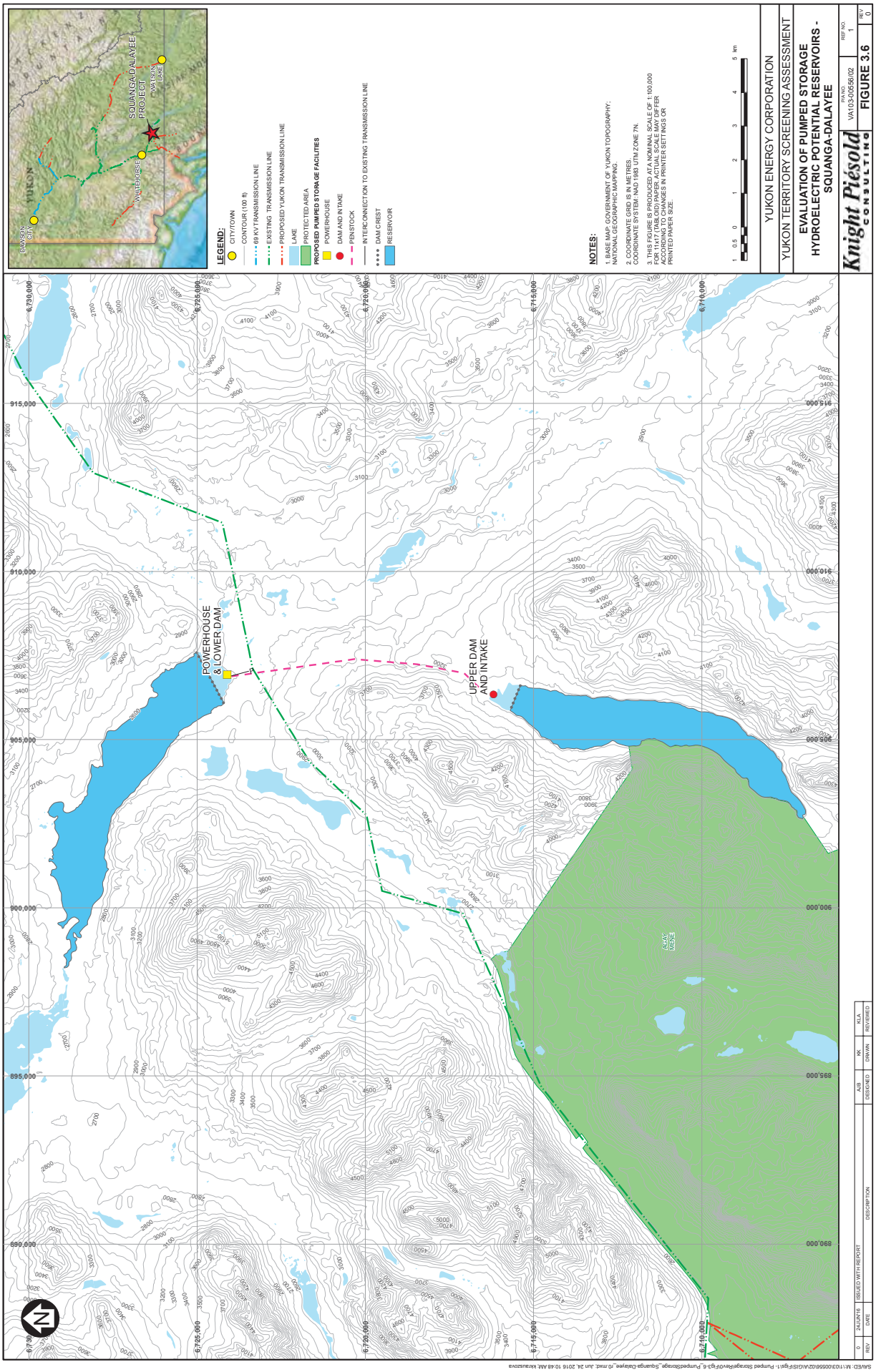
3.4.6 Squanga-Dalayee

This proposed facility is located between Squanga and Dalayee Lakes between Johnson's Crossing and Jake's Corner in the Yukon Territory. While the head is lower than some of the other highly ranked sites, the large existing lakes and short transmission distances offset the technical disadvantage of a lower head facility somewhat. The dams are relatively low (at approximately 20 m each for 100 GWh of storage), but are long due to the relatively wide valleys in which the lake outlets are situated. The penstock is a relatively direct route to the powerhouse located on the shore of Squanga Lake, less than 2 km from the nearest transmission line. The location of this facility relatively close to Whitehorse would provide advantages relative to the sites located in British Columbia at a greater distance from the Yukon's major load centre.

3.4.7 Canyon-Ittlemit

This project is located on Canyon Lake, with the upper reservoir formed by a conglomeration of a number of higher elevation lakes, including Ittlemit Lake. For the 100 GWh storage configuration, a large saddle would be required, adding to the cost of the facility. A major extension to the existing Canyon Lake dam would be required to allow construction of this facility, which will be difficult to manage without negatively impacting on flows through the Aishihik hydroelectric facility downstream. The penstock route between the two reservoirs is direct, and the transmission line would run along the western shore of Canyon Lake and the Aishihik River to the point of interconnection at the Aishihik substation. While integrating this facility on the same lake as an existing hydro facility would be challenging, it may provide potential benefits in providing additional regulation to the Aishihik hydroelectric facility. Determining the exact extent and configuration of a pumped-storage facility on Canyon Lake that would not impact the existing Aishihik facility would need to be investigated further in future project stages to determine whether it is possible.


DAWSON CITY
YUKON
WHITEHORSE
LINDEMAN-FRASER PROJECT
MARSH LAKE
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
69 KV TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED YUKON TRANSMISSION LINE
LAKE
PROPOSED PUMPED STORAGE FACILITIES
POWERHOUSE
DAM
DAM AND INTAKE
PENSTOCK
INTERCONNECTION TO EXISTING TRANSMISSION LINE
DAM CREST
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES; COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:70,000 FOR 11"x17" (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
1 0 0.5 1 2 3 4 km
YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL RESERVOIRS - LINDEMAN - FRASER
Knight Piésold CONSULTING
PROJECT NO. VA103-00556/02
REF NO. 1
REV. 0
FIGURE 3.5
LOWER RESERVOIR DAM
POWERHOUSE
UPPER RESERVOIR DAM AND INTAKE
840,000
835,000
830,000
825,000
6,645,000
6,640,000
6,635,000
REV. DATE ISSUED WITH REPORT
0 JUN/16
DESCRIPTION
AJB DESIGNED
CAC DRAWN
KLA REVIEWED
SAVED: M:\1\03\00556\02\A\GIS\Figs\1-Pumped Storage\fev\Fig3-5_PumpedStorage_Lindeman_r0.mxd: Jun 24, 2016 10:16 AM: kkavauzova


SQUANGA DALAYEE PROJECT
YUKON
DAWSON CITY
WHITEHORSE
WATSON LAKE
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
69 KV TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED YUKON TRANSMISSION LINE
LAKE
PROTECTED AREA
PROPOSED PUMPED STORAGE FACILITIES
POWERHOUSE
DAM AND INTAKE
PENSTOCK
INTERCONNECTION TO EXISTING TRANSMISSION LINE
DAM CREST
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:100,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
1 0 0.5 1 2 3 4 5 km
YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL RESERVOIRS - SQUANGA-DALAYEE
Knight Piésold CONSULTING
PIA NO. VA103-00556/02
REF NO. 1
REV 0
FIGURE 3.6
POWERHOUSE & LOWER DAM
UPPER DAM AND INTAKE
ARAY VEINE
N
REV DATE ISSUED WITH REPORT DESCRIPTION AJB DESIGNED DK DRAWN KLA REVIEWED
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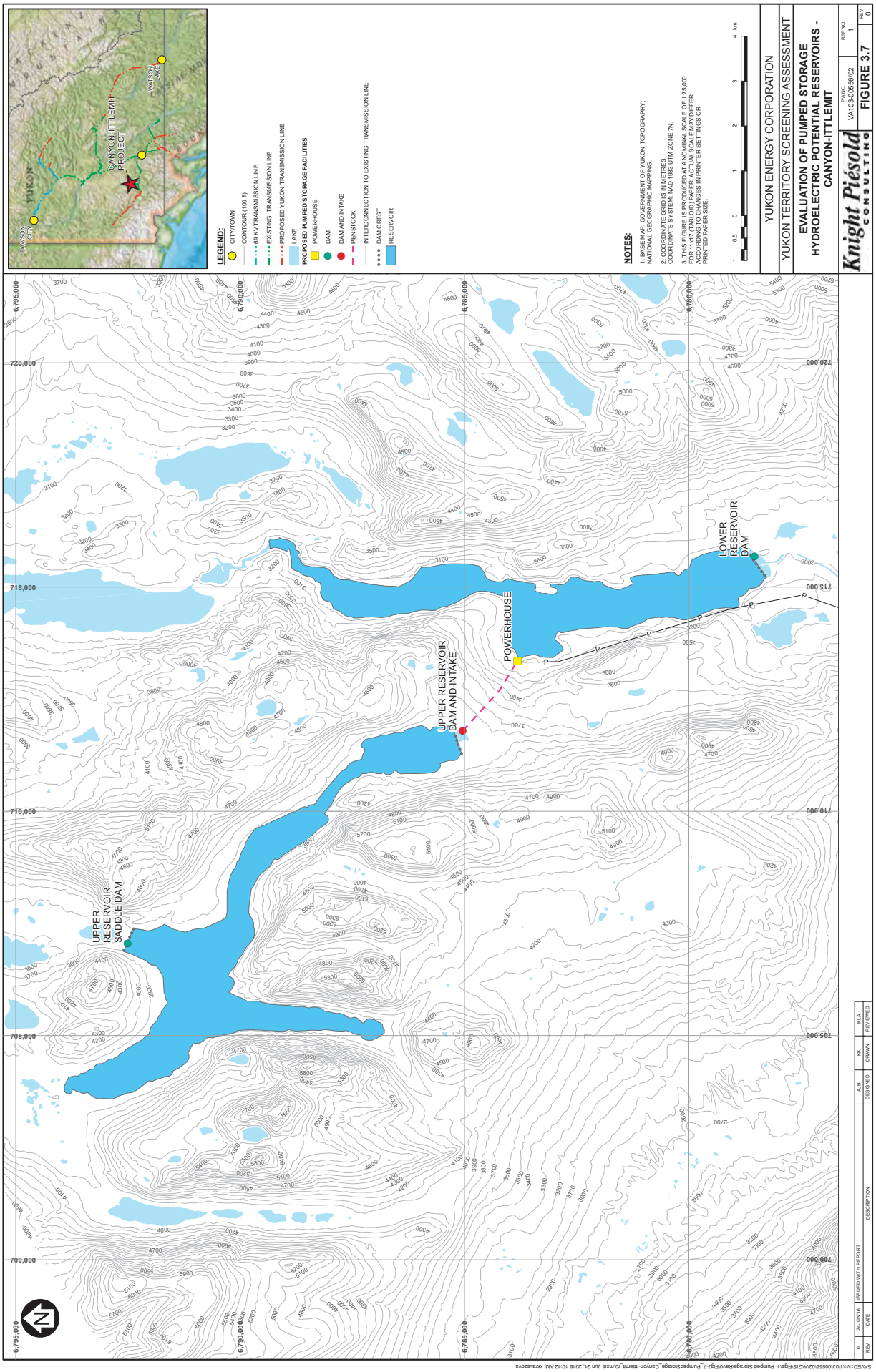
YUKON
DAWSON CITY
CANYON-ITTLEMIT PROJECT
VANTRESS LAKE
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
69 KV TRANSMISSION LINE
EXISTING TRANSMISSION LINE
PROPOSED YUKON TRANSMISSION LINE
LAKE
PROPOSED PUMPED STORAGE FACILITIES
POWERHOUSE
DAM
DAM AND INTAKE
PENSTOCK
INTERCONNECTION TO EXISTING TRANSMISSION LINE
DAM CREST
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES; COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
1 0 0.5 1 2 3 4 km
YUKON ENERGY CORPORATION
YUKON TERRITORY SCREENING ASSESSMENT
EVALUATION OF PUMPED STORAGE HYDROELECTRIC POTENTIAL RESERVOIRS - CANYON-ITTLEMIT
Knight Piésold CONSULTING
PROJECT NO. VA103-00556/02
REF NO. 1
REV. 0
FIGURE 3.7
UPPER RESERVOIR SADDLE DAM
UPPER RESERVOIR DAM AND INTAKE
POWERHOUSE
LOWER RESERVOIR DAM
6,795,000
6,790,000
6,785,000
6,780,000
720,000
715,000
710,000
705,000
700,000
REV. DATE DESCRIPTION DESIGNED DRAWN REVIEWED
0 24JUN16 ISSUED WITH REPORT AJB DK KLA

3.5 TRANSMISSION LINE CONSIDERATIONS

For this study it has been assumed the transmission lines from each project would interconnect to the closest possible point along an existing or future proposed transmission line via “Tee-Tap” type interconnection that would require expensive substation and/or switching station infrastructure. A indicative interconnection arrangement is depicted in Figure 3.8 below:

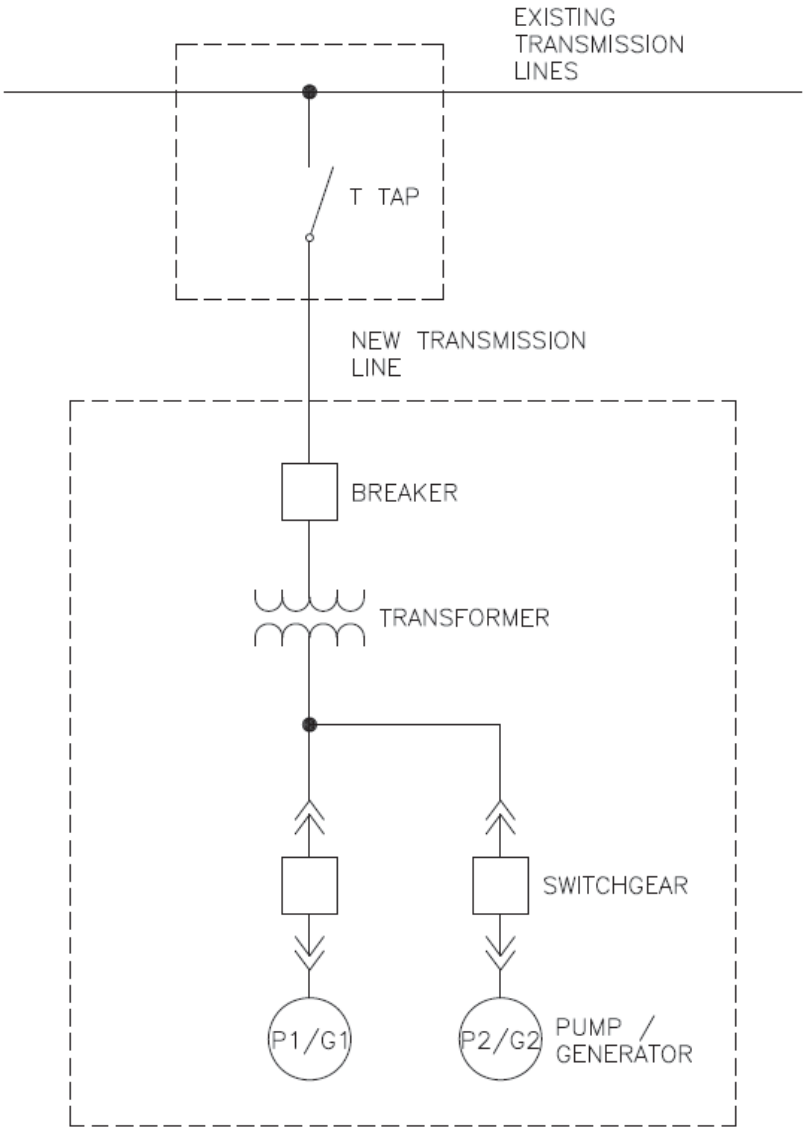

Figure 3.8 Indicative Interconnection Arrangement

However, there may be a few sites where a cheaper option exists to extend the transmission line slightly further to interconnect at an existing substation. In this case the avoided costs of building a new substation or switching station could outweigh the cost of extending the transmission line. This was not considered in this study, but should be in the next level of study.

3.6 CAPITAL COST EVALUATION

The capital cost estimates are based on the project configurations as outlined in Section 3.3. The Project Technical Attributes outlined in Table 3.1 through Table 3.4 were used to establish a size of project components, quantities and constructability. These technical attributes were used to estimate approximate material volumes for excavation, backfill, embankment material and reinforced concrete. Electrical and mechanical equipment requirements were estimated based on empirical data from KP's prior projects and published in industry technical reports.

The capital cost estimate includes an allowance for the Contractor's preliminary and general costs (overheads, insurance, bonus and profit etc.), an allowance for EPCM costs, and a variable contingency.

Unit rates for material production, equipment procurement and installation costs relied on KP's internal costing database including recent, relevant experience with similar sized hydroelectric projects in Western Canada and the Yukon Territory. KP's hydro project cost database also offered an "order of magnitude check of total estimated costs for individual facility components and complete facilities, based on projects with comparable characteristics such as, design flow, penstock pipe characteristics (length, diameter, etc.), gross head, generating capacity, powerhouse area, excavation quantities, reinforced concrete volumes, backfill quantities, switchyard capacity and transmission line capacity and length. Generating equipment costs are based on installed capacity, head and flow, while switchyard costs are interpolated based on installed capacity. Adjustments to reflect the higher construction costs in the Yukon Territory were included where appropriate. All dollars are shown in 2015 Canadian Dollars (CAD).

It is likely that capital costs will vary as more detailed assessments are undertaken. While the level of technical analysis is still preliminary, the estimates have been prepared with sufficient detail for a preliminary AACE Class 5 estimate. The analysis herein should be considered the minimum level required for an AACE Class 5 estimate, and the uncertainty in cost is likely at the higher end of the range for that Class of estimate ($\pm$50%). These costs should be used as a relative comparison estimate for other development options, rather than a reliable indication of the actual construction costs for any of these facilities.

A detailed summary of the estimated capital cost breakdown for the alternate pumped-storage project arrangements are presented in Appendix A, while the overall estimated costs for each project configuration are shown in Table 3.5.

3.7 OPERATION & MAINTENANCE COST

Operation and Maintenance (O&M) Costs have been assessed as fixed and variable (generation and pumping) costs. Fixed costs are estimated at a rate of 2.0% of the total project capital cost based on the methodology used in the BC Hydro's 2013 Resource Options Report[(1)]. This methodology assumed an estimated O&M cost at a rate of 1% of the total project capital cost for 1000 MW fresh water pumped storage sites and 1.5% for 500 MW fresh water pumped storage sites. By linear extrapolation of percent of capital versus project capacity there is a marginal difference between 15MW and 25 MW pumped storage sites, and a single value of 2.0% has been assumed.

1. Reference. Appendix 9A Section 3.2.4, viewed at: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/ror-update-appx-9a-20130802.pdf.

It should be noted that estimating fixed operating costs based on a percentage of capital cost is considered a reasonable approach for a conceptual level study. Once final general arrangement layouts of the various alternatives have been developed a more accurate estimation of fixed operating costs can be made that would typically include cost items such as:

- YEC Corporate Overhead
- Operations Staff Salaries and Benefits
- Provincial/Territory Resource Fees: Water Rental (Capacity, Energy Charge, Water Storage Charges), Land Rents and annual operating permits
- Regularly Scheduled Operations and Maintenance Costs
- Insurance, and
- Property and Corporate Taxes.

Variable O&M costs include the cost of energy to pump water from the lower reservoir to the upper reservoir at $0.05/kWh and the cost of generation and an equivalent value of $0.05/kWh. These values are estimated based on KP's experience and actual costs will depend on generation to pumping ratios which vary depending on pump-turbine technology and manufacturer.

3.8 FINANCIAL EVALUATION

KP has developed an in house financial model to assess the Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC) for the pumped-storage project configurations. The basic parameters used in the financial model include:

- Capital Cost Estimate — Varies by alternative
- Annual Fixed Operating Costs — 2.0% of initial capital cost
- Variable Operating Costs — 0.5¢/kWh of either pumping or generating
- Annual Generating Energy — 50 or 100 GWh
- Annual Pumping Energy — Varies by alternative
- Construction Period — 48 months
- Project Life — 65 years

No time value of money nor escalation/inflation is included in the financial evaluation, but interest rates are assumed for the real cost of capital as follows:

- YEC resource options — 3.38%
- IPP resource options — 4.61%
- High interest scenario — 8.82%

The loaded capital cost, or net present cost at Commercial Operation Date (COD) is calculated to take into account any interest accrued during construction, using the following formula:

$$C = \sum_{\mathrm{yr}=0}^{\mathrm{n}} \mathrm{c}(1+i)^{\mathrm{n-yr}}$$

Where:

$$C = loaded\ capital\ cost$$
$$c = construction\ cost\ in\ given\ year\ of\ interest$$
$$yr = construction\ year\ of\ interest$$

$$n = total\ number\ of\ years\ of\ construction \quad (4)$$
$$i = interest\ rate$$

Next, the levelized capital cost per year is calculated using the capital recovery factor formula:

$$LC = \frac{iC(1+i)^N}{(1+i)^N - 1}$$

Where:

$$LC = levelized\ capital\ cost\ per\ year$$
$$N = total\ project\ life$$

A summary of the project financial attributes is included in Table 3.5, and further detail is provided in Appendix B. Note that the summary Table 3.5 only provides levelized cost results for the assume YEC development real cost of capital rate of 3.38%. Refer to the detail provided in Appendix B for the evaluation undertaken using alternate interest rates.

TABLE 3.5

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

COST, ENERGY AND FINANCIAL SUMMARY

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ITEM	DESCRIPTION	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser	Squanga-Dalayee	Canyon-Ittlemit
	Installed Capacity (MW)	15	15	15	15	15	-	-
15 MW	Annual Generation (GWh)	50	50	50	50	50	-	-
50 GWh	Annual Pumping (GWh)	26.7	59.5	51.8	31.8	55.8	-	-
	Overnight Capital Cost ($)	$220,000,000	$235,000,000	$263,000,000	$438,000,000	$448,000,000		
YEC Rate	**LCOE ($/kWh)**	**$0.28**	**$0.30**	**$0.33**	**$0.54**	**$0.56**	-	-
(3.38%)	**LCOC ($/kW-yr)**	**$900**	**$1,000**	**$1,100**	**$1,800**	**$1,900**	-	-
IPP Rate	**LCOE ($/kWh)**	**$0.33**	**$0.36**	**$0.40**	**$0.66**	**$0.67**	-	-
(4.61%)	**LCOC ($/kW-yr)**	**$1,100**	**$1,200**	**$1,300**	**$2,200**	**$2,200**	-	-
High Rate	**LCOE ($/kWh)**	**$0.36**	**$0.38**	**$0.43**	**$0.70**	**$0.72**	-	-
(8.82%)	**LCOC ($/kW-yr)**	**$1,200**	**$1,300**	**$1,400**	**$2,300**	**$2,400**	-	-
	Installed Capacity (MW)	15	15	15	-	-	15	15
15 MW	Annual Generation (GWh)	100	100	100	-	-	100	100
100 GWh	Annual Pumping (GWh)	88.5	121.3	113.6	-	-	119.7	119.9
	Overnight Capital Cost ($)	$300,000,000	$411,000,000	$420,000,000	-	-	$525,000,000	$621,000,000
YEC Rate	**LCOE ($/kWh)**	**$0.19**	**$0.26**	**$0.27**	**-**	**-**	**$0.34**	**$0.49**
(3.38%)	**LCOC ($/kW-yr)**	**$1,300**	**$1,800**	**$1,800**	**-**	**-**	**$2,200**	**$3,300**
IPP Rate	**LCOE ($/kWh)**	**$0.23**	**$0.32**	**$0.32**	**-**	**-**	**$0.41**	**$0.59**
(4.61%)	**LCOC ($/kW-yr)**	**$1,500**	**$2,100**	**$2,100**	**-**	**-**	**$2,700**	**$3,900**
High Rate	**LCOE ($/kWh)**	**$0.25**	**$0.34**	**$0.34**	**-**	**-**	**$0.43**	**$0.63**
(8.82%)	**LCOC ($/kW-yr)**	**$1,600**	**$2,200**	**$2,300**	**-**	**-**	**$2,900**	**$4,200**
	Installed Capacity (MW)	25	25	25	25	25	-	-
25 MW	Annual Generation (GWh)	50	50	50	50	50	-	-
50 GWh	Annual Pumping (GWh)	26.7	59.5	51.8	31.8	55.8	-	-
	Overnight Capital Cost ($)	$257,000,000	$262,000,000	$301,000,000	$490,000,000	$515,000,000		
YEC Rate	**LCOE ($/kWh)**	**$0.32**	**$0.33**	**$0.38**	**$0.61**	**$0.64**	-	-
(3.38%)	**LCOC ($/kW-yr)**	**$650**	**$660**	**$760**	**$1,200**	**$1,300**	-	-
IPP Rate	**LCOE ($/kWh)**	**$0.39**	**$0.40**	**$0.46**	**$0.73**	**$0.77**	-	-
(4.61%)	**LCOC ($/kW-yr)**	**$780**	**$800**	**$900**	**$1,500**	**$1,500**	-	-
High Rate	**LCOE ($/kWh)**	**$0.42**	**$0.43**	**$0.49**	**$0.79**	**$0.83**	-	-
(8.82%)	**LCOC ($/kW-yr)**	**$830**	**$850**	**$1,000**	**$1,600**	**$1,700**	-	-
	Installed Capacity (MW)	25	25	25	-	-	25	25
25 MW	Annual Generation (GWh)	100	100	100	-	-	100	100
100 GWh	Annual Pumping (GWh)	88.5	121.3	113.6	-	-	119.7	119.9
	Overnight Capital Cost ($)	$329,000,000	$430,000,000	$450,000,000	-	-	$568,000,000	$640,000,000
YEC Rate	**LCOE ($/kWh)**	**$0.21**	**$0.27**	**$0.29**	**-**	**-**	**$0.36**	**$0.53**
(3.38%)	**LCOC ($/kW-yr)**	**$840**	**$1,100**	**$1,100**	**-**	**-**	**$1,400**	**$2,100**
IPP Rate	**LCOE ($/kWh)**	**$0.25**	**$0.33**	**$0.34**	**-**	**-**	**$0.44**	**$0.63**
(4.61%)	**LCOC ($/kW-yr)**	**$1,000**	**$1,300**	**$1,400**	**-**	**-**	**$1,700**	**$2,500**
High Rate	**LCOE ($/kWh)**	**$0.27**	**$0.35**	**$0.37**	**-**	**-**	**$0.47**	**$0.68**
(8.82%)	**LCOC ($/kW-yr)**	**$1,100**	**$1,400**	**$1,500**	**-**	**-**	**$1,900**	**$2,700**

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NOTES:

1. FINANCIAL SUMMARY ASSUMES REAL COST OF CAPITAL OF 3.38%, 4.61% AND 8.82% FOR YEC, IPP AND HIGH INTEREST DEVELOPMENT SCENARIOS RESPECTIVELY.
2. NO ASSESSMENT OF THE TIME VALUE OF MONEY IS INCLUDED.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
2	24SEP'16	ISSUED WITH REPORT	TJB	KLA

3.9 DEVELOPMENT SCHEDULE

A high level development schedule has been developed to illustrate the relative time lines for completing critical tasks associated with developing any pumped-storage project. Since the relative timelines for completing the major development tasks is similar for each pumped-storage project described above, this schedule should be taken as indicative. The major development tasks and time lines are listed below and presented in as a Gantt chart on Figure 3.9.

1. Feasibility Study – 1 year
   - Will require on site hydrology data that will require a minimum of one year of data collection
2. Environmental Assessment (Permitting and Baseline Studies) – 2 years (will start concurrent with Feasibiltiy Study)
   - Will include fisheries, hydrological and wildlife/terrestrial studies that will be inputs to the Environmental Assessment for each project
3. EPC Tendering Process – 1 year
   - EPC tender design can start immediately after Feasibility Study
4. Construction – 4 years
   - Will commence once Environmental Assessment Certificate is received and EPC contractor is selected
5. Commissioning – 4-6 months
   - Can start after Construction
6. Operations – 65 years

The minimum total development duration from the start of the Feasibility Study through to the end of Commissioning is approximately 6.5 years.

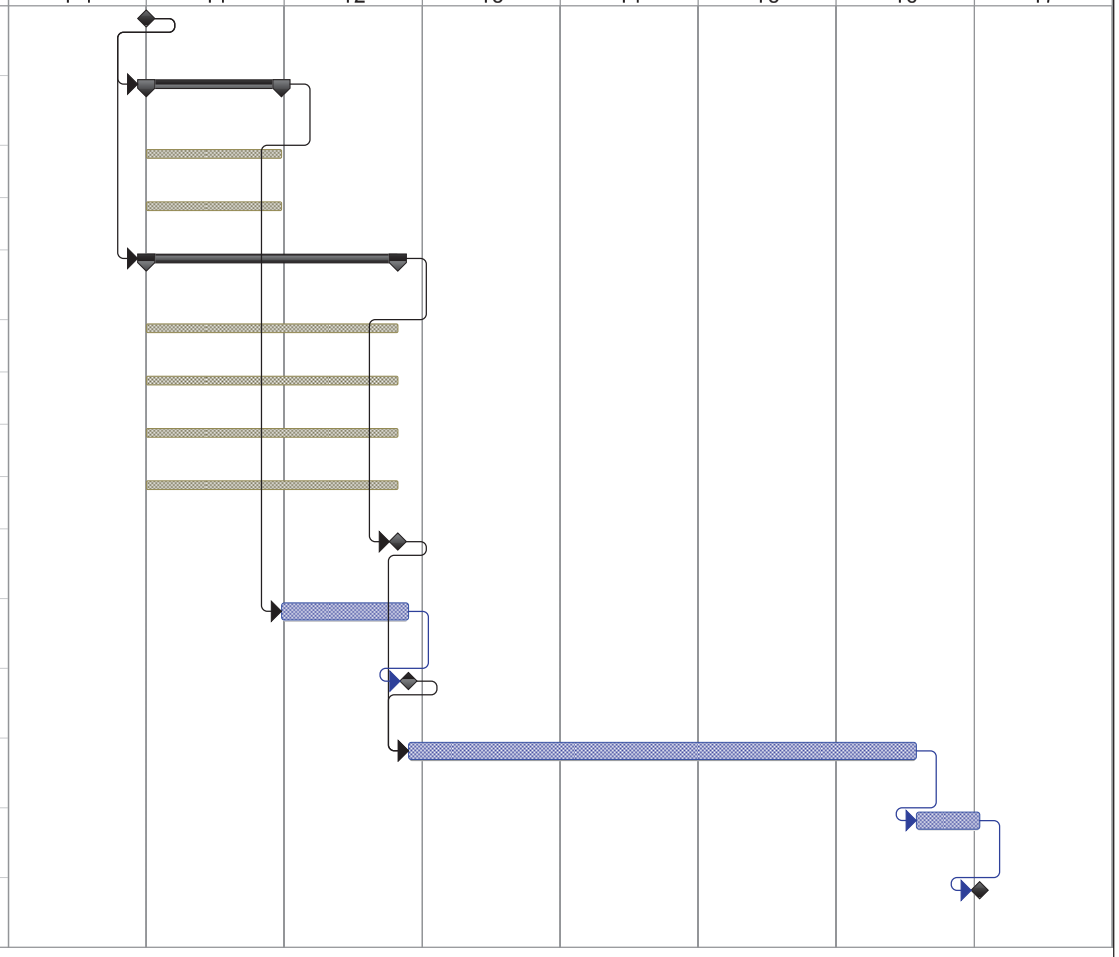
Knight Piésold CONSULTING

FIGURE 3.9

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT
DEVELOPMENT SCHEDULE - MAJOR TASKS

Print: Thu 6/30/16 2:59 PM

ID	WBS	Task Name
1	1	Notice to Proceed
2	2	Feasibility Study
3	2.1	Prefeasibility Engineering
4	2.2	Hydrology Assessment
5	3	Environmental & Social Assessment
6	3.1	Fisheries Studies
7	3.2	Wildlife & Terrestrial Studies
8	3.3	First Nations Consultation
9	3.4	Stakeholder Consultation
10	4	Environmental Certificate
11	5	EPC Tendering Process
12	6	Award EPC Contract
13	7	Construction
14	8	Commissioning
15	9	Commence Operation (65 Year Duration)



Project: VA103-00556/02-A/1
Date: Thu 6/30/16
By: Daniel Rohn

Task
Milestone
Task with Subtask(s)
Subtask

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Yukon Energy Corporation
2017-2018 General Rate Application
YUB-YEC-2-29 Attachment 1

4 – CONCLUSIONS AND RECOMMENDATIONS

4.1 CONCLUSIONS

A screening assessment of pumped-storage potential in the Yukon Territory has been undertaken and has examined a large area of the territory for potential sites. A total of 473 potential reservoir basins were assessed, yielding over 200 sites that were shown to be technically viable. The top ranked (preferred) sites were evaluated further, yielding the following results:

- 15 MW capacity and 50GWh storage configuration has a minimum $0.28/kWh LCOE and $900/kW-yr LCOC for the Tutshi-Moon facility
- 15 MW capacity and 100GWh storage configuration has a minimum $0.19/kWh LCOE and $1,300/kW-yr LCOC for the Tutshi-Moon facility
- 25 MW capacity and 50GWh storage configuration has a minimum $0.32/kWh LCOE and $650/kW-yr LCOC for the Tutshi-Moon facility, and
- 25 MW capacity and 100GWh storage configuration has a minimum $0.21/kWh LCOE and $840/kW-yr LCOC for the Tutshi-Moon facility.

In all cases, the Tutshi-Moon pumped-storage project was evaluated as the most cost-effective, which is encouraging given that it appears this is the facility for which YEC has currently expended the most effort in evaluating. The Atlin-Black Mt. and Racine-Mt. Brown facilities also have similarly competitive costs, particularly for the 50 GWh configurations. The Racine-Moon facility has technical constraints that make it less promising, as does the Lindeman-Fraser facility. The Squanga-Dalayee and Canyon-Ittlemit facilities are less cost effective than the Tutshi-Moon, Atlin-Black Mt. and Racine-Mt. Brown facilities, but warrant further investigation due to their relative proximity to existing YEC infrastructure, in comparison to the three projects located south of the BC border. It is not known at this stage whether a viable project configuration can be found for the Canyon-Ittlemit facility that does not negatively impact the existing Aishihik hydro facility, but this should be investigated further in future project stages.

The lowest LCOC ($650/kW-yr) is achieved with the 25 MW/50 GWh configuration (Table 4.1), suggesting that there is a trade-off between cost of stored energy and capacity for pumped-storage facilities. Conversely, the lowest LCOE ($0.19/kWh) is achieved with the 15 MW/100 GWh configuration (Table 4.2), suggesting that increasing storage volume and lowering installed capacity tends to optimise cost of stored energy. In contrast to typical pumped-storage facilities where daily or hourly load shaping is targeted, YEC requested KP to evaluate seasonal storage durations. Much lower LCOC could be achieved by reducing the energy storage requirement to a shorter period (10 days for example). Such a facility would not provide seasonal storage and shifting of energy from summer to winter months (as desired by YEC), but would provide additional security against unexpected outages of a key YEC hydro facility or transmission lines in the high-demand winter period.

TABLE 4.1

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT SUMMARY - LOWEST COST CAPACITY

ITEM	DESCRIPTION	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser
	Installed Capacity (MW)	25	25	25	25	25
	Dependable Capacity (MW)	25	25	25	25	25
	Annual Generation (GWh)	50	50	50	50	50
	Annual Pumping (GWh)	26.7	59.5	51.8	31.8	55.8
	Monthly Generation, Winter (GWh)	7.1	7.1	7.1	7.1	7.1
	Monthly Pumping, Summer (GWh)	5.3	11.9	10.4	6.4	11.2
	Overnight Capital Cost ($)	$257,000,000	$262,000,000	$301,000,000	$490,000,000	$515,000,000
	Fixed O&M Costs ($/yr)	$5,140,000	$5,240,000	$6,020,000	$9,800,000	$10,300,000
	Variable O&M Costs ($/yr)	$384,000	$548,000	$509,000	$409,000	$529,000
	Transmission Line Length to Point of Interconnection (km)	2.6	0.8	24.0	20.0	5.0
YEC Rate (3.38%)	**LCOE ($/kWh)**	**$0.32**	**$0.33**	**$0.38**	**$0.61**	**$0.64**
	LCOC ($/kW-yr)	**$650**	**$660**	**$760**	**$1,200**	**$1,300**
IPP Rate (4.61%)	**LCOE ($/kWh)**	**$0.39**	**$0.40**	**$0.46**	**$0.73**	**$0.77**
	LCOC ($/kW-yr)	**$780**	**$800**	**$900**	**$1,500**	**$1,500**
High Rate (8.82%)	**LCOE ($/kWh)**	**$0.44**	**$0.45**	**$0.52**	**$0.83**	**$0.88**
	LCOC ($/kW-yr)	**$880**	**$910**	**$1,000**	**$1,700**	**$1,800**

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NOTES:

1. FINANCIAL SUMMARY ASSUMES REAL COST OF CAPITAL OF 3.38%, 4.61% AND 8.82% FOR YEC, IPP AND HIGH INTEREST DEVELOPMENT SCENARIOS RESPECTIVELY.
2. NO ASSESSMENT OF THE TIME VALUE OF MONEY IS INCLUDED.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
2	24SEP'16	ISSUED WITH REPORT	TJB	KLA

TABLE 4.2

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT SUMMARY - LOWEST COST OF ENERGY

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ITEM	DESCRIPTION	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Squanga-Dalayee	Canyon-Ittlemit
	Installed Capacity (MW)	15	15	15	15	15
	Annual Generation (GWh)	100	100	100	100	100
	Annual Pumping (GWh)	88.5	121.3	113.6	119.7	119.9
	Monthly Generation, Winter (GWh)	14.3	14.3	14.3	14.3	14.3
	Monthly Pumping, Summer (GWh)	17.7	24.3	22.7	23.9	24.0
	Overnight Capital Cost ($)	$300,000,000	$411,000,000	$420,000,000	$525,000,000	$621,000,000
	Fixed O&M Costs ($/yr)	$6,000,000	$8,220,000	$8,400,000	$10,500,000	$12,420,000
	Variable O&M Costs ($/yr)	$943,000	$1,107,000	$1,068,000	$1,099,000	$1,100,000
	Transmission Line Length to Point of Interconnection (km)	2.6	0.8	24.0	0.8	13.9
YEC Rate (3.38%)	**LCOE ($/kWh)**	**$0.19**	**$0.26**	**$0.27**	**$0.33**	**$0.39**
	LCOC ($/kW-yr)	**$1,300**	**$1,800**	**$1,800**	**$2,200**	**$2,600**
IPP Rate (4.61%)	**LCOE ($/kWh)**	**$0.23**	**$0.32**	**$0.32**	**$0.40**	**$0.47**
	LCOC ($/kW-yr)	**$1,500**	**$2,100**	**$2,100**	**$2,700**	**$3,100**
High Rate (8.82%)	**LCOE ($/kWh)**	**$0.25**	**$0.34**	**$0.34**	**$0.43**	**$0.50**
	LCOC ($/kW-yr)	**$1,600**	**$2,200**	**$2,300**	**$2,800**	**$3,400**

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NOTES:

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2. NO ASSESSMENT OF THE TIME VALUE OF MONEY IS INCLUDED.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
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4.2 RECOMMENDATIONS

Further evaluation of pumped-storage facilities will depend on YEC's desired mix of generation options in the future. While the most effective sites have been identified, the financial viability would have to be assessed by evaluating the potential for any pumped-storage facility to offset diesel, LNG or other costly fuel sources, which KP understand currently only constitute a small percentage of YEC's generation. If it is expected that a pumped-storage facility will offset a significant amount of costly diesel or LNG fuel in the future, further assessment of pumped-storage projects may be warranted.

It is recommended that the following steps be undertaken as part of further assessing the preferred pumped-storage facilities identified in this study:

1. Preliminary site visits to the following projects to evaluate technical viability further:
   - Tutshi-Moon
   - Atlin-Black Mt.
   - Racine-Mt. Brown
   - Squanga-Dalayee
   - Canyon-Ittlemit
2. Prepare depth-area-capacity curves and dam construction volume vs. height curves for these five facilities to better estimate dam construction volumes and costs. This would require the acquisition of more detailed topographic data, such as PhotoSat satellite topographic data.
3. Update Capital Cost estimates based on more accurate construction quantities.
4. Screening assessment of social and environmental permitting constraints at each of the five proposed facilities.

Should the above assessment indicate that there are no technical or environmental showstoppers, further evaluation of the sites through detailed prefeasibility and feasibility studies should be pursued to prove the business case for construction of any of the proposed facilities.

Knight Piésold CONSULTING

5 – CERTIFICATION

This report was prepared and reviewed by the undersigned.

Prepared:

Travis Brown, P.Eng.
Senior Engineer

PROFESSIONAL ENGINEER
30 September 2016
YUKON TERRITORY
TRAVIS JESS BROWN

Reviewed:

Keith Ainsley, P.Eng.
Senior Engineer

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Approval that this document adheres to Knight Piésold Quality Systems: kk.

APPENDIX A

COST ESTIMATE SUMMARIES

(Pages A-1 to A-4)

TABLE A.1

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

CAPITAL COST ESTIMATE OF PREFERRED SITES
SUMMARY OF RESULTS - 15 MW, 50 GWh

13/04/2016 14:58

ITEM	DESCRIPTION	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser
100	MOB, DEMOB, INSURANCE, BONDS, OVERHEADS, CONTRACTOR'S PROFIT	$ 37,000,000	$ 39,000,000	$ 44,000,000	$ 73,000,000	$ 75,000,000
200	ACCESS AND SITE PREPARATION	$ 6,000,000	$ 3,000,000	$ 18,000,000	$ 18,000,000	$ 15,000,000
300	INTAKE, FOREBAY, HEADRACE AND TAILRACE	$ 20,000,000	$ 16,000,000	$ 18,000,000	$ 19,000,000	$ 18,000,000
400	WATER CONVEYANCE SYSTEM	$ 25,000,000	$ 21,000,000	$ 22,000,000	$ 129,000,000	$ 70,000,000
500	POWERHOUSE AND ANCILLARY SERVICES	$ 11,000,000	$ 11,000,000	$ 11,000,000	$ 11,000,000	$ 11,000,000
600	POWER GENERATION EQUIPMENT (WATER TO WIRE)	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000
700	SWITCHYARD, TRANSMISSION AND INTERCONNECTION	$ 5,000,000	$ 4,000,000	$ 20,000,000	$ 18,000,000	$ 7,000,000
800	UPPER STORAGE DAM(S) AND RESERVOIR	$ 29,000,000	$ 66,000,000	$ 38,000,000	$ 23,000,000	$ 119,000,000
900	LOWER STORAGE DAM AND RESERVOIR	$ 17,000,000	$ 1,000,000	$ 11,000,000	$ 18,000,000	$ 1,000,000
	SUB-TOTAL	**$ 159,000,000**	**$ 170,000,000**	**$ 191,000,000**	**$ 318,000,000**	**$ 325,000,000**
	EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 13,000,000	$ 14,000,000	$ 15,000,000	$ 25,000,000	$ 26,000,000
	CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 48,000,000	$ 51,000,000	$ 57,000,000	$ 95,000,000	$ 97,000,000
	TOTAL ESTIMATED CAPITAL COST	**$ 220,000,000**	**$ 235,000,000**	**$ 263,000,000**	**$ 438,000,000**	**$ 448,000,000**

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Preferred Sites\[Cost_Technical_Financial_15 MW, 50 GWh.xlsx]Financial Summary

NOTES:

1. TOTAL ESTIMATED CAPITAL COST DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. TOTAL ESTIMATED CAPITAL COSTS DO NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT VA103-556/2-1	MGP	KLA

TABLE A.2

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

CAPITAL COST ESTIMATE OF PREFERRED SITES
SUMMARY OF RESULTS - 15 MW, 100 GWh

13/04/2016 14:53

ITEM	DESCRIPTION	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Squanga-Dalayee	Canyon-Ittlemit
100	MOB, DEMOB, INSURANCE, BONDS, OVERHEADS, CONTRACTOR'S PROFIT	$ 50,000,000	$ 69,000,000	$ 70,000,000	$ 88,000,000	$ 104,000,000
200	ACCESS AND SITE PREPARATION	$ 6,000,000	$ 3,000,000	$ 18,000,000	$ 7,000,000	$ 9,000,000
300	INTAKE, FOREBAY, HEADRACE AND TAILRACE	$ 20,000,000	$ 16,000,000	$ 19,000,000	$ 19,000,000	$ 25,000,000
400	WATER CONVEYANCE SYSTEM	$ 25,000,000	$ 21,000,000	$ 22,000,000	$ 50,000,000	$ 11,000,000
500	POWERHOUSE AND ANCILLARY SERVICES	$ 16,000,000	$ 16,000,000	$ 16,000,000	$ 16,000,000	$ 16,000,000
600	POWER GENERATION EQUIPMENT (WATER TO WIRE)	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000	$ 9,000,000
700	SWITCHYARD, TRANSMISSION AND INTERCONNECTION	$ 5,000,000	$ 4,000,000	$ 20,000,000	$ 4,000,000	$ 13,000,000
800	UPPER STORAGE DAM(S) AND RESERVOIR	$ 56,000,000	$ 159,000,000	$ 115,000,000	$ 76,000,000	$ 172,000,000
900	LOWER STORAGE DAM AND RESERVOIR	$ 30,000,000	$ 1,000,000	$ 16,000,000	$ 112,000,000	$ 91,000,000
	SUB-TOTAL	**$ 217,000,000**	**$ 298,000,000**	**$ 305,000,000**	**$ 381,000,000**	**$ 450,000,000**
	EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 17,000,000	$ 24,000,000	$ 24,000,000	$ 30,000,000	$ 36,000,000
	CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 66,000,000	$ 89,000,000	$ 91,000,000	$ 114,000,000	$ 135,000,000
	TOTAL ESTIMATED CAPITAL COST	**$ 300,000,000**	**$ 411,000,000**	**$ 420,000,000**	**$ 525,000,000**	**$ 621,000,000**

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Preferred Sites\[Cost_Technical_Financial_15 MW, 100 GWh.xlsx]Cost Summary

NOTES:

1. TOTAL ESTIMATED CAPITAL COST DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. TOTAL ESTIMATED CAPITAL COSTS DO NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT VA103.-556/2-1	MGP	KLA

TABLE A.3

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

CAPITAL COST ESTIMATE OF PREFERRED SITES
SUMMARY OF RESULTS - 25 MW, 50 GWh

13/04/2016 14:55

ITEM	DESCRIPTION	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser
100	MOB, DEMOB, INSURANCE, BONDS, OVERHEADS, CONTRACTOR'S PROFIT	$ 43,000,000	$ 44,000,000	$ 50,000,000	$ 82,000,000	$ 86,000,000
200	ACCESS AND SITE PREPARATION	$ 6,000,000	$ 3,000,000	$ 18,000,000	$ 18,000,000	$ 15,000,000
300	INTAKE, FOREBAY, HEADRACE AND TAILRACE	$ 20,000,000	$ 16,000,000	$ 18,000,000	$ 20,000,000	$ 18,000,000
400	WATER CONVEYANCE SYSTEM	$ 34,000,000	$ 24,000,000	$ 31,000,000	$ 145,000,000	$ 95,000,000
500	POWERHOUSE AND ANCILLARY SERVICES	$ 16,000,000	$ 16,000,000	$ 16,000,000	$ 16,000,000	$ 16,000,000
600	POWER GENERATION EQUIPMENT (WATER TO WIRE)	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000
700	SWITCHYARD, TRANSMISSION AND INTERCONNECTION	$ 6,000,000	$ 5,000,000	$ 21,000,000	$ 19,000,000	$ 8,000,000
800	UPPER STORAGE DAM(S) AND RESERVOIR	$ 29,000,000	$ 66,000,000	$ 38,000,000	$ 23,000,000	$ 119,000,000
900	LOWER STORAGE DAM AND RESERVOIR	$ 17,000,000	$ 1,000,000	$ 11,000,000	$ 18,000,000	$ 1,000,000
	SUB-TOTAL	**$ 186,000,000**	**$ 190,000,000**	**$ 218,000,000**	**$ 356,000,000**	**$ 373,000,000**
	EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 15,000,000	$ 15,000,000	$ 17,000,000	$ 28,000,000	$ 30,000,000
	CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 56,000,000	$ 57,000,000	$ 66,000,000	$ 106,000,000	$ 112,000,000
	TOTAL ESTIMATED CAPITAL COST	**$ 257,000,000**	**$ 262,000,000**	**$ 301,000,000**	**$ 490,000,000**	**$ 515,000,000**

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Preferred Sites\[Cost_Technical_Financial_25 MW, 50 GWh.xlsx]Cost Summary

NOTES:

1. TOTAL ESTIMATED CAPITAL COST DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. TOTAL ESTIMATED CAPITAL COSTS DO NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT VA103-556/2-1	MGP	KLA

TABLE A.4

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

CAPITAL COST ESTIMATE OF PREFERRED SITES
SUMMARY OF RESULTS - 25 MW, 100 GWh

13/04/2016 15:01

ITEM	DESCRIPTION	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Squanga-Dalayee	Canyon-Ittlemit
100	MOB, DEMOB, INSURANCE, BONDS, OVERHEADS, CONTRACTOR'S PROFIT	$ 55,000,000	$ 72,000,000	$ 75,000,000	$ 95,000,000	$ 107,000,000
200	ACCESS AND SITE PREPARATION	$ 6,000,000	$ 3,000,000	$ 18,000,000	$ 7,000,000	$ 9,000,000
300	INTAKE, FOREBAY, HEADRACE AND TAILRACE	$ 20,000,000	$ 16,000,000	$ 19,000,000	$ 19,000,000	$ 25,000,000
400	WATER CONVEYANCE SYSTEM	$ 34,000,000	$ 24,000,000	$ 31,000,000	$ 67,000,000	$ 15,000,000
500	POWERHOUSE AND ANCILLARY SERVICES	$ 16,000,000	$ 16,000,000	$ 16,000,000	$ 16,000,000	$ 16,000,000
600	POWER GENERATION EQUIPMENT (WATER TO WIRE)	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000
700	SWITCHYARD, TRANSMISSION AND INTERCONNECTION	$ 6,000,000	$ 5,000,000	$ 21,000,000	$ 5,000,000	$ 14,000,000
800	UPPER STORAGE DAM(S) AND RESERVOIR	$ 56,000,000	$ 159,000,000	$ 115,000,000	$ 76,000,000	$ 172,000,000
900	LOWER STORAGE DAM AND RESERVOIR	$ 30,000,000	$ 1,000,000	$ 16,000,000	$ 112,000,000	$ 91,000,000
	SUB-TOTAL	**$ 238,000,000**	**$ 311,000,000**	**$ 326,000,000**	**$ 412,000,000**	**$ 464,000,000**
	EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 19,000,000	$ 25,000,000	$ 26,000,000	$ 33,000,000	$ 37,000,000
	CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 72,000,000	$ 94,000,000	$ 98,000,000	$ 123,000,000	$ 139,000,000
	TOTAL ESTIMATED CAPITAL COST	**$ 329,000,000**	**$ 430,000,000**	**$ 450,000,000**	**$ 568,000,000**	**$ 640,000,000**

M:\1\03\00556\02\A\Data\Task 300 - Pumped Storage\Preferred Sites\[Cost_Technical_Financial_25 MW, 100 GWh.xlsx]Cost Summary

NOTES:

1. TOTAL ESTIMATED CAPITAL COST DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. TOTAL ESTIMATED CAPITAL COSTS DO NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	12APR'16	ISSUED WITH REPORT VA103-556/2-1	MGP	KLA

APPENDIX B

FINANCIAL EVALUATION SUMMARIES

(Pages B-1 to B-4)

TABLE B.1

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT FINANCIAL ATTRIBUTES - 15 MW, 50 GWh

9/26/2016 13:32

ITEM	Rate	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser
Project Life (Yrs)	65					
Real Cost of Capital (YEC)	3.38%					
Real Cost of Capital (IPP)	4.61%					
Real Cost of Capital - High Rate Scenario	8.82%					
Installed Capacity (MW)		15.0	15.0	15.0	15.0	15.0
Annual Generation (GWh)		50.0	50.0	50.0	50.0	50.0
Annual Pumping Energy (GWh)		26.7	59.5	51.8	31.8	55.8
Monthly Generation, Winter (GWh)		7.1	7.1	7.1	7.1	7.1
Monthly Pumping, Summer (GWh)		5.3	11.9	10.4	6.4	11.2
Overnight Capital Cost ($)		**$220,000,000**	**$235,000,000**	**$263,000,000**	**$438,000,000**	**$448,000,000**
Construction Cost, Yr. 1	10%	$22,000,000	$23,500,000	$26,300,000	$43,800,000	$44,800,000
Construction Cost, Yr. 2	30%	$66,000,000	$70,500,000	$78,900,000	$131,400,000	$134,400,000
Construction Cost, Yr. 3	40%	$88,000,000	$94,000,000	$105,200,000	$175,200,000	$179,200,000
Construction Cost, Yr. 4	20%	$44,000,000	$47,000,000	$52,600,000	$87,600,000	$89,600,000
Fixed O&M Costs (% of Capital)	2.0%	$4,400,000	$4,700,000	$5,260,000	$8,760,000	$8,960,000
Variable Costs, Generation	0.5¢/kWh	$250,000	$250,000	$250,000	$250,000	$250,000
Variable Costs, Pumping	0.5¢/kWh	$134,000	$298,000	$259,000	$159,000	$279,000
YEC Rate Scenario						
Interest During Construction		$17,586,000	$18,785,000	$21,024,000	$35,013,000	$35,812,000
Loaded Capital Cost, at End of Construction Period ($)		**$237,586,000**	**$253,785,000**	**$284,024,000**	**$473,013,000**	**$483,812,000**
Levelized Capital Cost		$9,076,000	$9,695,000	$10,850,000	$18,070,000	$18,483,000
Levelized Annual Cost		$13,860,000	$14,943,000	$16,619,000	$27,239,000	$27,972,000
Capital Cost of Energy Storage	$/MWh	$4,800	$5,100	$5,700	$9,500	$9,700
Capital Cost of Capacity	$/kW-yr	$15,800	$16,900	$18,900	$31,500	$32,300
Levelized Cost of Energy	**$/kWh**	**$0.28**	**$0.30**	**$0.33**	**$0.54**	**$0.56**
Levelized Cost of Capacity	**$/kW-yr**	**$900**	**$1,000**	**$1,100**	**$1,800**	**$1,900**
IPP Rate Scenario						
Interest During Construction		$24,230,000	$25,882,000	$28,966,000	$48,240,000	$49,341,000
Loaded Capital Cost, at End of Construction Period ($)		**$244,230,000**	**$260,882,000**	**$291,966,000**	**$486,240,000**	**$497,341,000**
Levelized Capital Cost		$11,894,000	$12,705,000	$14,219,000	$23,681,000	$24,221,000
Levelized Annual Cost		$16,678,000	$17,953,000	$19,988,000	$32,850,000	$33,710,000
Capital Cost of Energy Storage	$/MWh	$4,900	$5,200	$5,800	$9,700	$9,900
Capital Cost of Capacity	$/kW-yr	$16,300	$17,400	$19,500	$32,400	$33,200
Levelized Cost of Energy	**$/kWh**	**$0.33**	**$0.36**	**$0.40**	**$0.66**	**$0.67**
Levelized Cost of Capacity	**$/kW-yr**	**$1,100**	**$1,200**	**$1,300**	**$2,200**	**$2,200**
High Interest Rate Scenario						
Interest During Construction		$47,988,000	$51,260,000	$57,367,000	$95,540,000	$97,721,000
Loaded Capital Cost, at End of Construction Period ($)		**$267,988,000**	**$286,260,000**	**$320,367,000**	**$533,540,000**	**$545,721,000**
Levelized Capital Cost		$13,052,000	$13,941,000	$15,602,000	$25,984,000	$26,578,000
Levelized Annual Cost		$17,836,000	$19,189,000	$21,371,000	$35,153,000	$36,067,000
Capital Cost of Energy Storage	$/MWh	$5,400	$5,700	$6,400	$10,700	$10,900
Capital Cost of Capacity	$/kW-yr	$17,900	$19,100	$21,400	$35,600	$36,400
Levelized Cost of Energy	**$/kWh**	**$0.36**	**$0.38**	**$0.43**	**$0.70**	**$0.72**
Levelized Cost of Capacity	**$/kW-yr**	**$1,200**	**$1,300**	**$1,400**	**$2,300**	**$2,400**

M:\1\03\00556\02\A\Report\1 - Pumped Storage\Rev 0\Tables\[Cost_Technical_Financial_15 MW, 50 GWh.xlsx]Financial Summary

NOTES:

1. INTEREST RATES ARE REAL COST OF CAPITAL AS PROVIDED BY YEC. NOMINAL RATES HAVE NOT BEEN INCLUDED.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
2	24SEP'16	ISSUED WITH REPORT	TJB	KLA

TABLE B.2

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT FINANCIAL ATTRIBUTES - 15 MW, 100 GWh

9/26/2016 13:42

ITEM	Rate	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Squanga-Dalayee	Canyon-Ittlemit
Project Life (Yrs)	65					
Real Cost of Capital (YEC)	3.38%					
Real Cost of Capital (IPP)	4.61%					
Real Cost of Capital - High Rate Scenar	8.82%					
Installed Capacity (MW)		15.0	15.0	15.0	15.0	15.0
Annual Generation (GWh)		100.0	100.0	100.0	100.0	100.0
Annual Pumping Energy (GWh)		88.5	121.3	113.6	119.7	119.9
Monthly Generation, Winter (GWh)		14.3	14.3	14.3	14.3	14.3
Monthly Pumping, Summer (GWh)		17.7	24.3	22.7	23.9	24.0
Overnight Capital Cost ($)		**$300,000,000**	**$411,000,000**	**$420,000,000**	**$525,000,000**	**$621,000,000**
Construction Cost, Yr. 1	10%	$30,000,000	$41,100,000	$42,000,000	$52,500,000	$62,100,000
Construction Cost, Yr. 2	30%	$90,000,000	$123,300,000	$126,000,000	$157,500,000	$186,300,000
Construction Cost, Yr. 3	40%	$120,000,000	$164,400,000	$168,000,000	$210,000,000	$248,400,000
Construction Cost, Yr. 4	20%	$60,000,000	$82,200,000	$84,000,000	$105,000,000	$124,200,000
Fixed O&M Costs (% of Capital)	2.0%	$6,000,000	$8,220,000	$8,400,000	$10,500,000	$12,420,000
Variable Costs, Generation	0.5¢/kWh	$500,000	$500,000	$500,000	$500,000	$500,000
Variable Costs, Pumping	0.5¢/kWh	$443,000	$607,000	$568,000	$599,000	$600,000
YEC Rate Scenario						
Interest During Construction		$23,981,000	$32,854,000	$33,574,000	$41,967,000	$49,641,000
Loaded Capital Cost, at End of Construction Period ($)		**$323,981,000**	**$443,854,000**	**$453,574,000**	**$566,967,000**	**$670,641,000**
Levelized Capital Cost		$12,377,000	$16,956,000	$17,328,000	$21,660,000	$25,620,000
Levelized Annual Cost		$19,320,000	$26,283,000	$26,796,000	$33,259,000	$39,140,000
Capital Cost of Energy Storage	$/MWh	$3,200	$4,400	$4,500	$5,700	$6,700
Capital Cost of Capacity	$/kW-yr	$21,600	$29,600	$30,200	$37,800	$44,700
Levelized Cost of Energy	**$/kWh**	**$0.19**	**$0.26**	**$0.27**	**$0.33**	**$0.39**
Levelized Cost of Capacity	**$/kW-yr**	**$1,300**	**$1,800**	**$1,800**	**$2,200**	**$2,600**
IPP Rate Scenario						
Interest During Construction		$33,041,000	$45,266,000	$46,258,000	$57,822,000	$68,395,000
Loaded Capital Cost, at End of Construction Period ($)		**$333,041,000**	**$456,266,000**	**$466,258,000**	**$582,822,000**	**$689,395,000**
Levelized Capital Cost		$16,220,000	$22,221,000	$22,708,000	$28,385,000	$33,575,000
Levelized Annual Cost		$23,163,000	$31,548,000	$32,176,000	$39,984,000	$47,095,000
Capital Cost of Energy Storage	$/MWh	$3,300	$4,600	$4,700	$5,800	$6,900
Capital Cost of Capacity	$/kW-yr	$22,200	$30,400	$31,100	$38,900	$46,000
Levelized Cost of Energy	**$/kWh**	**$0.23**	**$0.32**	**$0.32**	**$0.40**	**$0.47**
Levelized Cost of Capacity	**$/kW-yr**	**$1,500**	**$2,100**	**$2,100**	**$2,700**	**$3,100**
High Interest Rate Scenario						
Interest During Construction		$65,438,000	$89,650,000	$91,613,000	$114,517,000	$135,457,000
Loaded Capital Cost, at End of Construction Period ($)		**$365,438,000**	**$500,650,000**	**$511,613,000**	**$639,517,000**	**$756,457,000**
Levelized Capital Cost		$17,798,000	$24,383,000	$24,917,000	$31,146,000	$36,841,000
Levelized Annual Cost		$24,741,000	$33,710,000	$34,385,000	$42,745,000	$50,361,000
Capital Cost of Energy Storage	$/MWh	$3,700	$5,000	$5,100	$6,400	$7,600
Capital Cost of Capacity	$/kW-yr	$24,400	$33,400	$34,100	$42,600	$50,400
Levelized Cost of Energy	**$/kWh**	**$0.25**	**$0.34**	**$0.34**	**$0.43**	**$0.50**
Levelized Cost of Capacity	**$/kW-yr**	**$1,600**	**$2,200**	**$2,300**	**$2,800**	**$3,400**

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NOTES:

1. DISCOUNT RATES ARE REAL COST OF CAPITAL AS PROVIDED BY YEC. NOMINAL RATES HAVE NOT BEEN INCLUDED.

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2	24SEP'16	ISSUED WITH REPORT	TJB	KLA

TABLE B.3

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT FINANCIAL ATTRIBUTES - 25 MW, 50 GWh

9/27/2016 12:12

ITEM	Rate	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Racine-Moon	Lindeman-Fraser
Project Life (Yrs)	65					
Real Cost of Capital (YEC)	3.38%					
Real Cost of Capital (IPP)	4.61%					
Real Cost of Capital - High Rate Scenari	8.82%					
Installed Capacity (MW)		25.0	25.0	25.0	25.0	25.0
Annual Generation (GWh)		50.0	50.0	50.0	50.0	50.0
Annual Pumping Energy (GWh)		26.7	59.5	51.8	31.8	55.8
Monthly Generation, Winter (GWh)		7.1	7.1	7.1	7.1	7.1
Monthly Pumping, Summer (GWh)		5.3	11.9	10.4	6.4	11.2
Overnight Capital Cost ($)		**$257,000,000**	**$262,000,000**	**$301,000,000**	**$490,000,000**	**$515,000,000**
Construction Cost, Yr. 1	10%	$25,700,000	$26,200,000	$30,100,000	$49,000,000	$51,500,000
Construction Cost, Yr. 2	30%	$77,100,000	$78,600,000	$90,300,000	$147,000,000	$154,500,000
Construction Cost, Yr. 3	40%	$102,800,000	$104,800,000	$120,400,000	$196,000,000	$206,000,000
Construction Cost, Yr. 4	20%	$51,400,000	$52,400,000	$60,200,000	$98,000,000	$103,000,000
Fixed O&M Costs (% of Capital)	2.0%	$5,140,000	$5,240,000	$6,020,000	$9,800,000	$10,300,000
Variable Costs, Generation	0.5¢/kWh	$250,000	$250,000	$250,000	$250,000	$250,000
Variable Costs, Pumping	0.5¢/kWh	$134,000	$298,000	$259,000	$159,000	$279,000
YEC Rate Scenario						
Interest During Construction		$20,544,000	$20,944,000	$24,061,000	$39,170,000	$41,168,000
Loaded Capital Cost, at End of Construction Period ($)		**$277,544,000**	**$282,944,000**	**$325,061,000**	**$529,170,000**	**$556,168,000**
Levelized Capital Cost		$10,603,000	$10,809,000	$12,418,000	$20,216,000	$21,247,000
Levelized Annual Cost		$16,127,000	$16,597,000	$18,947,000	$30,425,000	$32,076,000
Capital Cost of Energy Storage	$/MWh	$5,600	$5,700	$6,500	$10,600	$11,100
Capital Cost of Capacity	$/kW-yr	$11,100	$11,300	$13,000	$21,200	$22,200
Levelized Cost of Energy	**$/kWh**	**$0.32**	**$0.33**	**$0.38**	**$0.61**	**$0.64**
Levelized Cost of Capacity	**$/kW-yr**	**$650**	**$660**	**$760**	**$1,200**	**$1,300**
IPP Rate Scenario						
Interest During Construction		$28,305,000	$28,856,000	$33,151,000	$53,967,000	$56,721,000
Loaded Capital Cost, at End of Construction Period ($)		**$285,305,000**	**$290,856,000**	**$334,151,000**	**$543,967,000**	**$571,721,000**
Levelized Capital Cost		$13,895,000	$14,165,000	$16,274,000	$26,492,000	$27,844,000
Levelized Annual Cost		$19,419,000	$19,953,000	$22,803,000	$36,701,000	$38,673,000
Capital Cost of Energy Storage	$/MWh	$5,700	$5,800	$6,700	$10,900	$11,400
Capital Cost of Capacity	$/kW-yr	$11,400	$11,600	$13,400	$21,800	$22,900
Levelized Cost of Energy	**$/kWh**	**$0.39**	**$0.40**	**$0.46**	**$0.73**	**$0.77**
Levelized Cost of Capacity	**$/kW-yr**	**$780**	**$800**	**$900**	**$1,500**	**$1,500**
High Interest Rate Scenario						
Interest During Construction		$56,059,000	$57,149,000	$65,656,000	$106,882,000	$112,335,000
Loaded Capital Cost, at End of Construction Period ($)		**$313,059,000**	**$319,149,000**	**$366,656,000**	**$596,882,000**	**$627,335,000**
Levelized Capital Cost		$15,247,000	$15,543,000	$17,857,000	$29,069,000	$30,552,000
Levelized Annual Cost		$20,771,000	$21,331,000	$24,386,000	$39,278,000	$41,381,000
Capital Cost of Energy Storage	$/MWh	$6,300	$6,400	$7,300	$11,900	$12,500
Capital Cost of Capacity	$/kW-yr	$12,500	$12,800	$14,700	$23,900	$25,100
Levelized Cost of Energy	**$/kWh**	**$0.42**	**$0.43**	**$0.49**	**$0.79**	**$0.83**
Levelized Cost of Capacity	**$/kW-yr**	**$830**	**$850**	**$1,000**	**$1,600**	**$1,700**

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NOTES:

1. DISCOUNT RATES ARE REAL COST OF CAPITAL AS PROVIDED BY YEC. NOMINAL RATES HAVE NOT BEEN INCLUDED.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
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TABLE B.4

YUKON ENERGY CORPORATION
PUMPED STORAGE ASSESSMENT

PROJECT FINANCIAL ATTRIBUTES - 25 MW, 100 GWh

9/26/2016 13:56

ITEM	Rate	Tutshi-Moon	Atlin-Black Mt.	Racine-Mt. Brown	Squanga-Dalayee	Canyon-Ittlemit
Project Life (Yrs)	65					
Real Cost of Capital (YEC)	3.38%					
Real Cost of Capital (IPP)	4.61%					
Real Cost of Capital - High Rate Scenario	8.82%					
Installed Capacity (MW)		25.0	25.0	25.0	25.0	25.0
Annual Generation (GWh)		100.0	100.0	100.0	100.0	100.0
Annual Pumping Energy (GWh)		88.5	121.3	113.6	119.7	119.9
Monthly Generation, Winter (GWh)		14.3	14.3	14.3	14.3	14.3
Monthly Pumping, Summer (GWh)		17.7	24.3	22.7	23.9	24.0
Overnight Capital Cost ($)		**$329,000,000**	**$430,000,000**	**$450,000,000**	**$568,000,000**	**$640,000,000**
Construction Cost, Yr. 1	10%	$32,900,000	$43,000,000	$45,000,000	$56,800,000	$64,000,000
Construction Cost, Yr. 2	30%	$98,700,000	$129,000,000	$135,000,000	$170,400,000	$192,000,000
Construction Cost, Yr. 3	40%	$131,600,000	$172,000,000	$180,000,000	$227,200,000	$256,000,000
Construction Cost, Yr. 4	20%	$65,800,000	$86,000,000	$90,000,000	$113,600,000	$128,000,000
Fixed O&M Costs (% of Capital)	2.0%	$6,580,000	$8,600,000	$9,000,000	$11,360,000	$12,800,000
Variable Costs, Generation	0.5¢/kWh	$500,000	$500,000	$500,000	$500,000	$500,000
Variable Costs, Pumping	0.5¢/kWh	$443,000	$607,000	$568,000	$599,000	$600,000
YEC Rate Scenario						
Interest During Construction		$26,300,000	$34,373,000	$35,972,000	$45,405,000	$51,160,000
Loaded Capital Cost, at End of Construction Period ($)		**$355,300,000**	**$464,373,000**	**$485,972,000**	**$613,405,000**	**$691,160,000**
Levelized Capital Cost		$13,573,000	$17,740,000	$18,565,000	$23,434,000	$26,404,000
Levelized Annual Cost		$21,096,000	$27,447,000	$28,633,000	$35,893,000	$40,304,000
Capital Cost of Energy Storage	$/MWh	$3,600	$4,600	$4,900	$6,100	$6,900
Capital Cost of Capacity	$/kW-yr	$14,200	$18,600	$19,400	$24,500	$27,600
Levelized Cost of Energy	**$/kWh**	**$0.21**	**$0.27**	**$0.29**	**$0.36**	**$0.40**
Levelized Cost of Capacity	**$/kW-yr**	**$840**	**$1,100**	**$1,100**	**$1,400**	**$1,600**
IPP Rate Scenario						
Interest During Construction		$36,235,000	$47,359,000	$49,562,000	$62,558,000	$70,488,000
Loaded Capital Cost, at End of Construction Period ($)		**$365,235,000**	**$477,359,000**	**$499,562,000**	**$630,558,000**	**$710,488,000**
Levelized Capital Cost		$17,788,000	$23,248,000	$24,330,000	$30,709,000	$34,602,000
Levelized Annual Cost		$25,311,000	$32,955,000	$34,398,000	$43,168,000	$48,502,000
Capital Cost of Energy Storage	$/MWh	$3,700	$4,800	$5,000	$6,300	$7,100
Capital Cost of Capacity	$/kW-yr	$14,600	$19,100	$20,000	$25,200	$28,400
Levelized Cost of Energy	**$/kWh**	**$0.25**	**$0.33**	**$0.34**	**$0.43**	**$0.49**
Levelized Cost of Capacity	**$/kW-yr**	**$1,000**	**$1,300**	**$1,400**	**$1,700**	**$1,900**
High Interest Rate Scenario						
Interest During Construction		$71,764,000	$93,795,000	$98,157,000	$123,896,000	$139,601,000
Loaded Capital Cost, at End of Construction Period ($)		**$400,764,000**	**$523,795,000**	**$548,157,000**	**$691,896,000**	**$779,601,000**
Levelized Capital Cost		$19,518,000	$25,510,000	$26,696,000	$33,697,000	$37,968,000
Levelized Annual Cost		$27,041,000	$35,217,000	$36,764,000	$46,156,000	$51,868,000
Capital Cost of Energy Storage	$/MWh	$4,000	$5,200	$5,500	$6,900	$7,800
Capital Cost of Capacity	$/kW-yr	$16,000	$21,000	$21,900	$27,700	$31,200
Levelized Cost of Energy	**$/kWh**	**$0.27**	**$0.35**	**$0.37**	**$0.46**	**$0.52**
Levelized Cost of Capacity	**$/kW-yr**	**$1,100**	**$1,400**	**$1,500**	**$1,800**	**$2,100**

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NOTES:

1. DISCOUNT RATES ARE REAL COST OF CAPITAL AS PROVIDED BY YEC. NOMINAL RATES HAVE NOT BEEN INCLUDED.

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Appendix 5.17
Moon Lake Pumped Storage Conceptual Study Report (Midgard 2015)

Moon Lake – Pumped Storage

Conceptual Study Report

Submitted By: Midgard Consulting Incorporated

Date: December 14, 2015

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Document Control & Signoff

DOCUMENT NUMBER

PROJ-0205-RPT-001-02

REVISION CONTROL

Revision	Description	Date
0	Draft - For YEC Review	September 25, 2015
1	Draft - Edited for Comments Received on Nov 23, 2015.	December 01, 2015
2	Final Report	Dec 14, 2015

REPORT SIGN-OFF

Prepared By: _____ Dec 04, 2015
ANNA LE, P.Eng., Midgard Consulting Inc. ***Date***

Checked By: _____ Dec 14, 2015
Michael Potyok, P.Eng., Midgard Consulting Inc. ***Date***

Approved By: _____ Dec 14, 2015
Michael Potyok, P.Eng., Midgard Consulting Inc. ***Date***

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Executive Summary

Yukon Energy Corporation ("YEC") is investigating the potential to develop a storage hydro project on Moon Lake, in northwestern British Columbia. As a utility, YEC experiences a winter peak load, combined with a summer peak in generation potential from its hydroelectric generating assets. A storage project at Moon Lake is intended to seasonally shift freshet flows and augment winter generation potential to better align with YEC's annual load profile.

Moon Lake, located 100 km south-southeast from Whitehorse, and 18 km south of the BC Yukon border, drains into Tutshi Lake from the south and is ultimately a tributary to the Yukon River, above Whitehorse. The project drainage area is estimated at 57.4 km^2 yielding an estimated Mean Annual Daily Flow ("MAD") of 0.79 m^3/s.

Midgard Consulting Incorporated ("Midgard") was retained by Yukon Energy Corporation ("YEC") to perform a preliminary study for a storage facility at the Project. Midgard was commissioned to study the Project as:

1) A conventional storage facility, and
2) A pumped storage facility.

Past studies for the Project as a conventional storage scheme or a run-of-river have been performed by Klohn-Crippen Consultant Ltd ("KCCL") in 1992, KGS Group ("KGS") in 2008 and HDR Inc. ("HDR") in 2011. Past studies have all assumed diverting the flows from at least one adjacent basin increasing the project drainage area by 25.7 km^2 to 57.3 km^2. The energy yield estimated from those studies range from 27.4 GWh to 51.3 GWh for a capacity of 6.7 MW to 11.5 MW.

Midgard has studied the Project under the following three scenarios:

1) Conventional Storage: Assuming the Project regulates the flow of the Moon Lake drainage area of 57.4 km^2 and generates from November 1st through May 14th.
2) Pumped Storage (48GWh): Assuming there is 48 GWh of available pumping energy from weeks 20 to 44 (based on YEC 2022 forecast) in addition to the natural inflows at the Project. Generation is assumed from weeks 45 to 19.
3) Pumped Storage (70GWh): Assuming there is 70 GWh of available pumping energy from weeks 20 to 44 in addition to the natural inflows at the Project. Generation is assumed from weeks 45 to 19. This scenario was not based on forecast but was studied to determine the additional energy the Project could yield given additional pumping energy.

The option's Full Supply Level ("FSL") were sized to utilize the available storage while minimizing spills and drawdowns below Minimum Operating Level ("MOL").

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As shown in **Table 1**, the Project yields 20 GWh of winter energy as a conventional storage scheme and 54 GWh to 69 GWh as a pumped storage scheme.

Table 1: Moon Lake Storage Energy Summary

Parameters	Conventional Storage	Pumped Storage (48 GWh)	Pumped Storage (70 GWh)
FSL (m)	1121	1125	1129
MOL (m)	1114	1114	1114
TWL (m)	713.2	713.5	713.5
Gross Head (m)	407.8	411.5	415.5
Generation Flow (m^3/s)	2.2	6.0	7.6
Pumping Flow (m^3/s)	N/A	4.1	6.2
Capacity (MW)	7.5	20.2	26.1
Annual Pumping Energy (GWh)	N/A	48	70
Annual Energy Output (GWh)	**20**	**54**	**69**

A pumped storage scheme will incur energy losses through the pumping phase and the generation phase. For the Project, about 30% losses were estimated. Therefore, the roundtrip efficiency of the pumped storage facility is estimated at 70%.

As a pumped storage scheme, the energy yield is limited by the available pumping energy. With an adequately sized dam, the terrain at the Moon Lake reservoir is able to accommodate more water than would be pumped by both the 48 GWh and / or 70 GWh of forecasted available pumping energy.

As the results from the conventional storage study were generally consistent with the results from past studies, it was agreed to primarily analyze the project as a pumped storage scheme and produce conceptual drawings, operation cost estimates, and levelized cost of energy ("LCOE") for the 48 GWh pumped storage scenario. From this base case alternative, cost estimates were then extended at a high level to the conventional storage and 70 GWh pumped storage alternatives.

The study was based on available previous reports, publically available mapping and hydrological data and from a brief site visit conducted in June 2015.

The proposed 48GWh pumped storage scheme will comprise a 31 m high, 700 m long earth dam at the outflow of Moon Lake, a 5.5 km long, 0.6 m diameter buried steel penstock, and a concrete and structural steel powerhouse some 400 m below on the shore of Tutshi Lake. The installed generation capacity will be 20.2 MW and pumping capacity of 18 MW.

The capital cost estimates for the three alternatives of the studied project options, exclusive of contingency, is shown in **Table 2**.

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Table 2: Project Capital Cost Estimates

Project Component	Conventional Storage ($M 2015)	Pumped Storage 48GWh ($M 2015)	Pumped Storage 70GWh ($M 2015)
Project Development	$2.2	$2.2	$2.2
Civil Construction Costs	$105.1	$143.1	$169.1
Generating Equipment Costs	$5.0	$14.0	$22.1
Transmission and Interconnection Costs	$2.8	$2.8	$2.8
Owners Costs During Construction	$2.1	$2.1	$2.1
Total Project Capital Cost	**$117.2**	**$164.2**	**$198.2**
Contingency	$22.6	$32.0	$38.8
IDC	$15.2	$21.4	$25.8
Grand Total Project Capital Cost	**$155.0**	**$217.5**	**$262.9**

Annual operating costs and a financial model for the estimation of the Levelized Cost of Energy ("LCOE") were estimated for the 48 GWh alternative only. For this alternative, the operating costs were estimated to be $1.9 million ($2015).

The resulting project LCOE assuming a full utilization of installed capacity was estimated to be $0.189/kWh. A sensitivity analysis was carried out on LCOE assuming different capacity utilizations. The results of this sensitivity analysis are presented in **Table 3**.

Table 3: LCOE Sensitivity Analysis - 48 GWh PSH Alternative

Capacity Factor	Full Utilization Generation (GWh)	NPE (GWh)	NPV ($M 2015)	LCOE ($/kWh)
100%	54	1,412.8	267.5	0.189
90%	48.6	1,271.5	267.3	0.210
80%	43.2	1,130.2	267.2	0.236
70%	37.8	989.0	267.0	0.270
60%	32.4	847.7	266.8	0.315

Several existing rights have been identified at the project site and its vicinity. Prior to advancing the project further, a detailed investigation of the current and future existing rights is recommended to identify potential development barriers.

If a decision is made to advance the project into the feasibility study stage, the following field studies and data collection programs are recommended:

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1) Prepare a submit a **water licence application** to Front Counter BC so as to secure first-in-line water rights to the project ahead of other potential claimants. British Columbia recognizes the rights to water on a first come, first serve basis. Several existing rights have been identified at the project site and its vicinity. Prior to advancing the project further, a detailed investigation of the current and future existing rights is recommended to identify potential development barriers.
2) Project preliminary engineering and design can be further advanced with greater precision topography, obtained with a **LIDAR survey**. This survey is recommended to refine the design and quantity cost estimate. The LIDAR survey area should comprise the dam site, the penstock route, suggested at 200 m each side of the proposed penstock alignment, and the powerhouse site. The estimated area of study is 3.5 km^2.
3) A **geotechnical investigation** program is recommended to assess the foundation conditions of the dam and powerhouse as well potential anchor block locations at select major bends along the penstock alignment.

   During early stage project definition and development, seismic refraction lines present a cost effective alternative to estimate overburden thickness without incurring the cost of mobilization of drilling rigs across Tutshi Lake and into the upper Moon Lake watershed. Two seismic lines are recommended at the dam site: one along the dam axis and one perpendicular to the dam axis at the maximum dam height. Two lines are suggested along the penstock near route and two at the powerhouse. As project certainty is achieved, greater expenditure for project definition is justified and the results from the seismic analysis can be confirmed with boreholes.

   Boreholes are indicated at the powerhouse location because of the importance of better characterizing the construction excavation conditions adjacent to Tutshi Lake as well as characterizing the rock quality at the powerhouse. Further, boreholes are an important along the dam foundation, not only to characterize the depth to bedrock, but to also investigate the rock quality and permeability in order to plan dam foundation treatment. As such, the dam boreholes should extend into bedrock to a depth commensurate with the dam height and include in situ permeability testing of the rock. Location of the boreholes should be determined once greater resolution mapping becomes available.

   Finally, a dedicated site investigation to secure and confirm a source pit for the material for construction or the dam is recommended to be included with any geotechnical programme.

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TABLE OF CONTENTS

Document Control & Signoff ii
Executive Summary iii
1 Introduction 1
1.1 Background 1
1.2 Purpose and Scope of the Report 2
1.3 Salient Features of the Project 2
2 Background Information 3
2.1 Review of Previous Studies 3
2.1.1 Klohn-Crippen Consultants Ltd. (“KCCL”) 3
2.1.2 KGS Group (“KGS”) 4
2.1.3 HDR Inc. (“HDR”) 4
2.2 Site Investigation 4
3 Site Characteristics 8
3.1 Access 8
3.2 Regional Terrain Characteristics 8
3.3 Topography 9
3.4 Reservoir Storage Curves 9
3.4.1 Moon Lake 9
3.4.2 Tutshi Lake 10
3.5 Hydrology 11
3.5.1 General 11
3.5.2 Stream Flow Gauges 12
3.5.3 Hydrology Used in the Energy Production Model 12
3.5.4 Frequency Distribution and Flood Estimates 14
3.6 Existing Water and Land Rights 14
3.7 Terrestrial Wildlife and Aquatic Habitat 15
4 Facility Description 17
4.1 Background 17
4.2 Diversion 17
4.3 Dam 18
4.4 Spillway 18
4.5 Fish Passage 19
4.6 Reservoir 19
4.7 Intake 19
4.8 Penstock 20
4.9 Powerhouse 20
4.10 Generating Equipment Selection 20
4.11 Switchyard 21
4.12 Transmission Line and Interconnection 21
4.13 Temporary Construction Works 23

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4.14 Access Structure 23
4.15 General Arrangement 23
5 Energy Yield Models 25
5.1 Inputs and Assumptions 25
5.1.1 Hydraulics 25
5.1.2 Hydraulic Losses 26
5.1.3 Other Model Inputs 26
5.2 Conventional Storage Scheme 27
5.3 Pumped Storage Scheme 27
5.3.1 48 GWh Scenario 29
5.3.2 70 GWh Scenario 29
5.4 Results 30
6 Project Development in British Columbia 33
6.1 Project Permitting 33
6.2 Development phases 34
7 Cost Estimates 36
7.1 Project Capital Costs 36
7.1.1 Project Development Costs 36
7.1.2 Civil Construction Costs 36
7.1.3 Generating Equipment Costs 37
7.1.4 Transmission Line and Interconnection Costs 38
7.1.5 Owner's Costs During Construction 38
7.2 Capital Cost Summary 39
7.3 Operating Costs 40
8 Financial Modeling 42
8.1 LCOE 42
8.2 Assumptions 42
8.3 Full Utilization LCOE 42
8.4 LCOE Sensitivity Analysis 43
9 Results and Recommendations 44
9.1 Results 44
9.2 Recommendations 45
Appendix A: Geotechnical Memo 48
Appendix B: Generating Facility Capital Cost Estimate 49

LIST OF FIGURES

Figure 1: Site Visit Flight Path 5
Figure 2: Proposed Dam Location 6
Figure 3: Saddle-Break Location 6
Figure 4: Proposed Powerhouse Location 7

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Figure 5: Moon Lake Storage Curve 10
Figure 6: Moon Lake and Tutshi Lake Areas 11
Figure 7: Moon Lake Gauge Flow Duration Curves 13
Figure 8: Prior Rights Summary 15
Figure 9: Overhead Transmission Route Alternative 22
Figure 10: Underwater Transmission Route Alternative 22
Figure 11: General Arrangement 24
Figure 12: Pumped Storage – 48GWh Scenario – Water Level 29
Figure 13: Pumped Storage – 70GWh Scenario – Water Level 30
Figure 14: Project Development Phases Schedule 35
Figure 15: Recommended LiDAR Survey Area 46
Figure 16: Recommended Seismic Refraction Line and Boreholes Drilling 47

LIST OF TABLES

Table 1: Moon Lake Storage Energy Summary iv
Table 2: Project Capital Cost Estimates v
Table 3: LCOE Sensitivity Analysis - 48 GWh PSH Alternative v
Table 4: Moon Lake Measured Water Level 9
Table 5: Moon Lake Storage Areas 10
Table 6: Tutshi Lake Estimated Water Level 10
Table 7: Regional Stream Flow Gauges 12
Table 8: Synthetic Average Monthly Flows (m^3/s) 13
Table 9: Estimated Flood Flows at the Proposed Dam 14
Table 10: Hydraulic Characteristics 26
Table 11: Energy Model Inputs 27
Table 12: Yukon Energy Forecast 28
Table 13: Surplus Energy Available for Pumping 28
Table 14: Pumped Storage – 48GWh Scenario - Results 31
Table 15: Monthly Energy Yields (GWh) 31
Table 16: Moon Lake Energy Yield Summary 32
Table 17: Project Development Costs 36
Table 18: Summary of Civil Capital Costs 37
Table 19: Summary of Generating Equipment Costs 37
Table 20: Transmission and Interconnection Cost Estimate 38
Table 21: Owners Costs During Construction 38
Table 22: Project Capital Cost Estimate 39
Table 23: Project Options Capital Cost Estimate 39
Table 24: Provincial Resource Fees 40

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Table 25: Project Annual Operating Costs 41
Table 26: LCOE Sensitivity Analysis 43
Table 27: Moon Lake Energy Yield Summary 44
Table 28: Project Capital Cost Estimate 44
Table 29: Project Annual Operating Costs 45

LIST OF ACRONYMS

CPI	Consumer Price Index
EAO	Environmental Assessment Office
FSL	Full Supply Level
IBA	Impact Benefits Agreement
IDC	Interest during Construction
IDF	Inflow Design Flood
ISD	In-Service Date
LCOE	Levelized Cost of Energy
MAD	Mean Average Daily Flow
MAR	Mean Annual Runoff
MOL	Minimum Operating Level
O&M	Operations and Maintenance
POI	Point of Interconnection
PSH	Pumped Storage Hydro
RFP	Request for Proposal
ROR	Run of River
ROW	Right of Way
SRW	Statutory Right of Way
TWL	Tail Water Level
UREP	Use, Recreation and Enjoyment of the Public
VFD	Variable Frequency Drive
WSC	Water Survey of Canada
YEC	Yukon Energy Corporation

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1 Introduction

1.1 Background

Yukon Energy Corporation ("YEC") is investigating the potential to develop a storage hydro project on Moon Lake, in northwestern British Columbia. As a utility, YEC experiences a winter peak load, combined with a summer peak in generation potential from its hydroelectric generating assets. A storage project at Moon Lake is intended to seasonally shift freshet flows and augment winter generation potential to better align with YEC's annual load profile.

YEC has a surplus of summer energy, resulting for a lower demand during those months combined with high freshet flows on the Yukon River and others. Currently, installed capacity on the Yukon River at Whitehorse is underutilized during the summer months and the surplus freshet flows are spilled.

Moon Lake, located 100 km south-southeast from Whitehorse, and 18 km south of the BC Yukon border, drains into Tutshi Lake from the south and is ultimately a tributary to the Yukon River, above Whitehorse. The Klondike Highway, between Carcross Yukon and Skagway Alaska traverses the north shore of Tutshi Lake.

A storage project at Moon Lake would have a double benefit to YEC inasmuch as stored summer flows would provide direct winter generation as well as marginally reduced freshet flows that would be spilled at Whitehorse. The winter generation flows at Moon Lake would also, ultimately report to the Whitehorse generating station as well.

A project on Moon Lake has been investigated several times in the past. These include studies by Klohn Crippen Consultants ("KCCL"), in 1992; KGS Group ("KGS"), in 2008; and HDR Inc. in 2011. KCCL and KGS proposed several arrangements of conventional storage schemes, simply storing summer flows at Moon Lake until winter and then slowly generating with those flows during YEC's peak load period (HDR proposed a run-of-river project directly on Moon Creek).

Tutshi Lake and its catchment have even greater flows than available in the Moon Lake catchment. YEC has proposed to develop a seasonal pumped storage scheme at Moon Lake, wherein spilled flows at Whitehorse, as well as other potential intermittent renewable energy sources (such as wind) would be used to pump flows from Tutshi Lake up to a dam on Moon Lake during periods of surplus energy. These flows, would then be stored with the natural flows in currently in the Moon Lake system to be used for generation during periods of generation deficit.

Midgard Consulting Inc. ("Midgard") has been retained to investigate the viability of a seasonal pumped storage hydro ("PSH") scheme on Moon Lake.

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1.2 Purpose and Scope of the Report

This report describes available background information and site characteristics as the basis for determining the overall viability of a pumped storage scheme for the Moon Lake Pumped Storage Project ("Project"). It details project site conditions, project hydrology estimates, the proposed project layout and ultimately a Class 5 cost estimate.

The Project, although being proposed by YEC, is in the Province of British Columbia. A high level Project Development Plan has also been prepared that outlines the steps and process, at a high level, to develop a hydroelectric project in that Province. This plan also provides preliminary cost estimates associated with project permitting and development activities, which also feed into the project capital cost estimates.

The report has been prepared to provide YEC with an assessment of the Project's potential to store and re-generate surplus energy from the YEC system to quantify its benefit. This combined with the capital cost estimates, and estimates of project operating costs, feed into an estimate the project's Levelized Cost of Energy ("LCOE").

The LCOE can provide a measure of project value relative to competing sources of winter energy that may be available to meet YEC's load in the future.

1.3 Salient Features of the Project

The proposed project will create a 690 ha reservoir over the existing Moon Lake and draw flows as need for generation from the reservoir. Water is stored directly from flows into the reservoir from the upper Moon Creek catchment as well as from pumped flows up from the lower Tutshi Lake.

Tutshi Lake has a nominal water level of 714 metres. The Moon Lake reservoir level will vary from a Minimum Operating Level ("MOL") of 1,114 meters and Full Supply Level ("FSL") of 1,125 metres.

The proposed project arrangement comprises a 31 m high, 700 m long earthfill dam with south abutment spillway and a low level outlet intake; a 5.24 km long, 1.6 m diameter buried steel penstock; and concrete and steel surface powerhouse containing a 20.2 MW vertical axis Pelton turbine and synchronous generator as well as two 9.4 MW peak power, variable speed drive vertical axis pumps. Flows are discharged to or drawn from a 7 m deep sump connected to Tutshi Lake.

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2 Background Information

2.1 Review of Previous Studies

2.1.1 Klohn-Crippen Consultants Ltd. ("KCCL")

KCCL performed a study of the project as a conventional storage facility in 1992. The study proposed three layout alternatives, each involving inter-basin diversion from neighbouring catchments into Moon Lake. For each of the three diversion alternatives, the remaining project layouts remained similar and comprised: an earthfill dam across Moon Creek, downstream of Moon Lake, a combined power canal and buried steel penstock conveyance to a concrete and steel powerhouse, founded on bedrock on the shore to Tutshi Lake.

The three proposed diversion alternatives were the following:

1) **Alternative 1:** Would regulate flows in the 58.9 km^2 Moon Lake catchment and would capture and divert flows from a 25.7 km^2 sub-catchment to the north of Moon Lake. The resulting combined project catchment of 84.6 km^2 would result in a mean annual discharge ("MAD") of 1.35 m^3/s. The 8.5 MW plant would generate an estimated annual energy of 36.3 GWh. Estimated project cost was $28.8 million ($1992) excluding transmission.
2) **Alternative 2:** Would regulate the flow from Moon Lake and divert and capture flow from an additional six neighbouring sub-catchments with a combined drainage area of 57.3km^2. The total resulting project catchment of 116.2 km^2 would result in an estimated average runoff of 1.83m^3/s and annual energy generation of 49.2 GWh from an 11.5 MW plant. Estimated project cost was $35.4 million ($1992) excluding transmission.
3) **Alternative 3:** Would be similar to the Alternative 2 diversion scheme but would generate energy throughout the year as opposed to through the winter period only. This would result in a smaller dam and reservoir as well as a lower installed capacity. Assumed generation throughout the year would be 51.3 GWh on an installed capacity of 8.5 MW. Project cost was estimated to be $30.1 million ($1992) excluding transmission.

It is noted that the proposed project layout by Midgard retains several similarities to the schemes proposed by KCCL. The proposed dam alignment and layout are similar as is the selection of conveyance route and powerhouse location.

However, unlike KCCL, a power canal is not generally suited to a pumped storage scheme, with the need to balance flows both in and out of the reservoir, at varying water levels. Further, in the current permitting regime in British Columbia, it is not considered practical to successfully permit hydroelectric projects that incorporate inter-basin transfer of flows. No such supplementary diversion infrastructure is contemplated in this report.

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2.1.2 KGS Group ("KGS")

In 2007 and 2008, KGS prepared an Assessment of Potential Hydroelectric Sites. This study included a concept study of eight potential hydro project sites, one of which was the Moon Lake site.

KGS proposed a conventional storage project with either a 3 m high dam or a 30 m high dam, with a water conveyance along the left (south) bank of Moon Creek and a powerhouse on the shore of Tutshi Lake. KGS also proposed an inter-basin diversion of flows for a total project catchment of 84.6 km^2. The three alternatives were the following:

1) **Alternative A** – 3 m high dam/intake/spillway and intake, with a canal or penstock to one of two powerhouse locations on the east shore of Tutshi Lake. Estimated annual energy was 33 GWh on an installed capacity of 5.7 MW.
2) **Alternative B** – 30 m high dam/intake/spillway, canal or penstock, intake to the powerhouse options on Tutshi Lake. KGS did not report energy and capacity for this alternative.
3) **Alternative C** – 3 m high dam at Moon Lake and a low level intake located further downstream, and then a canal or penstock to the powerhouse on Tutshi Lake. The estimated annual energy was 28 GWh with an installed capacity of 4.9 MW.

2.1.3 HDR Inc. ("HDR")

HDR performed a study of the Project as a run-of-river facility in 2011. The project estimated capacity was 6.7 MW and annual energy was 27.4 GWh.

2.2 Site Investigation

On June 24th 2015, a helicopter over-flight of the site was carried out for the purpose of confirming the overall site terrain as well as providing visual reference to the geological and geotechnical inferences developed from review of previous studies and desktop available data.

Conditions were ideal, with high visibility and calm winds. The itinerary for the visit was as follows:

1. Transit from Whitehorse to Bennett, BC;
2. Flight over upper Tutshi watershed to develop a visual sense of terrain and glacier cover;
3. Flight up Moon Creek from Tutshi Lake to upper Moon Lake catchment to confirm terrain;
4. Touch down on lake to confirm barometric elevation;
5. Slow flight down and then up Moon Creek from dam site to powerhouse to confirm conveyance route and powerhouse location;
6. Touch down on Tutshi Lake to confirm barometric elevation of Tutshi Lake;
7. Fly over Tutshi Lake outflow between Tutshi and Tagish Lakes to develop visual sense of reach aquatic habitat;

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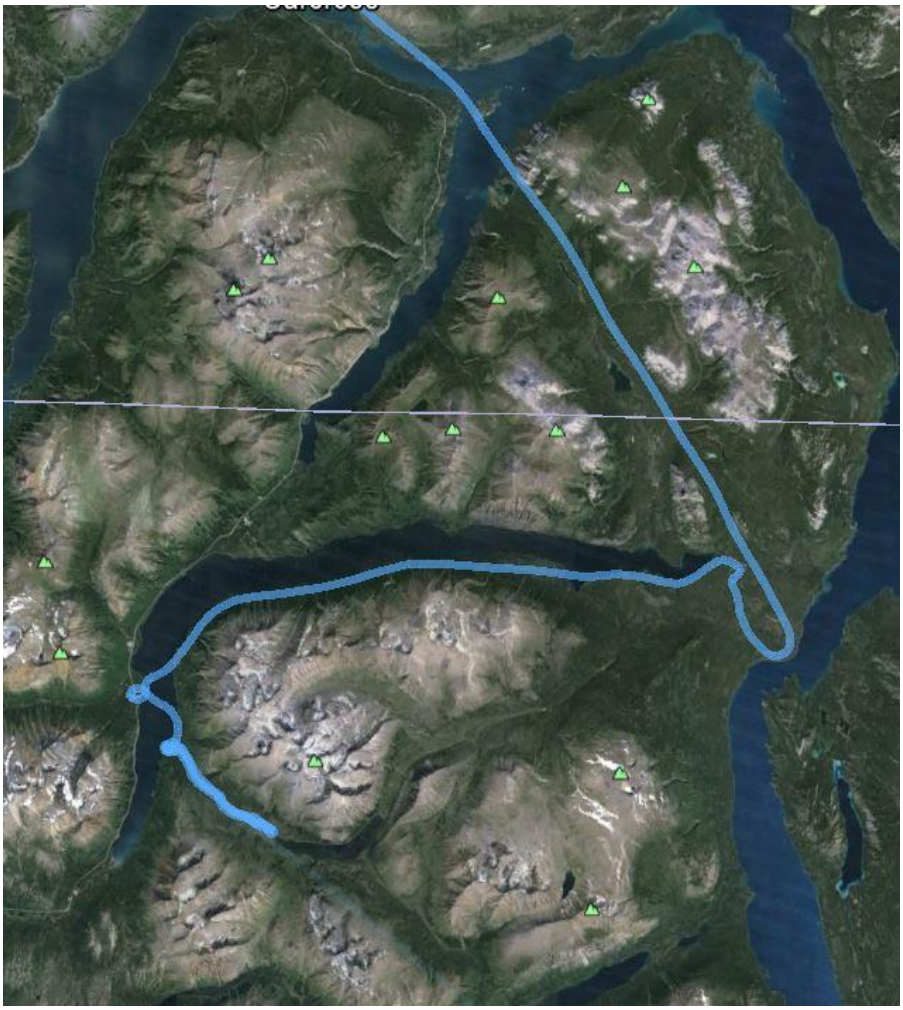
8. Return transit to Whitehorse.

Figure 1 shows a partial flight path around Moon and Tutshi Lakes.

Figure 1: Site Visit Flight Path



The following are discussions and conclusions derived from the site visit.

Dam Axis Alignment

During the site visit, several potential dam alignments were reviewed. It was concluded that a dam axis crossing the creek approximately 1.4 km downstream of the outfall of the lake. The approximate coordinates are Latitude 59°50'16.24"N and Longitude 134°41'56.08"W. This location was selected because of evident surficial bedrock and presumed near surface bedrock along the dam alignment as well as favorable topography along the left abutment that will tend to reduce dam height and material volumes. **Figure 2** provides a view of the proposed dam alignment at the creek, looking upstream toward Moon Lake.

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Figure 2: Proposed Dam Location

Maximum Reservoir Containment Elevation

The best available topographic mapping is at a 20 metre contour resolution. A tributary to the lake from the southeast was identified as having a relatively low saddle-break into the adjacent watershed. Using comparative barometric elevations from the lake surface to the saddle-break, it was established that the maximum reservoir elevation that would be contained within the watershed, without the addition of a saddle dam at this location is 1141 metres. The location of the saddle-break is shown on **Figure 3**.

Figure 3: Saddle-Break Location

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Penstock Alignment

A conveyance alignment on the river-left (Southwest) bank was selected due to more favorable terrain and lower gradient cross slopes.

Powerhouse Location and Tutshi Lake Elevation

The powerhouse is proposed at a cleared area north of the confluence between Moon River and Tutshi Lake (See **Figure 4**). The Tutshi Lake water level was measured on site at 714 m.

Figure 4: Proposed Powerhouse Location

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3 Site Characteristics

3.1 Access

The Klondike Highway, between Carcross, Yukon and Skagway, Alaska, runs along the north shore of Tutshi Lake. There is no current or historical road access to Moon Creek. Construction of road access around the upstream end of Tutshi Lake would require 7 km of new, fairly difficult road construction, combined with a significant bridge span across the Tutshi River.

For the purposes of this study, it is therefore concluded that construction access to the site would be by barge across the lake from the Klondike Highway.

For this purpose, there is ample low bank access to the lake along the highway for barge access on the lake.

3.2 Regional Terrain Characteristics

The Moon Lake watershed lies within the Boundary Ranges of British Columbia Coast Mountains. The topography of the region is typified by broad U-shaped valleys flanked by hanging valleys with steep side slopes.

The Boundary Ranges extend some 800 km northwest from the mount of the Nass River along the BC-Alaskan border into the Yukon. The peaks of this range are typically lower than the peaks of the southern coast mountains but retain significant glaciation due to their northern latitude. Geologically, the predominant bedrock of the region is from granitic intrusions of the Coast Arc Range of the Late Cretaceous geologic period (66 to 100 million years ago). The granitic intrusions formed the basement of the Coast Arc volcanoes, which have substantially eroded away. One notable exception is the Bennett Lake volcanic complex, remnants of which remain some 40 km to the northwest of the project.

SLR characterized the project area more specifically as “mountainous with glaciated valleys having veneer of glacial drift over bedrock. Moon Lake is located within a broad U-shaped valley that is flanked by high elevation mountainous terrain. The area of the outflow channel from Moon Lake and several hundred metres downstream appears to have a thicker organic layer that may have be an infilled section of the lake basin composed of alluvial material. Bedrock outcrops are evident a few hundred metres downstream of Moon Lake becoming more frequent with distance from Moon Lake. It appears that the stream to Tutshi Lake is generally bedrock controlled. Glaciofluvial features also appear to be evident down the valley from Moon Lake to Tutshi Lake where there are high banks of exposed overburden. This material is a possible source of both fine and course dam construction fill (to be verified).” See Appendix A for SLR’s Geotechnical Memorandum.

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3.3 Topography

The project general arrangement concepts as well as hydrologic assessment of the watersheds has been carried out using mapping from DataBC with 20 m contours topography based on the Provincial TRIM 20,000 scale dataset.

Bathymetric data for neither Tutshi Lake nor Moon Lake was found. Based on the site visit, it is evident that the outflow of Moon Lake is bedrock controlled, limiting the practicality of accessing negative storage from the existing lake.

3.4 Reservoir Storage Curves

3.4.1 Moon Lake

A reservoir storage curve was developed for the proposed Moon Lake reservoir using the 20 m topography. Reservoir surface areas were measured at 20 m contour intervals and the assumed dam axis alignment. Volumes were computed using an average end area methodology.

In order to establish a base water level, data from the installed Water Survey of Canada ("WSC") gauge near the outflow of the lake was access. Select water levels from that gauge, as measured through 2013, are summarized in **Table 4** below.

Table 4: Moon Lake Measured Water Level

Item	Water Level (m)
Min Water Level (m)	1,113.8
Max Water Level (m)	1,114.2
Average Water Level (m)	1,113.9
Average Winter Lake Level (m)	1,113.8
Average Summer Lake Level (m)	1,113.9

Further, during the June 24th site visit, using a barometric pressure altimeter from the helicopter, the lake water level at Moon Lake was also measured at 1,114 m. For the purposes of this report, it was concluded that, due to the relative low variation in lake level, the base water level at Moon Lake is 1,114 m.

A Moon Lake reservoir storage curve was developed from the base lake level of 1,114 m up to 1,160 m at 20 m intervals. The available live storage volume are shown in **Table 5** and **Figure 5**.

The measured lake area at EL. 1,114 m is 3.44 km^2.

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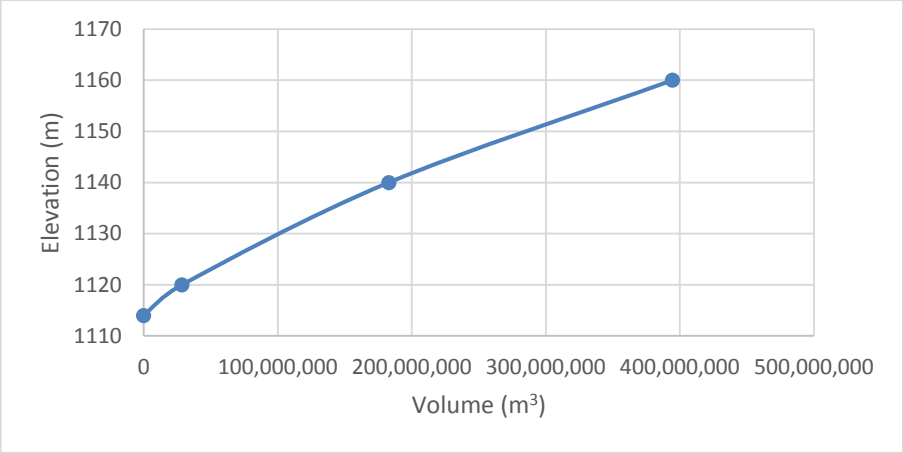
Table 5: Moon Lake Storage Areas

Elevation (m)	Area(km^2)	Volume (m^3)
1,114	3.437838	0
1,120	6.080000	28,553,514
1,140	9.350000	182,853,514
1,160	11.810000	394,453,514

Figure 5: Moon Lake Storage Curve



3.4.2 Tutshi Lake

Similarly, the WSC gauge, 09AA018, at Tutshi Lake recorded lake levels throughout 2012. The lake water level on Tutshi Lake was measured at 714 m during the June 24th site visit. Select measured water levels on Tutshi Lake are shown in **Table 6**.

Table 6: Tutshi Lake Estimated Water Level

Item	Water Level (m)
Min Water Level (m)	713.1
Max Water Level (m)	714.6
Average Water Level (m)	713.5
Average Winter Lake Level (m)	713.2
Average Summer Lake Level (m)	713.9

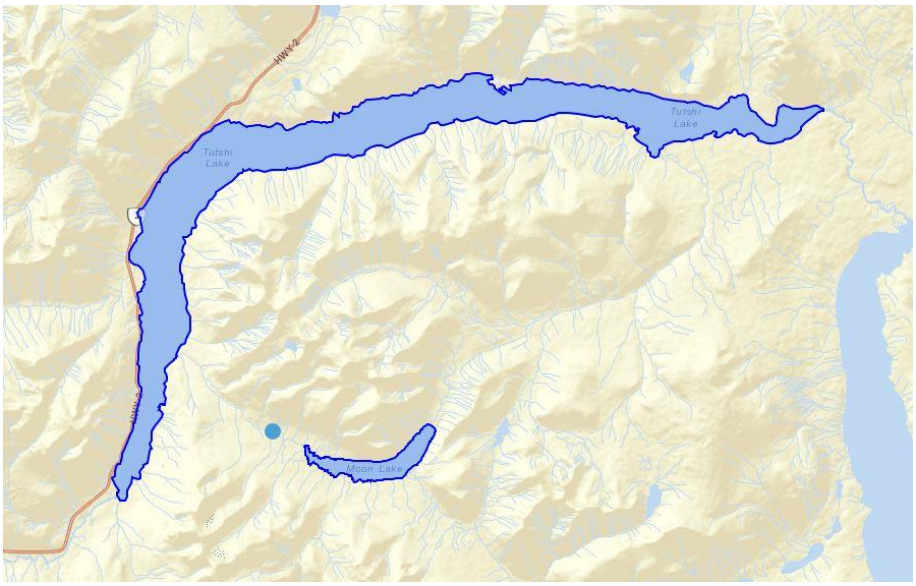
A base lake level of 714 m was selected for this report.

The measured surface area of Tushi Lake at EL. 714 m is 52.84 km^2. The Tushi Lake surface area is significantly larger than the proposed Moon Lake reservoir. Further, inflows and outflows from Tutshi Lake will remain uncontrolled during project operations and as such, project operations are not expected to have a

material effect on the water levels of Tutshi Lake. Particularly not within the resolution of available mapping. Consequently, no storage curve was developed for Tutshi Lake.

The Project Lake and the Tutshi Lake areas are shown in **Figure 6**.

Figure 6: Moon Lake and Tutshi Lake Areas



3.5 Hydrology

3.5.1 General

Moon Creek is a second order creek draining Moon Lake and the flanks of Jack Peak to the north and Skelly Peak to the south. The drainage basin is situated in the Boundary Ranges of the Coast Mountains of BC and Alaska.

Moon Creek has a drainage area of 57.4 km^2 at the proposed dam, of which 6 percent (3.44 km^2) is lake surface area. There is no appreciable glacial ice within the watershed.

Tutshi River is a third order river draining into Tutshi Lake and from Tutshi Lake to Tagish Lake from its headwaters to the west near the Alaska border. Tutshi Lake, at its outflow, has a drainage area of 979 km^2 of which 6.8 percent is lake surface area (66 km^2) and 1.5 percent (14 km^2) is glacial ice or snow field.

The region's hydrology is nival, driven primarily being the melt of annual snowpack over the summer, which produces a moderate but sustained flow.

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3.5.2 Stream Flow Gauges

Environment Canada, through the Water Survey of Canada ("WSC"), maintains two current streamflow gauges in the area of the project. **Table 7** provides a summary of the average annual flows or Mean Annual Runoff ("MAR"), drainage areas and years of record for the two gauges.

Table 7: Regional Stream Flow Gauges

Gauge Name	WSC Number	Period	Complete Years of Record	Drainage Area (km^2)	Mean Annual Runoff ($L/s/km^2$)
Moon Creek near the outlet of Moon Lake	09AA018	2012 - 2015	2	53.0	14.9
Tutshi River at outlet of Tutshi Lake	09AA013	1956-2015	45	989	16.2

The estimation of the project hydrology is very much facilitated in this instance because there has been a gauge installed on the same third order catchment as the project stream and there are at least two concurrent years of data between the project gauge and the long run gauge. The Moon Lake gauge represents 5.3 percent of the Tutshi Lake basin. Both gauges are maintained by the WSC.

Both gauges demonstrate a comparable MAR and both have similar areas of lake coverage. There is marginally more glacial coverage in the Tutshi basin, which, in this period of glacial retreat, can help to explain the marginally higher MAR within that basin.

3.5.3 Hydrology Used in the Energy Production Model

Midgard developed a synthetic daily flow series for the proposed dam site using a regression analysis on the concurrent data from the Moon Lake and Tutshi Lake gauges.

Data was sorted by month and compared using a direct temporal (day for day) comparison in order to generate a relationship for each month. The regression was performed with each daily matched pair of flows from July 27, 2012 through July 6, 2015[1].

The data at the Moon Lake and Tutshi Lake gauges demonstrated strong correlation as expected. The synthetic average monthly flows are listed in **Table 8** and a comparison of flow duration curves of the measured and the synthetic data set is shown in **Figure 7.**

[1] The 2014 to 2015 data are provisional. Provisional data has not undergone WSC's QA/QC confirmation yet. Midgard chose to make use of the additional data because the benefit of the additional data in refining regression results. The results may be refined when WSC publishes its final data.

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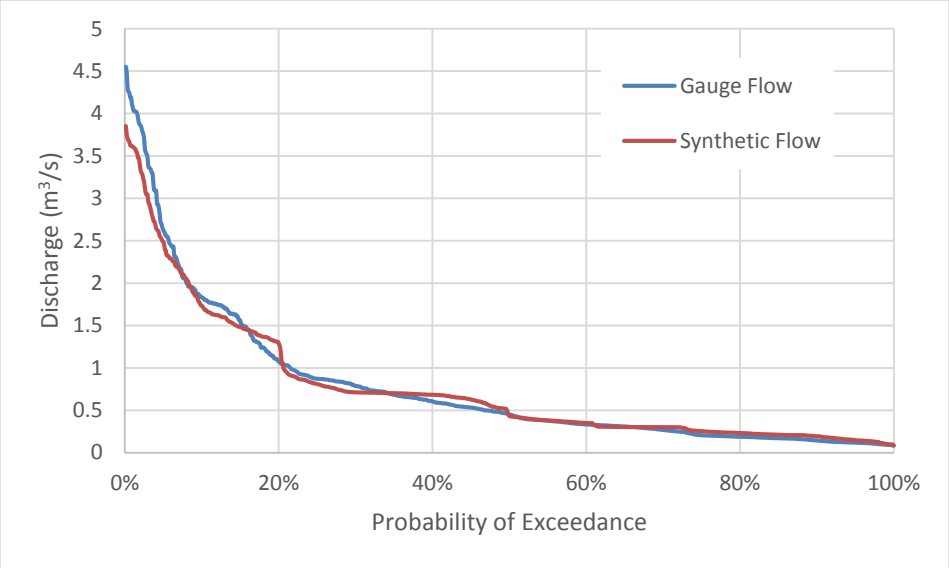
Table 8: Synthetic Average Monthly Flows (m^3/s)

Month	WSC Gauge Site	Dam Site
January	0.21	0.23
February	0.23	0.25
March	0.21	0.22
April	0.19	0.20
May	0.72	0.78
June	2.25	2.44
July	1.89	2.05
August	0.85	0.92
September	0.71	0.77
October	0.57	0.61
November	0.36	0.39
December	0.30	0.33
Average	**0.71**	**0.77**

Figure 7: Moon Lake Gauge Flow Duration Curves



Based on the regression model results, a synthetic string was obtained from the Tutshi Lake Gauge data and the area proration between the Moon Lake Gauge watershed area and the Project watershed area. The drainage area factor between the gauge and the project is 1.08.

Data was recorded at the Tutshi Lake Gauge from 1956 to today, however, only the data from 1966 to today was recorded continuously. Only partial data was recorded in 1987 and 2000, and no data was recorded in 1998 and 1999, therefore year 1987, 1998, 1999 and 2000 were removed from the dataset to generate a 45-year synthetic string.

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3.5.4 Frequency Distribution and Flood Estimates

A frequency distribution analysis of the synthetic annual maxima was carried out to estimate expected flood flows and their respective probability at the dam site.

At this level of study, and given the limited amount of regional data, Midgard elected to extend the frequency distribution analysis for extreme floods for the purposes of sizing flood routing capabilities at the dam site up to 1000-year flood. It is acknowledged that an extended frequency distribution for long return period annual maxima is generally considered to be inappropriate for determining the inflow design flood ("IDF") for dam and spillway design. Further flood estimates are warranted if the project advances through higher stages of development and design.

The flood flows, using Log-Pearson III distribution, are presented in **Table 9**. The 500-year and 1000-year floods were estimated by extrapolation.

Table 9: Estimated Flood Flows at the Proposed Dam

Frequency	Flood (m^3/s)
5-year	4.41
10-year	4.98
50-year	6.15
100-year	6.61
200-year	7.06
500-year	7.55
1000-year	7.90

3.6 Existing Water and Land Rights

The successful development of a waterpower project in British Columbia on Crown Land presumes that there are no competing prior rights to either the land base or the surface water rights. A preliminary investigation was carried out using the publically available provincial database to ascertain the potential existence of any prior rights.

The search revealed several prior land rights and one water licence being present on or near the project area as summarized in **Figure 8**.

1) A protected area tenure exists on the downstream portion on Tutshi Lake. The tenure has an explicit clause precluding the development of hydroelectric projects or any water control facility. The protected area does not include the project area, but it is worth noting.
2) A Commercial License to Occupy exists on the project area for Guide Outfitters. The tenure does not preclude other licenses on the project area. However, in concert with this licence, there is a cabin near the south shore of Moon Lake which would be impacted by the proposed reservoir of the project.

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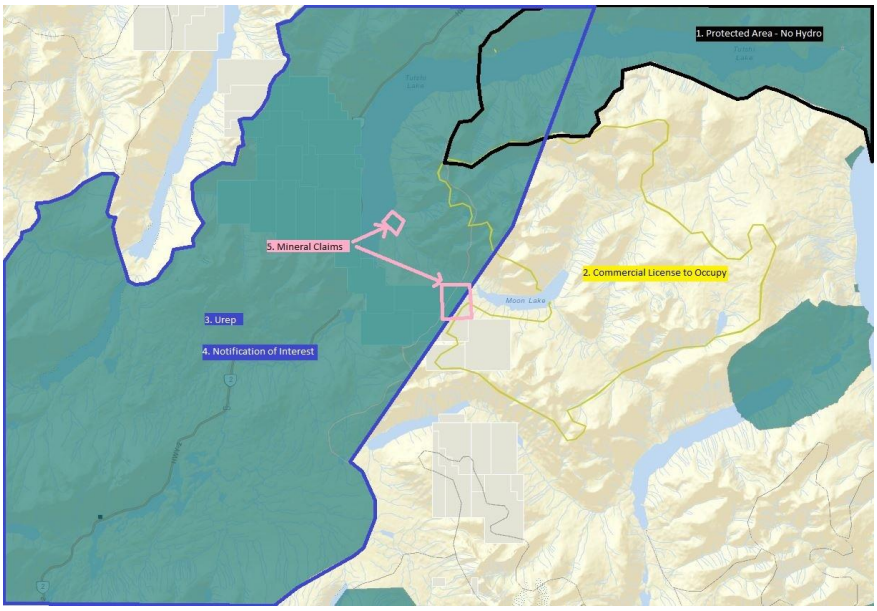
3) A Use, Recreation and Enjoyment of the Public ("UREP") map reserve exists on Tutshi Lake and the downstream portion of the project. A map reserve is a land use reserve that is established under Sections 11 or 12 of the Land Act over an area of Crown land outside of Provincial Forests to guard against unwarranted disposition or unplanned use (in this case, sale or use that would compromise an area's current or potential recreation values or uses).[2]
4) A notification of interest exists on the project area.[3]
5) Five mineral claims exist on downstream portion of the project area.
6) A historic water licence application was registered in 1991 for a power project on Moon Lake. This application has since been abandoned.

Figure 8: Prior Rights Summary



3.7 Terrestrial Wildlife and Aquatic Habitat

No Specific research was carried out on terrestrial wildlife or aquatic habitat values.

It is noted that the Tutshi River, between Tutshi Lake and Tagish Lake is a broad riffled reach with an average gradient of 0.5% over its 7.3 km length. Visual observation during the over-flight suggests that there are no falls or other potential barriers to fish migration.

[2] https://www.for.gov.bc.ca/hfp/publications/00201/appen05/appen05.htm

[3] A notification of interest is one types of land status regarding the apportionment, setting apart or earmarking of land or water for an indication of interest.

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Due to the nature of the channel, a higher than typical instream flow is assumed to be required to maintain an overall wetted perimeter in the channel and preserve fish habitat. An instream flow in the reach is assumed because, pumping flow from Tutshi Lake into Moon Lake can impact outflows from Tutshi Lake.

The Moon Creek reach between Moon Lake and Tutshi Lake is very steep, with an average gradient over 7 percent. Anecdotally, Moon Lake is fish bearing but this has not been confirmed. A lower instream flow release has been assumed between the dam and Tutshi Lake but a cost allowance has been made for maintaining fish passage over the dam.

There were no evident showstoppers to the project from the perspective of terrestrial wildlife values.

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4 Facility Description

4.1 Background

The basic concept of the facility is to develop an upper reservoir on Moon Lake that will enable the generation of winter energy, when regional flows and flows on the Yukon River basin are at their lowest. To achieve this, a dam is proposed downstream of the outlet of the lake equipped with a gated intake tower, spillway and low level outlet. A buried penstock will convey flows from the intake to a powerhouse on the shores to Tutshi Lake, some 400 m below in elevation.

As a conventional storage facility, the dam height would be optimized to accommodate the annual freshet and summer flow from the upper basin of Moon Lake, with some allowance for potential spill during extreme flood years. The penstock would be optimized for its cost versus the present value of foregone energy that result from hydraulic losses of head in the system. The powerhouse would house a turbine and generator unit, most likely a Pelton unit given the head and flow profile of the project.

For a pumped storage scheme, the overall project layout would remain the same as a conventional scheme with the following exceptions. First, the dam height would increase to not only impound natural flows from the upper catchment, but also the volume of flow that would be pumped from Tutshi Lake; second, the penstock would be optimized for a higher design flow; and third, the powerhouse would also have to accommodate a pump and intake from Tutshi Lake.

This section describes the conceptual layout of the Project as a pumped storage facility. During high flow period, the energy generated from the spill at Whitehorse hydroelectric station or other to be determined energy sources on the YEC grid, will be used to pump water from Tutshi Lake into the Moon Lake reservoir for winter energy storage. During low flow periods, energy will be generated form the stored water to contribute to the Yukon winter load demand.

4.2 Diversion

In order to construct the dam across the outlet of Moon Lake, it is necessary to divert flows from the dam foundation. Typically, this is accomplished with a temporary diversion channel or tunnel, which allows the dam to be constructed in the dry. In the case of this project, a low-level outlet pipe is proposed under the dam foundation. During construction, the water at Moon Lake will be diverted through the low-level outlet pipe of the dam.

The 200 m long diversion pipe will be encased in concrete. The dam will constructed be on top of the diversion pipe, which will stay in place after construction.

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4.3 Dam

The dam will be founded on bedrock. The depth of overburden is assumed to be 3 m and will need to be verified through a geotechnical investigation program. The overburden is assumed to be consisting of glacial moraine deposits and organics. Primary to tertiary grouting curtains will be placed to prepare the foundation.

The project is designed with a 31 m high[4] and 700 m long earthfill dam. The dam structure is primarily composed of a homogeneous core of fine local till material. At this stage the material is assumed sufficiently fine to limit most of the seepage. An upstream bituminous liner may be installed to provide additional seepage control but was no included at this stage. Bituminous liners are often used in the north because of the ease of placement during cold weather and its ability to handle extreme temperature fluctuations. An internal drainage system consisting of a downstream gravel filter and drainage blanket will be incorporated to the structure. Riprap will be placed on the upstream face to provide erosion protection.

Per the Canadian Dam Association's Dam Safety Guidelines:

1) "Significant" hazard classification implies only temporary population at risk within the dam-breach inundation zone (e.g., seasonal cottage use, passing through transportation routes, or participating in recreational activities). In the event of a dam failure, the potential loss of life is unspecified, no significant loss or deterioration of fish or wildlife habitat is expected, and losses to recreational facilities, seasonal workplaces, and infrequently used transportation routes are expected.
2) "High" hazard classification implies only permanent population at risk within the dam-breach inundation zone. In the event of a dam failure, the potential loss of life is 10 or fewer, significant loss or deterioration of *important* fish or wildlife habitat is expected, and high economic losses affecting infrastructure, public transportation, and commercial facilities are expected.

For conservatism at this stage of the study, the dam is classified in the "High" hazard category and is designed for a 2475-year seismic event. The design includes 3 m of freeboard for flood retention and to prevent overtopping, and a spillway over the south rock abutment to pass high flow events such as floods and summer peak flows. The dam crest is assumed to be 6 m wide.

4.4 Spillway

The dam includes a 2 m wide and 300 m long gated concrete spillway structure on the river-left (South) bank rock abutment that controls water flow releases during high flow periods. The spillway is designed to release flows up to the Inflow Design Flood ("IDF")[5]. The spillway structure includes a concrete inlet channel with a 2 m X 2 m gate, stoplogs and concrete chutes which return the water to the river. The foot of the spillway and

[4] Includes 3 m of excavation.

[5] At this stage of study, the IDF is assumed as 1000-year return period flood flow.

area immediately downstream includes a stilling basin designed to withstand the erosive effects of the spillway water flows and to dissipate energy.

4.5 Fish Passage

A fish passage has been assumed to facilitate potential downstream fish migration. Given the overall gradient of the creek below the dam, it is assumed that there will not likely be significant upward fish migration. However, given anecdotal suggestion that the lake is fish bearing, it bears consideration that the lake population may seed downstream fish populations in the creek. Additional research is required to ascertain the practicality of fish passage over the dam.

4.6 Reservoir

The proposed dam creates a reservoir upstream of the dam site. The natural lake level area is 3.44 km^2. The minimum operating level ("MOL") of the water reservoir is 1,114 m. The estimated FSL of the water reservoir is 1,125 m and floods a total area of approximately 6.90 km^2, providing a live storage volume of 67.1 million m^3.[6] The incremental flooding area is from the lake level to FSL is 3.46 km^2.

The flooded area includes an existing outfitter cabin in the southeast shore of Moon Lake.

4.7 Intake

The water intake is a concrete tower structure located on the river-right (North) bank and is based on rock foundation. The intake is connected to the penstock that will convey water for electric generation and pumping during operation up to the full plant design flow of 6 m^3/s. The intake box will provide sufficient submergence to prevent vortex formation from FSL to Minimum Operating Level of 1,114 m.

The main components of the intake include:

1) Trash Racks - To prevent driftwood and other floating debris such leaves from being entrained by the water conveyance structures.
2) Trash Rack Cleaning Equipment - To allow for clearing of entrained debris.
3) Head Gate Structure - To provide the ability to stop water flow into the water conveyance structures as part of regular maintenance or for emergency purposes.
4) Sluice Gate – To flush out the sediment from the intake box.
5) Fish exclusion screen – To prevent fish and other aquatic species from entering the penstock.
6) IFR pipe design for constant IFR of 5% MAD, through the dam
7) Electrical Power Supply and Controls.

[6] Live storage volume is between FSL and MOL.

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All steel metal work shall be galvanized for corrosion protection.

4.8 Penstock

A 1.6 m diameter buried steel penstock will convey water for generation and pumping. A minimum of 1.2 m of soil cover is assumed at this stage. The proposed alignment is 5.5 km long on the river-left (Southwest) bank. The alignment includes 7 bends that will likely require structural restraint such as soil restraint or anchor block. The penstock crosses 4 stream channels that will likely require overdrains or bridge crossings. A surge shaft is assumed at this stage, however further transient analysis studies may discard the need for a surge shaft. The penstock includes a bifurcation at the end of the alignment to connect to the pumping and generating unit at the powerhouse.

4.9 Powerhouse

The surface powerhouse is located downstream of the dam on the river-left (Southwest) bank. The approximate footprint of the powerhouse is 550 m^2. The powerhouse is designed one horizontal Pelton unit and one vertical shaft pump.

The powerhouse will be a cast concrete substructure, founded on bedrock, with a pre-fabricated structural steel superstructure.

The powerhouse contains all required operational, maintenance, and protection and control equipment required to operate the facility. Loading bays and an overhead crane will allow for maintenance access during operations. A tailrace channel directs water from the submergence pool back to the river.

4.10 Generating Equipment Selection

The relative smaller scale of the project limits the commercially available alternatives for turbines and pumps. A larger scale pumped storage scheme would typically combine the turbine and pump equipment by using a Francis Turbine, which is physically capable of both modes of operation.

When generating with a Francis turbine, available flows are controlled by the use of wicket gates that can close or open to either control the throughput of the unit, or maximize the efficiency of a unit to available flows. The wicket gates are not used during pumping operations. Pumping can be made more flexible with the addition of a variable frequency drive (“VFD”) which allows the unit to be optimized to available flow and power.

It is unlikely that an optimized and efficient solution is commercially available for an under 20 MW Francis unit. Further, the head and flow profile of the scheme indicates a Pelton generating unit, which is not capable of pumping operations.

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Consequently, the selected solution for this report is a vertical axis Pelton turbine with synchronous generator mounted above the 200-year flood level (715.6 m) of Tutshi Lake. The Pelton unit will accommodate generation flows from 3 m^3/s to 6 m^3/s.

Two separate, vertical axis, pumps, with direct coupled VFD and an extended shaft, will be 7 m below normal lake level of 713.5 m for submergence. The pumps have a combined design flow capacity of 4.1 m^3/s. The use of Variable Frequency Drive will allow the pump to accommodate flows from 50% to 100% of the capacity of each pump. Multiple pumps have been selected because of the potential range in pumping energy as well as to minimize overall size of the units.

4.11 Switchyard

The switchyard is a fenced area which contains transformers and electrical protection equipment (such as circuit breakers and disconnect switches). The approximate footprint of the switchyard is 250 m^2. The electricity produced via the turbine-generators inside the powerhouse is conveyed at an intermediate voltage to the switchyard located adjacent to the powerhouse. In the switchyard, the intermediate voltage is transformed up to a 138 kV transmission voltage and transported to the Yukon electrical grid via a 138 kV transmission line.

4.12 Transmission Line and Interconnection

The work assumes the pre-existence of a 138 kV transmission corridor along the South Klondike Highway all the way to Whitehorse.

Two potential interconnection options are available. These are either an overhead span across Tutshi Lake or a sub-marine cable under the lake.

The overhead alternative would comprise an overhead transmission line 400 m south from the powerhouse switchyard up the hill to elevation 840 m, then a 1.6 km span across the lake and a 200 m overhead line down to the assumed 138 kV ROW along the Klondike Highway.

This transmission option is shown in **Figure 9**.

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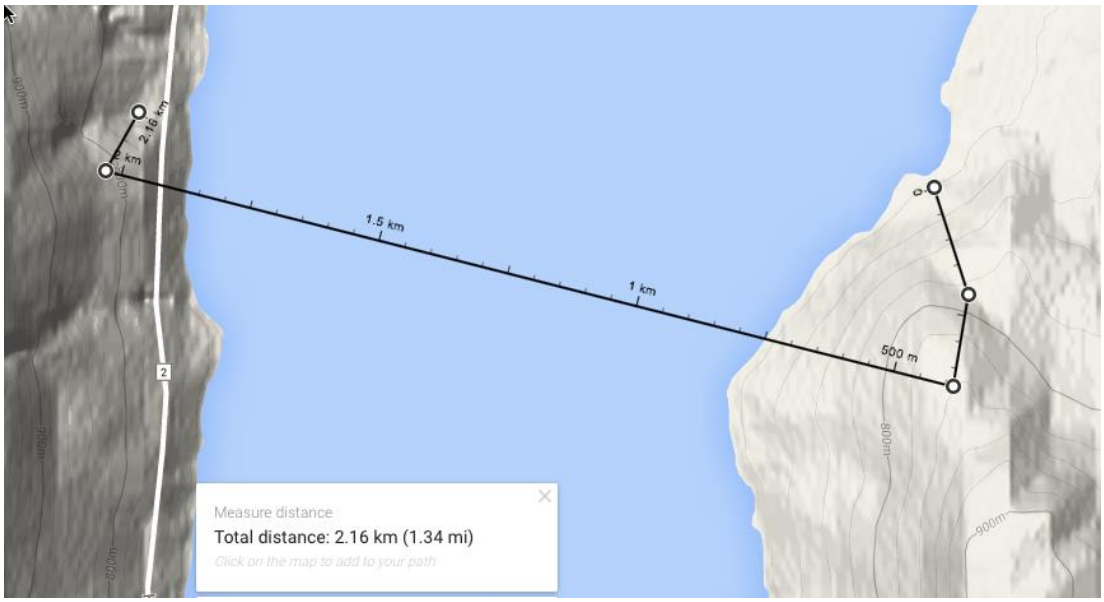
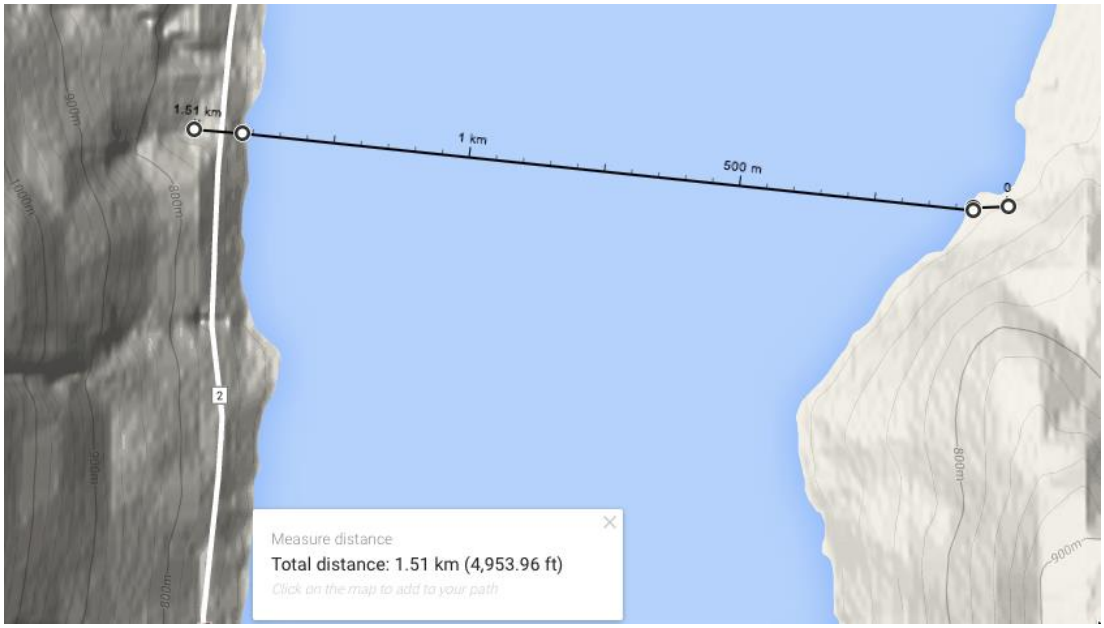
Figure 9: Overhead Transmission Route Alternative



The underwater alternative would comprise a 50 m buried cable, directly from the powerhouse switchyard to the lakeshore and a 1.4 km underwater cable across the lake and a 50 m buried cable to a riser structure at the assumed ROW. This alternative is shown in **Figure 10**.

Figure 10: Underwater Transmission Route Alternative



High level cost estimates indicate that both alternatives have the same order of magnitude cost. The final selection of the alternative will be combination of final cost and permitting constraints.

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4.13 Temporary Construction Works

Additionally, a number of temporary construction phase facilities are anticipated during the construction period, including:

1) Site Office and Construction Camp
2) Workshops, labs, and testing facilities
3) Fabrication shops
4) First aid / safety / safety stations
5) Staging / lay down areas
6) Waste water treatment plant
7) Concrete batch plants
8) Truck washing stations
9) Explosives storage
10) Fuel storage and refuelling

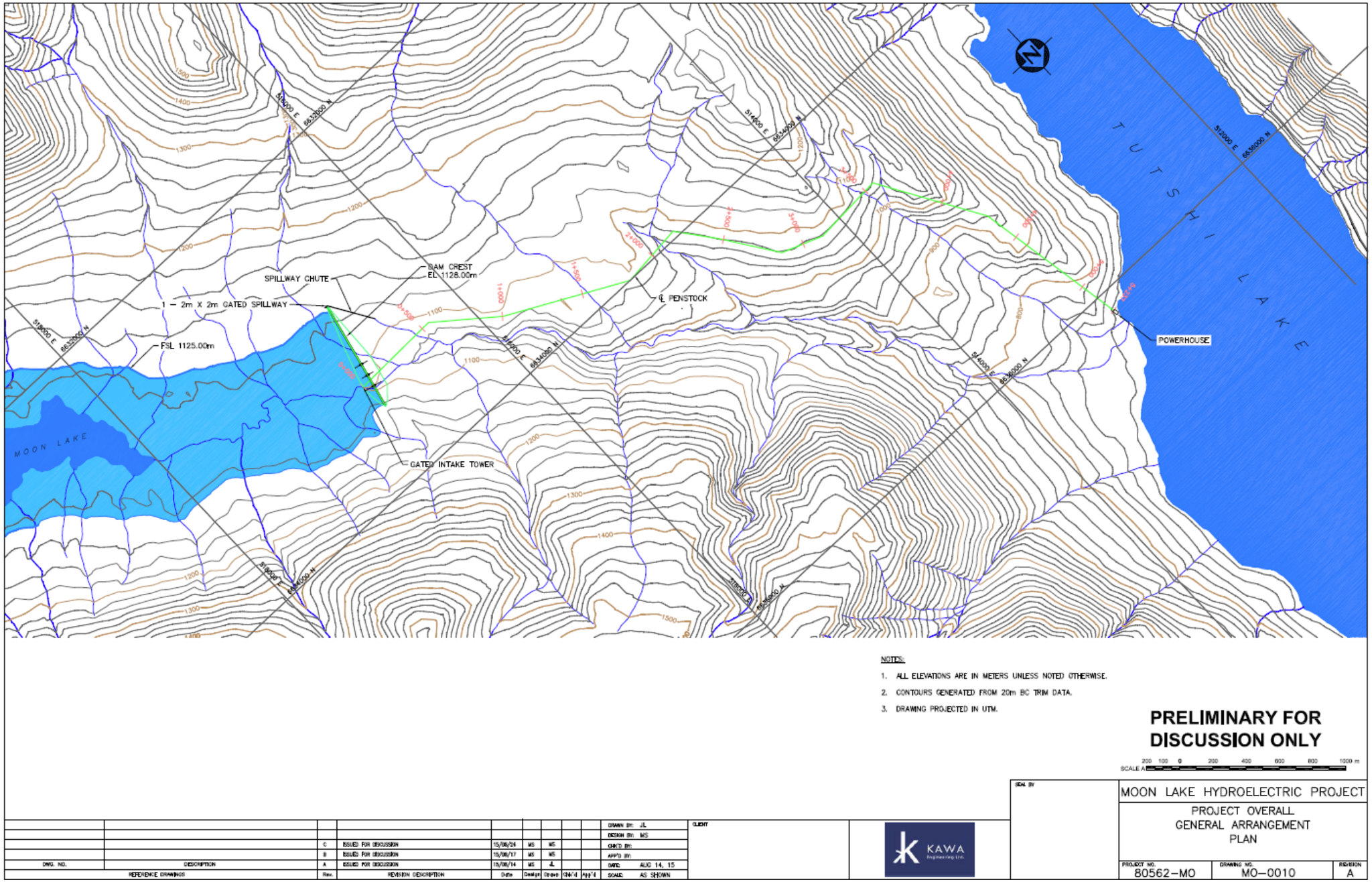
4.14 Access Structure

A barge access from the Klondike Highway to the east shore of Tushi Lake is assumed. Approximately 5.5 km of new road is required to access the project from the barge access to the dam site. The proposed access infrastructure is required for both construction activities (e.g. moving of heavy equipment and materials) and operations activities (e.g. operator access). The road alignment will approximately follow the penstock alignment.

4.15 General Arrangement

Figure 11 shows the proposed general arrangement.

Figure 11: General Arrangement



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5 Energy Yield Models

The conversion of a long run flow series to an appropriate forward looking estimate of Project energy generation requires the application of project specific design parameters, environmental in-stream flows and operating assumptions and limitations.

Two energy yield models were developed by Midgard to estimate the energy production of the Project based on the daily synthetic flow series;

- Conventional Storage Model; and
- Pumped Storage Model (48 GWh and 70 GWh scenarios).

The conventional storage model operates on a daily water balance basis. The model estimates the energy generation as a conventional storage project, with flows available only from the upper Moon Lake catchment.

The pumped storage model was created to estimate the energy consumption and net generation of the Project with flows available from both Moon Lake and Tutshi Lake, where flows from Tutshi Lake are pumped into the Project storage reservoir during high flow/low energy demand periods.

Inputs to both models include the daily estimated flow series (based on the WSC gauges); the environmental flows that have been assumed based on the diversion reaches; the conceptual project layout; the available gross head and the estimated hydraulic efficiency of the water conveyance system; the assumed turbine and generator efficiencies; and estimates of transmission and transformer losses.

For the conventional storage scenario, the model examines the daily average flow for each day of the flow series and deducts the In-stream Flow Releases ("IFR") to obtain the available flows for generation, then calculates the head losses and the resulting net head, selects the appropriate water-to-wire efficiency and calculates the daily energy generation.

For the pumped storage scenario, the model performs an analysis on the season and available flows in Tutshi Lake for pumping to first fill the reservoir and then, estimates winter energy generation as in the conventional scenario.

5.1 Inputs and Assumptions

5.1.1 Hydraulics

The gross and net heads of the plants are governed by natural and existing features as well as the head losses incurred at the plant. For Pelton turbines, the available gross head is defined as the difference between the headwater level in the reservoir and the centreline of the turbine runner.

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The powerhouse floor and the resultant turbine runner centreline are typically controlled by the flood elevations for varying flood events with the setting normally being higher than the 200-year flood event level. The gross head inputs for the three scenarios are listed in **Table 10**.

5.1.2 Hydraulic Losses

Hydraulic losses are losses of energy that typically result from the following:

- Hydraulic friction between the water flowing through the passages;
- Changes in flow velocities; and
- Factors that disturb the flow pattern such as trash racks, penstock, trifurcation, needle valves, etc.

The hydraulic losses are measured in meters and vary exponentially with flow velocity. These losses result in a corresponding reduction in the available net head and resultant power output and energy.

Midgard has assumed friction losses within the penstock using as a maximum of 5% of the maximum gross head of the project. The penstock was sized from this assumption. At lesser flows, the hydraulic losses are estimated with the following relationship:

$$Head\ Loss = k \times Q^2$$

Where:

$$k = \frac{5\% \times Max\ Gross\ Head}{Q_D^2}$$

Table 10 presents the Project's hydraulic characteristics utilized as inputs to the energy models.

Table 10: Hydraulic Characteristics

Input	Conventional Storage Model	Pumped Storage Model (48WGh Case)	Pumped Storage Model (70WGh Case)
Maximum Plant Flow (m^3/s)	2.2	6.0	7.6
Full Supply Level (m)	1121	1125	1129
Minimum Tailwater Level (m)	713.2 (Winter Average)	713.5 (Yearly Average)	713.5 (Yearly Average)
Maximum Gross Head (m)	407.8	411.5	415.5
Modeled Maximum Head Losses (5% of Gross Head) (m)	20.4	20.6	20.8
Minimum Net Head (@ Q_D)	387.4	390.9	394.7

5.1.3 Other Model Inputs

The daily flows and the reservoir storage levels that played into the storage models are described in Section 3.5: Hydrology and Section 3.4: Reservoir Storage Curve, respectively.

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In-stream Flow Requirements ("IFRs") were assumed to be the following:

a. Moon Lake: Estimated at 5% of MAD throughout the year.
b. Tutshi Lake: Estimated at 10% of MAD from November through May, and 30% of MAD from June through October.

Other major inputs that played into the storage models were assumed as described in **Table 11** below.

Table 11: Energy Model Inputs

Input	Conventional Storage Model	Pumped Storage Model
Turbine efficiencies[1]	90%	90%
Generator efficiencies	98%	98%
Transmission Line Losses[2]	1%	1%
Transformer efficiency	99.5%	99.5%
Pump Efficiency[3]	N/A	90%
Scheduled and Unscheduled Outage	4%	4%
Station Usage	50 kW	50 kW
MOL (m)	1,114	1,114
Daily Generation/Pumping Profile	15 hrs	15 hrs
Yearly Generation Profile	November 1st through May 15th	November 1st through May 15th
Energy output estimate	At POI	At POI

Note 1: A preliminary turbine efficiency is assumed to be a flat 90%. This will be refined when the models are refined and the turbine and generator solution for the project is selected.
Note 2: Assumed from the point of interconnection ("POI") to the switchyard.
Note 3: Preliminary assumption of 90% until a final pump solution is determined.

5.2 Conventional Storage Scheme

The conventional storage scheme assumes the project would regulate the flow of the Moon Lake drainage area of 57.4 km^2 (MAD = 0.79 m^3/s). The dam height was optimized to:

- Contain most of the summer flows in the reservoir while spilling excess water for 4 years out of 45-year hydrology string,
- Use all the storage water for generation while drawing down to MOL only 1 year out of the 45-year hydrology string.

The estimated FSL of the project is 1,121 m and its gross head is 407.8 m. The design flow is assumed at 2.2 m^3/s.

5.3 Pumped Storage Scheme

The Yukon energy load and surplus energy profile forecast was provided by YEC for years 2022, 2028, 2029 and 2030 as shown in **Table 12** below. The available energy for pumping includes surplus hydro (Whitehorse spill) and wind generation. The diesel generation to be displaced represents the load "shortfall" that is

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forecast to be generated with thermal generation sources (diesel or the LNG system in Whitehorse). This is effectively the target energy that winter generation at Moon Lake could serve over time.

Table 12: Yukon Energy Forecast

Year	Surplus Energy Available for Pumping (MWh)	Diesel Generation to be Displaced (MWh)
2022	47,939	23,754
2028	39,183	36,360
2029	34,789	45,878
2030	30,946	56,308

As can be noted, over time, the system load increases, which both reduces the available surplus for available for pumping and increases the load that would be served by Moon Lake.

After discussions with YEC, it was concluded to size a project that reflected the surplus available in 2022 based on the assumption that incremental renewable generation resources could be added to the system which the PSH project at Moon Lake could support.

In order to model the project's performance from week to week, the forecast weekly distribution of surplus energy, including that estimated from potential wind generation resources was applied to the model. This distribution, as provided by YEC, is shown in **Table 13**.

Table 13: Surplus Energy Available for Pumping

Yearly Generation /Pumping Profile			
Week	**Surplus Energy with Wind (MWh)**	**Week**	**Surplus Energy with Wind (MWh)**
20	389	33	2912
21	701	34	2501
22	1190	35	2476
23	1544	36	1814
24	1860	37	1944
25	2194	38	1913
26	2346	39	1915
27	2525	40	2007
28	2840	41	1632
29	3094	42	726
30	3095	43	215
31	3015	44	74
32	3017	**TOTAL**	**47,939**

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The pumped storage scheme assumes the project regulates the flow of the Moon Lake drainage area of 57.4 km^2 (MAD=0.79 m^3/s) in addition to pumped flow. The assumption was made that the desired scheme would be to store during the weeks where surplus energy for pumping is available (i.e., week 20 to 44) and generate during the other weeks (i.e., week 45 to 19).

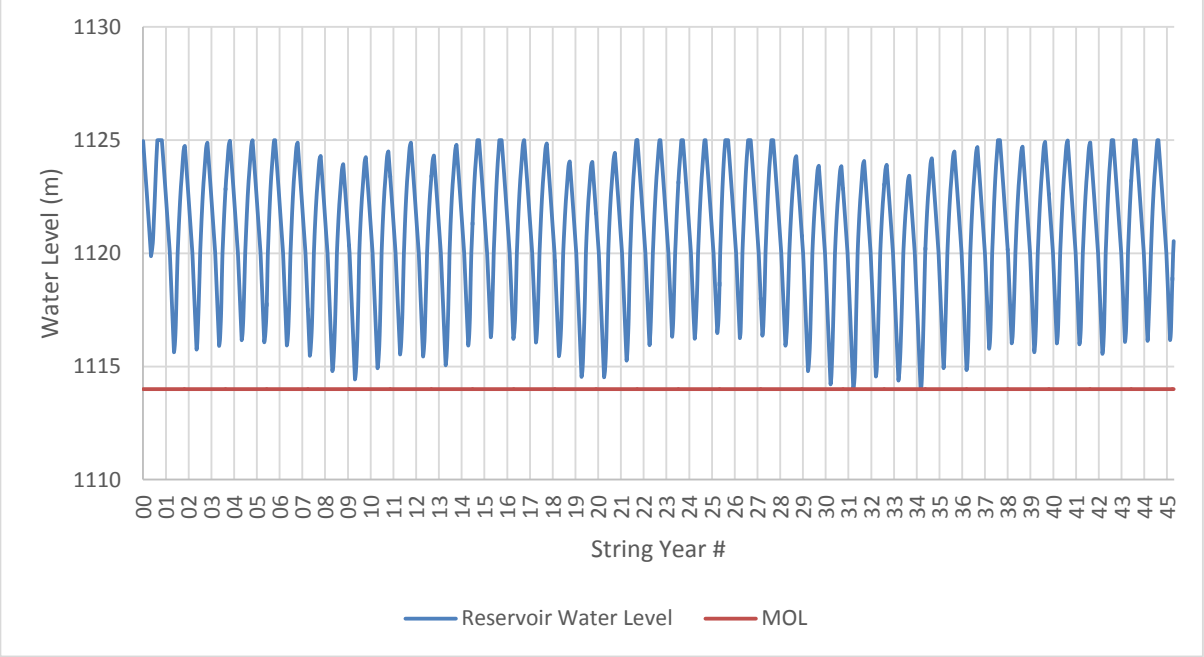
The dam height was optimized to contain most of the summer flows and pumped flows in the reservoir, and use all the storage water for generation while remaining above MOL.

5.3.1 48 GWh Scenario

In the 48 GWh scenario, the available pumping energy is based on the available surplus energy forecast listed in **Table 13**. The estimated FSL of the project is 1,125 m and its gross head is 411.5 m. The generation design flow is assumed at 6 m^3/s and the pumping design flow is estimated at 4.1 m^3/s.

Assuming the available pumping energy remains constant at 48 GWh, the water level at the Project over the 45-year hydrology string is shown in **Figure 12**. Out of the 45-year string, the water at the reservoir is estimated to spill 16 years and draw down to MOL 2 years out of the string.

Figure 12: Pumped Storage – 48GWh Scenario – Water Level



5.3.2 70 GWh Scenario

A second scenario was assessed, which would assume an annual surplus of 70 GWh available for pumping. The intent of this second scenario was to evaluate the potential system performance assuming greater increment generation resources on the YEC system over time. The project described herein does not

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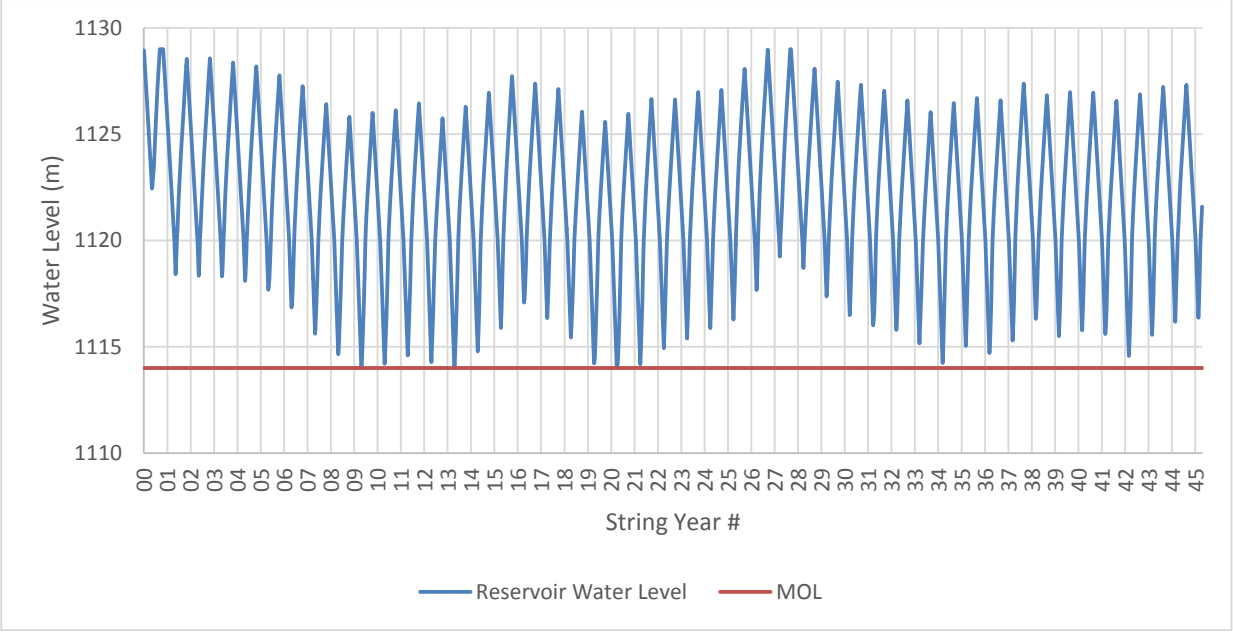
contemplate the infrastructure required for this larger system. The scenario is described here only as the energy potential of a larger scheme.

In the 70 GWh scenario, the available pumping energy is not based on forecast but was rather suggested by YEC. The weekly available energy for pumping was assumed constant from week 20 to 44 (25 weeks) for a total of 70 GWh over the pumping period (2.8 GWh/week). This scenario illustrates the ability to store and generate additional energy at Moon Lake should additional surplus energy for pumping become available in the future.

The estimated FSL of the project is 1,129 m and its gross head is 415.5 m. The generation design flow is assumed at 7.6 m^3/s and the pumping design flow is estimated at 6.2 m^3/s. Assuming the available pumping energy remains constant at 70 GWh, the water level at the Project over the 45-year hydrology string is shown in **Figure 13**. Out of the 45-year string, the water at the reservoir is estimated to spill 2 years and draw down to MOL 3 years out of the string.

Figure 13: Pumped Storage – 70GWh Scenario – Water Level



5.4 Results

As a conventional storage scheme, the project yields an annual winter energy output of 20 GWh from the natural inflows at Moon Lake with a capacity of 7.5 MW.

As a pumped storage scheme with an annual summer pumping energy of 48 GWh, the project yields an annual winter energy output of 54 GWh for a plant capacity of 20.2 MW. The energy yields at Moon Lake for the different surplus energy at a given year are shown in **Table 14**.

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Table 14: Pumped Storage – 48GWh Scenario - Results

Year	Surplus Energy Available for Pumping (GWh)	Diesel Generation to be Displaced (GWh)	Moon Lake Generation (GWh)	Net Diesel Generation (GWh)
2022	48	24	54	-30
2028	39	36	47	-11
2029	35	46	43	3
2030	31	56	40	16

As a pumped storage scheme with an annual summer pumping energy of 70 GWh, the project yields an annual winter energy output of 69 GWh for a plant capacity of 26.1 MW.

In addition, the pumped energy will incur losses through the pumping and the generation process. Overall, the pumped storage scheme roundtrip efficiency is estimated at 70% which includes all losses described in Section 5.1: Inputs and Assumptions.

Average monthly energy yields for the three alternatives are shown in **Table 15**.

Table 15: Monthly Energy Yields (GWh)

Month	Conventional Storage	Pumped Storage (48GWh)	Pumped Storage (70GWh)
Jan	3.3	8.8	11.3
Feb	3.0	8.0	10.2
Mar	3.2	8.7	11.2
Apr	3.0	8.4	10.7
May	1.3	2.7	3.5
Jun	0.0	0.0	0.0
Jul	0.0	0.0	0.0
Aug	0.0	0.0	0.0
Sep	0.0	0.0	0.0
Oct	0.0	0.1	0.2
Nov	3.2	8.1	10.5
Dec	3.3	8.8	11.3
Total Annual	**20**	**54**	**69**

Table 16 summarizes the modeling results for the three alternatives.

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Table 16: Moon Lake Energy Yield Summary

Parameters	Conventional Storage	Pumped Storage (48GWh)	Pumped Storage (70GWh)
FSL (m)	1121	1125	1129
MOL (m)	1114	1114	1114
TWL (m)	713.2	713.5	713.5
Gross Head (m)	407.8	411.5	415.5
Generation Flow (m^3/s)	2.2	6.0	7.6
Pumping Flow (m^3/s)	N/A	4.1	6.2
Capacity (MW)	7.5	20.2	26.1
Annual Pumping Energy (GWh)	N/A	48	70
Annual Energy Output (GWh)	**20**	**54**	**69**

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6 Project Development in British Columbia

6.1 Project Permitting

Water rights in BC are owned by the Crown and are devolved through water licences on a first in line rights basis. A water licence is appurtenant to a neighbouring land parcel.

The development of a waterpower project in BC requires the proponent to secure a water licence and rights to the land base. A well defined process has evolved over the past 15-years which outlines the expectations of provincial regulators prior to the issuance of a waterpower water licence.

In the instance of Moon Lake, this would require a water licence with a Point of Diversion ("POD") on Moon Creek, at the dam site. A second POD would be required under this licence for Tutshi Lake. Finally, a Storage Licence would be required to permit the creation of the reservoir. This process will be complicated by the Commercial Licence to Occupy land tenure in the Moon Lake catchment.

The dam, penstock and powerhouse would be covered under a long term licence of occupation. The bed of the reservoir would likely be covered under a Permit Over Crown Land.

The process to obtain these primary permits requires the preparation of a Project Development Plan. The Development Plan is a key deliverable and contains a detailed description of the project as well as a summary of environmental and hydrological studies. It is submitted as part of the Water Licence application to FrontCounter BC.

The Development Plan must include:

- Introduction, project purpose and description
- Preliminary or conceptual design drawings
- Description of electrical works, to point of grid interconnection
- Description of: staging areas, access roads, fish passage requirements, intake, penstock, powerhouse and tailrace, switchyard and transmission lines, debris management, area flooded
- Elevation/capacity curves, slope stability
- Geotechnical considerations: site geology and any subsurface exploration
- Seismic considerations
- Flooding and erosion concerns
- Complete legal description of affected lands including new roads and transmission lines
- Water *quantity* information including:
    - Period of time and amount of water required
    - Any reserves or restrictions
    - Climatic information
    - Watershed area, aspect and slope
    - All sources of inflow

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  - Flow estimation methodologies, hydrographs, mean annual discharge
  - Flow duration for streams that are not year-round
  - Inflow design flood, design flood water level
  - Return period of design flood
  - Area-Elevation curves
  - Flow estimates of water availability (mass curve and water balance)
- Water *quality* information (e.g. temperature)
- Instream requirements: assessment of fish species, distribution, timing.
- Recreational, aesthetic and cultural uses
- Affected water users downstream
- Construction schedule, methodology and timeframe, including description of how instream work can be done to minimize impacts, engineering review if required
- Downstream consequences of failure, and hazard classification according to Schedule 1 – Dam Safety Regulation
- Operation order or rule, monitoring and record keeping
- Archeological information known, use of environmental monitors
- Labour pool requirements

Site environmental baseline studies are multi-year studies, which are expected to collect baseline data over multiple seasons and several years. Each project is unique and subject to its own data requirements.

After the collection of baseline data and the preparation of the Project Development Plan, a review period of 6-months to a year often passes before the issuance of licence and land tenures.

The Moon Lake project proposes a larger dam with a significant reservoir and would project its zone of impact to Tutshi Lake and below because of the withdrawals of water from that waterbody. For these reasons, we would estimate project permitting costs, for studies, application preparation, process shepherding, and project management to be in the range of $1.0 to $1.5 million.

Because the rated capacity of the Moon Lake Project is less than 50 MW, the project falls below the threshold of review by the Environmental Assessment Office (“EAO”) of the BC Government.

6.2 Development phases

Four phases of development have been assumed for the Project. Below is a brief summary of those phases as well as estimates of project costs that have been assumed for each phase. Those costs have been assumed to be capitalized into the total project cost for the purposes of estimating the LCOE.

The timelines proposed are high level estimates. It is expected that the can be some overlap in the phases – particularly in early stage collection of baseline environmental data. In total, it is expected that, this project, pursued continuously and diligently, would take in the order of 6 years to achieve operations.

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A. **Feasibility and Preliminary Engineering** *(Estimated 1 year)* - The purpose of the Feasibility phase is to study the project to a sufficient level of detail to allow for a go/no-go gate review decision to continue investing and begin the permitting phase of development. Work completed in this phase includes refined assessments of available resources (using site specific gauge data), site investigations, updated design and preliminary engineering, capital cost estimates, and financial modeling. A review of existing data, including environmental assessments done to date, is completed in preparation for the commencement of multi-year field studies. *Budget assumed is $200,000.*

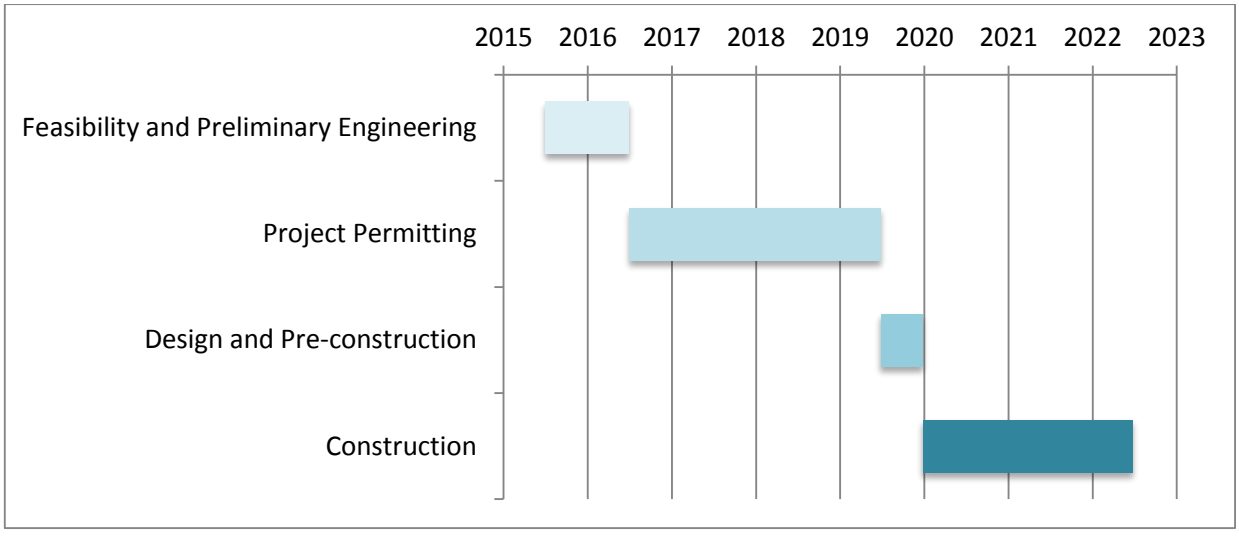
B. **Project Permitting** *(Estimated 2.5-3 years)* - Obtain all licenses, tenures, and other material permits required for construction and commissioning of the project. *Budget assumed is $1.5 million.*

C. **Design & Pre-Construction** *(Estimated 6 months)* - The purpose of Design & Pre-Construction is to prepare the execution of project construction. Work completed in this phase includes contractor selection, negotiation and execution of engineering and construction contracts, submitting for and obtaining all required late-stage permits, ensuring all other required agreements are in place, and completing the design of the project. The construction contractor is readied to initiate work and any long-lead time equipment is selected and ordered as required. *Budget assumed is $500,000. This budget is for preliminary engineering only and does not include the cost of final engineering and design of the project, which has been included within the project capital cost estimates.*

D. **Construction** *(Estimated 2.5 years)* – The Construction phase (the most critical phase) covers the project's construction. Additional tasks also fall into this phase, including continued environmental monitoring, and the execution of the environmental management plan.

The project development schedule is shown in **Figure 14**.

Figure 14: Project Development Phases Schedule



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7 Cost Estimates

Project costs, which are a fundamental input into estimates of the project's LCOE are comprised of upfront capital costs, and ongoing operation costs.

7.1 Project Capital Costs

A capital cost estimate has been developed for the project which is comprised of capitalized development costs, civil construction costs, water to wire equipment costs, transmission and interconnection costs, and capitalized interest costs from the construction period.

It is important to note that at this stage, no estimate was considered for the following project aspects:

1) First Nation consultation, assessments, studies, agreements, royalty payments etc.
2) Archeological assessments
3) Impact benefit assessments
4) Property tax

7.1.1 Project Development Costs

A high level estimate of project development costs was presented in Section 6. These costs are summarized in **Table 17**.

Table 17: Project Development Costs

Development Phase	Cost Estimate ($ 2015)
Feasibility and Preliminary Engineering	$200,000
Project Permitting	$1,500,000
Design and Pre-construction	$500,000
TOTAL	**$2,200,000**

7.1.2 Civil Construction Costs

Kawa Engineering ("Kawa") was retained to develop a civil capital cost estimate and corresponding bill of quantity.

The estimate was specified as a Class 5 estimate, per the standardized AACE International Cost Estimate Classification System. A Class 5 estimate is intended for concept screening and represents a level of project

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definition of 0% to 2%. The expected low accuracy ranges from -20% to -50% and the high accuracy ranges from +30% to +100%.[7]

Kawa prepared the cost estimate using a combination of quantity estimates for the large, significant project components such as the dam and penstock etc., and used a parametric relationships for the balance of the plant. A summary of the Kawa cost estimate is presented in **Table 18**.

Table 18: Summary of Civil Capital Costs

Project Component	Cost Estimate ($M 2015)
General Cost[8]	$32.7
Dam (Earthworks, Grouting, Spillway)	$55.9
Diversion	$1.0
Intake	$1.1
Powerhouse Civil	$5.5
Penstock	$43.6
Switchyard – Civil Works	$2.0
Roads	$1.3
Total Civil Works Cost	**$143.1**

The detailed bill of quantity from Kawa is presented in Appendix B: Generating Facility Capital Cost Estimate.

7.1.3 Generating Equipment Costs

The cost estimate for the turbine, generator and associated balance of plant was estimated based on previous delivered equipment for projects in BC. These are summarized in **Table 19**.

Table 19: Summary of Generating Equipment Costs

Project Component	Cost Estimate ($M 2015)
Turbine and Generator	$5.5
Pumps with variable frequency drives	$5.0
Balance of plant	$3.5
Total Generating Equipment Cost	**$14.0**

[7] AACE International Recommended Practice No. 17R-97

[8] General costs include mobilization and demobilization, reservoir clearing, engineering, miscellaneous metals, contractor's insurance, permits, land use and survey.

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An inquiry was initiated with equipment supplier, Andritz, who have significant experience in the smaller hydro space as well as with pumped storage equipment. At the time of this report, response was still outstanding.

7.1.4 Transmission Line and Interconnection Costs

The estimated cost for the transmission is $2.3 million and is based on the sub-marine cable cost estimate. The transmission line costs were estimated based on parametric assumptions based on previous similar operating voltage projects in BC, taking into account the voltage and capacity of the line.

The main step-up transformer, disconnects and circuit breakers for the switchyard plant was been assumed to be $500,000 installed.

Transmission and interconnection costs are summarized in **Table 20**.

Table 20: Transmission and Interconnection Cost Estimate

Project Component	Cost ($M)
Transmission Line	$2.3
Switchyard Electrical	$0.5
Total Tx and Interconnection Costs	**$2.8**

7.1.5 Owner's Costs During Construction

Certain costs will be incurred be the owner during the construction period. These include onsite administration and overhead, engaging the Independent Engineer and Independent Environmental Monitor, as required under water licencing regulations, and funding ongoing compliance monitoring during construction.

The estimate of these costs are provided in **Table 21**.

Table 21: Owners Costs During Construction

Project Component	Cost ($M)
Administration and Overhead	$0.5
Land Tenure Surveys	$0.2
Compliance Monitoring	$0.2
Independent Engineer	$0.4
Independent Env. Monitor	$0.8
Total Owners Costs During Construction	**$2.1**

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7.2 Capital Cost Summary

The total estimated project capital cost estimate, exclusive of contingency, for the 48 GWh pumped storage scenario is show in **Table 22** below. A project contingency of 20% of capital costs exclusive of owner's costs has been added at this time and interest during construction estimated assuming a 2-year construction term, with 100% debt finance at the blended cost of capital of 5.45%.

Table 22: Project Capital Cost Estimate

Project Component	Cost ($M)
Project Development	$2.2
Civil Construction Costs	$143.1
Generating Equipment Costs	$14.0
Transmission and Interconnection Costs	$2.8
Owners Costs During Construction	$2.1
Total Project Capital Cost	**$164.2**
Contingency	$32.0
IDC	$21.4
Grand Total Project Capital Cost	**$217.6**

For comparison purposes, a high level capital cost estimate for the conventional storage and the 70 GWh pumped storage options was extended from the 48 GWh alternative cost estimate. This was achieved by scaling the quantity estimates and unit costs from the 48 GWh alternative based on dam height, penstock diameter, reservoir size and installed capacity. A summary of the cost estimates for the conventional storage and the two pumped storage options (48 GWh and 70 GWh) is shown in **Table 23**.

Table 23: Project Options Capital Cost Estimate

Project Component	Conventional Storage ($M 2015)	Pumped Storage 48GWh ($M 2015)	Pumped Storage 70GWh ($M 2015)
Project Development	$2.2	$2.2	$2.2
Civil Construction Costs	$105.1	$143.1	$169.1
Generating Equipment Costs	$5.0	$14.0	$22.1
Transmission and Interconnection Costs	$2.8	$2.8	$2.8
Owners Costs During Construction	$2.1	$2.1	$2.1
Total Project Capital Cost	**$117.2**	**$164.2**	**$198.2**
Contingency	$22.6	$32.0	$38.8
IDC	$15.2	$21.4	$25.8
Grand Total Project Capital Cost	**$155.0**	**$217.5**	**$262.9**

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7.3 Operating Costs

Project operating costs are categorized into the general operating and maintenance expenses in running and maintaining the plant and indirect and overhead costs associated with plant operations. The O&M expenses arise from labour costs for plant operators, minor spare parts, consumable supplies, and contract labour for irregular maintenance activities. Other direct operating costs comprise water rental and land lease fees to the BC government. Indirect operating costs include overhead and administration costs, insurance etc.

Finally, a fixed annual contribution to a Major Maintenance Reserve Account ("MMRA") is assumed for sustaining capital investments and is intended to account for semi-regular major maintenance items that are expected over the life of the plant.

All costs are stated in $2015.

The general O&M cost is estimated based on an assumed labour pool of 2 full time equivalent operators and an allowance for expenses, consumable supplies and contract labour. It is assumed that operating labour will be staffed by YDC and appropriate shift coverage will be allocated across plants. **The all in cost is estimated to be $400,000**.

An MMRA deposit of $75,000 is assumed to be adequate for covering major maintenance items.

The annual water rental rates associated with power production are estimated based on published rates established by the BC government. As of 2015, rates are assessed for both the installed capacity of the plant and the actual energy generated. Further, there is a rental rate for water storage. Land costs have been estimated based on published rates. The rates and project costs are summarized in **Table 24**.

Table 24: Provincial Resource Fees

Resource	Rate ($2015)	Project Cost $2015
Water Rental – Capacity Charge	$4.334 / kW	$90,000
Water Rental – Energy Charge	$1.301 / kWh	$70,000[9]
Water Rental – Storage Charge	$0.01 / 1000 m^3	$1,000
Permit over Crown Land - Dam	$120 / ha.	$1,000
Permit over Crown Land – Flooded Reservoir	$7.50 / ha.	$5,000
Land Lease – Powerhouse	Based on land value	$500
ROW - Penstock	Based on land value	$500
ROW – Transmission Line	Based on land value	$500
Total Resource Fees – Operating Cost		**$168,500**

[9] This assumes a plant output of 24 GWh, which is the forecasted energy deficit for 2022. The cost is variable from year to year depending on the amount of energy actually generated at the plant.

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Management, administration and overhead cost is assumed to be $250,000/year. Insurance, using a premium based on $3 per $1,000 of constructed cost, is assumed at $500,000/year. Finally, it is assumed that the project will attract property tax at the assumed rural mill rate of $2.87 per $1000 of assessed value, which equals $500,000. The resulting estimated annual operating cost associated with the project is summarized in **Table 25**.

Table 25: Project Annual Operating Costs

Component	Cost ($2015)
General O&M	$400,000
Major Maintenance Allowance	$75,000
Provincial Resource Fees	$168,500
Management, Administration and Overhead	$250,000
Insurance	$500,000
Property Tax	$500,000
Total Annual Operating Cost	**$1,893,500**

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8 Financial Modeling

8.1 LCOE

In the 2011-2030 Resource Plan YEC defined the LCOE as:

> *"LCOE indicates on a consistent and comparable basis each option's overall costs per kWh. It includes capital and operating costs and, where specified, any related transmission, storage or capacity costs. This cost is subject to ongoing annual inflation for each subsequent year of operation in order to assess costs over the option's economic life."*[10]

The LCOE is calculated as follow:

$$LCOE = \frac{Present\ Value\ of\ Costs}{Present\ Value\ of\ Energy\ Output}$$

The Project LCOE was calculated for the 48 GWh pumped storage scenario and is described in the following sections.

8.2 Assumptions

The following economic assumptions were used to calculate the Project LCOE:

1) Blended cost of capital: 5.45%;
2) Inflation: 2%;
3) Real Discount Rate: 3.38% based on blended cost of capital and inflation rate from the RFP. LCOE discounts both costs (numerator) and energy (denominator) using the Real Discount Rate; and
4) Life Span: 65 years.

8.3 Full Utilization LCOE

The full utilization LCOE assumes constant pumping energy and constant load profile. It implies that the Yukon will install new generation (wind or hydro) to maintain the amount of available low cost summer energy for pumping as the energy load increases. It also implies that the full energy output at Moon Lake is generated every year for the life of the project and that all energy is consumed.

The project Full Utilization LCOE is $0.189/kWh.

[10] Source Details: Yukon Energy Corporation, "20-Year Resource Plan: 2011-2030", December 2011, p. 67

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8.4 LCOE Sensitivity Analysis

The LCOE is directly related to the actual usable energy from the project. Because the YEC grid is islanded from other load jurisdictions, the utilization of the Moon Lake project is dependent on both the surplus energy from the YEC system that is available energy for pumping, as well as the system load that can ultimately be served from the reciprocal generation. Further, the surplus energy and load balance will change over time, depending of the planning forecast of the system.

The LCOE estimate was based on a 65-year project life, which, while appropriate for a long-lived asset such as a hydroelectric plant, is beyond the planning horizon of YEC. In order to estimate the sensitivity of the Moon Lake project to differing scenarios of surplus energy and load, a sensitivity analysis was performed for the Project LCOE by simply adjusting plant capacity factors ranging from 60% to 100% as shown in **Table 26**.

The capacity factor represents the plant utilization over the generation period. The 100% capacity factor scenario is the base case scenario for which the energy yield were estimated in this report.

Table 26: LCOE Sensitivity Analysis

Capacity Factor	Full Utilization Generation (GWh)	NPE (GWh)	NPV ($M 2015)	LCOE (S/kWh)
100%	54.0	1,412.8	267.5	0.189
90%	48.6	1,271.5	267.3	0.210
80%	43.2	1,130.2	267.2	0.236
70%	37.8	989.0	267.0	0.270
60%	32.4	847.7	266.8	0.315

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9 Results and Recommendations

9.1 Results

As shown in **Table 27**, as a conventional storage scheme, the Project yields 20 GWh of winter energy. As a pumped storage scheme, the Project yields 54 GWh of winter energy with 48 GWh of available pumping energy, or 69 GWh with 70 GWh of available pumping energy.

Table 27: Moon Lake Energy Yield Summary

Parameters	Conventional Storage	Pumped Storage (48 GWh)	Pumped Storage (70 GWh)
FSL (m)	1,121	1,125	1,129
MOL (m)	1,114	1,114	1,114
TWL (m)	713.2	713.5	713.5
Gross Head (m)	407.8	411.5	415.5
Generation Flow (m^3/s)	2.2	6.0	7.6
Pumping Flow (m^3/s)	N/A	4.1	6.2
Capacity (MW)	7.5	20.2	26.1
Annual Pumping Energy (GWh)	N/A	48	70
Annual Energy Output (GWh)	**20**	**54**	**69**

A breakdown for estimated cost estimate exclusive of contingency for the 48 GWh pumped storage scenario is show in **Table 28**.

Table 28: Project Capital Cost Estimate

Project Component	Cost ($M)
Project Development	$2.2
Civil Construction Costs	$143.1
Generating Equipment Costs	$14.0
Transmission and Interconnection Costs	$2.8
Owners Costs During Construction	$2.1
Total Project Capital Cost	**$164.2**
Contingency	$32.0
IDC	$21.4
Grand Total Project Capital Cost	**217.6**

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The estimated yearly cost associated with the projects are shown in **Table 29**.

Table 29: Project Annual Operating Costs

Component	Cost ($2015)
General O&M	$400,000
Major Maintenance Allowance	$75,000
Provincial Resource Fees	$168,500
Management, Administration and Overhead	$250,000
Insurance	$500,000
Property Tax	$500,000
Total Annual Operating Cost	**$1,893,500**

The project full utilization LCOE is $0.189/kWh.

9.2 Recommendations

Several existing rights have been identified at the project site and its vicinity. A detailed investigation of the current and future existing rights is recommended to identify potential development barriers.

If a decision is made to study the project further, first and foremost, it is strongly recommended that YEC prepare and submit a Water Licence Application from Front Counter BC to secure first-in-line rights to the water. Subsequent to this, the following steps, field studies and data collection programs are recommended:

1) Prepare a submit a **water licence application** to Front Counter BC so as to secure first-in-line water rights to the project ahead of other potential claimants. British Columbia recognizes the rights to water on a first come, first serve basis. Several existing rights have been identified at the project site and its vicinity. Prior to advancing the project further, a detailed investigation of the current and future existing rights is recommended to identify potential development barriers.
2) Project preliminary engineering and design can be further advanced with greater precision topography, obtained with a **LIDAR survey**. This survey is recommended to refine the design and quantity cost estimate. The LIDAR survey area should comprise the dam site, the penstock route, suggested at 200 m each side of the proposed penstock alignment, and the powerhouse site. The estimated area of study is 3.5 km^2 (See **Figure 15**).
3) A **geotechnical investigation** program is recommended to assess the foundation conditions of the dam and powerhouse as well potential anchor block locations at select major bends along the penstock alignment (See **Figure 16**).

   During early stage project definition and development, seismic refraction lines present a cost effective alternative to estimate overburden thickness without incurring the cost of mobilization of

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drilling rigs across Tutshi Lake and into the upper Moon Lake watershed. Two seismic lines are recommended at the dam site: one along the dam axis and one perpendicular to the dam axis at the maximum dam height. Two lines are suggested along the penstock near route and two at the powerhouse. As project certainty is achieved, greater expenditure for project definition is justified and the results from the seismic analysis can be confirmed with boreholes.

Boreholes are indicated at the powerhouse location because of the importance of better characterizing the construction excavation conditions adjacent to Tutshi Lake as well as characterizing the rock quality at the powerhouse. Further, boreholes are an important along the dam foundation, not only to characterize the depth to bedrock, but to also investigate the rock quality and permeability in order to plan dam foundation treatment. As such, the dam boreholes should extend into bedrock to a depth commensurate with the dam height and include in situ permeability testing of the rock. Location of the boreholes should be determined once greater resolution mapping becomes available.

Finally, a dedicated site investigation to secure and confirm a source pit for the material for construction or the dam is recommended to be included with any geotechnical programme.

Figure 15: Recommended LiDAR Survey Area

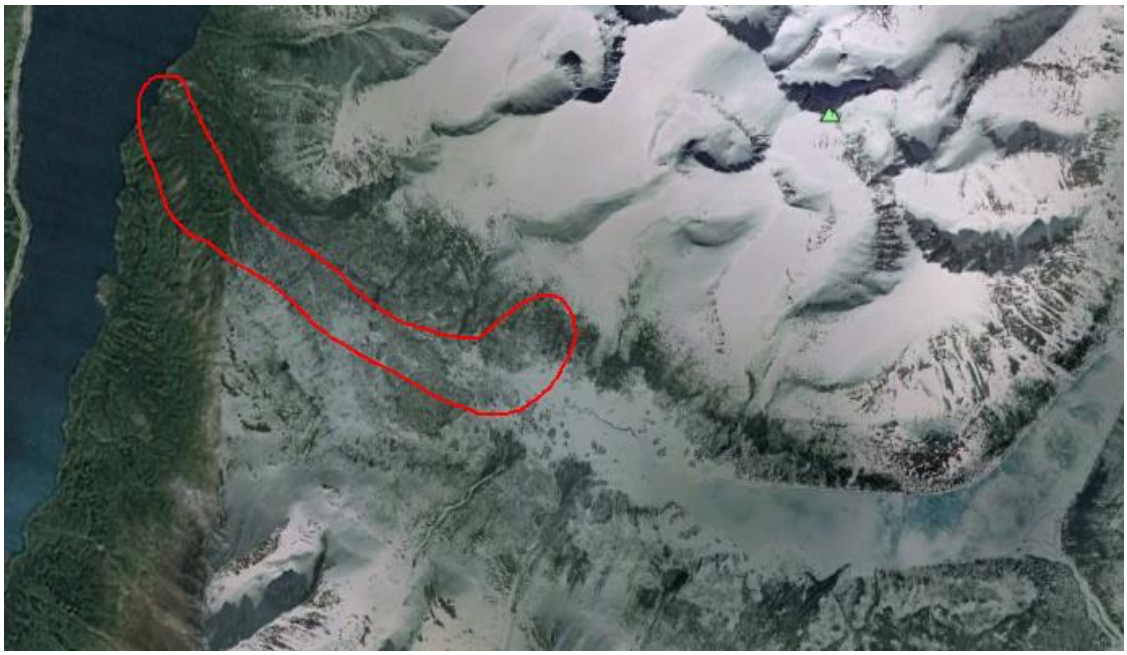

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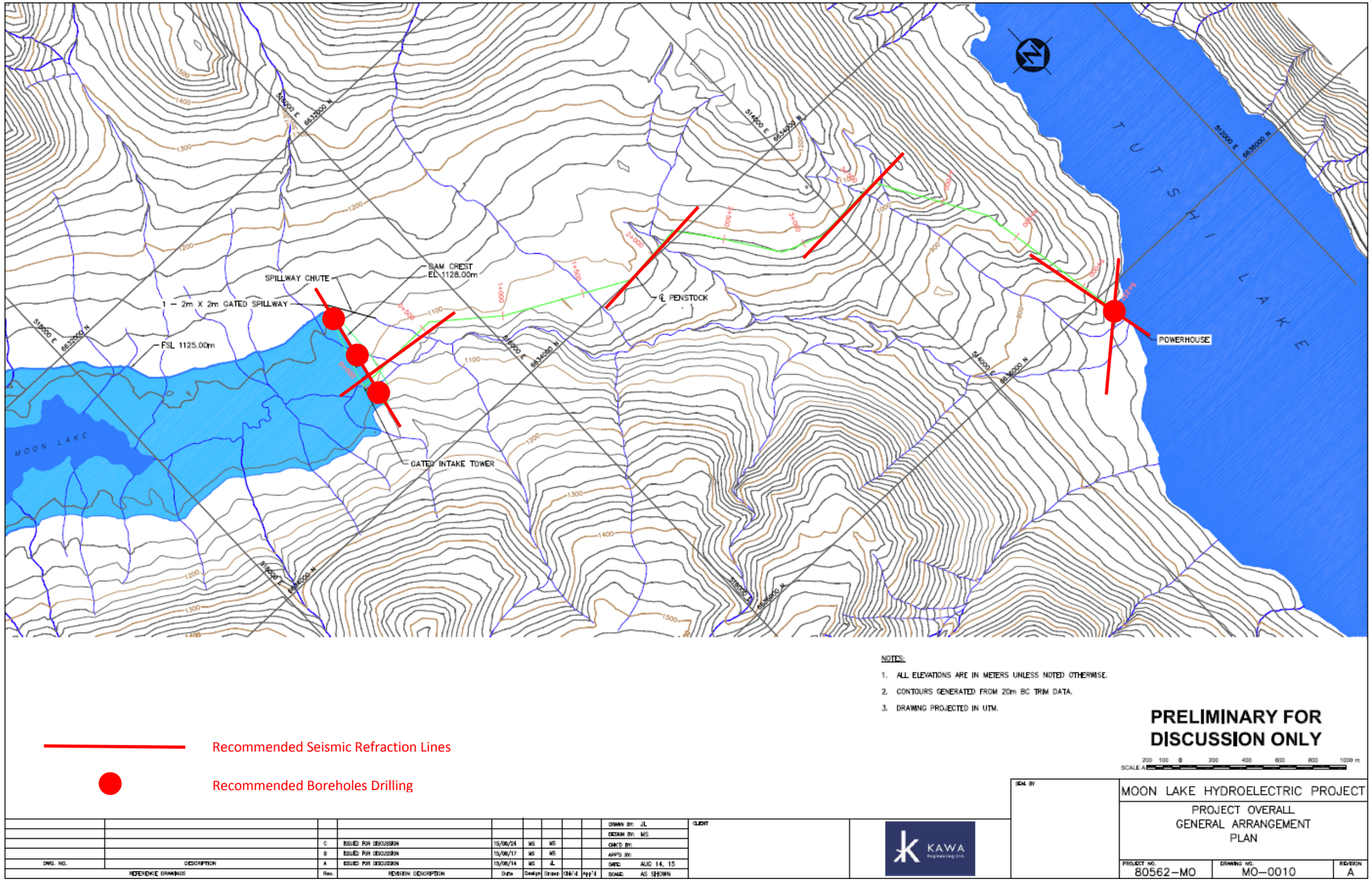
Figure 16: Recommended Seismic Refraction Line and Boreholes Drilling



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Appendix A: Geotechnical Memo

A geotechnical memo about the observation and conclusion from previous studies review and the June 24th site visit is included in the section.

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Memorandum

To:	Michael Potyok	**From:**	Stephen Morison, M.Sc., P.Geol. Irwin Wislesky, P.Eng.
Company:	MIDGARD Consulting Inc.		
cc:		**Date:**	December 18, 2015
Subject:	***FIELD SITE REPORT FOR THE PROPOSED MOON LAKE HYDRO PROJECT***		

1.0 INTRODUCTION

Midgard Consulting Inc. (Midgard) retained SLR Consulting (Canada) Ltd. (SLR) to assist them in providing a geotechnical/geological assessment with regards to design and construction of an earth fill dam near the outlet of Moon Lake. Moon Lake is located about 100 km south of Whitehorse in British Columbia, just south of the Yukon border.

The purpose of constructing a dam across the outlet of Moon Lake is to provide additional water storage capacity within the Moon Lake Basin for winter hydro-power production. The intention is to pump water from Tutshi Lake into Moon Lake during the summer months when there is excess water and store it there until the winter when water availability for hydro-power is limited and demand is high.

SLR's scope of work for this project included a review of existing documentation and participation in a reconnaissance site visit by helicopter. The site visit took place on June 24, 2015 along with Michael Potyok and Anna Le of Midgard and Glen Ichikawa of Kawa Engineering. The information provided for review included the following documents:

- KGS Group draft report to Yukon Energy on the Assessment of Potential Hydroelectric Sites, Conceptual Study, dated February 2008.
- KGS Group Draft Memorandum to Gord McPhail Re: Summary of site inspection and Terrain Assessment for the Moon Lake Site, Northern British Columbia, dated February 14, 2008.
- Klohn-Crippen report to Yukon Electrical Company Ltd. titled, "Moon Lake Hydroelectric Project, Layout Report (Report No. KCCL-106, dated January 1992.
- Moon and Tutshi Hydroelectric Projects, General Arrangement Plan, by HDR for Peter Kiewit Infrastructure Co., October 31, 2011, DWG 172193-G-0001 Revision A.
- Moon and Tutshi Hydroelectric Projects, Earthworks quantities, by HDR for Yukon Energy, October 31, 2011

2.0 SITE VISIT

Prior to the site visit, the information provided by Midgard was reviewed to gain a general appreciation of the site conditions and to plan the field visit. There are no roads to the site, thus the site was accessed by helicopter from Whitehorse. The field visit included:

- Aerial tour of Moon Lake and the surrounding catchment;
- Aerial view along the outlet channel from Moon Lake down to Tutshi Lake;
- Aerial view in the likely area for the proposed powerhouse near the shore of Tutshi Lake, by the outflow from Moon Lake;
- Aerial view along Tutshi Lake and the outlet stream into Tagish Lake and one stop on land downstream of Moon Lake where extensive bedrock outcropping was observed; and
- Two landings downstream of Moon Lake to traverse and view ground conditions at potential dam locations and one upstream of Moon Lake along one of the tributaries that flow into Moon Lake.

During the site visit several photographs were taken and approximate GPS coordinates/ elevations were recorded to mark key features and elevations.

2.1 Visual Site Description

The area can generally be characterized as mountainous with glaciated valleys having a variety of glacially related landforms over bedrock. Moon Lake is located within a broad U-shaped valley that is flanked by high elevation mountainous terrain. The area of the outflow channel from Moon Lake and several hundred metres downstream appears to be dominated by a wetlands with a thicker surface organic layer that may have been an infilled section of the lake basin composed of alluvial material. Bedrock outcrops are evident a few hundred metres downstream of Moon Lake becoming more frequent down gradient from Moon Lake. It appears that the stream to Tutshi Lake is generally bedrock controlled. Glaciofluvial features also appear to be evident down the valley from Moon Lake to Tutshi Lake where there are high banks of exposed gravelly sediments. This material is a possible source of both fine and course dam construction fill (to be verified).

2.2 Possible Dam Locations

Three possible locations have been previously identified by others for a dam near the outlet of Moon Lake. One is at the lake outlet; a second is located about 800m downstream and; a third is located about 1300m downstream in an area where bedrock outcropping is predominant. During this site reconnaissance, the downstream area was flown over to view the outcrops and general ground conditions. Scattered bedrock outcroppings were observed a few hundred metres downstream of the Moon Lake outlet along with the occasional overburden knoll rising a few metres above the generally flat terrain. From these observations it appears that bedrock is generally located at shallow depth but could be quite variable and is likely at greater depth near the lake. The stream flow near Moon Lake (within 1 km) is shallow and meandering, with the stream bottom covered in gravel, indicating possible shallow bedrock. The quality of the bedrock was difficult to assess, however bedrock was highly fractured where exposed in the stream.

Several considerations must be evaluated prior to selecting the optimum location for the dam and these include the following:

- The height of the required dam will be greater the farther it is from Moon Lake because of an increase in the catchment area and the drop off in the ground level.
- The elevation requirement for the dam and ultimate lake level may be lower, the farther the dam is from Moon Lake because of the greater area available for storage.
- Additional streams can enter Moon Lake and add to the catchment the further downstream the dam is located (this may not be important if pumping water into Moon Lake during the summer is considered free).
- If bedrock is relatively shallow, the depth of cut-off required may not be significantly different between locations suggesting the location providing the shortest and least height (least fill volume) might be the best (from a strictly geotechnical perspective).
- The location for the dam should take into consideration a spillway within bedrock at one of the abutments.

From the site visit and review of the data, the preliminary recommendation for the dam location is in the area near the first bedrock exposure downstream of the lake (see photo below). This site was selected because of bedrock outcrops and an apparent rise in the ground level on both sides of the stream which could minimize excavation as well as fill materials required to construct the dam. In addition, the ground level has not dropped off significantly at this point from Moon Lake.

Proposed Dam Location (red line). Easterly view towards Moon Lake.

2.3 Geological Hazards and Construction Considerations

A detailed assessment of geologic hazards has not been carried out for this study, however during the field investigation no major hazards were observed. However, given the location of the Moon Lake site and the high elevation setting, possible effects from earthquake must be considered in the design of the dam including foundation stability and the possible consequences of a failure. This would require a surface and subsurface assessment of the bedrock including lithology, faulting, depths and subsurface profiles, distribution, thickness and genesis of surficial geological landforms, permafrost characteristics and other features such as organic landforms. There are other factors that will need to be integrated into the planning of this facility including local climate characteristics such as snow depth, hydrology, storm events and other natural events.

Construction in this area will likely involve issues such as excavation in discontinuous permafrost, a short construction season, frozen overburden that must be thawed prior to use as fill, bedrock grouting where frozen rock and possible ice lenses occur, dewatering, water diversion and restricted access for equipment and supplies. Clear logistics planning and scheduling will be required to facilitate construction of the dam and ancillary features.

3.0 CONCLUSIONS AND RECOMMENDATIONS

This assessment has been based primarily on a short aerial field tour and review of reconnaissance level information. Of primary importance is the need for better ground survey data since the contour accuracy from existing topographic maps that are available are not sufficient to accurately establish a location, length and volume of the dam. Once this has been made available, several seismic lines could be investigated to establish depth of bedrock along preferred locations. This could be followed by a drilling investigation to confirm overburden depths and the bedrock profile and condition along the dam alignment, as well as investigate possible borrow materials for dam construction.

4.0 CLOSURE

SLR trusts that this report suitably provides the preliminary site assessment requested by Midgard. Please contact the undersigned to discuss any of the issues raised in this document or your needs with respect to the next phase of this project. It has been a pleasure working with you on this most interesting project and hope to be of continued service in the near future.

Yours very truly,

Irwin Wislesky, P. Eng.
Technical Director, Tailings and Mine Waste

Stephen Morison, M.Sc., P.Geol.
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MIDGARD

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Appendix B: Generating Facility Capital Cost Estimate

The detailed cost estimate for the dam, intake, spillway, penstock, switchyard, powerhouse and appurtenances is included in this section.

MIDGARD CONSULTING INC.

MOON LAKE PROJECT

SCHEDULE OF QUANTITIES
DATE: 09/21/2015
REVISION: B

ITEM NO.	DESCRIPTION	UNIT	QUANTITY	UNIT PRICE	AMOUNT	NOTES
1000	**GENERAL AND MISCELLANEOUS**					
1001	MOBILIZATION & DEMOBILIZATION	% of total	1	$ 11,000,000.00	$ 11,000,000	ASSUMED 10% OF SUBTOTAL, INCLUDES BARGE LANDING AND CAMP
1002	RESERVOIR CLEARING AND GRUBBING	m^2	3,500,000	$ 1.00	$ 3,500,000	LAKE AREA PROVIDED AS 3.46 km^2
1003	ENGINEERING SERVICES FOR DETAILED DESIGN AND CONSTRUCTION SUPERVISION	% of total	1	$ 8,800,000.00	$ 8,800,000	ASSUMED 8% OF SUBTOTAL
1004	FISH LADDER AND MISCELLANEOUS METALS (RAILINGS, LADDERS ETC.)	% of total	1	$ 5,600,000.00	$ 5,600,000	ASSUMED DENIL TYPE FISH LADDER
1005	CONTRACTORS INSURANCE	% of total	1	$ 440,000.00	$ 440,000	ASSUMED 0.4% OF SUBTOTAL
1006	PERMITS	% of total	1	$ 2,800,000.00	$ 2,800,000	ASSUMED 2.5% OF SUBTOTAL
1007	SURVEYING	% of total	1	$ 550,000.00	$ 550,000	ASSUMED 0.5% OF SUBTOTAL
1008	PERMINANT ACCESS ROAD	km	8.6	$ 150,000.00	$ 1,290,000	ASSUMED TO GENERALLY FOLLOW PENSTOCK ROUTE
2000	**DAM STRUCTURE COMPONENTS**					
2100	**DAM EARTHWORKS**					
2101	DAM SITE CLEARING AND GRUBBING	m^2	130,000	$ 1.50	$ 195,000	INCLUDES AREA REQUIRED FOR DAM, COFFER DAMS, AND DIVERSION SYSTEM.
2102	EXCAVATION - ROCK	m^3	58,000	$ 48.00	$ 2,784,000	
2103	EXCAVATION - SOIL MATERIALS	m^3	180,000	$ 9.00	$ 1,620,000	
2104	EMBANKMENT FILL SUPPLY, HAULING AND COMPACTED	m^3	650,000	$ 45.00	$ 29,250,000	
2105	FILTER SAND SUPPLY, HAULING AND COMPACTION	m^3	16,000	$ 54.00	$ 864,000	
2106	GRAVEL FILTER SUPPLY, HAULING AND COMPACTION	m^3	170,000	$ 30.00	$ 5,100,000	
2107	RIPRAP SUPPLY, HAULING AND PLACED	m^3	58,000	$ 25.00	$ 1,450,000	INCLUDES UPSTREAM FACE OF DAM AND PERIMETER AT BASE OF DAM
2200	**DAM GROUTING**					
2201	FOUNDATION TREATMENT	LUMP SUM	1	$ 13,000,000.00	$ 13,000,000	APPROXIMATED AS 30% OF DAM EARTHWORKS AND CONCRETE, INCLUDES GROUTING AND DRAIN HOLES
2300	**SPILLWAY**					
2301	CLEARING AND GRUBBING	m^2	900	$ 0.60	$ 540	
2302	EXCAVATION - ROCK	m^3	1,200	$ 48.00	$ 57,600	
2303	EXCAVATION - SOIL MATERIALS	m^3	1,200	$ 9.00	$ 10,800	
2304	CONCRETE	m^3	580	$ 2,500.00	$ 1,450,000	INCLUDING FORMWORK AND REBAR
2305	GATES	LUMP SUM	1	$ 160,000.00	$ 160,000	INCLUDES GUIDES AND HOIST, TRANSPORTATION, INSTALL
3000	**DIVERSION SYSTEM / SLUICEWAY / LOW LEVEL OUTLET**					
3001	GATE	LUMP SUM	1	$ 600,000.00	$ 600,000	COST INCLUDES TWO GATES TO BE USED FOR DIVERSION AND AS SLUICEWAY
3002	CONCRETE	m^3	110	$ 2,500.00	$ 275,000	INCLUDING FORMWORK AND REBAR
3003	PIPE WYE	LUMP SUM	1	$ 100,000.00	$ 100,000	
3004	PIPE TEE	LUMP SUM	0	$ -	$ -	INCLUDED IN INTAKE TOWER QUANTITIES
4000	**INTAKE & RELATED WORKS**					
4001	EXCAVATION - ROCK	m^3	0	$ 48.00	$ -	INCLUDED IN DAM QUANTITIES
4002	EXCAVATION - SOIL MATERIALS	m^3	0	$ 9.00	$ -	INCLUDED IN DAM QUANTITIES
4003	HEAD GATES	LUMP SUM	1	$ 300,000.00	$ 300,000	INCLUDES GUIDES AND HOIST, TRANSPORTATION, INSTALL
4004	TRASHRACKS	LUMP SUM	1	$ 96,000.00	$ 96,000	INCLUDES SUPPLY AND INSTALL
4005	TOWER AND BRIDGE	LUMP SUM	1	$ 640,000.00	$ 640,000	INCLUDES SUPPLY AND INSTALL
4006	MISC. SYSTEMS (RACK CLEANER, CONTROL SYSTEMS, CORROSION PROTECTION)	LUMP SUM	1	$ 40,000.00	$ 40,000	APPROXIMATED AS 10% OF TOTAL INTAKE WORKS
5000	**POWER HOUSE WITH AUXILIARY EQUIPMENT AND TAILRACE**					
5001	EXCAVATION - ROCK	m^3	5,500	$ 48.00	$ 264,000	ASSUME 25% SOIL CUT, 75% ROCK CUT, INCLUDES TAILRACE
5002	EXCAVATION - SOIL MATERIALS	m^3	1,900	$ 9.00	$ 17,100	ASSUME 25% SOIL CUT, 75% ROCK CUT, INCLUDES TAILRACE
5003	CONCRETE	m^3	1,100	$ 2,500.00	$ 2,750,000	ASSUMED SOFT ROCK FOUNDATION
5004	SUPERSTRUCTURE (STEEL STRUCTURE, WALLS, AND ROOFING)	LUMP SUM	1	$ 2,500,000.00	$ 2,500,000	ASSUMED PREENGINEERED BUILDING
5005	TURBINE, TIV AND GENERATOR	LUMP SUM	1	$ -	$ -	PRICE PROVIDED BY OTHERS
5006	PUMP	LUMP SUM	1	$ -	$ -	PRICE PROVIDED BY OTHERS
5007	BALANCE OF PLANT	LUMP SUM	1	$ -	$ -	40% OF TURBINE, TIV AND GENERATOR
5008	OTHER (CRANE, HVAC, WATER SYSTEMS, ROCK ANCHORS, MISC METALS) AS % OF PH COSTS	LUMP SUM	1	$ -	$ -	5% OF TURBINE, TIV AND GENERATOR
6000	**PENSTOCK**					
6001	PENSTOCK	TONNES	2,000	$ 12,000.00	$ 24,000,000	INCLUDES TRANSPORTATION, WELDING, COATING

MIDGARD CONSULTING INC.

MOON LAKE PROJECT

SCHEDULE OF QUANTITIES
DATE: 09/21/2015

REVISION: B

ITEM NO.	DESCRIPTION	UNIT	QUANTITY	UNIT PRICE	AMOUNT	NOTES
6002	EXCAVATION - ROCK	m^3	200,000	$ 48.00	$ 9,600,000	ASSUME 75% SOIL CUT, 25% ROCK CUT
6003	EXCAVATION - SOIL MATERIALS	m^3	64,000	$ 9.00	$ 576,000	ASSUME 75% SOIL CUT, 25% ROCK CUT
6004	BACKFILL	m^3	120,000	$ 24.00	$ 2,880,000	PRICE IS BASED ON WEIGHTED AVERAGE OF DIFFERENT MATERIALS
6005	ANCHOR BLOCK CONCRETE	m^3	2,500	$ 2,500.00	$ 6,250,000	
6006	SURGE SHAFT	TONNES	24	$ 12,000.00	$ 288,000	
7000	**SWITCHYARD**					
7001	SWITCHYARD	LUMP SUM	1	$ 2,000,000.00	$ 2,000,000	ASSUMED $100,000/MW
	SUBTOTAL				$ 110,000,000	INCLUDES ALL ITEMS EXCEPT THOSE IN SECTION 1000
	TOTAL CONSTRUCTION COST				**$ 150,000,000**	

Appendix 5.18
Faro Mine Pumped Storage Conceptual Assessment (EMC2 and Picacho and Associates 2015)

EMC² PICACHO ASSOCIATES

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TECHNICAL MEMORANDUM

To: Marc-Andre Lavigne
Yukon Energy Corporation
Box 5920, 2 Miles Canyon Road
Whitehorse, YT Y1A6S7

Project 1355-1

From: Stephen Taylor, P.E., EMC²-Picacho

Date: March 10, 2016

Subject: Faro Mine Pumped Storage
Conceptual Assessment of Seasonal Pumped Storage Power Facilities at the Faro Mine Complex

Introduction

In response to a series of discussions with Yukon Energy Corporation (YEC) in June 2015, EMC²-Picacho proposed a scope of work to YEC to perform a high-level assessment of the economics, social acceptability, regulatory requirements; environmental impacts; geotechnical issues; and geographic/geological attractiveness of a pumped storage facility at the Faro Mine. The purpose was to provide YEC with information to support and inform their decision-making process for further research into, or elimination of, the Faro Mine Complex area for consideration for potential pumped storage project development. This high-level study relied on:

- The judgment of experienced individuals;
- Existing industry cost databases developed for hydro power projects; and
- EMC²-Picacho's own cost databases.

In September 2015, EMC²-Picacho's Stephen Taylor and Joe Flynn met with YEC representatives in Whitehorse and travelled to the Faro Mine for a site visit and for an initial pumped storage options review and technical discussion. Completion of this visit provided the basis for refining the evaluation.

This technical memorandum presents results of our assessment based upon the above considerations.

Background

The purpose of this evaluation was to complete conceptual site assessments and conceptual designs, including economic viability, for several seasonal pumped storage projects. The studied sites are within the vicinity of the Faro Mine Complex, including the Faro Mine area, Rose Creek Tailings area and the Vangorda Plateau area (see Figure 1 attached in Appendix A).

The Faro Mine Complex is located in south-central Yukon, approximately 14 kilometers (km) north of the town of Faro. The Faro Mine Complex began mining in 1969 and lasted approximately 30 years.

The mine is currently being reclaimed and remediated to a stable condition. The current layout of the mine consists of large open pit, the Faro pit, which is approximately 1,675 meters by 975 meters in surface area. The pit is surrounded by approximately 250 million tonnes of waste rock. To the southwest of the Faro Mine pit lies the Rose Creek Tailings, containing approximately 55 million tonnes of tailings. The tailings facility consists of a series of three dams to hold the tailings, and a fourth dam to store water. To the East of the Faro Mine, and connected by a haul road, lies the Vangorda Plateau consisting of two open pits: the Vangorda Pit, with approximately 20 million tons of waste rock; and the Grum Pit, with approximately 100 million tonnes of waste rock.

The study range for this conceptual assessment was confined to the Faro Mine Complex and nearby surrounding areas. Potential site locations of the pumped storage schemes were kept to within a reasonable distance of waste rock (pit areas) to try to exploit previously-disturbed areas and to minimize the cost of new transmission lines and access roads.

A total of 11 different locations and schemes were analyzed in this study (Schemes A through K). Due to factors affecting scheme viability, we selected three potentially promising schemes (Schemes, A, B and C) for further more detailed study.

A brief summary describing each scheme layout and its potential is provided, as well as the reasons why each scheme was discarded or carried forward for further study. For Schemes A, B and C, detailed cost estimates (accurate to approximately -20% to +50%) are provided, assuming 1) costs with no support from mining operations and 2) costs if some support is received from a current mining operation (i.e., closure) or a potential future mining operation, e.g., the further development of ore bodies in the Vangorda Pit or from the Grizzly Deposit.

Design Criteria and Assumptions

Potential Seasonal Pumped Storage Schemes

Numerous potential locations were assessed at a high level for siting pumped storage facilities. From these, a total of 11 schemes were analyzed having a wide range of design concepts, capacities and costs. Many schemes were eliminated as viable economics seemed unlikely. This report presents in detail three potential pumped storage locations: the Faro Pit Scheme (Scheme A), the Rose Creek Scheme (Scheme B) and the Vangorda Scheme (Scheme C). See Figure 1 for a plan view of the three schemes. Some of the rejected schemes are briefly summarized and shown in Figure 5.

Power and Energy Potential

Storage capacities for each scheme were chosen based on the suitability of the topography. In all cases we tried to find the maximum possible storage without making the reservoir embankments excessively large. Based on the storage volume, the head between upper and lower reservoirs and the requirement to deliver power during the four or five winter months, capacities for each scheme were chosen. For the three schemes A, B and C studied in detail, the capacities were 4, 8 and 40 megawatts (MW), and the stored energy 9.4, 9.6 and 134 gigawatt hours (GWh), respectively. For all schemes a system efficiency of 82% was assumed.

Hydrology

Weather in the area consists of long cold winters and warm summers. The annual precipitation for the study area ranges from 300-400 millimeters (mm), with a little over two-thirds falling as rain and one-third as snow. Climate normal and rainfall averages for the Yukon were obtainable from the Canadian Environmental department. The Yukon area contains approximately 19 weather stations. The data range used for this study is from 1981 to 2010. The total yearly average precipitation is 319.7 mm. May to October yields the highest precipitation depths during the year.

Catchment areas were delineated using topographic information obtained from the United States Geological Survey. The available topographic contour interval for the area is 10 meters (m). Yearly catchment volumes were determined using the rational method with a runoff coefficient of 0.80.

Geology

Most of the superficial geological materials within the Faro Complex area were deposited during the McConnell Glaciation period, and include thin till veneers and rock blankets which cover much of the mid to upper slopes. Glacial river sand, gravel, lake silts, sand and clays are common on low valley slopes contiguous to existing drainage pathways. Recent alluvium and organic deposits are found throughout the mid to lower valleys.

The central Yukon shows signs of moderate seismic activity. The rocks in the Faro Mine site are sulphide-rich and are currently undergoing treatment for Acid Rock Drainage (ARD) so ARD should be expected from waste dumps until closure plans are implemented. A preliminary desk-top geologic study was done for the area and is presented in Appendix B.

This conceptual site assessment assumes that low-permeability material is potentially available for the earthen embankments, and the in-situ impoundment materials are fairly impermeable. However, allowances are made for impoundment and embankment lining using an 80-mil high-density polyethylene (HDPE) geomembrane placed on a bedding. The proportion of the area chosen for lining was based on high-level judgment considering embankment size, impoundment depth, soils underlying the impoundment, and amount of storm water run-on into the impoundment that could offset seepage losses. The cost of the geomembrane is a significant part (~10%) of the overall capital cost.

Reservoirs

Embankments

All reservoir embankments dams were designed as earth fill with side slopes of 2.5:1, and a 5m crest width as shown on the figures. It is possible that if suitable rock is available, these sideslopes could be steepened.

It is also possible that steeper embankments built out of roller-compacted concrete could more economical in some locations; however, this option was not explored. The stability and constructability of the dams would need further geotechnical evaluation including seismic assessment. The earthwork volume quantities are based on neat-line values and do not include soil swell or shrinkage.

Pits

Only for Scheme A was a pit, the Faro Pit, used as a lower reservoir, and we could not exploit the entire Pit volume due to limitations on the size of the upper reservoir. The Grum and Vangorda Pits were found to be too small and do not have suitable surrounding topography to be useful.

Pumped Storage Layout and Equipment

For the three most promising schemes pumped storage capacities ranged from 4 to 40 MW, flows from 1.5 to 11.6 m3/s, heads from 92 to 390m, and seasonal storage from 11.7 to 123 million m^3.

In all cases, above-ground penstocks and power houses were chosen. This seemed like the most economical alternative; however, if any one of the options were to advance to the next level of design, then the full range of penstock design alternatives should be investigated. For Scheme A, a floating barge was chosen as a means to support the turbine-pump and generators. The full ramifications of such a solution would need to be investigated in further studies, but it does seem to be a viable solution based on the success of floating barges used for pump stations by the mining industry.

With the above flows, a preliminary screening showed that a Francis turbine is likely the most cost-efficient turbine choice, and hence was used for each of the schemes.

Types of electrical generation, control and other equipment were not studied in detail beyond estimating costs of typical equipment.

Existing power lines to Faro Mine were assumed to be adequate and would require only relatively short extensions (up to 6,000m) for the schemes considered.

Costs and Economic Analysis

Preliminary cost estimates were performed for all 11 schemes, but only the three most promising schemes results are presented. The major cost and financial analysis assumptions are listed below.

TABLE 1
Major Cost Analysis Assumptions

Life of the Project	50 years
Term	40 years
Debt Interest Rate	6%
Inflation Rate (over past 5 years)[1]	2%
Operations and Maintenance (O&M)	EPI Formula (HDR 2014)
Contingency	25%
Summer power rate[2]	US$0.03
Winter power rate[3]	US$0.20

1. Future inflation of power rates and O&M was assumed to match chosen interest rates.
2. A nominal amount to cover O&M.
3. Based off YEC personal communication; assuming CDN$0.2 for natural gas generated power, CDN$0.29 for diesel generated power, an assumed 50/50 mix and a 0.8 US$ to CDN$ conversion.

Cost and financial tables are presented in Appendix C.

The cost estimates developed are high-level and based on limited design. Accordingly, costs are expected to fall within the range of -20% to +50% of the presented cost.

Scheme A: Faro Pit

The Faro Pit pumped storage scheme consists of an upper reservoir located on top of the existing waste rock dump south of the Faro Pit, with the Faro Pit itself serving as the lower reservoir. Figure 3 shows a possible layout for the reservoir and penstocks.

The waste rock dump is believed to have approximately 250 million tonnes of waste. Waste rock areas west of the Faro Pit are smaller in size and are not suitable for a reservoir.

This scheme assumes closure and remediation of the waste rock slopes could be undertaken in a way that meets both closure criteria and forms the upper reservoir. For closure, the existing waste sideslopes (assumed to be 1.5:1) would likely be cut back to 3:1 slopes to provide a stable, erosion-resistant surface that could be revegetated. In addition, the waste dump surface would likely need to be covered with a geomembrane to prevent water infiltration and contamination of groundwater. By regrading the 1.5:1 slopes to 3:1 slopes, cut waste would be used to create the embankments for the upper water storage reservoirs. See Section 1 on Figure 3 for this cut configuration. The dam embankments would be 20m high, with a 5m top width and sideslopes of 3:1. Lining the impoundment and embankment surfaces would provide the necessary environmental protection and a watertight reservoir. The storage volume for the scheme is constrained by the limited space available on top of the waste dump and is approximately 11.7 million m^3.

There is limited information on the existing conditions of the Pit. For completion of this assessment, the pit was assumed to have 1:1 side walls and to be approximately 300m deep, with an estimated total volume of 134 million m^3. Top and bottom pit elevations of 1190m and 840m, respectively, were estimated. Using an existing water surface elevation depicted on Google™ Earth images, the water level of the pit water was estimated at approximately 1,240m for an estimated water volume of 79 million m^3.

The Faro Pit scheme will consist of a pump/turbine in the pit area which will pump stored water to the waste dump reservoirs. In return, water will drop via a penstock pipe to the pump/turbine installed on a floating barge on the pit lake. The total available head is estimated to be at least 300m.

The assumption of the pump and turbine on a floating barge would require a somewhat flexible penstock from the upper reservoir to the pit lake. As the capacity of the scheme is relatively small, the penstock pipe would need to be about 500mm in diameter, and could be made of articulating steel pipe or possibly even steel-reinforced HDPE pipe. Although this would present somewhat of a challenge, this could be more economical than excavating for the penstocks and power house.

Based on this design, the Scheme A could provide 4 MW capacity and a seasonal storage of 9.6 GWh. The scheme was estimated to cost US$89 million as a standalone project with no support from the Mine. If the Mine picked up 50% of the reclamation costs (i.e., regrading the upper reservoir sideslopes and lining the upper reservoir with an 80mil HDPE geomembrane), then the capital costs reduce to US$47

million. Similarly if the Mine picked up all the upper reservoir costs, which is work they would do anyway to close the dump, then the scheme would cost US$4.5 million leading to a profitable venture.

Scheme B: Rose Creek

The Rose Creek Scheme is located between the Faro and Grum pit. In this scheme, water is pumped out of the Faro Pit, is treated and then further pumped to the upper reservoir. Water from the upper reservoir is then released directly into Rose Creek. The scheme assumes that there would be sufficient ground water inflows into the Faro Pit, possibly augmented by surface flows redirected from the pit diversion channel. In total, about 18 million m^3 of inflows would be required per year, which is likely attainable just from the diverted surface water. If this assumption is not true, then the scheme is not technically viable. Creating such an inflow into the pit will reduce groundwater contamination and is environmentally beneficial.

The upper water reservoir is about 4.8 km southeast of the pit and about 4 km north of the haul road. The distribution waterline system is a combination of steel pipe at lower elevations, and HDPE pipe at higher elevations. The elevation difference from Faro Mine to the reservoir's discharge point is 290m. The pumps and pipeline were designed for a flow of 0.93 m3/s (14,700 gpm) or 17.9 million m^3 in seven months.

The dam embankment is 27m high, 5m top width and sideslopes of 2.5:1. The reservoir will provide a total water storage volume of 17.9 million m^3. The total available head is 192m with a 4,400m-long penstock leading to the power house located along the haul road. The contributing catchment area will provide an approximate flow volume of 3.2 million m^3 per year of natural inflow. See Figure 3 for scheme layout.

The economics of this scheme are only viable if support for the water treatment plant is provided by the mine.

Scheme C: Vangorda Pit

The Vangorda Scheme is located just east of the existing Vangorda Pit. This option consists of two reservoirs: the upper reservoir with a storage volume capacity 123 million m^3 and a lower reservoir with a storage capacity of 70 million m^3. Water from the Vangorda Pit operations could be blended into the 106 million m^3 per year of natural inflow volume from the upper and lower catchments, as shown on Figure 5. Such a blending could be beneficial to the Mine treatment operations currently ongoing at the Pit.

The upper reservoir dam embankments would be a maximum of 95m high, with 5m top crest width and sideslopes of 2.5:1. The upper reservoir would be built on the generally flat plateau east of the Vangorda Pit, abutting the waste dump on the south side of the Vangorda Pit. Just west of the upper reservoir is the Grizzly Deposit, an unexploited zinc/lead/nickel deposit previously identified as a potentially viable deposit (see Appendix B). If this ore body were ever to be developed, the upper reservoir embankment could be created from mine waste at almost no extra cost to the mining operation. This would make this an attractive option. For costing purposes, we have assumed that 50% of the upper reservoir is lined with an 80-mil HDPE geomembrane. We are not certain as to the likely seepage

in this area, but the inflow of 6.3M m^3 of stormwater would offset some leakage, hence the 50% estimate, which is likely conservative.

The lower reservoir embankment would be a maximum of 80m high, with a 5m top width and sideslopes of 2.5:1, and would be located in a very narrow region of the stream below the upper reservoir. The lower reservoir has a large natural inflow of water and hence can be smaller than the upper reservoir.

The total available head is 390m with a 1,780m-long penstock leading to the power house located next to the lower embankment. This gives a length to height ratio (l/h) of 4.6, which is attractive. See Figure 5 for a schematic layout.

Several other options in this area that may provide greater head and a larger upstream catchment. Thus there is a good chance that a better scheme in the area could be identified in a more in-depth and comprehensive study.

This option shows viable economics if the embankment costs are offset by at least 50% by using mine waste.

Other Schemes

As part of the site assessment process, several other schemes were considered. Some had more potential than others; however, due to a lack of head elevation, distance, or storage capacity the economic viability of these schemes was assessed to be low, and hence they were rejected for further study. Each of these schemes is briefly described below.

Scheme D

Scheme D is located just south of the Vangorda Pit. Similar to Scheme C, this option consists of two reservoirs: the upper reservoir with a storage volume capacity of 205 million m^3 and the lower reservoir (same as Scheme C) with a storage capacity of 70 million m^3. Water from the Vangorda Pit operations can be used, as well as a combined 107.2 million m^3 per year of natural inflow volume from catchment areas north of the reservoir.

The upper reservoir consists of two embankments with 2.5:1 sideslopes and 5m top width. The total available head is 310m with a penstock leading to the power house located on the lower reservoir (see Figure 5).

This scheme would have similar economics as Scheme C and hence was not studied further.

Scheme E

Scheme E is located south of the Faro Mine Pit. Similar to Scheme A, this option consists of using the Faro Pit as an upper reservoir and the Rose Creek tailing area as a lower reservoir (see Figure 5).

The limited head differential and relatively small storage volumes made this option unattractive.

Scheme F

Scheme F is located between Faro Mine pit and the Grum Pit. Similar to Scheme B, water from the Faro Mine complex will be pumped in an easterly direction to the water reservoir 3 kilometers (km) northeast of the Haul road.

The dam embankments are 40m height, 5m top width a sideslope of 2.5:1. The reservoir will provide a total water storage volume of 17 million m^3. The total available head is 430m with a 3,500m-long penstock leading to the power house located along the Haul road (see Figure 5).

This scheme would have similar economics as Scheme B and hence was not studied further.

Scheme G

Scheme G is located north of the Grum Pit. Similar to Schemes B and F, water from Grum Pit will be pumped in a northerly direction to the water reservoir 4.1 km northeast of the Haul road.

The dam embankments are 90m high, 5m top width and a sideslope of 2.5:1. The reservoir will provide a total water storage volume of 25 million m^3. The available head is 375m with a 4,175m-long penstock along the Vangorda Creek and leading to the power house located north of the Vangorda Pit (see Figure 5).

Scheme H

Scheme H is located north of the Vangorda Pit and Grizzly Deposit. Similar to the Vangorda schemes (C and D), Scheme H consists of an upper and lower reservoir. The upper reservoir dam embankments are 338m high, 5m top width and a sideslope of 2.5:1. Storage capacity for the upper reservoirs is approximately 470 million m^3. The lower reservoir dam embankments are 40m in height, 5m top width and a sideslope of 2.5:1. Storage capacity for the lower reservoirs is approximately 180 million m^3. The available head is 660m with a 6,457m-long penstock leading to the power house located along the lower embankment (see Figure 5).

The upper reservoir embankment is very large and would likely make the scheme less economical.

Scheme I

Scheme I is located 17.6 km east of the Faro Pit. Scheme I does not contain dam embankments but instead uses the natural topography for water storage. The reservoir has a storage capacity of 4.2 million m^3. The total available head is 300m with a 17,603m-long penstock leading to the power house located along the Rose Creek/Haul road (see Figure 5).

The extremely long penstock makes this scheme unattractive.

Scheme J

Scheme J is located directly north of Faro Pit. The dam embankment consists of 2.5:1 sideslopes, 60m high, 5m top width and a storage capacity of 7.3 million m^3. The total available head is 163m with a 3,166m-long penstock leading to the power house located at the Faro Pit (see Figure 5).

The long penstock and small upper reservoir makes this scheme unattractive.

Scheme K

Similar to Scheme J, Scheme K is located directly north of the Faro Pit but higher in elevation from Scheme J to produce greater head. Several dam embankments were designed, all consisting of 2.5:1 sideslopes, 20m high and 5m top widths. Storage capacities varied from 0.3 million m^3 to 3.7 million m^3. The total available head is 420 meters with a 6,911m-long penstock leading to the power house located at the Faro Pit (see Figure 5).

The long penstock and small upper reservoirs makes these schemes unattractive.

Results

Table 2 below provides a summary of the physical characteristics, storage, capacity and capital cost for each of the schemes.

TABLE 2
Scheme Characteristics

Scheme	Upper Reservoir Storage Volume (Mm^3)	Design Head (M)	Power Capacity (MW)	Energy Storage (GWh)	Estimated Cost (US$ 2015) Millions	Estimated Cost with Mining Support (US$ 2015) Millions
A: Faro Pit	11.7	300	4	9.6	89	48
B: Rose Creek	17.9	192	8	9.4	46	38
C: Vangorda	123.3	390	40	144.5	392	230

Table 3 provides a summary of the financials for each of the schemes. As can be seen, using our best assumptions, none of the schemes are financially viable without some support from the mining operations.

However, with some mining support, using our best estimate of an equitable sharing of costs, we see that Schemes A and C could be financially viable. We do caution that this viability is sensitive to interest rates, capital costs, winter and summer power costs/rates, and the capital costs would need to be confirmed in more detailed studies. In all schemes, the highest cost is the upstream reservoir, required to store the season's energy.

TABLE 3

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Preliminary Financial Analysis of Options US$2015

Cost Item	Unit	Scheme A: Faro Pit	Scheme A: Faro Pit with Mining (3)	Scheme B: Rose Creek	Scheme B: Rose Creek with Mining (3)	Scheme C: Vangorda	Scheme C: Vangorda with Mining (3)
Project Capital Cost 2015	$/kW	$ 22,379	$ 3,545	$ 5,767	$ 4,834	$ 9,821	$ 5,759
Capacity	MW	4.00	4.00	8.00	8.00	40.00	40.00
Seasonal Storage	GWh	9.60	9.60	9.40	9.40	134.00	134.00
Total Capital Cost		**$ 89,514,500**	**$ 14,178,580**	**$ 46,139,521**	**$ 38,673,706**	**$ 392,824,500**	**$ 230,374,500**
Debt/Equity		80/20	80/20	80/20	80/20	80/20	80/20
Interest Rate (2015)		6%	6%	6%	6%	6%	6%
Term	Years	40	40	40	40	40	40
Principal & Interest		($4,759,417)	($753,864)	($2,453,203)	($2,056,251)	($20,886,176)	($12,248,834)
Equity Rate (2015)		9%	9%	9%	9%	9%	9%
Equity Return		($1,611,261)	($255,214)	($830,511)	($696,127)	($7,070,841)	($4,146,741)
Annual Amortized Capital Costs	/year	**($6,370,678)**	**($1,009,079)**	**($3,283,714)**	**($2,752,378)**	**($27,957,017)**	**($16,395,575)**
Winter Rate	$/kWh	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Summer Rate	$/kWh	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
Winter/ Summer Rate		$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.67
Capacity rate	$/ kW-yr	$ -	$ -	$ -	$ -	$ -	$ -
Transfer Efficiency		82%	82%	82%	82%	82%	82%
Winter Energy (generating)	GWh	9.60	9.60	9.40	9.40	134.00	134.00
Summer Energy (pumping)	GWh	11.71	11.71	11.46	11.46	163.41	163.41
Winter Revenue		$ 1,920,000	$ 1,920,000	$ 1,880,000	$ 1,880,000	$ 26,800,000	$ 26,800,000
Capacity Revenue		$ -	$ -	$ -	$ -	$ -	$ -
Annual Revenue		**$ 1,920,000**	**$ 1,920,000**	**$ 1,880,000**	**$ 1,880,000**	**$ 26,800,000**	**$ 26,800,000**
Summer Pumping Cost		$ (351,220)	$ (351,220)	$ (343,902)	$ (343,902)	$ (4,902,439)	$ (4,902,439)
Depreciation		NA	NA	NA	NA	NA	NA
O&M (2)		(232,732)	(232,732)	(288,515)	(288,515)	(1,160,514)	(1,160,514)
Annual Capital Cost		$ (6,370,678)	$ (1,009,079)	$ (3,283,714)	$ (2,752,378)	$ (27,957,017)	$ (16,395,575)
Annual Costs		**$ (6,954,629)**	**$ (1,593,030)**	**$ (3,916,131)**	**$ (3,384,795)**	**$ (34,019,970)**	**$ (22,458,529)**
Annual Earnings (Pre-Tax)		**$ (5,034,629)**	**$ 326,970**	**$ (2,036,131)**	**$ (1,504,795)**	**$ (7,219,970)**	**$ 4,341,471**
Present Value (40 years) (3)		**$ (201,385,164)**	**$ 13,078,809**	**$ (81,445,244)**	**$ (60,191,793)**	**$ (288,798,805)**	**$ 173,658,844**
Present Value (50 years) (3, 4)		**$ (188,024,675)**	**$ 26,439,298**	**$ (68,969,415)**	**$ (47,715,963)**	**$ (81,428,339)**	**$ 381,029,309**

Notes
1. Shaded cells have variables that can be changed.
2. Based on EPRI Formula. See HDR 2014.
3. Power rates and O&M assumed to increase at rate of inflation for calculation of Present Values.
4. The Present Value based on 50 years assumes that there are no debt payments for the last 10 years.

Conclusions

A range of seasonal pumped storage schemes were found within the relatively small Faro Mine Complex area, showing how rich the area is in potential opportunities for pumped storage.

From the range of schemes studied, the most significant cost in all the schemes is the large upper reservoir and embankment required for the seasonal storage volume. This has a correspondingly large influence on the seasonal pumped storage economics. When comparing seasonal pumped storage schemes to daily or weekly pumped storage schemes, we see that the more frequent use of the upper reservoir by the daily/weekly schemes results in a smaller upper reservoir and better economics.

Only when the costs of the upper reservoir are shared by a mining operation do any of the schemes studied become potentially economically viable. When the Vangorda Scheme (Scheme C) is developed in conjunction with the Grizzly resource, we see a yearly income of about US$4 million on an investment of US$230 million. This is largely due to being able to locate the upper reservoir adjacent to the ore deposit, which would allow the mine's waste rock to be judiciously dumped to form the upper reservoir's embankment. We are of the opinion that this dumping would cost the mine little, if any more, than if dumped in a conventional heap. As an upper bound, we estimated that the additional dumping cost (due to building a dam rather than a waste dump) could potentially be $4.38/m^3 of dumped rock. If this US$4.38/m^3 were reduced to a still-credible US$2.38/m^3, then the yearly return rises to US$8 million and the investment drops to US$176 million.

Another factor influencing project economics is the catchment area to the upper reservoir. Obviously a large catchment provides free energy to the upper reservoir and improves the project economics. Several of the schemes were able to exploit large catchments.

Based on this study, we see good potential for seasonal pumped storage facilities co-developed with mining projects, as the plentiful mine waste can be used to inexpensively build the large upper reservoir required by seasonal storage. Of course, the cost of power transmission is also absorbed by the mine development.

We see the Yukon Territory itself proving good opportunity for seasonal pumped storage due to the rugged terrain and strong flowing water often providing near-ideal locations. Admittedly, a thorough and intensive search would be needed to find suitable locations.

References

- Report to PacifiCorp, "Energy Storage Screening Study" Final July, 2014, HDR.
- Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest. U.S. Army Corps of Engineers Northwest Division Hydroelectric Design Center. Final Report August 2009, MWH.
- Natural Resources Canada, RETScreen International 'Clean Energy Project Analysis RETScreen Engineering & Cases Textbook, Small Hydro Project Analysis', 2004.
- Natural Resources Canada, RETScreen Clean Energy Analysis Software, v2013.

Appendices

Appendix A: Figures
Appendix B: Faro Mine Complex Structural Geology
Appendix C: Scheme Costs and Financials

APPENDIX A

FIGURES

TECHNICAL MEMORANDUM

FARO MINE PUMPED STORAGE
CONCEPTUAL ASSESSMENT OF SEASONAL PUMPED STORAGE POWER FACILITIES AT THE FARO MINE COMPLEX
YUKON ENERGY CORPORATION – YUKON TERRITORY, CANADA

EMC² – Picacho

Plot Date: Tue 15-Dec-2015 - 04:24PM
User: lvis

ID	STORAGE VOL. (M^3)	HEAD (M)	ENERGY GWH	CAPACITY MW	PENSTOCK LENGTH (L) (M)	EMBANKMENT FILL VOL. (2) (M^3)
SCHEME A	11.7 M	300	9.6	4	990	1.4 M
SCHEME B	17.9 M	192	9.4	8	4,220	0.49 M
SCHEME C	123.3 M	390	144.5	40	1,700	27.9 M
SCHEME D	205.6 M	310	173.7	40	2,417	23.2 M
SCHEME E	22.9 M	300	18.7	8	957	5.6 M
SCHEME F	17.1 M	349	16.2	6	2,693	16.1 M
SCHEME G	25 M	385	26.2	8	4,200	19.7 M
SCHEME H	457 M	660	882	60	6,397	117 M
SCHEME I	4.2 M	289	3.3	-	16,615	0.0
SCHEME J	7.3 M	163	3.2	-	3,118	2.6 M
SCHEME K	3.7 M	420	4.3	-	6,700	0.3 M

NOTES:
1. SEASONAL ENERGY STORAGE.
2. ASSUMING 2.5H:1V EMBANKMENT SLOPES.

LEGEND

- SCHEME RESERVOIR
- PIPE/PENSTOCK
- TURBINE
- PUMP STATION
- TREATMENT PLANT

SCHEME K
SCHEME J
SCHEME I
FARO PIT
ROSE CREEK
SCHEME E
SCHEME F
SCHEME A,
FARO PIT
ROSE CREEK
SCHEME B,
ROSE CREEK
SCHEME H
(UPPER RESERVOIR)
SCHEME G
HAUL
ROAD
VANGORDA CREEK
GRUM PIT
PELLY RIVER
VANGORDA PIT
SCHEME C
(UPPER RESERVOIR)
GRIZZLY
DEPOSIT
SCHEME H
(LOWER RESERVOIR)
SCHEME D
SCHEME C
(LOWER RESERVOIR)

SCALE
0 1000 2000 3000m
CONTOUR INTERVAL = 20 m

PRELIMINARY

REFERENCE:

1. EXISTING SURFACE OBTAINED FROM: UNITED STATE GEOLOGICAL SURVEY (USGS) NATIONAL ELEVATION DATA SET, ELEVATION LAYER OF THE USGS NATIONAL MAP.

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PROJECT:
YUKON ENERGY
FARO MINE PUMPED STORAGE

TITLE:
PUMPED STORAGE OPTIONS
ALL SCHEMES EXPLORED

FIGURE NO.
1

ISSUED/REVISION:
B

File: G:\Work Folder\Engineering\Projects\Faro\CADD\2.0 Plan Set\Faro Storage Figures.dwg

Plot Date: Tue 15-Dec-2015 - 03:41PM
User: lvis

LEGEND

- SCHEME RESERVOIR
- PIPE/PENSTOCK
- B / 3 — SCHEME ID; FIGURE NUMBER WHERE SCHEME IS LOCATED

ROSE CREEK
FARO PIT
FARO MINE AREA
ROSE CREEK TAILING AREA
A / 3 SCHEME A: FARO PIT
SCHEME B: ROSE CREEK B / 4
ROSE CREEK
HAUL ROAD
GRUM PIT
VANGORDA CREEK
PELLY RIVER
VANGORDA PLATEAU AREA
VANGORDA PIT
GRIZZLY DEPOSIT
VANGORDA WASTE DUMPS (CONTOURS ARE APPROXIMATIONS)
Faro, YT
C / 5 SCHEME C: VANGORDA PIT

SCALE
0 1000 2000 3000M

Image © 2015 DigitalGlobe
Image Landsat

PRELIMINARY

REFERENCE:

1. ALL IMAGES OBTAINED FROM GOOGLE EARTH V7.1.5.1557, IMAGERY DATE 2013-2015.

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FARO MINE PUMPED STORAGE

TITLE: PUMPED STORAGE OPTIONS
SCHEMES A, B AND C

FIGURE NO. 2

ISSUED/REVISION: B

File: G:\Work Folder\Engineering\Projects\Faro\CADD\2.0 Plan Set\Faro Storage Figures.dwg

April 6, 2018

A-3194

Plot Date: Tue 15-Dec-2015 - 03:57PM
User: lvis

LOWER RESERVOIR (FARO PIT ASSUMED VALUES):
SIDE SLOPE: 1H:1V
BOTTOM ELEV: 840 M
WATER LEVEL ELEV: 1140 M
ESTIMATED TOTAL VOLUME: 134 M^3
WATER VOLUME: 79M M^3

EXISTING WASTE ROCK

EXISTING WASTE ROCK

EXISTING WASTE ROCK

MAINTENANCE ROAD

BARGE POWER HOUSE:
CAPACITY: 4 MW

PENSTOCK:
HEAD= 300 M

1/3

1/3

1/3

1/3

EXISTING WASTE ROCK

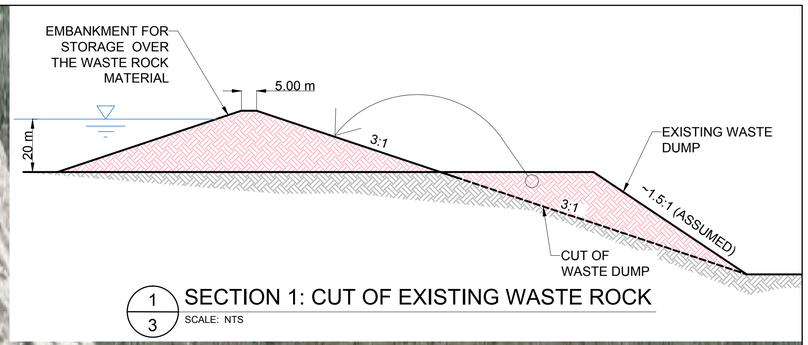
UPPER RESERVOIR :
STORAGE VOL: 11.7M M^3
CATCHMENT VOL: 0.0 M^3

EMBANKMENT:
FILL VOL: 7.9 M M^3
SIDE SLOPE: 3:1
TOP ELEV: 1260 M
BOTTOM ELEV: 1240 M
TOP WIDTH: 5 M
HEIGHT=20 M

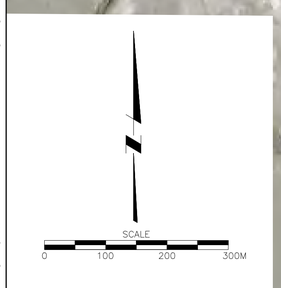
ROSE CREEK TAILING AREA

EXISTING WASTE ROCK

HAUL ROAD



1/3 SECTION 1: CUT OF EXISTING WASTE ROCK
SCALE: NTS



A/1 SCHEME A, FARO PIT

Image © 2015 DigitalGlobe

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FARO MINE PUMPED STORAGE

TITLE:
SCHEME A: FARO PIT

FIGURE NO.
3

ISSUED/REVISION:
B

File: G:\Work Folder\Engineering\Projects\Faro\CADD\2.0 Plan Set\Faro Storage Figures.dwg

Plot Date: Tue 15-Dec-2015 - 04:22PM
User: Ivis

LEGEND

- 4692 — EXISTING GROUND SURFACE
- 20" STEEL PIPELINE (SUMMER USAGE, PRESSURE SYSTEM)
- 24" HDPE PIPELINE SDR 7 (SUMMER USAGE,PRESSURE SYSTEM)
- PENSTOCK
- PUMP STATION
- TURBINE
- RESERVOIR CATCHMENT AREAS
- WATER TANK
- TREATMENT PLANT

ROSE CREEK

FARO PIT

SEEPAGE

POTENTIAL INFLOW

OPEN CHANNEL

BOOSTER PUMP STATION 1:
NUMBER OF PUMPS: 6
PUMP HORSE POWER: 1,250 HP
PUMP MAX. FLOW: 3,000 GPM (PER PUMP)

ROSE CREEK TAILING AREAS

HAUL ROAD

ROSE CREEK

EXTENT OF WATER STORAGE

UPPER RESERVOIR:
STORAGE VOL:17.9M M^3
CATCHMENT AREA: 13.3M M^2
CATCHMENT VOL: 3.2M M^3/YR

EMBANKMENT:
FILL VOL: 773,271 M^3
SIDE SLOPE: 2.5H:1V
TOP WIDTH: 5 M
HEIGHT : 27 M

PENSTOCK:
HEAD=192 M

WATER TANK:
9M DIA. BY 3M HIGH

BOOSTER PUMP STATION 2:
NUMBER OF PUMPS: 6
PUMP HORSE POWER: 1,250 HP
PUMP MAX. FLOW: 3,000 GPM (PER PUMP)

MAINTENANCE ROAD

POWER HOUSE:
TURBINE RUNNER SIZE: 1.01 M
CAPACITY: 8 MW

GRUM PIT

VANGORDA PIT

GRIZZLY DEPOSIT

PRELIMINARY

SCALE
0 800 1600 2400M

PELLY RIVER

Faro, YT

B
1
SCHEME B, ROSE CREEK

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PROJECT:
YUKON ENERGY
FARO MINE PUMPED STORAGE

TITLE:
SCHEME B: ROSE CREEK

FIGURE NO.
4

ISSUED/REVISION:
B

Plot Date: Tue 15-Dec-2015 - 04:17PM

User: lvis

LEGEND

- 4692 — EXISTING GROUND SURFACE
- PENSTOCK
- PUMP STATION
- TURBINE
- RESERVOIR CATCHMENT AREAS

ROSE CREEK

HAUL ROAD

VANGORDA CREEK

GRUM PIT (ASSUMED VALUES):
SIDE SLOPE: 1H:1V
TOP ELEV: 1295 M
BOTTOM ELEV: 1195 M
WATER LEVEL ELEV: 1295 M
WATER STORAGE: 8.9M M^3

EXTENT OF WATER STORAGE

UPPER RESERVOIR:
STORAGE VOL: 123.3M M^3
CATCHMENT AREA: 26.3M M^2
CATCHMENT VOL: 6.3M M^3/YR

EMBANKMENT:
FILL VOL: 34.7M M^3
SIDE SLOPE: 2.5H:1V
TOP WIDTH: 5M
TOP ELEV: 1195 M
BOTTOM ELEV: 1100 M
HEIGHT: 95 M

VANGORDA PIT (ASSUMED VALUES):
SIDE SLOPE: 1H:1V
TOP ELEV: 1125 M
BOTTOM ELEV: 1025 M
WATER LEVEL ELEV: 1125 M
WATER STORAGE: 3.3M M^3

MAINTENANCE ROAD

GRIZZLY DEPOSIT

VANGORDA WASTE DUMPS
(CONTOURS WERE APPROXIMATED USING A SIDES LOPE OF 1.5H:1V AND TOP ELEVATION OF1250 M)

EXTENT OF WATER STORAGE

DRAINAGE SLOT

Faro, YT

EMERGENCY SPILLWAY

PENSTOCK:
HEAD= 390 M

PELLY RIVER

POWER HOUSE:
TURBINE RUNNER SIZE= 1.73
CAPACITY: 40MW

LOWER RESERVOIR:
STORAGE VOL: 70.5M M^3
CATCHMENT AREA: 415.9M M^2
CATCHMENT VOL: 99.8M M^3/YR

EMBANKMENT:
FILL VOL: 1.4M M^3
SIDE SLOPE: 2.5H:1V
TOP WIDTH: 5M
TOP ELEV: 790 M
BOTTOM ELEV: 720 M
HEIGHT: 70 M

Google earth

SCALE
0 800 1600 2400M

C
1

SCHEME C, VANGORDA PIT

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YUKON ENERGY
FARO MINE PUMPED STORAGE

TITLE:
SCHEME C: VANGORDA PIT

FIGURE NO.
5

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B

APPENDIX B

FARO MINES COMPLEX STRUCTURAL GEOLOGY

TECHNICAL MEMORANDUM

FARO MINE PUMPED STORAGE
CONCEPTUAL ASSESSMENT OF SEASONAL PUMPED STORAGE POWER FACILITIES AT THE FARO MINE COMPLEX
YUKON ENERGY CORPORATION – YUKON TERRITORY, CANADA

EMC^2 – Picacho

Vangorda Pumped Storage Feasibility Study

Author: H. Blyth, P. Geo. of Blyth Consulting

Location

The Faro area, which in this report includes the Vangorda and Grum pits as well as the Grizzly deposit, is located within central Yukon, approximately 10 kilometres east of Faro, at 62°14'20.67"N, 133° 9'2.87"W (Figure 1).

Figure 1: Study area, including approximate catchments in green and magenta

Climate

Typical of much of the Yukon, climate in the Faro area consists of long cold winters and warm summers ranging from -60° to +35° Celsius (C) but average about -23° in the winter and 19° C in the summer. Total annual precipitation is ranges from 300-400 mm, with a little over two-thirds falling as rain one-third as snow. Winter snow pack rarely exceeds 1 metre in depth (McFaull, 1996).

Physiography

Faro, Yukon lies in the north of the western most physiographic region of Canada known as the Canadian Cordilleran physiographic region (Fulton, 1989). The complex nature of the Cordilleran Region encompasses steep mountains with narrow valleys, plains and plateaus. The Faro, Grum, Vangorda and Grizzly sites are located within the Anvil District of the Yukon Plateau physiographic subdivision. At the core of this district is the Anvil Range, which rises to 1800 metres above sea level (m asl) and is flanked by the midland, Vangorda Plateau.

The Canadian Cordillera is composed of five northwest-trending morphogeological belts (Hart, 2002), which are parallel to the continental margin (Figure 2). The Faro area lies within the glaciated portion of the Omineca Belt, the most varied complex of the five morphogeological belts, composed of a variety of metamorphosed sedimentary and granitic rock (Hart, 2002). The Omineca Belt presents itself as large mountain ranges with localized centres of high mountains called massifs. The Massifs tend to centre on granitic intrusions whose heat has metamorphosed the surrounding sedimentary bedrock (Hart, 2002).

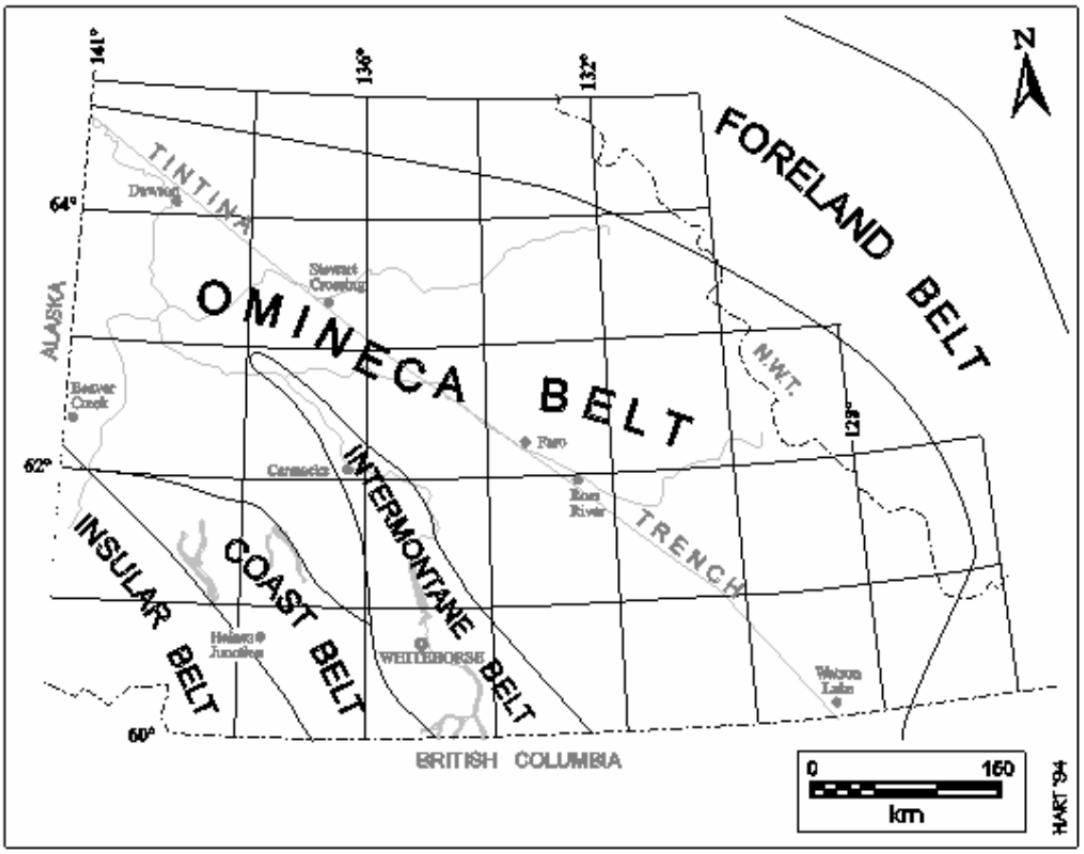

Figure 2: The five northwest-trending morphogeological belts of the Canadian Cordillera (After: Hart, 2002)

The study area lies at the edge of the Tintina Trench/Valley and the McMillan Plateau (Bostock, 1948) and ranges in elevations from 1120 m asl to as high as 2050 m asl in the upslope catchment areas (Figure 1).

Bedrock Geology:

The Grum and Vangorda pits, as well as the Grizzly deposit, rest within the Selwyn geologic Basin, west of the Selwyn Mountains (Figure 3). The Selwyn Basin is an area, in east-central Yukon, where deep water clastic sediments (e.g. siltstone, chert and minor carbonates) accumulated along the margin of the ancestral North American basin during the late Proterozoic and Paleozoic (Figure 3 - Yellow) (McFaull, 1996).

Between the Jurassic and Cretaceous a period of oblique, tectonic collision occurred, which initiated metamorphism and deformation of the Selwyn Basin rocks by northeast directed thrust faulting and folding. The Tintina Fault (within the Tintina Valley) developed during this period of oblique tectonic collision as allochthon of volcanic-plutonic rocks (Slide Mountain Terrane - brown) overrode the rocks of the Ancestral North American craton (Figure 3 – yellow), culminating with the intrusion of mid-Cretaceous granites (McFaull, 1996; Colpron and Nelson, 2011).

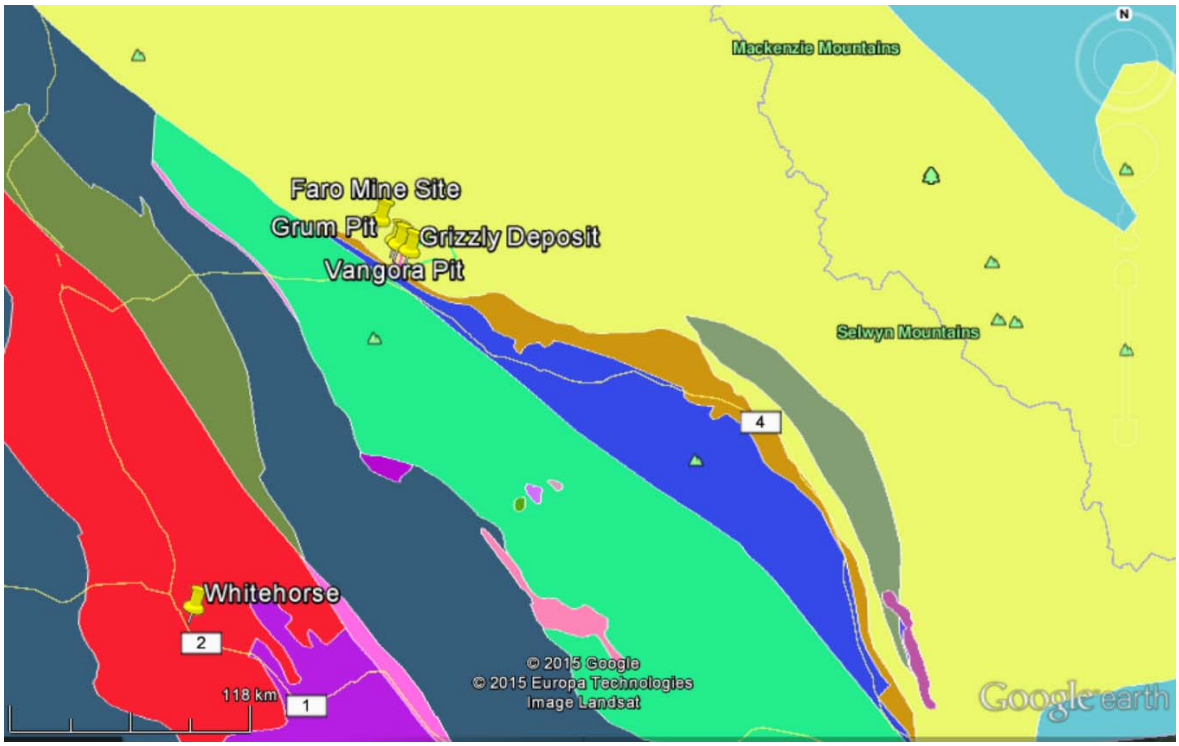

Figure 3: Geologic Terranes of the Faro area (McFaull, 1996; Colpron and Nelson, 2011)

Consistent with the regional history, the bedrock surrounding the Grizzly deposit as well as the Grum and Vangorda pits consists of phyllite, schist and graphitic phyllite of the Vangorda (Figure 4 – burgundy and lime green) and Mount Mye Formations (Figure 4 – forest and olive green) (Pigage, 2004; YGS, 2015). The locally calcareous and carbonaceous phyllite and schist commonly contain thin quartzose siltstone interbeds and interbands of dark green gabbro dykes and sills (Pigage, 2004). The stratigraphic sequences of which the Precambrian to Ordovician Mount Mye and Vangorda Formations are generally

composed consist of: deep marine schists and phyllite sequences intruded by granite, granodiorite and quartz monzonite of the Anvil Range Plutonic suite (Robertson and Kirsten, 2002).

Figure 4: Detailed geology of the Faro area (After: Pigage, 2004)

Mineral Reserves

Yukon metallurgical deposits are typically located along the margins of Selwyn Basin in fault-controlled basins and troughs (MacIntyre, 2005). The Grum and Vangorda deposits appear to rest on or near a north-south trending normal fault. The Grizzly deposit may also be associated with a northeast-southwest trending strike-slip fault (Pigage, 2004). The following table (Table 1) shows proven or inferred reserves for the Faro, Dy (Grizzly), Grum and Vangorda deposits.

Table 1: Sedimentary Exhalative Zn-Pb-Ag - Faro Yukon Area									
Deposit	**Tonnes**	**Ag (g/t)**	**Pb (%)**	**Zn (%)**	**Au (g/t)**	**Mineralogy**	**Host Rock**	**Minfile #**	**Activity**
FARO	57,600,000	36	3.4	4.7	N/A	py, sph, galena, pyrrhotite, chalcopyrite, marcasite with patchy barite and trace tetrahedrite, bournonite, arsenopyrite in siliceous gangue, magnetite	Mt Mye biotite-andalusitemuscovite-schist, 100 m below contact with Vangorda calc-silicate. Amphibolite grade.	105K 061	Mined out
DY (GRIZZLY)	Inferred and indicated mineral resource: 21,300,000	81.1	5.54	7.33	0.87 (using 9% combined cut-off grade)	sphalerite, galena, pyrite and minor chalcopyrite	Poorly defined Mt Mye/ Vangorda contact, uppermost horizon within Vangorda fm, remainder of horizons in Mt Mye fm.	105K 101	Drilling discovery, additional exploration required. Mining would be underground.
GRUM	Proven mineral reserves 16, 900,000 (open-pit mineable)	47	3	4.9	N/A	sphalerite, galena, pyrite (cp, aspy and sulphosalts) (po, mt); massive sulphide facies within each of the main horizons	From approx. 50m below Mt Mye/ Vangorda contact to 100m above it; lowest horizon 30m below main graphitic phyllite, another one immediately below it, others within Vangorda fm.	105K 056	Partially mined
VANGORDA	71,000,000	48	3.4	4.3	0.75	pale yellow sphalerite, galena, minor amounts of chalcopyrite, and traces of tetrahedrite, bournonite and arsenopyrite	Basal Vangorda carbonaceous phyllite, very well developed and thick.	105K 055	Mined out
After: Yukon Geological Survey - Selwyn Basin Metallogeny (2014) pp. 55. http://www.geology.gov.yk.ca/metallogeny_projects.html									

Acid Rock Drainage:

Acid Rock Drainage (ARD) refers to the outflow of acidic water as a common side effect to with mining projects associated with metal sulphides (Spitz and Trudinger, 2009). Though the generation of sulphuric acid is a natural occurrence over thousands of years of weathering of sulphide bearing rocks, mining accelerates the process by fragmenting and exposing sulphide bearing materials to the atmosphere and removing the filtering topsoil layers (Spitz and Trudinger, 2009).

As the rock types in the Vangorda, Grum and Grizzly deposits are similar to those of the sulphide rich Faro Mine site (YGS, 2014, IPRP, 2007), which is presently undergoing treatment for ARD, ARD should be expected throughout the study area.

Seismic Activity:

The northern Cordillera and southwestern Yukon Territories are some of the most seismically active areas of Canada. The largest earthquake recorded in this area, to date, is the magnitude 6.9 earthquake of December 23, 1985 in the Mackenzie Mountains of the Northwest Territories and numerous magnitude 6-plus earthquakes have occurred in the Richardson Mountains of the Yukon Territory (NRC, 2015). The central Yukon (e.g. around Faro, Yukon) shows signs of moderate to low seismic activity (Figure 5) (NRC, 2015).

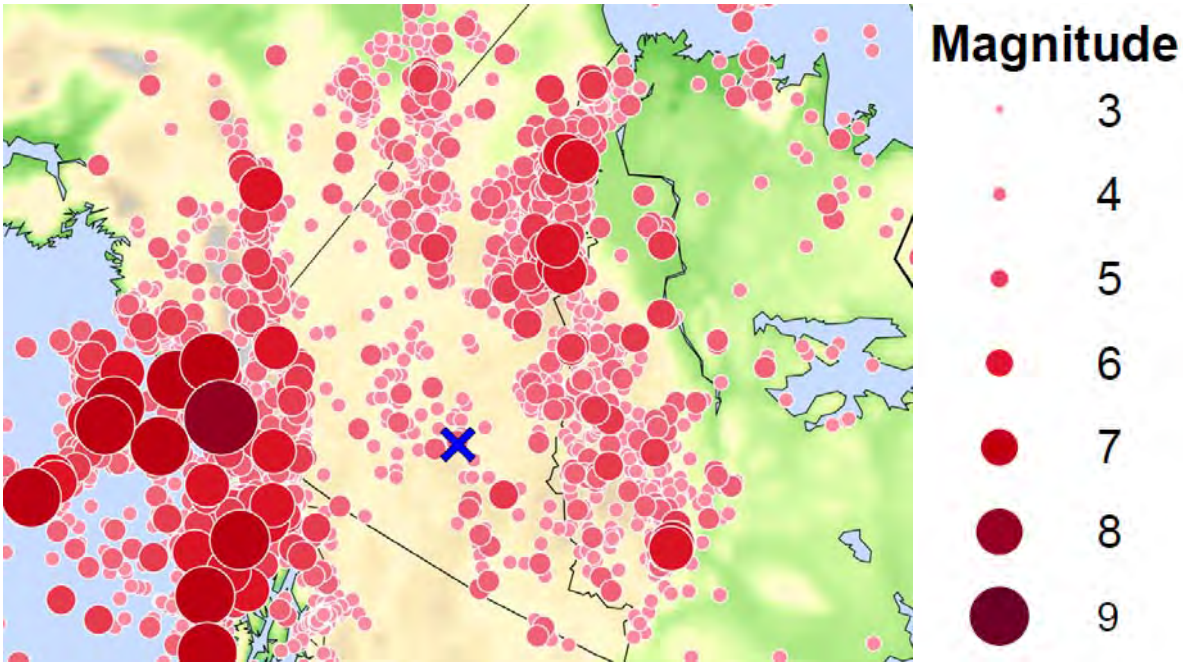

Figure 5: Earthquakes in the Yukon from 1627-2012 (X is the approximate location of Faro Yukon)

Surficial Geology:

The Faro region has undergone several glaciations, the last of which occurred between 25,000 and 10,000 years ago in the Late Wisconsinan and is known as the McConnell Glaciation (Bond, 2001). Significant surficial materials were deposited during this period including thin till veneers (<1m thick) and blankets (>lm thick), which cover much of the mid to upper slopes. Glaciofluvial (glacial river) sand and gravel and glaciolacustrine (lake) silts, sands and clays are common on low valley slopes flanking active drainage channels. Recent alluvium and organic deposits are found throughout the mid to lower valleys while veneers of colluviated till and rock blanket the upland slopes. Figure 6 below, shows the surficial geology of the Faro area followed by a written description of their common characteristics.

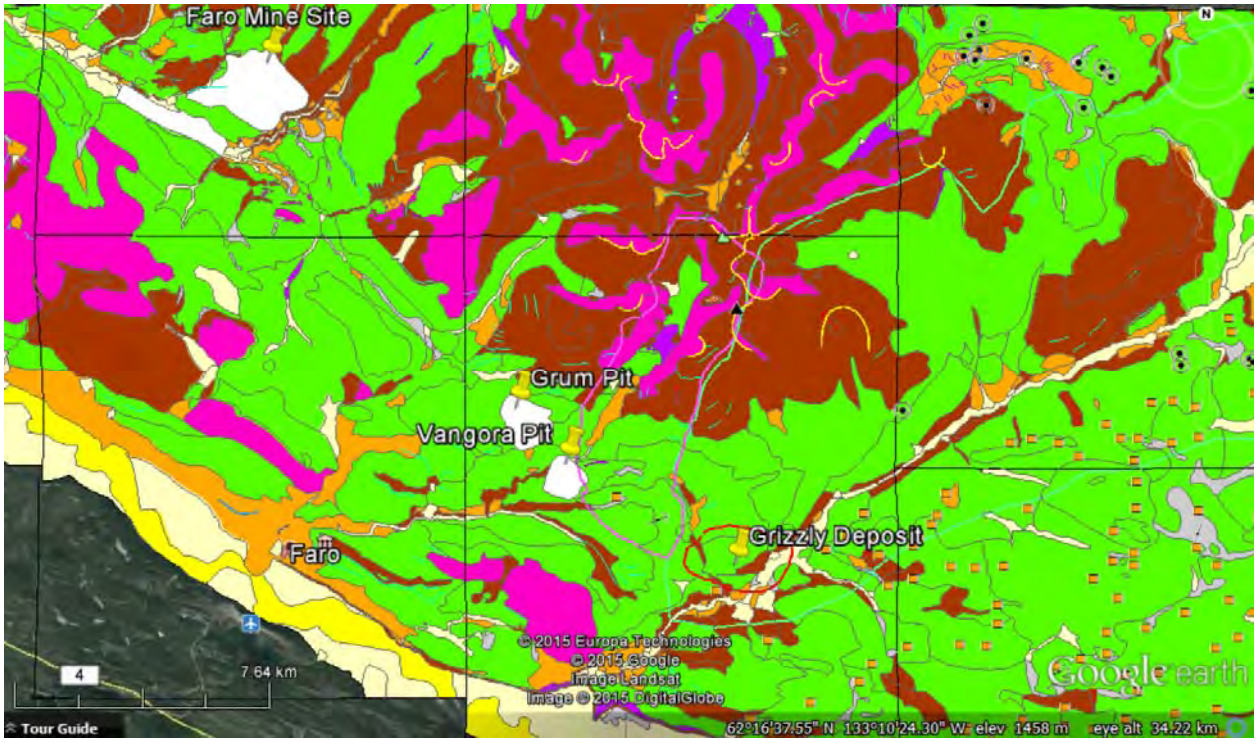

Figure 6: The surficial geology of the Faro area (After: Bond, 2001, 1999)

Green = Till (may contain oversized material, otherwise it consists of clay to boulder sized clasts, is abundant in the area and should compact well for embankments).

Orange = Glaciofluvial sand and gravel (tends to consists of interbedded sand to boulder gravel; is generally a good source of aggregate/construction material; and tends to be very porous unless interbedded with fine, glaciolacustrine sediments). There appears to be a reasonable sized source up stream of the Grum pit and downslope of the Grizzly Deposit.

Purple = Glaciolacustrine sediments (interbedded sand, silt and clay with rare drop-stones; commonly contains low porosity layers of silt and clay but is potentially unstable, particularly if undercut). If needed, there appears to be a source up valley of the Grum pit. The source up slope of the Grum pit indicates post-glacial lake impoundment; expect sub-surface glacial lacustrine deposits and seepage below the colluvium in this area.

Grey = Organic (poorly decomposed organic material; tends to be prone to seepage and permafrost). Small occurrences may be found throughout the area, the largest notable ones are due east of Vangorda pit, northwest of the Grum pit and below the Grizzly deposit in the valley.

White = Anthropogenic. These are areas altered by human activity and would need to be seen to determine porosity/seepage and other characteristics.

Beige = Fluvial material (interbedded silt, sand and gravel; usually porous, a good source of aggregate if away from active riparian zones). There may be available deposits down slope of the Grizzly deposit.

Magenta = Bedrock and colluviated till (bedrock colluvium in these area may be useful as construction material but the characteristics of each deposit will be variable depending on the source).

Dark reddish brown = Colluvium over bedrock (irregular porosity due to stratification and variable source material).

Notes: Seepage commonly occurs between materials of varied texture and compaction. This includes any surficial material contacting bedrock, stratified surficial materials and textural variations derived along weathering fronts.

Permafrost is soil or rock that remains frozen from one year to the next and may or may not contain significant quantities of ice. Permafrost covers approximately 25% southern Yukon and is continuous north of Dawson but the Faro area is within what is known as *The Extensive Discontinuous Permafrost Zone* where anywhere from 50-90% of the ground may be frozen (YGS, 2015b).

Warming and thawing of permafrost occurs in response to fires, climate change and to environmental disturbances associated with human activity and can cause ground instability and alter drainage patterns. Warming, thawing and refreezing of permafrost has implications for natural systems and infrastructure integrity, including but not limited to, landslides and ground subsidence (thermokarst). The extent of permafrost in the project area should be established during the planning stage of any construction project in this area to avoid structural problems, cost overruns and slope instability.

Summary

Upon completion of this preliminary desktop review there appears to be extensive till and some glaciolacustrine sediment, which should prove an acceptable aquatard for a pumped storage facility in the Vangorda area.

The geology at the Vangorda, DY (Grizzly) and Grum sites is similar to that of the very productive Faro mine site. The reserves, though requiring further confirmation at the DY (Grizzly) site, appear richer in silver, lead, zinc and gold than at the confirmed Faro mine site and even at the Grum site appear similar or better than those at the mined-out Faro site. This similarity, with the Faro mine site also extends to the bedrock being conducive to acid rock drainage.

Recommendations

A detailed gap analysis should be conducted to identify data weaknesses in the bedrock and surficial geologic knowledge of the area. This could include but not be limited to: bedrock distribution, specific ARD susceptibilities, stratigraphy and structural characteristics, material depths, distributions, textural and drainage characteristics; as well as detailed permafrost characteristics, avalanche, slope stability issues and the geochemical characteristics of potential aquitard materials. Accurately locating contacts between various materials (e.g. interbeds of porous and non-porous material) and structures (e.g. faults or sharp contacts) as well as textural and geochemical characteristics of till, glaciolacustrine and mineral deposits will be paramount to the success of this project.

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Yukon Geological Survey (2015b) Permafrost in the Yukon
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APPENDIX C

SCHEME COSTS AND FINANCIALS

TECHNICAL MEMORANDUM

FARO MINE PUMPED STORAGE
CONCEPTUAL ASSESSMENT OF SEASONAL PUMPED STORAGE POWER FACILITIES AT THE FARO MINE COMPLEX
YUKON ENERGY CORPORATION – YUKON TERRITORY, CANADA

EMC² – Picacho

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Scheme A: Faro Pit
P=4MW, E=9.6GWh, h=300m, L=600m, V=11.7M m3
Preliminary Cost Estimate US$2015

Work Item	Unit	Unit Cost (2015 US$)	Estimated Quantity	Estimated Cost
Direct Costs (supply and install without profit and overhead)				
Reservoirs				
Upper Reservoir Embankment (cut to fill)	m3	6	7,900,000	$ 47,400,000
Upper Reservoir Liner (80 mil HDPE on bedding)	m2	12	775,000	$ 9,300,000
Lower Reservoir (Upgrade)	sum	200,000	1	$ 200,000
Penstocks & Power Station Complex				
Penstocks Excavation/Anchoring/Intake	sum	200,000	1	$ 200,000
Penstock pipe (d=500mm, t_{av}=7mm). [4]	m	730	600	$ 438,000
Barge Pump Platform and Ancillaries.	sum	350,000	1	$ 350,000
Maintenance/ Access Roads	m	100	500	$ 50,000
Equipment (supply and install without profit and overhead)				
Substation	sum	$ 85,000	1	$ 85,000
Mechanical/ Electrical Equipment. [5.]	sum	$ 1,150,000	1	$ 1,150,000
Sub-Total Direct Costs				**$ 59,173,000**
General Requirements				
Land acquisition/ rights	sum	$ 500,000	1	$ 500,000
Water Fill	m3	$ -	-	$ -
Additional Power Line	m	$ 250	500	$ 125,000
Feasibility Studies, including geotech, water quality investigations, etc.	sum	$ 130,000	1	$ 130,000
Engineering Procurement, Permitting/Licensing [1, 2]	%	$ 2	-	$ 1,183,460
Construction Management, Surveying, QA/QC	%	$ 2	-	$ 1,183,460
Sub-Total General Requirements Costs				**$ 3,121,920**
Indirect Costs (as a percentage of direct costs)				
Contractor Mobilization/ Demobilization	%	$ 3	-	$ 1,775,190
Contractor Site Personnel and Other Indirect Costs	%	$ 8	-	$ 4,733,840
Contractor Profit/ Overhead	%	$ 10	-	$ 5,917,300
Contingency/Unpriced Items/Market Conditions	%	$ 25	-	$ 14,793,250
Sub-Total Indirect Costs				**$ 27,219,580**
Total Project Cost (-20% to +50%)				**$ 89,514,500**

Notes:

1. Percentages are percent of direct costs.
2. Assume most environmental compliances are in place.
3. None.
4. Above-ground penstocks with special provision for pipe articulation joints.
5. Supply and install electromechanical equipment including the turbine-generator(s), governor and controls, electrical protection and control (including remote monitoring system and powerhouse electrical equipment), pumps, gates, powerhouse crane.

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Scheme A: Faro Pit with Mining (3)
P=4MW, E=9.6GWh, h=300m, L=600m, V=11.7M m3
Preliminary Cost Estimate US$2015

Work Item	Unit	Unit Cost (2015 US$)	Estimated Quantity	Estimated Cost
Direct Costs (supply and install without profit and overhead)				
Reservoirs				
Upper Reservoir Embankment (cut to fill)	m3	$ 3	7,900,000	$ 23,700,000
Upper Reservoir Liner (80 mil HDPE on bedding)	m2	$ 6	775,000	$ 4,650,000
Lower Reservoir (Upgrade)	sum	$ 200,000	1	$ 200,000
Penstocks & Power Station Complex				
Penstocks Excavation/Anchoring/Intake	sum	$ 200,000	1	$ 200,000
Penstock pipe (d=500mm, t_{av}=7mm). [4]	m	$ 730	600	$ 438,000
Barge Pump Platform and Ancillaries.	sum	$ 350,000	1	$ 350,000
Maintenance/ Access Roads	m	$ 100	500	$ 50,000
Equipment (supply and install without profit and overhead)				
Substation	sum	$ 85,000	1	$ 85,000
Mechanical/ Electrical Equipment. [5.]	sum	$ 1,150,000	1	$ 1,150,000
Sub-Total Direct Costs				**$ 30,823,000**
General Requirements				
Land acquisition/ rights	sum	$ 500,000	1	$ 500,000
Water Fill	m3	$ -	-	$ -
Additional Power Line	m	$ 250	500	$ 125,000
Feasibility Studies, including geotech, water quality investigations, etc.	sum	$ 130,000	1	$ 130,000
Engineering Procurement, Permitting/Licensing [1, 2]	%	$ 4	-	$ 1,078,805
Construction Management, Surveying, QA/QC	%	$ 4	-	$ 1,078,805
Sub-Total General Requirements Costs				**$ 2,912,610**
Indirect Costs (as a percentage of direct costs)				
Contractor Mobilization/ Demobilization	%	$ 3	-	$ 924,690
Contractor Site Personnel and Other Indirect Costs	%	$ 8	-	$ 2,465,840
Contractor Profit/ Overhead	%	$ 10	-	$ 3,082,300
Contingency/Unpriced Items/Market Conditions	%	$ 25	-	$ 7,705,750
Sub-Total Indirect Costs				**$ 14,178,580**
Total Project Cost (-20% to +50%)				**$ 47,914,190**

Notes:

1. Percentages are percent of direct costs.
2. Assume most environmental compliances are in place.
3. Mining support decreases costs of highlighted items. Reduce rates by 50%
4. Above-ground penstocks with special provision for pipe articulation joints.
5. Supply and install electromechanical equipment including the turbine-generator(s), governor and controls, electrical protection and control (including remote monitoring system and powerhouse electrical equipment), pumps, gates, powerhouse crane.

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Scheme B: Rose Creek
P=8MW, E=9.4GWh, L=4220m, V=17.9M m3
Preliminary Cost Estimate US$2015

Work Item	Unit	Unit Cost (2015 US$)	Estimated Quantity	Estimated Cost
Direct Costs (supply and install without profit and overhead)				
Treatment				
Lime Treatment Plant	Sum	$ 5,000,000	1	$ 5,000,000
Water Supply				
Open Channel	m	$ 500	1,253	$ 626,500
Vertical Pump + Motor	Each	$ 350,000	12	$ 4,200,000
Steel Pipeline (600 mm diameter)	m	$ 630	3,845	$ 2,422,350
HDPE Pipeline (400mm diameter)	m	$ 412	7,512	$ 3,094,944
Water Tank (Steel)	Each	$ 45,000	1	$ 45,000
Maintenance Road	m	$ 100	4,041	$ 404,100
Reservoirs				
Upper Reservoir Embankment	m3	$ 6	773,271	$ 4,639,626
Upper Reservoir Liner (assume run-on equals seepage)	m2	$ 12	-	$ -
Lower Reservoir Embankment	m3	$ 5	-	$ -
Lower Reservoir Liner	m2	$ 12	-	$ -
Penstocks & Power Station Complex				
Penstocks Excavation/Anchoring/Intake	sum	$ 1,500,000	1	$ 1,500,000
Penstock pipe (d=1m, t_{av}=7mm). [4]	m	$ 800	4,220	$ 3,376,000
Power Station Complex (above ground)	sum	$ 500,000	1	$ 500,000
Maintenance/ Access Roads	m	$ 100	550	$ 55,000
Equipment (supply and install without profit and overhead)				
Substation	sum	$ 155,000	1	$ 155,000
Mechanical/ Electrical Equipment. [5.]	sum	$ 2,400,000	1	$ 2,400,000
Sub-Total Direct Costs				**$ 28,418,520**
General Requirements				
Land acquisition/ rights	sum	$ 1,000,000	1	$ 1,000,000
Water Fill	m3	$ -	-	$ -
Additional Power Line	m	$ 250	3,500	$ 875,000
Feasibility Studies, including geotech investigations.	sum	$ 500,000	1	$ 500,000
Engineering Procurement, Permitting/Licensing [1, 2]	%	$ 4.00	-	$ 1,136,741
Construction Management, Surveying, QA/QC	%	$ 4.00	-	$ 1,136,741
Sub-Total General Costs				**$ 4,648,482**
Indirect Costs (as a percentage of direct costs)				
Contractor Mobilization/ Demobilization	%	$ 3	-	$ 852,556
Contractor Site Personnel and Other Indirect Costs	%	$ 8	-	$ 2,273,482
Contractor Profit/ Overhead	%	$ 10	-	$ 2,841,852
Contingency/Unpriced Items/Market Conditions	%	$ 25	-	$ 7,104,630
Sub-Total Indirect Costs				**$ 13,072,519**
Total Project Cost (-20% to +50%)				**$ 46,139,521**

Notes:

1. Percentages are percent of direct costs.
2. Assume most environmental compliances are in place.
3. None.
4. Above-ground penstocks.
5. Supply and install electromechanical equipment including the turbine-generator(s), governor and controls, electrical protection and control (including remote monitoring system and powerhouse electrical equipment), pumps, gates, powerhouse crane.

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Scheme B: Rose Creek with Mining (3)
P=8MW, E=9.4GWh, L=4220m, V=17.9M m3
Preliminary Cost Estimate US$2015

Work Item	Unit	Unit Cost (2015 US$)	Estimated Quantity	Estimated Cost
Direct Costs (supply and install without profit and overhead)				
Treatment				
Lime Treatment Plant	Sum	$ 5,000,000	0	$ -
Water Supply				
Open Channel	m	$ 500	1,253	$ 626,500
Vertical Pump + Motor	Each	$ 350,000	12	$ 4,200,000
Steel Pipeline (600 mm diameter)	m	$ 630	3,845	$ 2,422,350
HDPE Pipeline (400mm diameter)	m	$ 412	7,512	$ 3,094,944
Water Tank (Steel)	Each	$ 45,000	1	$ 45,000
Maintenance Road	m	$ 100	4,041	$ 404,100
Reservoirs				
Upper Reservoir Embankment	m3	$ 6	773,271	$ 4,639,626
Upper Reservoir Liner (assume run-on equals seepage)	m2	$ 12	-	$ -
Lower Reservoir Embankment	m3	$ 5	-	$ -
Lower Reservoir Liner	m2	$ 12	-	$ -
Penstocks & Power Station Complex				
Penstocks Excavation/Anchoring/Intake	sum	$ 1,500,000	1	$ 1,500,000
Penstock pipe (d=1m, t_{av}=7mm). [4]	m	$ 800	4,220	$ 3,376,000
Power Station Complex (above ground)	sum	$ 500,000	1	$ 500,000
Maintenance/ Access Roads	m	$ 100	550	$ 55,000
Equipment (supply and install without profit and overhead)				
Substation	sum	$ 155,000	1	$ 155,000
Mechanical/ Electrical Equipment. [5.]	sum	$ 2,400,000	1	$ 2,400,000
Sub-Total Direct Costs				**$ 23,418,520**
General Requirements				
Land acquisition/ rights	sum	$ 1,000,000	1	$ 1,000,000
Water Fill	m3	$ -	-	$ -
Additional Power Line	m	$ 250	3,500	$ 875,000
Feasibility Studies, including geotech investigations.	sum	$ 500,000	1	$ 500,000
Engineering Procurement, Permitting/Licensing [1, 2]	%	$ 4.50	-	$ 1,053,833
Construction Management, Surveying, QA/QC	%	$ 4.50	-	$ 1,053,833
Sub-Total General Costs				**$ 4,482,667**
Indirect Costs (as a percentage of direct costs)				
Contractor Mobilization/ Demobilization	%	$ 3	-	$ 702,556
Contractor Site Personnel and Other Indirect Costs	%	$ 8	-	$ 1,873,482
Contractor Profit/ Overhead	%	$ 10	-	$ 2,341,852
Contingency/Unpriced Items/Market Conditions	%	$ 25	-	$ 5,854,630
Sub-Total Indirect Costs				**$ 10,772,519**
Total Project Cost (-20% to +50%)				**$ 38,673,706**

Notes:

1. Percentages are percent of direct costs.
2. Assume most environmental compliances are in place.
3. Assume mining support takes away treatment plant.
4. Above-ground penstocks.
5. Supply and install electromechanical equipment including the turbine-generator(s), governor and controls, electrical protection and control (including remote monitoring system and powerhouse electrical equipment), pumps, gates, powerhouse crane.

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Scheme C: Vangorda
P=40MW, E=134GWh, L=1780m, V=123.6M m3
Preliminary Cost Estimate US$2015

Work Item	Unit	Unit Cost (2015 US$)	Estimated Quantity	Estimated Cost
Direct Costs (supply and install without profit and overhead)				
Reservoirs				
Upper Reservoir Embankment	m3	$ 6	34,700,000	$ 208,200,000
Upper Reservoir Liner (50%, because of stormwater run-on)	m2	$ 12	2,250,000	$ 27,000,000
Lower Reservoir Embankment	m3	$ 6	1,400,000	$ 8,400,000
Lower Reservoir Liner	m2	$ 12	-	$ -
Drainage Slot (included as part of embkt borrow)	m3	$ -	230,000	$ -
Penstocks & Power Station Complex				
Penstocks Excavation/Anchoring/Intake	sum	$ 2,000,000	1	$ 2,000,000
Penstock pipe (d=1.25m, t_{av}=12mm). [4]	m	$ 1,500	1,780	$ 2,670,000
Power Station Complex (Above ground)	sum	$ 3,000,000	1	$ 3,000,000
Maintenance/ Access Roads	m	$ 100	12,600	$ 1,260,000
Equipment				
Substation	sum	$ 353,000	1	$ 353,000
Mechanical/ Electrical Equipment	sum	$ 6,000,000	1	$ 6,000,000
Sub-Total Direct Costs				**$ 258,883,000**
General Requirements				
Land acquisition/ rights	sum	$ 2,000,000	1	$ 2,000,000
Water Fill	m3	$ -	-	$ -
Additional Power Line	m	$ 250	6,000	$ 1,500,000
Feasibility Studies, including geotech investigations.	sum	$ 1,000,000	1	$ 1,000,000
Engineering Procurement, Permitting/Licensing [1, 2]	%	$ 2.0	-	$ 5,177,660
Construction Management, Surveying, QA/QC	%	$ 2.0	-	$ 5,177,660
Sub-Total General Costs				**$ 14,855,320**
Indirect Costs (as a percentage of direct costs)				
Contractor Mobilization/ Demobilization	%	$ 3	-	$ 7,766,490
Contractor Site Personnel and Other Indirect Costs	%	$ 8	-	$ 20,710,640
Contractor Profit/ Overhead	%	$ 10	-	$ 25,888,300
Contingency/Unpriced Items/Market Conditions	%	$ 25	-	$ 64,720,750
Sub-Total Indirect Costs				**$ 119,086,180**
Total Project Cost (-20% to +50%)				**$ 392,824,500**

Notes:

1. Percentages are percent of direct costs.
2. Assume most environmental compliances are in place.
3. None.
4. Above-ground penstocks.
5. Supply and install electromechanical equipment including the turbine-generator(s), governor and controls, electrical protection and control (including remote monitoring system and powerhouse electrical equipment), pumps, gates, powerhouse crane.

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Scheme C: Vangorda with Mining (3)
P=40MW, E=134GWh, L=1780m, V=123.6M m3
Preliminary Cost Estimate US$2015

Work Item	Unit	Unit Cost (2015 US$)	Estimated Quantity	Estimated Cost
Direct Costs (supply and install without profit and overhead)				
Reservoirs				
Upper Reservoir Embankment	m3	$ 3	34,700,000	$ 104,100,000
Upper Reservoir Liner (50%, because of stormwater run-on)	m2	$ 12	2,250,000	$ 27,000,000
Lower Reservoir Embankment	m3	$ 3	1,400,000	$ 4,200,000
Lower Reservoir Liner	m2	$ 6	-	$ -
Drainage Slot (included as part of embkt borrow)	m3	$ -	230,000	$ -
Penstocks & Power Station Complex				
Penstocks Excavation/Anchoring/Intake	sum	$ 2,000,000	1	$ 2,000,000
Penstock pipe (d=1.25m, t_{av}=12mm). [4]	m	$ 1,500	1,780	$ 2,670,000
Power Station Complex (Above ground)	sum	$ 3,000,000	1	$ 3,000,000
Maintenance/ Access Roads	m	$ 100	12,600	$ 1,260,000
Equipment				
Substation	sum	$ 353,000	1	$ 353,000
Mechanical/ Electrical Equipment	sum	$ 6,000,000	1	$ 6,000,000
Sub-Total Direct Costs				**$ 150,583,000**
General Requirements				
Land acquisition/ rights	sum	$ 2,000,000	1	$ 2,000,000
Water Fill	m3	$ -	-	$ -
Additional Power Line	m	$ 250	6,000	$ 1,500,000
Feasibility Studies, including geotech investigations.	sum	$ 1,000,000	1	$ 1,000,000
Engineering Procurement, Permitting/Licensing [1, 2]	%	$ 2.0	-	$ 3,011,660
Construction Management, Surveying, QA/QC	%	$ 2.0	-	$ 3,011,660
Sub-Total General Costs				**$ 10,523,320**
Indirect Costs (as a percentage of direct costs)				
Contractor Mobilization/ Demobilization	%	$ 3	-	$ 4,517,490
Contractor Site Personnel and Other Indirect Costs	%	$ 8	-	$ 12,046,640
Contractor Profit/ Overhead	%	$ 10	-	$ 15,058,300
Contingency/Unpriced Items/Market Conditions	%	$ 25	-	$ 37,645,750
Sub-Total Indirect Costs				**$ 69,268,180**
Total Project Cost (-20% to +50%)				**$ 230,374,500**

Notes:
1. Percentages are percent of direct costs.
2. Assume most environmental compliances are in place
3. Assume waste rock from mine is placed in embankments: reduce rates by 50%.
4. Above-ground penstocks.
5. Supply and install electromechanical equipment including the turbine-generator(s), governor and controls, electrical protection and control (including remote monitoring system and powerhouse electrical equipment), pumps, gates, powerhouse crane.

Conceptual Assessment of Seasonal Pumped Storage Facilities at the Faro Mine Complex
Preliminary Financial Analysis of Options US$2015

Cost Item	Unit	Scheme A: Faro Pit	Scheme A: Faro Pit with Mining (3)	Scheme B: Rose Creek	Scheme B: Rose Creek with Mining (3)	Scheme C: Vangorda	Scheme C: Vangorda with Mining (3)
Project Capital Cost 2015	$/kW	$ 22,379	$ 3,545	$ 5,767	$ 4,834	$ 9,821	$ 5,759
Capacity	MW	4.00	4.00	8.00	8.00	40.00	40.00
Seasonal Storage	GWh	9.60	9.60	9.40	9.40	134.00	134.00
Total Capital Cost		**$ 89,514,500**	**$ 14,178,580**	**$ 46,139,521**	**$ 38,673,706**	**$ 392,824,500**	**$ 230,374,500**
Debt/Equity		80/20	80/20	80/20	80/20	80/20	80/20
Interest Rate (2015)		6%	6%	6%	6%	6%	6%
Term	Years	40	40	40	40	40	40
Principal & Interest		($4,759,417)	($753,864)	($2,453,203)	($2,056,251)	($20,886,176)	($12,248,834)
Equity Rate (2015)		9%	9%	9%	9%	9%	9%
Equity Return		($1,611,261)	($255,214)	($830,511)	($696,127)	($7,070,841)	($4,146,741)
Annual Amortized Capital Costs	/year	**($6,370,678)**	**($1,009,079)**	**($3,283,714)**	**($2,752,378)**	**($27,957,017)**	**($16,395,575)**
Winter Rate	$/kWh	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Summer Rate	$/kWh	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
Winter/ Summer Rate		$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.67	$ 6.67
Capacity rate	$/ kW-yr	$ -	$ -	$ -	$ -	$ -	$ -
Transfer Efficiency		82%	82%	82%	82%	82%	82%
Winter Energy (generating)	GWh	9.60	9.60	9.40	9.40	134.00	134.00
Summer Energy (pumping)	GWh	11.71	11.71	11.46	11.46	163.41	163.41
Winter Revenue		$ 1,920,000	$ 1,920,000	$ 1,880,000	$ 1,880,000	$ 26,800,000	$ 26,800,000
Capacity Revenue		$ -	$ -	$ -	$ -	$ -	$ -
Annual Revenue		**$ 1,920,000**	**$ 1,920,000**	**$ 1,880,000**	**$ 1,880,000**	**$ 26,800,000**	**$ 26,800,000**
Summer Pumping Cost		$ (351,220)	$ (351,220)	$ (343,902)	$ (343,902)	$ (4,902,439)	$ (4,902,439)
Depreciation		NA	NA	NA	NA	NA	NA
O&M (2)		(232,732)	(232,732)	(288,515)	(288,515)	(1,160,514)	(1,160,514)
Annual Capital Cost		$ (6,370,678)	$ (1,009,079)	$ (3,283,714)	$ (2,752,378)	$ (27,957,017)	$ (16,395,575)
Annual Costs		**$ (6,954,629)**	**$ (1,593,030)**	**$ (3,916,131)**	**$ (3,384,795)**	**$ (34,019,970)**	**$ (22,458,529)**
Annual Earnings (Pre-Tax)		**$ (5,034,629)**	**$ 326,970**	**$ (2,036,131)**	**$ (1,504,795)**	**$ (7,219,970)**	**$ 4,341,471**
Present Value (40 years) (3)		**$ (201,385,164)**	**$ 13,078,809**	**$ (81,445,244)**	**$ (60,191,793)**	**$ (288,798,805)**	**$ 173,658,844**
Present Value (50 years) (3, 4)		**$ (188,024,675)**	**$ 26,439,298**	**$ (68,969,415)**	**$ (47,715,963)**	**$ (81,428,339)**	**$ 381,029,309**

Notes

1. Shaded cells have variables that can be changed.
2. Based on EPRI Formula. See HDR 2014.
3. Power rates and O&M assumed to increase at rate of inflation for calculation of Present Values.
4. The Present Value based on 50 years assumes that there are no debt payments for the last 10 years.

Appendix 5.19
Evaluation of Energy Storage Technologies (Transgrid Solutions 2016)

Engineering Support Services for:

Energy Storage Technologies

Yukon Energy Corporation

Attention:

Mr. Marc-Andre Lavigne

Report R1382.01.01

Evaluation of Energy Storage Technologies

Prepared by:

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CANADA

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April 18, 2016

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Revisions

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Document Title:	Evaluation of Energy Storage Technologies
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Last Action Date:	April 18, 2016

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01	IFA	R. Kolt N. Field D. Aming	D. Kell R. Valiquette M. Mohaddes	April 18, 2016	Final report with Yukon comments included

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Approved by Client	ABC
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Table of Contents

Executive Summary ..... **iv**
1. Introduction **1**
2. Scope of Work **2**
2.1 Literature Review 2
2.2 Cost Estimation/Project Schedules/Footprints 2
2.3 Risks and Show stoppers 2
3. Yukon Energy Load Profile **3**
4. Energy Storage Technologies **6**
4.1 Mechanical 7
4.2 Chemical 11
4.3 Electrochemical 12
4.4 High Temperature Batteries 18
4.5 Electrical Field 29
4.6 Magnetic Field 31
4.7 Thermal 33
5. Comparison of Energy Storage Technologies **35**
5.1 Determining the Energy Storage System Power and Rating 38
6. Cost Estimates, Schedule, and Footprints **41**
6.1 Battery Energy Storage System Components and Footprint 41
6.2 Development of Cost Schedule 49
6.3 System Cost vs Utilization Sensitivity Study 53
6.4 Generation of high level project schedule 54
6.5 Environmental and Societal Considerations 55
6.6 Spinning Reserve 56
7. Conclusions **57**
8. References **59**

Table of Figures

Figure 1 Yukon Energy Power Generation and Transmission System 3
Figure 2 Yukon Energy Load Forecast 4
Figure 3 Hydro and Diesel Generation for 2015 5
Figure 4 Classifications of Energy Storage Systems 6
Figure 5 Cutaway of a Typical Pumped Storage System 7
Figure 6 Diagram of a Compressed Air Storage System 8
Figure 7 Flywheel Cross Section. 10
Figure 8 Lead Acid Storage Cell 12

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Figure 9 Nickel Cadmium Battery 15
Figure 10 Lithium Ion Function and Components 17
Figure 11 Sodium Sulfur Cell Diagram 19
Figure 12 Deign and Features of a Zebra Battery 21
Figure 13 Flow Battery Construction 22
Figure 14 Vanadium Redox Battery System 23
Figure 15 Prudent Energy 600kW/3 600 kWh VRB 25
Figure 16 Zinc Bromine Cell Configuration 25
Figure 17 Zinc Air Battery Diagram 27
Figure 18 Capacitor Construction Diagram 29
Figure 19 Diagram of a SMES System 31
Figure 20 Molten Salt Energy Storage System 33
Figure 21 Crescent Dunes Solar Collector Site 34
Figure 22 Rated Power Energy and Discharge Duration 37
Figure 23 Comparison of Discharge Time Rating 37
Figure 24 Frequency Plot for Different Power Levels 38
Figure 25 Cumulative Distribution Function of Optimum Power Levels 39
Figure 26 Cumulative Distribution Function for Energy Levels 40
Figure 27: 4 MW, 40 MWh Battery Energy Storage System Configuration 43
Figure 28: 6 MW, 60 MWh; 8 MW 80 MWh and 8 MW, 40 MWh 44
Figure 29 4 MW, 40 MWh Proposed Arrangement 45
Figure 30 6 MW, 60 MWh Proposed Arrangement 46
Figure 31 8 MW, 80 MWh Proposed Arrangement 47
Figure 32 8 MW, 40 MWh Proposed Arrangement 48
Figure 33 Battery Energy Storage System vs NPV Utilization 54
Figure 34 Battery Energy Storage System Timeline 55

List of Tables

Table 1 Commercial D-SMES in the United States 32
Table 2 Comparison of Energy Storage Systems 36
Table 3 Battery Configuration to the PCS 41
Table 4 Power Conversion System Major Equipment List 42
Table 5 Economic Parameters 49
Table 6 Energy Storage System Parameters 50
Table 7 Balance of Plant Parameters 50
Table 8 Operation and Maintenance Parameters 51
Table 9 Base Case NPV for Energy Storage Systems 52
Table 10 LCOE and LCOC 53
Table 11 Operation Parameters 53

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Executive Summary

Energy storage technology for power system application has recently attracted significant interest and attention as an enabling technology for energy management and integrating the growing capacity of variable renewable energy resources into the electric grid. Energy storage systems are likely to become an essential contributor to grid modernization investments to meet the future constraints under low carbon emissions limits.

The report will provide the Yukon Energy Corporation better understanding of what types of energy storage technologies are available to support their power system requirements. The selection of an appropriate energy storage technology combined with a responsive power conversion system will have to accommodate their present and future energy demands in terms of power quality, grid support and load shifting and possible integration of other renewables in to their power grid.

Based on the requirements for a reduction of their diesel generation utilization during peak load conditions and addressing power quality aspects, two energy storage options have been selected to address this. Electrochemical battery technology using lead acid batteries or lithium ion batteries are capable to supply the power and energy demands during the peak load conditions and as well as mitigating power quality concerns on the electrical grid.

Based on the financial model provided by Yukon Energy, the power and energy requirements determined from the 2015 load data and the total cost of a completely installed Battery Energy Storage System (BESS) under study, the net present value was calculated for 4 storage options. There were 3 lead acid based systems rated at 4 MW, 40 MWh (power/energy), 6 MW, 60 MWh, and 8MW, 80 MWh capacities and a lithium ion with an 8 MW, 40 MWh capacity. Over the 30 year lifetime of the project, all options studied had significantly higher costs as compared with their respective benefits and hence a negative NPV.

The lead acid 4 MW, 40 MWh Battery Energy Storage System (BESS) had the best Net Present Value followed by the lithium ion 8 MW/40 MWh BESS. The timeline for bringing this system online is approximately 18 months. This includes engineering and drawing, preparatory civil works, purchase and delivery of the system components, construction, and testing.

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1. Introduction

The Yukon Energy Corporation is entering a new planning cycle scheduled to be completed at the end of 2016 with the issuance of its Integrated Resource Plan. An early component of the planning process is to look at potential resource options to meet the long term load forecast (2016-2035). With the higher penetration of intermittent energy sources, Yukon Energy would like a better understanding of the various energy storage technologies to offset the use of diesel generation and to support integration of renewables. The energy storage system would increase capacity during period of shortage in terms of power quality, T&D grid support, and load shifting and bulk power management. Hence, Yukon Energy is looking for technical support for a review of current energy storage technologies and to recommend viable technologies could assist the Corporation in the future.

Energy storage mediates between variable sources and variable loads. Without storage, the present energy generation must equal energy consumption. Energy storage works by moving energy through a time period, energy generated at one time can be used at another time through storage when needed. Electricity storage is one form of energy storage.

The objective of this project is to identify and evaluate energy storage technologies that would help the system meet its present and future long term energy demand by increasing capacity during times of power shortage, and that would support the integration of renewables (intermittent energy sources). Currently, the Yukon power system's main source of energy is supplied via three hydroelectric plants.

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2. Scope of Work

The scope of work is to review the current energy storage technologies available for Yukon Energy Corporation's power/energy requirements for power management, grid support & load shifting and power quality. The work will include the following topics.

2.1 Literature Review

The literature review includes a high level evaluation of the mature and emerging energy storage technologies including the pros and cons of each of these technologies as they apply specifically to the Yukon power system. The evaluation will also take into consideration the sizing of the power and energy requirements of the storage system to offset some of the existing diesel generation and provide an energy storage system capable of suppling optimal power and energy requirements during peak load conditions. Included will be a review of the maturity and current trends in cost of each of these technologies and identify sites if possible where these technologies have already been implemented.

The literature review will also consider storage options based on the following specific usages for the Yukon power grid:

- Power quality
- T&D grid support and load shifting
- Bulk power management (excluding pumped storage)

2.2 Cost Estimation/Project Schedules/Footprints

Develop cost estimates and high level project schedules from early planning to commissioning of any viable options of these technologies and the potential life of these various assets will be assessed. Additionally, the minimum footprint required to implement the storage technologies will be evaluated.

2.3 Risks and Show stoppers

The report will also assess each potential energy storage technology in terms of the risks, located within or near Whitehorse and potential barriers based on:

- Pros and cons of each technology
- Maturity of each technology
- Current trends
- Sites where the energy storage technology has been implemented
- Financial attributes
- Technical attributes
    - Installed capacity in terms of power(MW) and energy (MWh)

The evaluation of energy storage options against environmental and socio-economic attributes will be completed as a separate project by Yukon Energy.

The current scope of work does not include an evaluation of pumped storage as an energy storage technology or obtaining any environmental, geotechnical or physical data collection.

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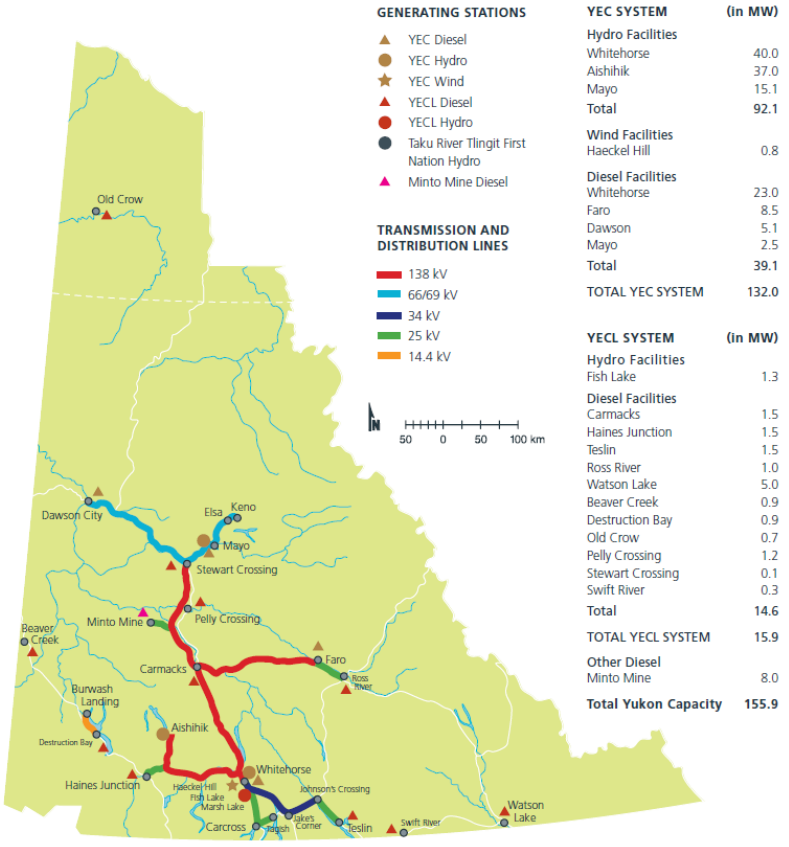
3. Yukon Energy Load Profile

The Yukon Territory is located in the northwestern part of Canada, bordered by the State of Alaska to the West, the Province of British Columbia which is to the South and the Northwest Territories to the East. As of March 2015, the population of the Territory was approximately 37,178. The Territory's capital is Whitehorse, having a population of 28,700 people and is the largest load center.

Current and committed generation capacity owned and operated by Yukon Energy Corporation (YEC or the Corporation) includes approximately 130 MW of installed generation on the Yukon Power System (approximately 92 MW hydroelectric, 0.8 MW wind, 37.8 MW thermal (diesel and natural gas)). The remaining generating assets connected to the Yukon Power System are owned by ATCO Electric Yukon and consist of about 1.3 MW of hydroelectricity and 6.8 MW of diesel.

As shown in Figure 1, there are three hydroelectric plants supplying more than 99% of the energy within the Territory. The plants are Aishihik Generating Station (37 MW, ~150 km west of Whitehorse), the Mayo Generating Station (15 MW located 450 km north of Whitehorse) and the Whitehorse Generating Station (40 MW). Transmission is at a voltage of 138 kV with the exception of the Mayo-Dawson line that operates at 69 kV.



YEC SYSTEM	(in MW)
Hydro Facilities	
Whitehorse	40.0
Aishihik	37.0
Mayo	15.1
Total	**92.1**
Wind Facilities	
Haeckel Hill	0.8
Diesel Facilities	
Whitehorse	23.0
Faro	8.5
Dawson	5.1
Mayo	2.5
Total	**39.1**
TOTAL YEC SYSTEM	**132.0**

YECL SYSTEM	(in MW)
Hydro Facilities	
Fish Lake	1.3
Diesel Facilities	
Carmacks	1.5
Haines Junction	1.5
Teslin	1.5
Ross River	1.0
Watson Lake	5.0
Beaver Creek	0.9
Destruction Bay	0.9
Old Crow	0.7
Pelly Crossing	1.2
Stewart Crossing	0.1
Swift River	0.3
Total	**14.6**
TOTAL YECL SYSTEM	**15.9**
Other Diesel	
Minto Mine	8.0
Total Yukon Capacity	**155.9**

Figure 1 Yukon Energy Power Generation and Transmission System

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Yukon Energy is entering a new planning cycle scheduled to be completed at the end of 2016 with the development of its Integrated Resource Plan. An early phase of the planning process is to explore potential resource options to meet the long term non-industrial load forecast under base case (2016-2035) as shown in Figure 2.

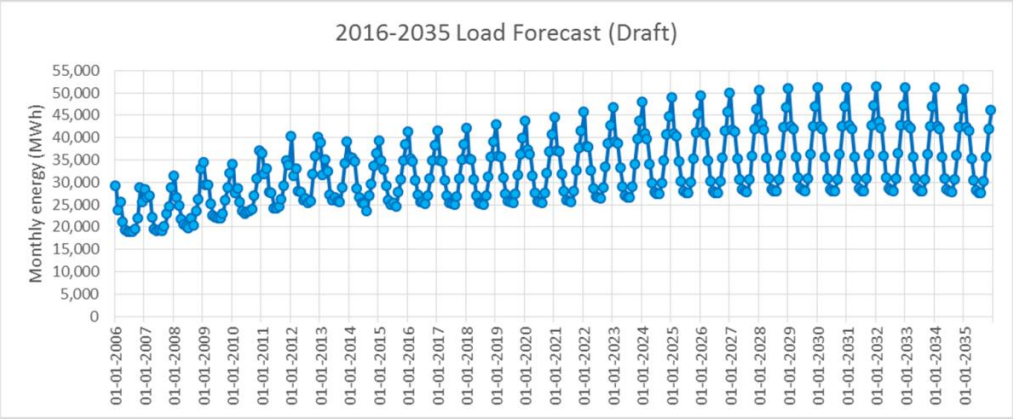

Figure 2 Yukon Energy Load Forecast

With the higher penetration of intermittent energy sources, Yukon Energy would like to better comprehend energy storage technologies to support integration of renewables and increase capacity during periods of shortage (i.e., power quality, T&D grid support, load shifting and bulk power management).

In terms of the verbal information provided during the conference calls, Yukon Energy is looking at basically two categories of an energy storage/delivery system to resolve:

1. Daily load variations
2. Intermittent generation , overvoltage problems and frequency variations

Yukon Energy has provided recent load profiles showing the electrical generation supplied from both hydro and diesel installations over the 2015 period as shown in Figure 3.

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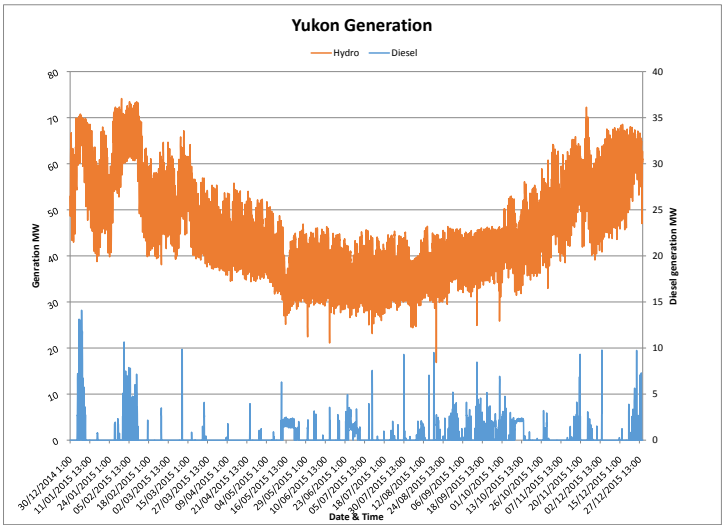

Figure 3 Hydro and Diesel Generation for 2015

Upon closer examination of the diesel generation output, the most active diesel generation time periods in terms of magnitude, frequency and duration were during the months of January and February of 2015. During these periods, the diesel generation reached a peak of 14 MW and the diesel activity was on a regular basis depending on weather conditions and customer energy demands.

As well, Yukon Energy has indicated that their electrical grid does experience overvoltage problems and some frequency deviations from time to time. Actual data was not provided regarding the severity of the frequency shifts (approximately 3 Hz), nevertheless the type of energy storage system must be capable of responding quickly to mitigate these power quality concerns.

Therefore the selection of an appropriate energy storage technology combined with an advanced power conversion system will eventually have to accommodate the present and future energy demands by Yukon Energy in terms of power quality, grid support and load shifting and possible integration of other renewables in to the power grid.

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4. Energy Storage Technologies

Information regarding the literature review originates from various research and technical papers as listed in the References section of this report.

An important characteristic of electricity is that electrical energy cannot be stored directly. Consequently, the supply of electricity must be balanced continuously with the demand for it. The constant balancing of supply and demand has significant operational and cost implications. For example, sufficient generating capacity needs to exist to supply the highest level of demand.

The following section outlines a description of various groups of popular energy storage technologies that were chosen according to the form of stored energy that is employed. Figure 4 illustrates these broad categories in terms of: mechanical energy storage, electrochemical (and chemical) energy storage, electrical and magnetic field energy storage and thermal energy storage.

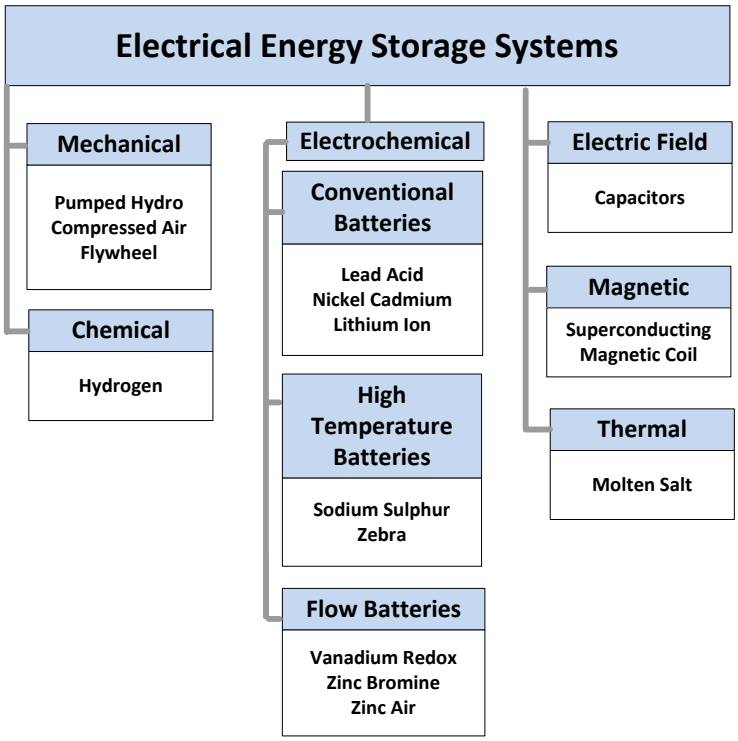

Figure 4 Classifications of Energy Storage Systems

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4.1 Mechanical

4.1.1 Pumped Hydro Storage

4.1.1.1 Technology

Many locations in the United States and around the world use pumped hydro electric energy storage as a large, mature, and commercial utility-scale technology for an energy storage option. Off peak electricity is used to pump water from a lower level reservoir up to another high level reservoir at a higher elevation. When electricity is required, water is released from the upper reservoir through a hydroelectric turbine into the lower reservoir to generate electricity as shown in Figure 5.

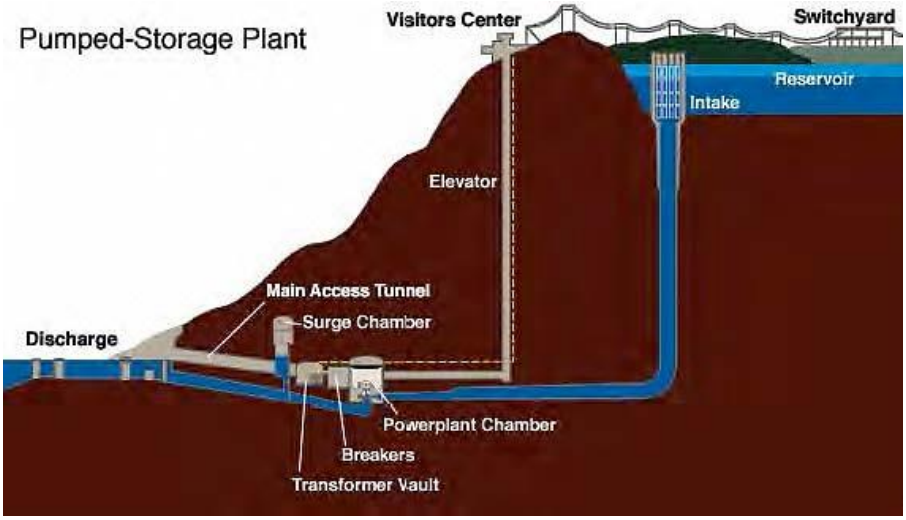

Figure 5 Cutaway of a Typical Pumped Storage System
DOE/EPRI 2013 Electricity Storage Handbook [1]

4.1.1.2 Performance

Depending on design, some projects may be practically sized up to 400 MW and operate at about 76%–85% efficiency. Pumped hydro plants have lifetimes on the order of 50-60 years. Typically a reservoir one kilometer in diameter, 25 meters deep and having an average head of 200 meters would hold enough water to generate around 10,000 MWh. [1]

4.1.1.3 Maturity and Commercial Availability

Pumped hydro storage is a mature form of energy storage. There is growing interest in opportunities for pumped hydro in the United States, however the siting, permitting, and associated environmental impact processes can take many years.

4.1.1.4 Pros and Cons as Applicable to Yukon Energy

For the scope of this work, Yukon Energy has excluded the subject of pumped hydro storage and will not be considered in this report.

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4.1.2 Compressed Energy Storage

4.1.2.1 Technology

Compressed Air Energy Storage (CAES) systems use off-peak electricity to compress air and store it in a reservoir, either an underground cavity or aboveground pipes or containers. When electricity is required on the grid, the compressed air is heated, expanded, and directed through an expander or conventional turbine-generator to generate electricity. [1] Figure 6 shows a typical diagram for an underground compressed air storage system.

There are two general types of CAES: bulk and small. Bulk CAES is practical for storage needs greater than 5 hours and hundreds of megawatts. Typical storage capacity ranges from 300 to 400 MW over the course of 10 to 30 hours. Aboveground systems typically are smaller and have capacities on the order of 10 to 20 MW and shorter discharge times (less than 6 hours). Small CAES systems use pipes, bladders, or other man-made vessels to store compressed air. [2]

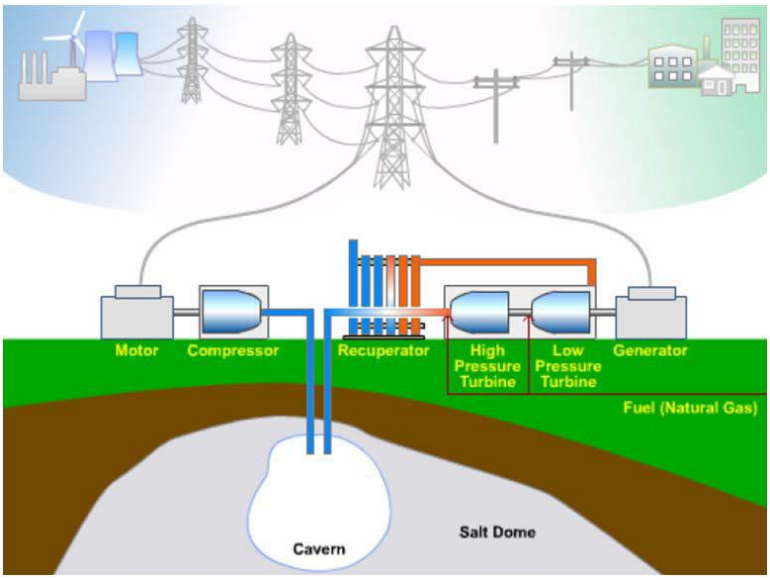

Figure 6 Diagram of a Compressed Air Storage System

Utility Scale Energy Storage Systems Benefits, Applications, and Technologies [2]

4.1.2.2 Performance

Aboveground CAES storage would typically be smaller than plants with underground storage, with capacities on the order of 10 to 20 MW. The discharge times would be 2 to 6 hours. Aboveground CAES plants are easier to locate but more expensive to build (on a $/kW basis) than using underground CAES systems. The reason is primarily due to the incremental additional cost associated with aboveground storage medium. [1]

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4.1.2.3 Maturity and Commercial Availability

CAES is a relatively mature energy storage technology and is the only commercial bulk energy storage plant available today other than pumped hydro. There are two operating first-generation systems: in Germany and Alabama. In the past few years, improved second-generation CAES system cycles have been defined and are being designed. Second-generation CAES hold the potential for lower installed costs, higher efficiency, and faster construction time than the first-generation systems

4.1.2.4 Site Implementation

Aboveground CAES plants are easier to site but more expensive to build (on a $/kW basis) than CAES plants using underground air storage systems, primarily due to the additional cost associated with aboveground storage medium.

Underground CAES storage systems are most cost-effective with storage capacities up to 400 MW and discharge times of 10 to 30 hours. Placement of such plants involves finding and verifying the air storage integrity of a geologic formation appropriate for CAES in a given utility's service area. [1]

4.1.2.5 Pros and Cons as Applicable to Yukon Energy

Yukon has advised that due to the local ground conditions, underground storage could not be considered and aboveground storage would have to be assessed on risk, ease of site implementation and environment considerations.

Recently Toronto Hydro has installed the first ever underwater compressed air storage system in 55 metres of water using balloon like structures. As a pilot project, this is a unique energy storage system as it uses compressed air and water pressure to run its system.

4.1.3 Flywheel

4.1.3.1 Technology

Flywheel Energy Storage (FES) stores energy in the form of the momentum in a rotating mass called the rotor. The work done to spin the rotor is stored in the form of kinetic energy. A flywheel energy system then changes the kinetic energy into AC power through the use of its controls and power conversion systems.

Most modern flywheel technology has some type of sealed housing for safety, reducing friction and performance enhancement purposes. The housing is usually a thick steel vessel surrounding the rotor, motor-generator, and other rotational components of the flywheel. See Figure 7 for a breakdown of the FES components. If there is a failure while spinning, the containment vessel would stop or impede flying parts and fragments, preventing injury and damage to the surrounding equipment or human contact. Containment systems are used also to enhance the performance of the flywheel by means of a vacuum or filled with a low-friction gas to reduce the effect of friction on the rotor. [1]

The rotor is the most important element of flywheel assembly. The rotor mass (diameter and material) influences its energy capacity. The bearings and casing are designed primarily to decrease the friction (which reduces efficiency and shortens life time). The motor-generator and power electronics characteristics determine the maximum power output of flywheel storage systems. An important aspect of flywheel systems is that power and

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energy capacities are relatively independent from each other. This permits the flywheel technology energy and power capacity to be optimized for specific applications. [2]

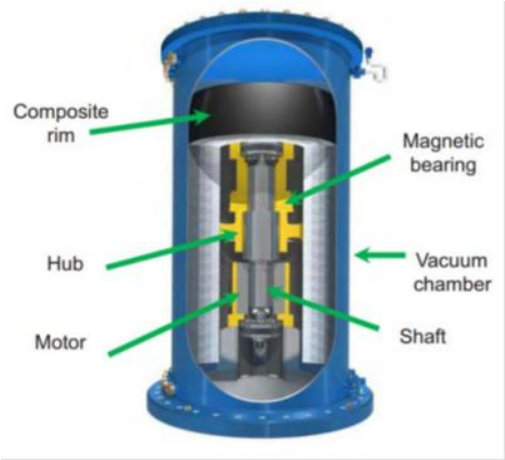

Figure 7 Flywheel Cross Section.

Utility Scale Energy Storage Systems Benefits, Applications, and Technologies [2]

4.1.4 Performance

The overall efficiency and standby power loss are critical design factors in energy flywheel design since the losses represent a degradation of the primary purpose provided by the storage system (energy). Losses are immaterial in a power flywheel design, although standby losses are a factor in operating cost in comparison with other storage technologies that have significantly lower losses. For these reasons, flywheels for energy usage usually require more advanced technologies than power flywheels applications.

The energy flywheels usually have composite rotors enclosed in vacuum containment systems, with magnetic bearings. Such systems typically store between 0.5 kWh and 10 kWh. The largest commercially available systems of this type are in the 2- to 6-kWh range, with plans for up to 25 kWh. Energy flywheels available currently are DC output systems. Overall efficiencies for energy flywheels are usually between 70% and 80%. The standby losses are very small, typically less than 25 W DC per kWh of storage and in the range of one to two percent of the rated output power.

Flywheels can be charged relatively quickly with recharge times comparable to discharge times for both power and energy flywheels designs. High-power flywheel systems can often deliver their energy and recharge in seconds, if adequate recharging power is available.

FES in general exhibit excellent cycle life in comparison with other energy storage systems. Most developers approximate the cycle life in excess of 100,000 full charge-discharge cycles. The rotor is subject to fatigue effects arising from the stresses applied during charge and discharge cycles. The most common failure mode for the rotor is the formation of cracks through the rotor over a period of time. The rotor parts may become loose and propelled by momentum into the surrounding environment, posing danger to personnel or equipment. There is also operating noise that may pose a constraint on the siting of flywheel systems. [2]

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4.1.4.1 Maturity and Commercial Availability

FES is currently being marketed as environmentally safe, reliable, modular, and high-cycle life alternatives to lead-acid batteries for UPS and other power-conditioning equipment designed to improve the quality of power delivered to critical or protected loads. Okinawa Power has installed a demo 23 MW flywheel system for frequency regulation. Fuji Electric has demonstrated the use of flywheel technology to stabilize wind power generation. [1]

They have a very fast response time of four milliseconds or less and can be sized typically between 100 kW and 1650 kW. FES is commonly used for short durations of up to one hour for power quality type applications. They are approaching very high efficiencies ranging from 80 to 90%, with lifetimes estimated at 20 years.

4.1.4.2 Pros and Cons as Applicable to Yukon Energy

Flywheel storage is currently employed for shorter energy duration systems, typically for durations of less than half an hour suitable for power quality type applications or for emergency back up and not generally suitable for Yukon Energy's energy storage requirements. Since FES are generally applicable to short term duration, the cost per kWh is very high ranging from $7800 to $ 8800 US (2010).

4.2 Chemical

Chemical energy storage relies on electric energy to create fuels that may be burned in conventional power plants. An advantage of synthetic methane (and hydrogen to some degree) is that it can be injected into the existing natural gas storage infrastructure. The benefit of chemical storage over some of the other technologies is the high energy density (kWh/liter) of chemical storage compared to most of the other technologies. [3]

4.2.1 Hydrogen

4.2.1.1 Technology

Hydrogen can be used in the combustion process with the compressed air storage technology. [2] In using hydrogen as a fuel, an above ground storage vessel would be advisable due to safety or environmental concerns in Whitehorse.

4.2.1.2 Performance

A typical hydrogen storage system consists of an electrolyzer, a hydrogen storage tank and a fuel cell. An electrolyzer is an electrochemical converter which splits water with the help of electricity into hydrogen and oxygen. It is an endothermal process, i.e. heat is required during the reaction. Hydrogen is stored under pressure in gas bottles or tanks, and this can be done practically for an unlimited time. To generate electricity, both gases flow into the fuel cell where an electrochemical reaction which is the reverse of water splitting takes place: hydrogen and oxygen react and produce water, heat is released and electricity is generated. For economic and practical reasons oxygen is not stored but vented to the atmosphere on electrolysis, and oxygen from the air is taken for the power generation. [5]

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4.2.1.3 Pros and Cons as Applicable to Yukon Energy

Yukon Energy advised that due to the ground conditions, underground gas storage could not be considered and deployment of above ground storage vessels would be a significantly risky option especially when dealing with hydrogen gas with safety and environmental concerns.

4.3 Electrochemical

The Electrochemical classification involves storage technologies that convert electricity to chemical potential for storage and then back again. There are three main categories of electrochemical batteries**:** conventional, high temperature, and flow batteries. This section reviews the basic components, functions, and common examples of each category of battery storage. [3]

4.3.1 Conventional Battery

Conventional batteries are composed of cells which contain 2 electrodes (a cathode and an anode) and electrolyte in a sealed container. During discharge, a reduction-oxidation reaction occurs in the cell in which electrons migrate from the anode (oxidation) to the cathode (reduction). During recharge, the electrochemical reaction is reversed through the ionization of the electrolyte that links the anode and cathode. Numerous combinations of electrodes and electrolytes exist for conventional batteries. Common chemistries for conventional battery energy storage projects include: lead-acid, nickel-cadmium, and lithium-ion. [2]

4.3.2 Lead Acid

4.3.2.1 Technology

Lead-acid batteries are the most established form of rechargeable battery technology. The positive electrode is composed of lead-dioxide, PbO2, while the negative electrode is composed of metallic lead, Pb as shown in Figure 8. The active material in both electrodes is extremely porous to maximize surface area. The electrolyte is a sulfuric acid solution, usually around 37% sulfuric acid by weight when the battery is fully charged.

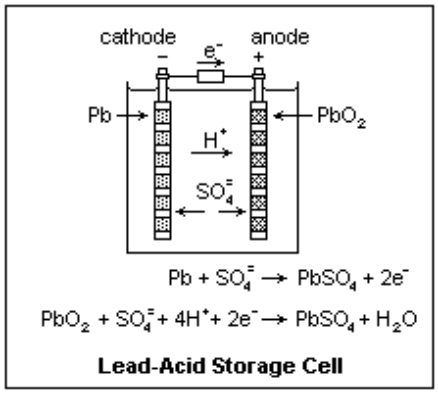

Figure 8 Lead Acid Storage Cell

Lead-acid energy storage technologies are divided into two types: lead-acid carbon technologies and advanced lead-acid technologies. Lead-acid carbon technology has a fundamentally different approach to lead-acid battery and is vented or flooded (VLA) through the inclusion of carbon to improve the power characteristics of the battery and to mitigate the effects of partial states of charge. [1]

Certain advanced lead-acid batteries are conventional valve-regulated lead-acid (VRLA) batteries with technologies that address the inadequacies of previous lead-acid products through incremental changes in the technology. [1]

Maintenance requirements for a lead acid battery involve a float charging, the equalization charging, water replacement and cell post maintenance. To prevent self-discharge, voltage is continuously applied to the already charged battery to generate a small current. Equalization charging corrects the inconsistency in state of charge between individual battery replacement is only necessary for flooded lead acid batteries (not for valve-regulated lead acid) to compensate for water lost through evaporation and electrolysis.

Furthermore, lead acid batteries contain toxic materials that pose environmental and safety hazards. In part due to regulation, lead acid batteries are one of the most recycled products. Regulations typically apply a fee when the battery is purchased which can be used to cover environmental consequences.

4.3.2.1.1 Lead-acid Carbon

Lead-acid carbon technology can exhibit a high-rate characteristic in both charge and discharge with no apparent detrimental effects as are typically experienced in traditional VLA and VRLA batteries. This characteristic allows the lead-acid carbon batteries to deliver and accept high current rates only available with higher-cost nickel metal-hydride (Ni-MH) and lithium ion (Li-ion) batteries. [1]

Presently there are three major lead-acid carbon technologies moving into the market with each having a different implementation of carbon integrated with the traditional lead-acid battery negative plate. The improvements include: significantly faster recharge rates, considerably longer cycle lives in deep discharge applications, and minimal maintenance requirements. The new cell configurations allow thousands of cells to be gathered in massive parallel and series matrices, suited for use in large-scale utility applications requiring many megawatts of power while still maintaining a manageable footprint. [1]

4.3.2.1.2 Advanced Lead-acid Technologies

Advanced lead acid technology has the properties that reduces maintenance requirements, extends life expectancy, and improves cell uniformity which increases both battery life expectancy and cost. These advanced lead-acid products focus on technology enhancements such as carbon-doped cathodes, granular silica electrolyte retention systems high-density positive active material, and silica-based electrolytes. [1]

Some advanced lead batteries even have supercapacitor-like features that give them fast response, similar to flywheels or Li-ion batteries. Advanced lead-acid systems from a number of companies are currently in early field trial demonstrations. [1]

One commercial example is the ultra-battery which is a hybrid advanced lead acid battery-capacitor that claims extended life expectancy. Thin metal film lead acid technology applies a new and fairly difficult construction

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technique to considerably increase power density at the expense of energy density. This research has dropped off due to manufacturing difficulty and short cycle life of these batteries.

4.3.2.2 Performance

Traditional VLA and VRLA batteries are typically designed for optimal performance in either a power application or an energy application, but not both. Which means that a battery specifically designed for power applications can indeed deliver significant amounts of energy but it is not designed to deliver substantial amounts of energy (e.g., 80-percent deep discharges) on a regular basis. [1]

Disposal of lead-acid batteries is an important part of the life cycle. The environmental and safety hazards associated with lead require a number of regulations concerning the handling and disposal of lead-acid batteries. Lead-acid batteries are among the most recycled product in the world.

Lead acid batteries have a 2 V nominal voltage and efficiency ranges between 75% and 85%. Some problems of lead batteries include: self-discharge, sensitivity to temperature, sulfation, hydration, and degradation. These batteries are inclined to self-discharge but can be resolved by injecting a float charge through the battery while it is not operational. Optimal operation for a lead acid battery is at room temperature, approximately 77°F (25°C). [2]

Some advanced lead batteries have supercapacitor-like features that give them fast response, similar to flywheels or Li-ion batteries. [1]

4.3.2.3 Maturity and Commercial Availability

Lead-acid batteries are the most commercially mature rechargeable battery technology in the world. VRLA batteries are used in a variety of applications, including automotive, marine, telecommunications, and uninterruptible power supply (UPS) systems. However, there have been few utility T&D applications for such batteries due to their relatively heavy weight, large bulk, cycle-life limitations, and perceived reliability issues (stemming from maintenance requirements).[1]

Lead acid is the most technologically mature of the battery technologies. It remains popular due to its low cost, despite toxicity, low specific energy and power, short life cycle and maintenance requirements. Lead acid is generally best suited to power quality applications. Overall efficiency is between 75 and 85% and expected life, depending on technology is between 3-10 years. A total of 35 MW of lead acid batteries are deployed for power applications worldwide. [3]

For example a 1-MW, 1.5-MWh lead-acid battery has been operating for 12 years in Metlakatla, AK. In this project, the battery system exhibited very little visible degradation upon post-test analysis and was replaced in 2008, after 12 years of continuous shallow discharge service. Other lead-acid carbon energy systems have been deployed in sizes of 10 to 20 MW. [1]

Hitachi is developing their advanced lead-acid product for renewable integration and smart grid projects in Japan, with the intent of competing with sodium-sulfur (NAS) and Li-ion batteries. In August 2009, Hitachi completed a 10.4-MWh battery, built to stabilize a 15-MW wind facility at Goshogawara in northern Japan. A similar plant was installed in late 2010 at another wind-generation site at Yuasa. This battery is now available to companies for integration into the United States, although costing for the United States is uncertain at this time. [1]

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4.3.2.4 Pros and Cons as Applicable to Yukon Energy

Based on the power/energy requirements by Yukon Energy during the cold and winter months, lead acid battery storage should be able to meet both the required power and energy prerequisites. Power quality attributes for frequency control is available with response times within milliseconds and is dependent on performance characteristics of the front end power conversion/inverter system.

4.3.3 Nickel Electrode

4.3.3.1 Technology

Nickel electrode batteries are known as dry cell batteries. Each dry cell contains a pair of electrodes, a positive nickel electrode and a negative electrode of cadmium, zinc, hydrogen, iron, or a metal halide. Depending on the chemistry of the negative electrode material, a divider is chosen to separate the two electrodes. After cell construction and packaging, liquid electrolyte is circulated into the porous electrodes. Only nickel-cadmium and nickel-iron have utility scale energy storage demonstrations or commercial installations. Of these two, nickel-cadmium remains the most popular for utility energy storage applications. [2] See Figure 9 which shows a typical Nickel Cadmium cell.

Figure 9 Nickel Cadmium Battery

4.3.3.2 Performance

Nickel electrode batteries experience both reversible and irreversible degradation. Reversible forms of degradation are reversed by completely discharging the cell and then recharging. Irreversible degradation varies across electrode types and application but is related to temperature and the depth and number of charge/discharge cycles. Some common irreversible degradation sources include: nickel-electrode corrosion, organic material decomposition into the electrolyte, formation of dendrites on the negative electrode, gas barrier failure, and electrode poisoning. [2]

Nickel electrode batteries have a nominal voltage of approximately 1.2 V and have an overall efficiency ranging from 65 to 85 %. Nickel cadmium batteries typically have much lower efficiency, around 60 and 70 percent (not including losses from ancillary equipment). Unfortunately cadmium is a highly toxic substance.

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This range in efficiency is caused from differences in electrolyte concentration, charging procedures, stand-by time, and operation temperature. Nickel electrode batteries tend to have relatively higher charge losses resulting from a variety of chemical interactions within the battery cells and deviances from ideal operating temperatures. Like many batteries nickel electrode cells are susceptible to "thermal runaway," a vicious cycle of heating and increased discharge and voltage. [2]

4.3.3.3 Maturity and Commercial Availability

Nickel cadmium batteries are the most common nickel electrode battery technology in the utility energy storage industry. Although more costly than lead acid batteries, the relative low cost, high energy density, high power delivery capabilities, hardiness, reliability, and life expectancy of nickel cadmium batteries makes them a popular choice for substation batteries and bulk storage. They are technologically mature and offer a longer life span than lead-acid of around 10-15 years. [3]

Several other nickel electrode battery chemistries are under development, but not yet in commercial use for utility scale storage. Nickel hydrogen batteries have attractive operational features, such as long cycle life, low maintenance requirements, and high reliability, but very high costs. The nickel metal hydride, an offshoot of the nickel hydrogen battery, has many of the same advantages of the nickel hydrogen battery and lower costs. However, it tends to be less hardy to electrical abuses such as overcharge and high rate discharge than nickel cadmium batteries. [2]

There has been one application of 27 MW of installed capacity for 15 minutes and commissioned in 2003 that is being used for electric power systems applications. Ni-Cd has also been used for stabilizing wind-energy systems, with a 3 MW system on the island of Bonaire commissioned in 2010 as part of a project for the island to become the first community with 100% of its power derived from sustainable sources. [ESA website]

4.3.3.3.1 Pros and Cons as Applicable to Yukon Energy

Nickel cadmium batteries are generally suited for grid angularity stability, grid frequency excursion suppression, short duration power quality, which suits some of the small scale applications. However for Yukon Energy, the amount of energy storage requirements for the grid support could not be met.

4.3.4 Lithium Ion

4.3.4.1 Technology

When compared to the long history of lead-acid batteries, Lithium Ion (Li-ion) technology is relatively new to the bulk power/energy storage field. In saying this, the technology is mature and well used in consumer applications and plug in hybrid electric vehicles.

In a Li-ion battery cell there are two reactive materials capable of undergoing an electron transfer chemical reaction. To experience this reaction, the materials must contact each other electrically, either directly or through a wire, and must be capable of exchanging charged ions to keep the overall charge neutrality as electrons are transferred. The battery cell is designed to keep the materials from directly contacting each other and to connect each material to an electrical terminal isolated from the other. These terminals are the cell's external contacts. [1]

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As shown in Figure 10, Lithium ion battery's components include: a carbon (graphite) negative electrode, a metal-oxide positive electrode, an organic electrolyte (ether) with dissolved lithium ions, and a micro-porous polymer separator. When the battery is charging, lithium ions flow from the positive metal oxide electrode to the negative graphite electrode. When the battery is discharging the reverse flow of ions takes place. [2]

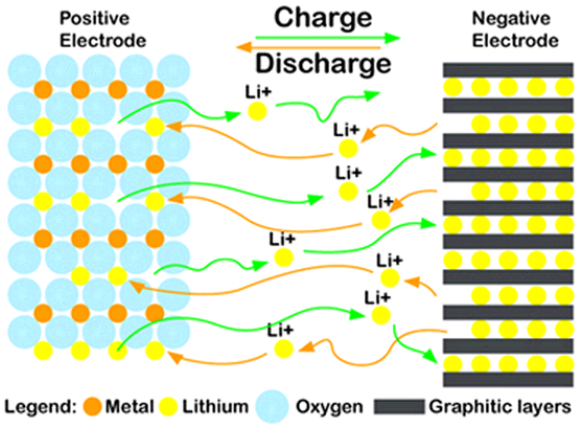

Figure 10 Lithium Ion Function and Components

Utility Scale Energy Storage Systems Benefits, Applications, and Technologies [2]

4.3.4.2 Maturity and Commercial Availability

Since 2000, Li-Ion batteries have become a popular choice for electric vehicle and aerospace applications. This resurgence in research and development of Li-Ion technology for electric vehicle purposes has also led to interest in demonstrating the battery's potential to perform utility functions. [2]

The large scale manufacturing of Li-ion batteries (estimated to be approximately 30 GWh by 2015) may result in possibly lower-cost battery packs which could also be used and integrated into systems for grid-support services that require about 4 hours of storage. Many stationary systems have been deployed in early field trials to gain experience in siting, grid integration, and operation. Li-ion systems now dominate the landscape for grid-scale storage systems in the United States. [1]

Recently, a large investor owned utility in California wanted to evaluate the performance of a battery energy storage system combined with new smart inverter technology. In 2013, the utility installed an 8 MW – 4 hour (32 MWh) lithium-ion battery combined with two 4.5 MVA EssPro PCS units from ABB. The installation was in one of California's largest wind resource areas. The many project benefits of installing this battery energy storage system include added voltage support and grid stabilization, decreases in transmission losses and congestion, frequency regulation support and optimization of the wind energy output through capacity firming and smoothing. [4]

One of the largest Li-Ion installations in the United States is in Elkins, West Virginia. This facility connects 98 MW of wind generation with 32 MW of storage for reserve capacity and renewables integration. [2]

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The technical characteristics of Li-Ion batteries are dependent on the electrodes and electrolyte materials but some observations can be made.

1. Due to their high energy density, Li-Ion cells have nominal voltage of 3.7 V. This is much higher than many other battery cell chemistries, which means fewer Li-Ion cells are needed to produce the same power output.
2. Like some other batteries, the response times are on the order of 20 milliseconds.
3. Li-Ion batteries have relatively high overall efficiency, usually ranging between 87 to 92 %
4. Li-Ion batteries have expected lifetimes of 2,000 to 3,000 cycles or 10 to 15 years.[2]

Li-Ion batteries have several disadvantages [2] as well such as:

1. The expected lifetime is related to the cycling depth of discharge. Li-Ion batteries should not be used for applications that require full discharge.
2. The metal oxide electrode can become thermally unstable due to over discharge or charge and be subject to thermal runaway if left unchecked.
3. Li-Ion batteries still face significant cost barriers.

4.3.4.3 Pros and Cons as Applicable to Yukon Energy

Lithium Ion battery system would be a good fit for the power and energy requirements as well as power quality (frequency regulation) for Yukon Energy needs. In 2013, an 8 MW (32MWhr) lithium-ion battery combined with two 4.5 MW power conversion units by ABB were install and California for grid support and frequency stabilization.

4.4 High Temperature Batteries

4.4.1 Sodium Sulphur Battery Energy Storage

4.4.1.1 Technology

Sodium-sulfur (NAS) batteries are a commercial energy storage technology which is finding applications in electric utility distribution for grid support, wind power integration, and high-value grid services. NAS battery technology has the potential for use in grid services because of its long discharge period (about 6 to 8 hours). Using a suitable inverter, it is capable of prompt and precise response to such grid requirements such as mitigation of power quality events. [1]

NAS battery cells contain a molten sodium (Na) anode as the negative electrode, a solid ceramic electrolyte, with a molten sulfur (S) cathode as the positive electrode. Positively charged sodium ions flow through the solid ceramic electrolyte into molten sulfur where an electrochemical reaction generates a current as shown in Figure 11. To enable ion transfer, the sodium and sulfur are kept molten at temperatures between 300° and 360°C (572° and 680°F). [2]

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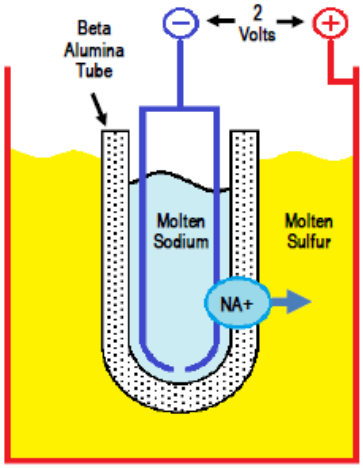

Figure 11 Sodium Sulfur Cell Diagram

Utility Scale Energy Storage Systems Benefits, Applications, and Technologies [2]

4.4.1.2 Performance

Energy density by volume for NAS batteries is 170kWh/m3 and by weight is 117kWh/ton. NGK projects its NAS to have a cycle life of 4500 cycles for rated discharge capacity of 6 MWh per installation MW. Rated at 4500 cycles, NAS batteries are projected to have a calendar life of 15 years. [1]

NAS batteries are suitable for energy, power, or both energy and power applications. Typically, NAS batteries primary function is long duration energy storage, used for load leveling, arbitrage, “islanding,” and renewables output smoothing. However, quick response time (1 millisecond) and the ability to provide pulse power make them suitable for many power quality applications [2].

4.4.1.3 Maturity and Commercial Availability

NAS installations providing the functional equivalent of about 160 MW of pumped hydro storage are currently deployed within Tokyo. NAS batteries are only available in multiples of 1-MW, 6-MWh units with installations typically in the range of 2 to 10 MW. The largest single installation is the 34-MW Rokkasho wind-stabilization project in Northern Japan that has been operational since August 1, 2008. At this time, about 316 MW of NAS installations have been deployed globally at 221 sites, representing 1896 MWh. Customers in the United States include American Electric Power (AEP) (11 MW deployed at five locations), PG&E (6 MW, in progress), and Xcel Energy (1 MW, deployed). [1]

NAS batteries are suitable for energy and/or power applications, generally long duration energy storage. This includes load leveling, arbitrage, “islanding,” and renewables output smoothing, although their fast response time (1 ms) and the ability to provide pulse power make them suitable for a very wide range of applications. [2]

NAS batteries are still in the early stages of commercialization, especially on the grid scale. Thus far, most of the grid applications are in Japan. The overall efficiency is generally high (70 to 90%), although the energy required to maintain the electrodes in a molten state may reduce this efficiency figure.

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Due to their early stage of commercialization, costs remain high and as with many other battery technologies, there are toxicity concerns. There are also safety concerns due to the high operating temperatures and explosive nature of sodium when exposed to water. [3]

In summary, NAS batteries are located in over 190 sites in Japan. More than 270 MW of stored energy suitable for 6 hours of daily peak shaving have been installed. The largest installation is a 34 MW 245 MWh unit for wind stabilization in northern Japan. US utilities have deployed 9 MW for peak shaving.

4.4.1.4 Pros and Cons as Applicable to Yukon Energy

Sodium-Sulfur batteries must operate at extremely high temperatures and can explode if they come into contact with water, making them a safety hazard if not handled properly. Like any battery, toxicity concerns, especially related to decommissioning and disposal, are still major obstacles to widespread installation. Consumers and environmentalists may protest the prospect of batteries located close to residential or highly populated areas.

Since this is still emerging as a commercial grid-scale energy storage technology, cost estimates still remain high. The NAS battery technology does provide the power and energy requirements for Yukon Energy as well as the power quality support available on demand. A drawback is there is currently one major off shore supplier of this technology and competitive pricing would be difficult.

4.4.2 Zebra (Sodium Nickel Chloride)

4.4.2.1 Technology

Sodium nickel chloride batteries are also referred to as Zero Emission Battery Research or (Zebra). Like the NAS battery, it is a molten sodium based battery. It contains a molten sodium negative electrode and a nickel chloride positive electrode as illustrated in Figure 12. To support in ion transfer, the battery operates around 270°C (518°F). [2]

When charging a Sodium-nickel-chloride battery at normal operating temperatures, salt (NaCl) and nickel (Ni) are transformed into nickel-chloride ($NiCl_2$) and molten sodium (Na). The chemical reactions are reversed during discharge and there are no chemical side reactions. The electrodes are divided by a ceramic wall (electrolyte) that is conductive for sodium ions but an isolator for electrons. The cell reaction can only occur if an external circuit allows electron flow match to the sodium ion current. The porous solid $NiCl_2$ cathode is impregnated with a sodium ion conductive salt ($NaAlCl_4$) that offers a conductive path between the inside wall of the separator and the reaction zone. Cells are hermetically sealed and bundled into modules of about 20 kWh each. [1]

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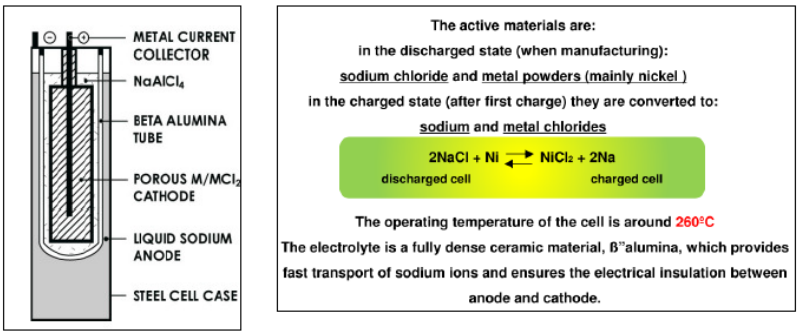

Figure 12 Deign and Features of a Zebra Battery

DOE/EPRI 2013 Electricity Storage Handbook [1]

This technology has been commercially available since 1995. So far, much of the recent research has been with electric vehicles however, there is development of Zebra systems for renewables integration and load leveling applications. [2]

4.4.2.2 Performance

Technically Zebra batteries are so far rated power between 5 and 500 kW with up to 100 kWh of energy. Zebra units have 85-90% overall efficiency, 20 millisecond response times, and expected cycle lives of up to 3,000 cycles at 80 percent depth of discharge.[2]

4.4.2.3 Maturity and Advantages

Advantages of Zebra over NAS technology includes:

- tolerance of overcharge and discharge
- higher cell voltage
- potentially better safety characteristics

Due to its high tolerance to short circuits, the failure of one cell does not cause complete failure of the Zebra battery. [2]

4.4.2.4 Pros and Cons as Applicable to Yukon Energy

Sodium nickel chloride technology does not have the energy capacity requirements of Yukon Energy.

4.4.3 Flow Batteries

Flow batteries are unlike conventional batteries and high temperature batteries because of cell construction. The electrolyte material is stored in tanks external to the electrodes. During discharge and charge, electrolyte is pumped from its container into the cell stack to interact with the electrodes, see Figure 13. Flow batteries are now considered a practical choice for energy applications requiring discharge durations greater than 5 hours due to cost efficiencies with large volumes of relatively low-cost electrolyte material. [2]

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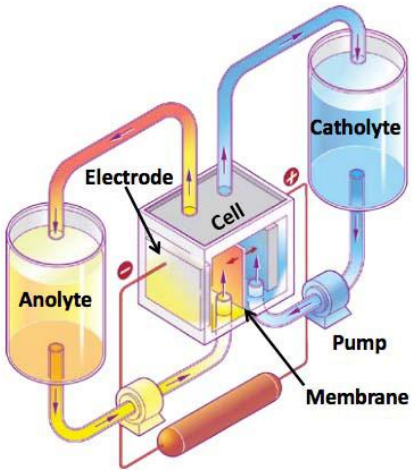

Figure 13 Flow Battery Construction

Utility Scale Energy Storage Systems Benefits, Applications, and Technologies [2]

Unique to flow batteries is the ability to independently control and vary energy and power capacity. The discharge duration (energy) is determined by the volume of electrolyte, while the power ratings are determined by the number of cells. The ease with which electrolyte can be chemically managed and replaced as well as tolerance for overcharge/discharge and partial state of charge makes them robust to processes that degrade conventional and high temperature batteries' lives.[2]

Disadvantages of flow batteries relate to cost and construction complexity. The addition of pipes, plumbing, tanks, and other non-electrochemical components increase probability and cost of repair and electrolyte leakage. Flow batteries have relatively low power and energy density compared to their conventional and high temperature counterparts. Additionally, there are efficiency losses accrued by auxiliary equipment used to pump electrolytes from tanks to cells. [2]

There are two types of flow batteries: hybrid flow batteries and redox flow batteries.

Hybrid Flow

Hybrid flow batteries have one or more electro-active components deposited as a solid layer and the battery cell contains one battery electrode and one fuel cell electrode. A hybrid flow battery's energy is limited by the size of the battery electrode. [2]

Redox Flow

Redox flow batteries are a reversible fuel cell in which electro-active components are dissolved in the electrolyte. A redox flow battery's energy is related to electrolyte volume and power is related to electrode area in the cells. Common redox flow battery chemistries include zinc bromine and vanadium. [2]

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4.4.4 Vanadium Redox

4.4.4.1 Technology

Vanadium redox flow batteries (VRB) contain vanadium ions that are dissolved in an acid aqueous solution. The main components of a VRB are the electrolyte, a carbon felt electrode, an ion exchange membrane that separates the electrolytes, a bipolar plate that separates cells, and the electrolyte tanks, pumps, and piping as shown in Figure 14. [2]

Both the negative and positive electrolytes (sometimes called the anolyte and catholyte, respectively) are made of vanadium and sulfuric acid mixture at approximately the same acidity as that found in a lead-acid battery. The electrolytes are stored in external chambers and pumped as needed to the cells. [1]

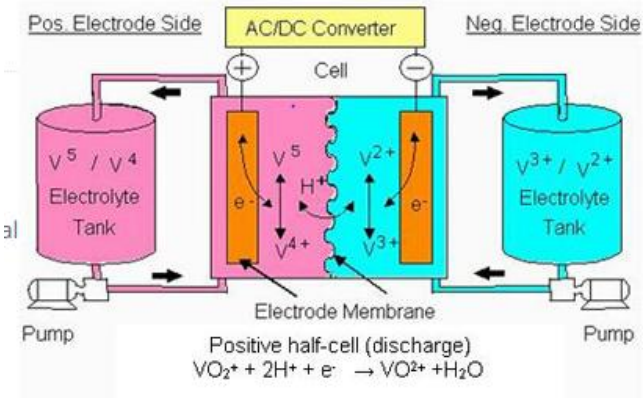

Figure 14 Vanadium Redox Battery System

4.4.4.2 Performance

VRB flow battery is suited for energy applications such as peak shaving and spinning reserve. Their full power discharge ranges from four to ten hours. Life expectancy is 10 to 15 years, with the internal membrane the limiting factor, although refurbishment can extend the lifetime to 20 years. Efficiencies are in the 60 to 70% range with nearly instantaneous response times for the battery itself (0.35 ms), although the pumps and power electronics have a slower response time, overall one can expect a response of several milliseconds. [3]

Vanadium redox batteries have recently demonstrated their compatibility with PV and wind generation, load leveling, and power quality and reliability, as well as spinning reserve. Like all flow batteries, rated energy and rated power are independently determined. Both the concentration of vanadium ions in the electrolytes and the tank volumes determine the energy storage capacity in a VRB. There are about 20 to 30 watt-hours per liter of electrolyte when the battery is fully charged. [3]

The electrode surface area determines the power of a VRB system. In contrast to conventional batteries, VRBs are generally useful for energy applications because the volume of electrolyte determines energy capacity. Full power

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discharge ranges between four and ten hours for systems as of 2006. Each cell has a nominal voltage of 1.4 V and supplies about 26 watts.

4.4.4.3 Maturity and Advantages

Flow batteries, including the VRB have a much larger space requirement than other electrochemical storage technologies, for example a VRB system rated at 2.5 MW and 10 MWh requires between 12,000 and 17,000 square feet. This is about twice as large as the estimated space requirements for other electrochemical storage technologies.

Current commercial units are around 5 kW in size, although some demonstration units are around 250 kW and expected rated power is between 100 kW and in the future up to 10 MW. Each liter of electrolyte provides 20 to 30 Whr at full charge. [2] Presently there are 50-kW, 100-kW, 500-kW, 600-kW, and 1000-kW systems in operation. The largest in the U.S. is a 600-kW/3600-kWh system in a customer energy-management application. A 1-MW, 5-MWh system is in operation in Japan.

Advantages

Vanadium redox batteries have two main advantages over other flow battery chemistries:

1. The positive and negative electrolytes are the same when the battery is in a discharged state. This has several implications for cost, manufacture, and efficiency. Costs to ship, store, and manage electrolyte are low and the electrolytes will not contaminate each other should they be mixed (the battery will only self-discharge).

2. The sulfuric-based electrolyte does not release poisonous or corrosive vapors like other flow batteries using halide-based electrolytes.

The Vanadium redox battery could be suitable for power systems with future demonstration projects ranging in size with ratings of 100kW to 10 MW and storage durations in the 2 to 8 hour range.

4.4.4.4 Pros and Cons as Applicable to Yukon Energy

Size is a concern, as a flow battery generally has twice the footprint of a similar electrochemical storage device. Figure 15 shows system consists of 200-kW modules providing a total of 6 hours of electrochemical energy storage.

This type of technology could be suitable for the requirements of Yukon Energy depending on the rating and size requirements and as long as there are no physical constraints on site. The socio- economics still would have to be evaluated for this technology.

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Figure 15 Prudent Energy 600kW/3 600 kWh VRB

DOE/EPRI 2013 Electricity Storage Handbook [1]

4.4.5 Zinc Bromine

4.4.5.1 Technology

Another type of flow battery is the Zinc-bromine battery in which the zinc is solid when charged and dissolved when discharged. The bromine is always dissolved in the aqueous electrolyte. The cell is made of two electrode surfaces and two electrolyte flow streams separated by a micro-porous film. The positive electrolyte is called a catholyte; the negative is the anolyte. Both electrolytes are aqueous solutions of zinc bromine (ZnBr2). [1]

During the charging, elemental zinc is plated onto the negative electrode. Elemental bromine is formed at the positive electrode. Ideally, this elemental bromine remains only in the positive electrolyte. The micro-porous separator allows zinc ions and bromine ions to migrate to the opposite electrolyte flow stream for charge equalization as shown in Figure 16. At the same time, it inhibits elemental bromine from crossing over from the positive to the negative electrolyte, reducing self-discharge because of direct reaction of bromine with zinc. [1]

Zinc bromide batteries are still in the initial stages of development, but have the potential for low cost and high energy density. Sometimes the zinc builds up unevenly on the electrodes and as a result the battery must be fully discharged every 5 to 10 cycles.[3]

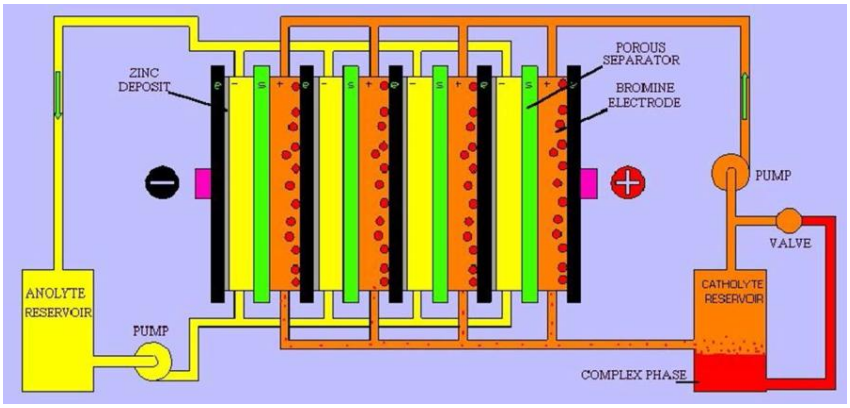

Figure 16 Zinc Bromine Cell Configuration

DOE/EPRI 2013 Electricity Storage Handbook [1]

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4.4.5.2 Performance

The most common factor in degradation and potential failure of Zinc-bromine batteries arises from the extremely corrosive nature of the elemental bromine electrolyte. This substance tends to attack all the components of the Zinc-bromine system that are exposed to it. Past failure modes have included damaged seals, corrosion of current collectors, and warped electrodes. The active materials themselves do not degrade. The significance of this fact is that the lifetime is not strongly dependent on the number of cycles or the depth of discharge, but on the number of hours that the system has been operational. During normal operation, Zinc-bromine batteries do not present unusual environmental hazards. They do contain materials however that can become environmental contaminants. Bromine is a toxic material and should be recovered in the event of a spill or when the unit is decommissioned. Zinc-bromine is a corrosive and should be handled appropriately. Zinc is considered a transition-metal contaminant in some locales and thus should be properly recovered when the unit is decommissioned [1].

Zinc bromide flow batteries have relatively high total efficiencies ranging between 70 and 80 percent depending on system design. A typical ZnBr cell has a nominal voltage of 1.8 V and operates at or slightly above room temperature, between 20ºC and 50ºC. Although system temperature does impact efficiency, it is to a lesser degree than some other storage technologies. [2]

As bromine is extremely corrosive the limiting factor in lifetime of the units is not charge cycles but simply hours the storage system has been in operation, with estimates of around 6,000 hrs. The corrosive property is potentially a human and environmental hazard as well.[3]

4.4.5.3 Maturity and Applicability & Availability

Zinc-bromine batteries are in an early stage of field deployment and demonstration trials. While field experience is currently limited, vendors claim estimated lifetimes of 20 years, long cycle lives, and operational AC-to-AC efficiencies of approximately 65%. Module sizes vary by manufacturer but can range from 5 kW to 1000 kW, with variable energy storage duration from two to six hours. In the United States, electric utilities plan to conduct early trials of 0.5 – 1.0 MW systems for grid support and reliability by 2014. [1]

Zinc bromine flow batteries are best suited for load shifting and applications requiring high energy density as opposed to high power density. Example applications currently in use include load shifting (peak shaving) (Japan and Australia), regulation control (load following) (Detroit, Michigan), and renewables time shifting (50 kW, 100 kWh New York). The Imajuku plant in Fukuoka, Japan is rated at 1 MW and 4 MWh and is directly connected to the grid to perform peak shaving purpose. [2]

4.4.5.4 Pros and Cons as Applicable to Yukon Energy

As a consequence of corrosive liquid bromine in the electrolyte there is the possibility of hazardous environmental event or personnel exposure. Although not expected to leak, should some electrolyte contaminate the surrounding area, it could prove hazardous to proximate personnel.

The corrosiveness of the liquid bromine is a significant environmental concern when making decommissioning and disposal preparations. Due to energy limitations this technology would not be applicable to Yukon Energy requirements.

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4.4.6 Zinc Air

4.4.6.1 Technology

Zinc-air batteries are a type of metal-air electrochemical cell technology. Metal-air batteries use an electropositive metal, such as zinc, aluminum, magnesium, or lithium, in an electrochemical couple with oxygen from the air to produce electricity. Since these batteries only require one electrode, they can potentially have very high energy densities. In addition, the metals used in most metal-air designs are relatively low cost. The oxygen serves as an electrode, while the battery construction includes an electrolyte and a zinc electrode that channels air inside the battery as shown in Figure 17.[1]

A current is created when the air electrode is discharged with the help of catalysts that produce hydroxyl ions in the liquid electrolyte. The zinc electrode is then oxidized to releases electrons to form an electric current. During recharging, the process is reversed, and oxygen is released into the air electrode.

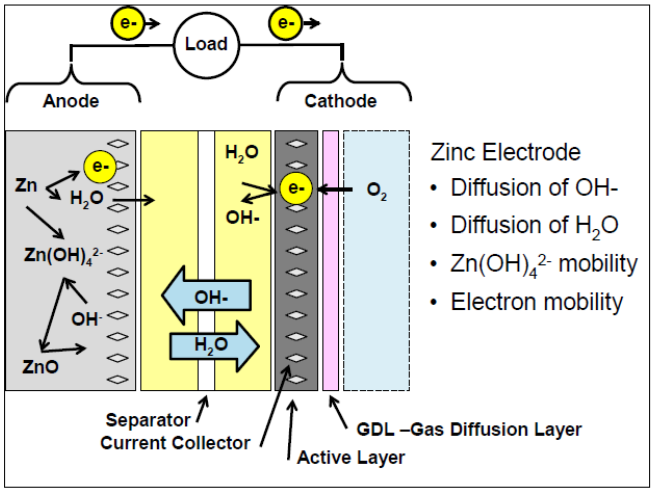

Figure 17 Zinc Air Battery Diagram
DOE/EPRI 2013 Electricity Storage Handbook [1]

4.4.6.2 Performance

Electric recharge has been challenging and inefficient with metal-air batteries, with typical overall efficiencies between 50 and 75% percent. Various manufacturers have tried to overcome low efficiencies with mechanically rechargeable systems in which the discharged metal anode is replaced with a fresh metal anode and the system continues to operate. [1]

Zinc-air batteries have up to three times the energy density of Li-ion, but unlike Li-ion, Zinc-air batteries neither produce potentially toxic or explosive gases, nor contain toxic or environmentally dangerous components., The main material in a zinc-air battery is Zinc-oxide which is 100-percent recyclable.[1]

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4.4.6.3 Maturity and Commercial Availability

Zinc-air technology is still in early R&D phase for stationary storage systems for grid services markets although technology holds a great deal of potential due to its low capital cost for grid support and potentially for electric transportation applications.

Research and Development is underway by several manufactures to bring this energy-dense, high-operating-efficiency, better depth-of-discharge stationary technology into the market for utility T&D grid support, with some research still in the university laboratory stage.

4.4.6.4 Pros and Cons as Applicable to Yukon Energy

Zinc air energy storage is a relatively new technology and would not be suitable for the requirements of Yukon Energy.

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4.5 Electrical Field

4.5.1 Electrochemical Capacitors

In general capacitors consist of two electrical conductors separated by a non-conducting material (a dielectric), is used to store energy in the form of an electric field. When a charge is applied across the conductors, opposite electrical charges build up on the conductors, creating an electric field. Energy is stored in the electric field. The capability of the capacitor to store energy is determined by the surface area of the conductors and the distance between. Most capacitors consist of two plates separated by a thin dielectric.

There are three types of capacitors: electrostatic, electrolytic, and electrochemical. An electrolytic capacitor is distinguished from an electrostatic capacitor because it uses a liquid electrolyte as one of the plates. [2]

In electrochemical capacitors (also called double layer, super-capacitors or ultra-capacitors) have a higher energy density than other capacitors. Some double layer capacitors have a voltage rating at or above 600V. This makes them suitable for power quality and intermittent renewables fluctuation suppression applications. [2]

4.5.1.1 Technology

Electrochemical capacitors are usually called double layer capacitors (DLC) or commonly known as super-capacitors or ultra-capacitors. They are distinct from other capacitors because of their high energy density. Electrochemical capacitors consist of two electrodes, a separator, an electrolyte, two current collectors and a container as shown in Figure 18. Capacitors store energy statically as opposed to batteries which store energy chemically. Electrochemical technology is similar to battery technology in that they use aqueous electrolyte and are configured into cells. [2]

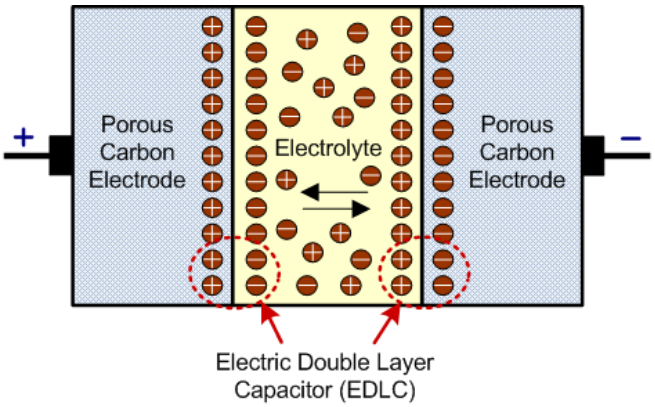

Figure 18 Capacitor Construction Diagram

Utility Scale Energy Storage Systems Benefits, Applications, and Technologies

General Electric introduced a two-terminal charge storage device in the late 1950's and by 1979, capacitor storage was used for computer memory backup applications. They have since evolved and are able to store much more electricity, with some series of electrochemical capacitors having voltages at or above 600 V. These high power levels make it suitable for power quality and intermittent renewables fluctuation suppression applications. [2]

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There are two basic double-layer capacitor (DLC) electrode configurations, symmetric and asymmetric. Symmetric configurations have identical electrodes, while asymmetric designs have different electrodes. [2]

The two main features of capacitor technology are the extremely high capacitance values, of the order of many thousand farads, and the possibility of very fast charges and discharges due to extraordinarily low inner resistance which are features not available with conventional batteries. [5]

4.5.1.2 Performance

The disadvantages of DLCs are firstly the interdependence of the cells, sensitivity to voltage imbalances between cells and maximum voltage thresholds, and the safety issues. If just one cell in the string fails, it may lead to the breakdown of the entire string, or it may lead to a voltage and stress increase across the other cells. This then follows into the second disadvantage that the cells life expectancies are directly tied to stringent maximum voltages. [2]

Due to their chemical properties, DLCs are suited especially to applications with a large number of short charge/discharge cycles, where their high performance characteristics can be used. However DLCs are not suitable for the storage application requiring energy over longer periods of time because of their high self-discharge rate, their low energy density and high investment costs. [5]

4.5.1.3 Safety

There are several safety issues associated with electrochemical capacitors including electrical, chemical, fire, and explosion hazards. Electrical and chemical hazards are similar to those common to batteries. The voltages of double layer capacitors are often lethal and should be treated with the same precautions as other high voltage devices. Type I and III capacitors have aqueous electrolyte which eliminates the possibility of hazardous fires, but allows for the possibility to chemical burns similar to those from other electrochemical storage devices. Type II poses a potential fire threat and health threats if inhaled, ingested, or contacts skin. [2]

There are also environmental implications due to the lack of recycling programs for electrochemical capacitors. This may contribute to siting, permitting, and disposal costs.

4.5.1.4 Applicability to Yukon Energy

Due to their low energy storage capacity, short duration of discharge and safety issues with capacitor technology, the use of DLC technology is not considered a viable option for Yukon's application.

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4.6 Magnetic Field

4.6.1 Superconducting Magnetic Energy Storage

4.6.1.1 Technology

Superconducting Magnetic Energy Storage (SMES) uses the flow of direct current through a cryogenically-cooled, superconducting coil to produce a magnetic field that stores energy. Once the superconducting coil is charged, the current does not decay and the magnetic energy can be stored for an indefinite amount of time. The stored energy can be released whenever needed by discharging the coil. To keep the magnetic coil cool enough to have superconducting properties, cryogenic refrigeration must be an essential part of the storage system. See Figure 19 which shows a simplified diagram of the system. [2]

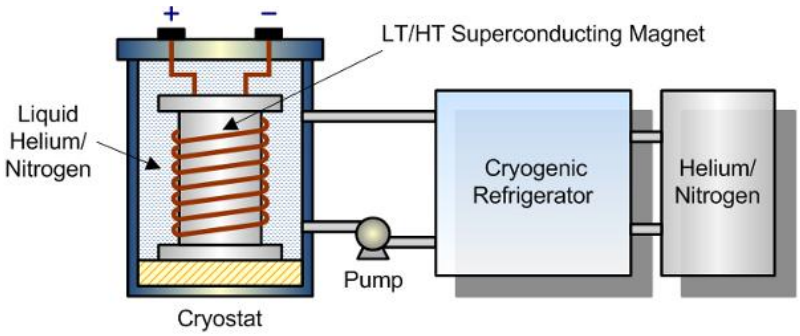

Figure 19 Diagram of a SMES System

4.6.1.2 Performance

SMES systems have several advantages including permanent storage, immediate response, life expectancy that is independent of duty cycle, high efficiency, and high reliability. The implied permanent storage relates to the stored energy may be held indefinitely, meaning that there are no standby losses. This is due to the sources of efficiency loss such as heat dissipation, and evaporation do not exist for SMES technology. Also a SMES system is capable of almost instantaneous response and is limited only by solid state materials ability to react in a charge/discharge cycle. [2]

The charging and discharging characteristics of the magnetic field has a much faster process than the mechanical and chemical energy conversion processes. This quality makes a SMES an excellent choice for UPS and power quality applications. The life expectancy of SMES a does not rely on the number of cycles or the depth of discharge as other storage technologies. The SMES overall efficiency is above 95 percent and there are very few mechanical moving parts. This means that there are less chances of failure and makes the SMES highly reliable technology. Some major disadvantages of SMES technology are the refrigeration energy requirements, the use of huge magnetic fields, and system costs.

The only commercial large scale SMES systems available around the 2000 to 2002 time frame were the D-SMES systems manufactured by American Superconductor (AMSC). The D-SMES unit is trailer-mounted system with a

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capacity to deliver 3 MW for about 1 second and 8 MVAR continuously at 480 Volts (AC). Their primary use was for grid stabilization.Table 1 below shows the locations and applications of these three D-SMES systems. [2]

Table 1 Commercial D-SMES in the United States

In Service Date	Utility	Location	Application
June 2000	Wisconsin Public Service	Northern Wisconsin	Transmission loop stability
July 2000	Alliant Energy	Reedsburg, Wisconsin	Transmission voltage stability
May 2002	Entergy	North Texas	Voltage stability

4.6.1.3 Maturity and Commercial Availability

Prior to making the D-SMES units, American Superconductor had manufactured several smaller SMES units designed for power quality applications where fast response times are needed. These units were used mostly in industrial settings to deal with voltage sag issues.

4.6.1.4 Pros and Cons as Applicable to Yukon Energy

SMES technology does not have the energy and discharge capability to supply the Yukon power grid's energy requirements.

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4.7 Thermal

There are several thermal storage technologies that are used to provide support to the electric power grid. Only molten salt energy storage will be considered since most of the other thermal storage technologies are on the consumer's side of the meter.

4.7.1 Technology

In a basic system, molten salt is pumped to a receiver which absorbs reflected sunlight from a heating chamber. The molten salt then is circulated through highly specialized piping in the receiver (heat exchanger) during the day, and held in storage tanks at night. The tanks store the salt at atmospheric pressure. Use of molten salt for both heat transfer and thermal energy storage minimizes number of storage tanks and salt volumes needed. Molten salt is stored at 1050°F (566°C) until electricity is needed, whether or not the sun is shining. As electricity is required, molten salt is pumped from the hot tank through a heat exchanger to create super-heated steam which then powers a conventional steam turbine. The molten salt never needs replacing or topping up for the entire 30+ year life of the plant. Heat loss is usually only 1°F per day. The molten salt, an environmentally friendly mixture of sodium nitrate and potassium nitrate, is able to be utilized as high grade fertilizer when the plant is eventually decommissioned. [3]

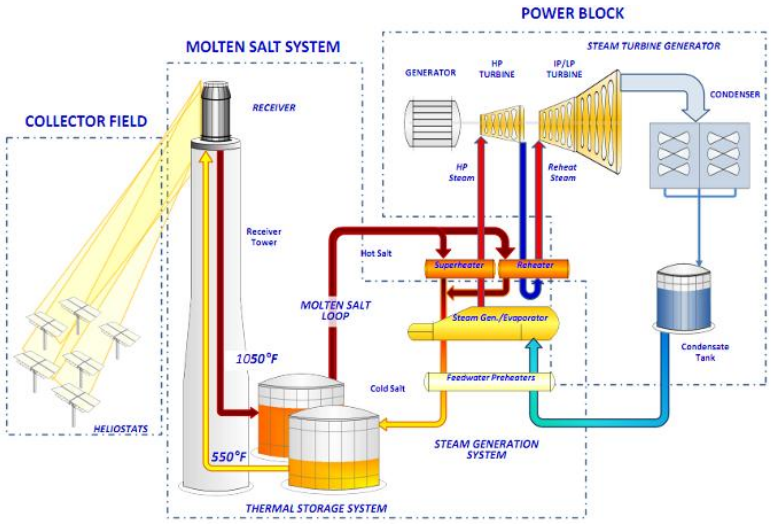

Figure 20 Molten Salt Energy Storage System

4.7.2 Performance

There a two solar heat facilities in the United States. One is the Abengoa's Solana 280 MW solar power station in Arizona which began operating in October 2013 with six hours of thermal energy storage.

Another project is Solar Reserve's 110 MW Crescent Dunes power tower solar thermal plant near Tonopah, Nevada that will have 10 hours of storage and is scheduled for completion in 2014. [3] In late September, 2011, the project received a $737 million loan guarantee from the US Department of Energy. ACS Cobra was the EPC contractor which carried out the engineering design, procured the equipment and materials necessary, and then constructed and delivered the facility to Tonopah Solar Energy. The project entered commissioning phase in

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February 2014 following completion of construction. See Figure 21 which shows an overview of this solar collector site.

Figure 21 Crescent Dunes Solar Collector Site

All power generated by the Crescent Dunes project in the next 25 years will be sold to Nevada Power Company for $0.135 per kW hour. It has been in operation since September 2015.

The relatively low efficiency (25-35%) may be offset by relatively low capital costs if the resistance heating capability is added to an existing solar thermal plant.

4.7.3 Maturity and Applicable to Yukon Energy

Molten salt energy storage is widely used with solar power energy applications. This type of technology would not be compatible with the energy storage requirements for Yukon Energy as there are no solar energy installations at present.

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5. Comparison of Energy Storage Technologies

There is a wide range of different energy storage technologies that are available as documented in the previous section. The selection of the most applicable technology(s) depends on the particular application which is based on the rated power, rated energy, and discharge duration demands of the electrical grid. The selected technology must also address any power quality requirements such as frequency regulation with a front end inverter and storage that can quickly respond to these variations.

Table 2 summarizes the various energy storage systems that were looked at for this project. From this table, there are four promising storage technologies that have been identified based on an estimated power rating requirement ranging from 1 to 10 MW and with an energy component ranging from 30 to 60 MWh with discharge duration between 2 to 5 hours. The power, energy and discharge requirements are an approximation derived from the Yukon Energy's diesel power generation over the 2015 time period. The selection of the four technologies was also verified by Figure 22 which confirms that the technologies that were selected were appropriate for the energy capabilities. Figure 23 shows how quickly these technologies can discharge and is useful when considering which technologies are best for providing power quality and grid support aspects.

There are also requirements that that promising technologies be mature and proven with minimal risks and be a cost effective solution to offset the present diesel generation of their grid.

The four promising energy storage technologies that were identified were all electrochemical based and are as follows:

1. Lead Acid Battery
2. Lithium Ion Battery
3. Sodium Sulphur Battery
4. Vanadium Redox Battery

Of these four energy storage technologies, only two were selected based on safety, overall cost and proven technology, and those were the lead acid battery and lithium ion battery.

The determination of the power, energy and discharge characteristics will be determined which will provide further information into the costing and footprint of the system. The next section of the report explains the cost estimates and physical size of these two technologies and options for the integration into the electrical grid. A comparison then can be made of which energy storage system would be most economical and best fit.

As reported previously, there is only one off shore supplier of the Sodium Sulphur battery, therefore competitive pricing would be an issue and there are safety concerns due to high operating temperatures. The Vanadium Redox battery would have a large footprint and is still in the development stage with the largest commercial system in service system at 600 kW

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Table 2 Comparison of Energy Storage Systems

Storage Type	Power	Capacity (MWh)	Discharge Duration hrs	% Efficiency or Total Cycles	Lifetime years	Total Capital Cost (USD/kW) Note 1
Pumped Hydro	250 MW -400 MW	1600 – 14,000	2 to 24	76%-85% >13,000	50 to 60	1500 – 4300 Size dependant
CAES (Above Ground)	3 to 50 MW	250	2 to 6	>13,000	35	390 - 430
Flywheel	100 kw to 1650 Max:20 MW	0.5 to 10 kWh Plans to 25	5 sec to 15 min	70 to 80% >100,000	20	1950 to 2200
Hydrogen	Demo NA	Demo NA	Demo NA	30 to 45%	demo	1370 to 2740
Lead acid Batteries (advanced)	3 to 50 MW	250	10 sec to several hrs	75-80 (DC) 70-75 (AC) 4500 cycles	3 to 10	1740 to 2580
Nickel Cadmium Batteries	3	Total installed capacity 27 MW	15 min	60 to 70%	10 to 15	NA
Lithium Ion Batteries	8 MW	32 MWh	15 min to several hours	87 to 92% 2000 to 3000	10 to 15	4300 to 6200
Sodium Sulfur High Temp	34 MW	245 MWh	8 hr	80 to 85%	15	3100 to 3300
Sodium Nickel Chloride (Zebra)	50 kW to 2 MW	Up to 8hrs	80% depth of charge	85 to 90%	Up to 3000 cycles	4500 and 10,00
Vanadium Redox	4 MW	Demo up to 250 MWh	2 to 8 hrs	60 to 70%	10 to 15	3100 to 3700
Zinc Bromine	40 to 100kW Demo to 1 MW	4 MWh	2 to 6 hrs	60 to 80%	20	1450 to 2420
Zinc Air	1 MW	5.4 MWh	5.4	50 to 75%	4500	1900 to 3900
Electrochemical Capacitors (DLC)	1 MW	Very low	Up to 30 seconds	90%	>500,00 cycles	1500 to 2500
SMES	1 to 3 MW	low	milliseconds to 3 seconds	90%	>30,000 cycles	1000 to 10,000
Thermal Molten Salt	Demo 280 MW	Demo	6hrs	25 to 35%	NA	NA

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Note 1 : Costs are estimations based on several sources between 2003 and 2013 and are representative of that time period and do not reflect the 2015 dollar values. [1], [2], [3], [7]

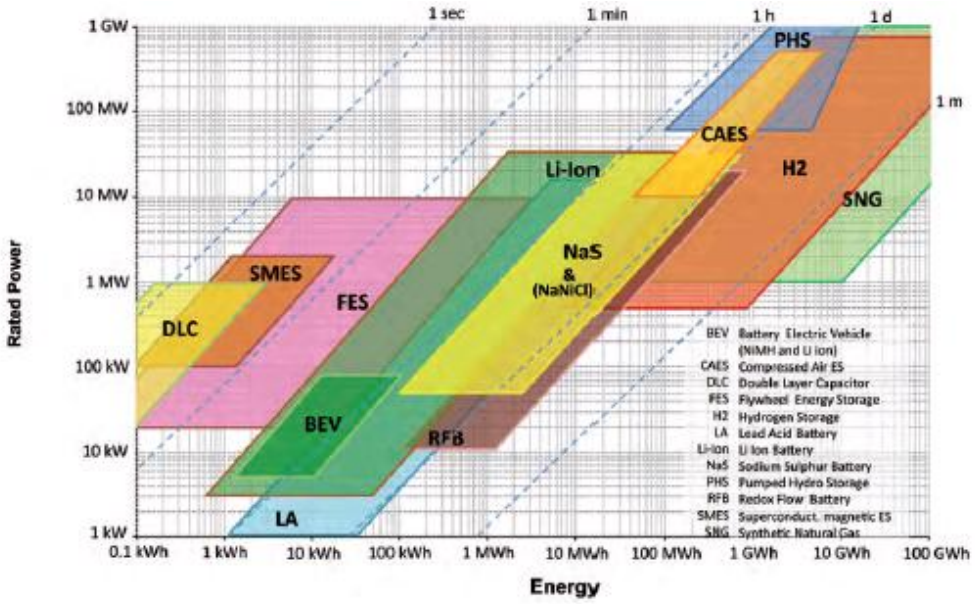

Figure 22 Rated Power Energy and Discharge Duration

Utility Scale Energy Storage Systems Benefits, Applications, and Technologies [2]

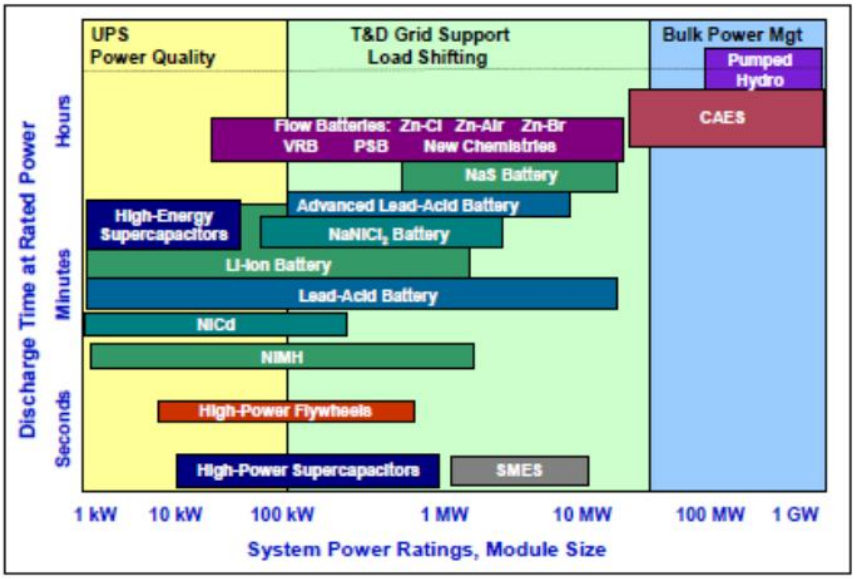

Figure 23 Comparison of Discharge Time Rating

Prospects for Large Scale Energy Storage in Decarbonized Power Grids [7]

5.1 Determining the Energy Storage System Power and Rating

The battery energy storage system power rating will be determined to reduce the use of the diesel generation while utilizing the two natural gas reciprocating engines (8.8 MW in total) during peak demand. Yukon Energy provided information that the two gas units are rated at 4.4 MW each and can be base loaded for at least 4 hours. The use of the gas generation will decrease the rating of the storage system to an optimal size based on the Yukon's Energy's requirements for a safe and mature technology.

In order to understand how often the peak power demand in 2015 reaches distinct values, a chart was developed which shows the frequency of the peak diesel power demand (see Figure 24).

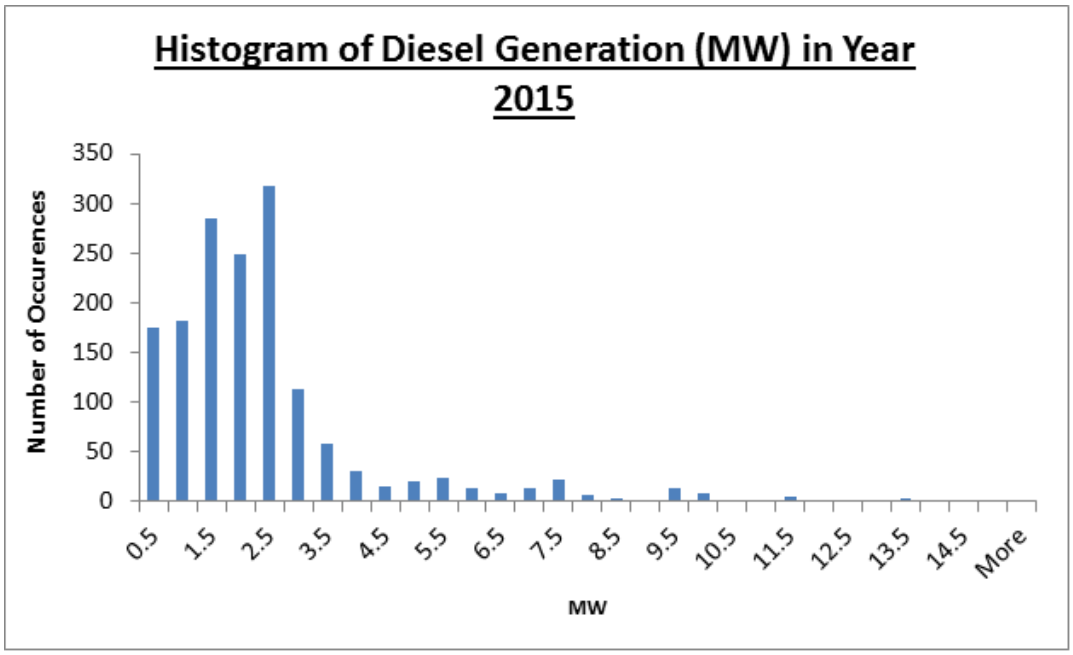

Figure 24 Frequency Plot for Different Power Levels

The general shape of the histogram is that of a Weibull distribution rather than a normal distribution, so that the median and mean values are not equal. Figure 25 shows the cumulative probability distribution for the peak power demand.

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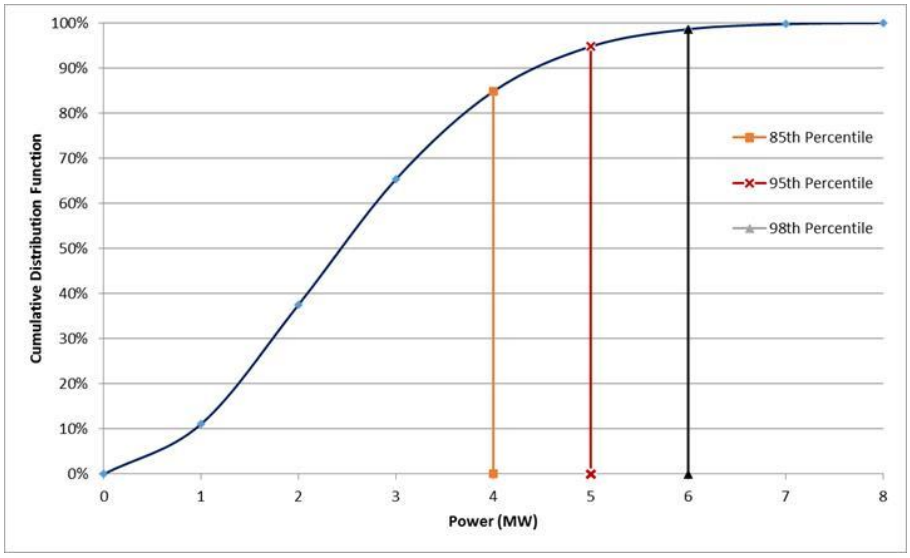

Figure 25 Cumulative Distribution Function of Optimum Power Levels

The mean value was calculated as the average of the power values, which was 2.58 MW. More importantly, from this curve, the 85th percentile value for peak power demand was approximately 4.0 MW. This means that 85% of the time (during the year 2015) the power demand was equal to or less than 4.0 MW. Only for 15% of the time did the power demand have very brief excursions above that value. Similarly, the 98th percentile value for peak power demand was approximately 6.0 MW. Therefore, 4.0 MW value was chosen as the minimum desired power output rating of the system.

With a 4.0 MW energy storage system added to the available natural gas reciprocating engine power of about 8.0 MW, the total production would be 12.0 MW to offset the diesel generation used for peaking purposes. The diesel generation is still expected to operate should the peaking demand grow greater than the combined generation of the energy storage system and natural gas units. In the data provided, this higher demand was found during the winter months.

Similar to determining the desired power rating of the energy storage, its energy rating was determined by analyzing the cumulative probability distribution of diesel energy requirements for the entire year of 2015 (see Figure 26). The median for the distribution is approximately 22.81 MWh. Using the 90th percentile point, an energy rating of approximately 40 MWh would cover greater than 90 percent of the energy demand. Similarly, the 96th percentile value for the energy demand was approximately 50 MWh. Therefore, 40 MWh value was chosen as the minimum desired energy output rating of the system.

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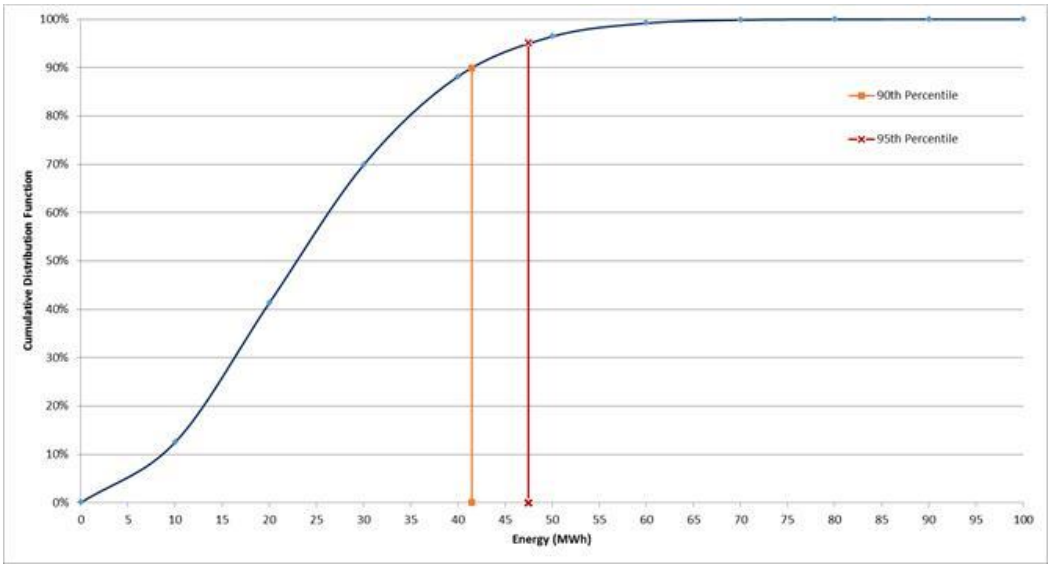

Figure 26 Cumulative Distribution Function for Energy Levels

Therefore the minimum recommended ratings for power and energy of the storage system are 4 MW and 40 MWh.

One of the mature energy storage technologies capable of providing the recommended ratings is the lead acid storage technology. Other technologies, due to having a significantly shorter discharge time, would have to have a significantly higher power output to have the same energy rating. Another mature battery energy storage technology capable of meeting the recommended energy and discharge ratings is the lithium ion battery system.

For this study, a 4 MW, 40 MWh lead acid battery energy storage system (ESS) was first selected. Due to the high MW and MWh usage in the months of January and February, this ESS will need to be complemented by the use of both 8 MW natural gas generation units. To reduce the use of the natural gas generation units, a 6 MW/60 MWh and an 8 MW/80 MWh lead acid battery energy storage systems were also studied as options. For price comparison purposes, an 8 MW/40 MWh lithium ion battery energy storage system was also considered.

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6. Cost Estimates, Schedule, and Footprints

The 2015 load data for hydro-electric and diesel generation provided by Yukon Energy Corporation (see Figure 3) was used to assess the power capacity need of an energy storage system. The data showed diesel and natural gas generation was used mainly for peak demand. Diesel generation is a mature and well developed technology and has a low capital cost but a very high operation and maintenance cost. The diesel generators, as well as the trucks transporting the fuel, produce environmentally damaging SOx and NOx gas emissions. Other known problems associated with diesel generation include fuel storage leaks, leakage of generator lubricants, and variations in fuel price. Hence there is a focus to curtail diesel generation with an energy storage system together with the natural gas generation.

As discussed in Section 5, the type of energy storage chosen was a battery energy storage system (BESS), specifically either the lead acid or lithium ion batteries. Going forward in this report, all references to an ESS will imply battery energy storage. Battery Energy Storage Systems possess many advantages for the improvement of power reliability over diesel generation. One advantage is that these systems (both the power conversion systems and energy storage technologies) are modular so that they can be installed in a reasonable time frame and power capacity can be added in small increments as the demand grows. The modular concept is also beneficial for equipment transportation. Most energy storage technologies should be built in a modular arrangement and not install the energy storage system with full capacity at the beginning. This could be wasteful in terms of the utilization of the energy storage technology due to their relatively short lifespan and high costs. Also, by adding to the BESS in increments, one can take advantage of future improvements in battery technology and efficiency.

These systems are considered multifunctional, aside from assisting in continuing the supply of power during peak demand, the energy storage systems may contribute for improvements in transient stability, voltage stability, frequency regulation, transmission and distribution grid support, load shifting, bulk power management and power quality.

6.1 Battery Energy Storage System Components and Footprint

To evaluate the minimum footprint of each energy storage system one needs to examine the major components of a battery energy storage system. The BESS can be broken down into the following three categories.

1. The Energy Storage Technology (EST) consist of all equipment necessary to store and supply energy to the Power Conversion System (PCS), duties, shipping and installation at site, and engineering support for installation and commissioning. For this study, the lead acid and lithium ion battery manufacturer's recommended battery connections to the PCS are shown in Table 3.

Table 3 Battery Configuration to the PCS

Energy Storage System Model	Battery Connections to the PCS
4 MW 40 MWh Lead Acid	Four (4) 1 MW connections
6 MW 60 MWh Lead Acid	Eight (8) 750 kW connections
8 MW 80 MWh Lead Acid	Eight (8) 1 MW connections
8 MW 40 MWh Lithium Ion	Four (4) 2 MW connections

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2. The PCS consist of all necessary power electronic equipment that will control the supply of electrical energy from the utility grid to the ESS and that will later discharge the stored energy in the ESS, returning it to the grid. The PCS converts the DC power of the energy storage device to AC power used by the utility grid and vice versa when the grid power is used to re-charge the storage device. Table 4 lists the major PCS equipment required for the four options of battery energy storage systems being studied.

Table 4 Power Conversion System Major Equipment List

Energy Storage System Model	PCS Equipment
4 MW, 40 MWh Lead Acid	One (1) PCS Module packaged in one 40' trailer. The one module includes the following: • Four (4) 1 MW inverters with AC and DC circuit breakers; thermal management; control and protection • Four (4) 1000 kVA padmount transformers : 35 kV : 267 VAC • One (1) MUC (Multiple Unit Control)
6 MW, 60 MWh Lead Acid	Two (2) PCS Modules packaged in two 40' trailers. Each module includes the following: • Four (4) 750 kW inverters with AC and DC circuit breakers; thermal management; control and protection • Four (4) 750 kVA padmount transformers : 35 kV : 267 VAC • One (1) MUC (Multiple Unit Control)
8 MW, 80 MWh Lead Acid	Two (2) PCS Modules packaged in two 40' trailers. Each module includes the following: • Four (4) 1 MW inverters with AC and DC circuit breakers; thermal management; control and protection • Four (4) 1000 kVA padmount transformers : 35 kV : 267 VAC • One (1) MUC (Multiple Unit Control)
8 MW, 40 MWh Lithium Ion	Two (2) PCS Modules packaged in two 40' trailers. Each module includes the following: • Two (2) 2 MW inverters with AC and DC circuit breakers; thermal management; control and protection • Two (2) 2000 kVA padmount transformers : 35 kV : 454 VAC • One (1) MUC (Multiple Unit Control)

3. The Balance of Plant (BoP) consists of the utility's costs for the project engineering, construction management and grid connection to build an energy storage system substation.

   For the study the major equipment and requirements included:

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- All required site preparation, foundations, grounding, support structures, cabling, bus work, protection, controls, and SCADA at the substation.
- The building for housing the batteries
- The slabs on grade for the PCSs,
- 3 three-phase 34.5 kV circuit breakers
- 3 three-phase motor operated disconnects
- 3 three-phase manual disconnects
- Cabling between the substation and PCS
- Cabling between the PCS and EST

The proposed development single line diagrams of the battery energy storage systems are shown in Figure 27 for the 4 MW, 40 MWh BESS and Figure 28 for the 6 MW, 60 MWh, the 8 MW, 80 MWh and the 8MW, 40 MWh (lithium ion)BESS.

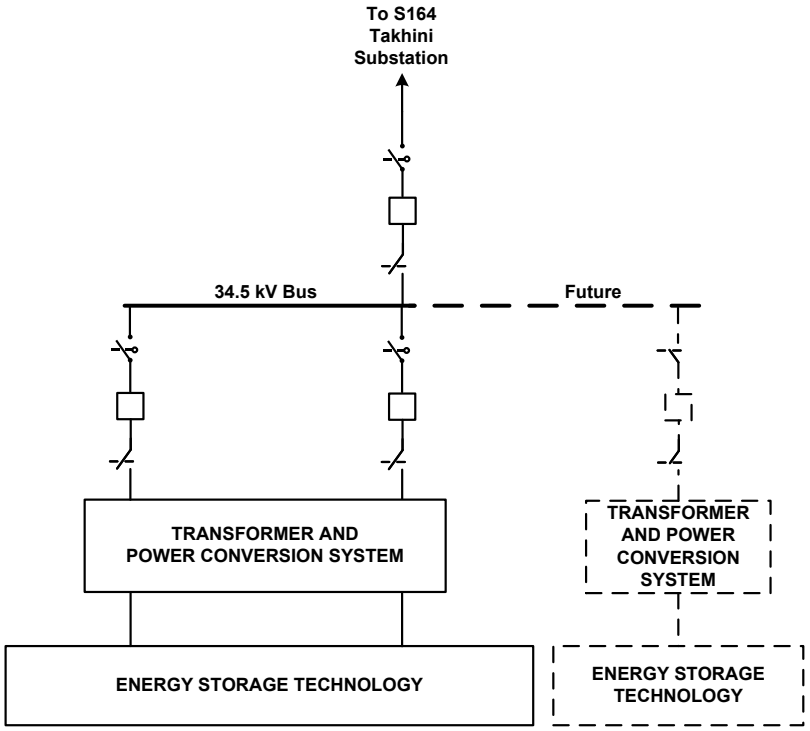

Figure 27: 4 MW, 40 MWh Battery Energy Storage System Configuration

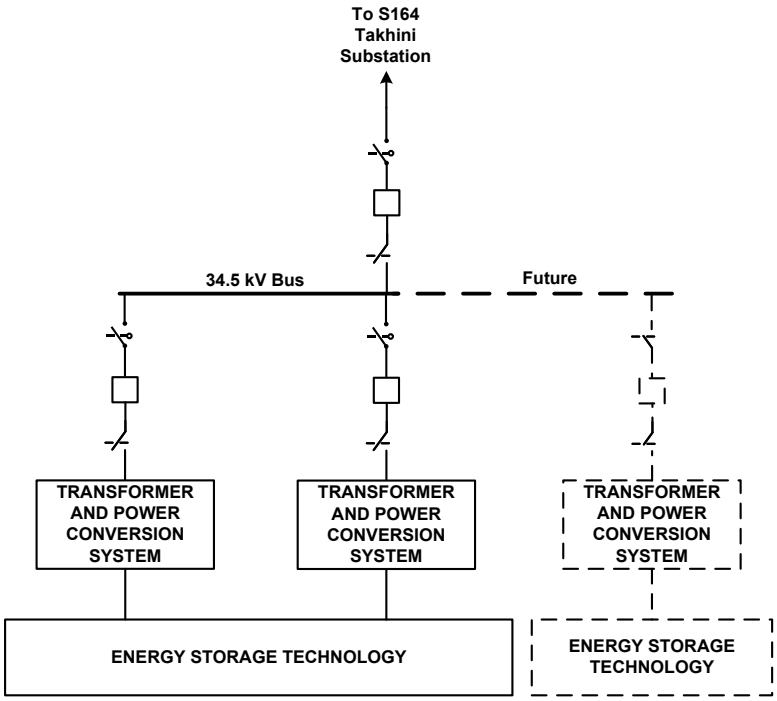

Figure 28: 6 MW, 60 MWh; 8 MW 80 MWh and 8 MW, 40 MWh Battery Energy Storage Sytems Configuration

The energy storage system was treated as a separate substation and the anticipated location is near the S164 Takhini 138 kV / 34.5 kV substation. The energy storage system will connect to the 34.5 kV system as shown in Figure 27 and Figure 28. By connecting to the relatively low transmission line voltage of 34.5 kV, the need for a second step-up transformer was avoided. A detailed engineering study of the electrical system at the S164 Takhini substation was not studied in regards to the effects on and the interaction with the energy storage system and should be considered if the project proceeds. Modular design was considered when designing the energy storage system. The proposed footprints for the different energy storage systems are shown below in the following figures.

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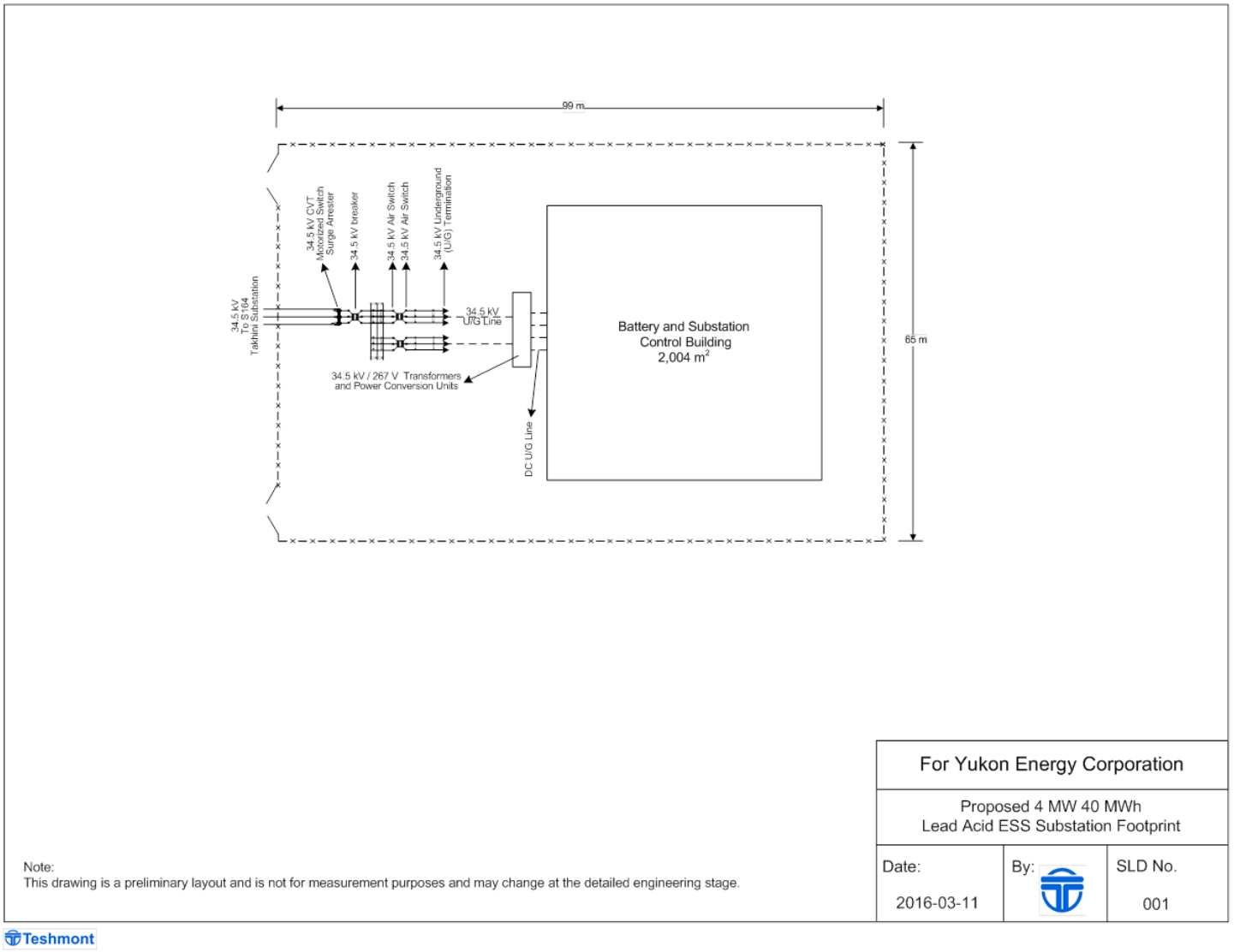

Figure 29 4 MW, 40 MWh Proposed Arrangement

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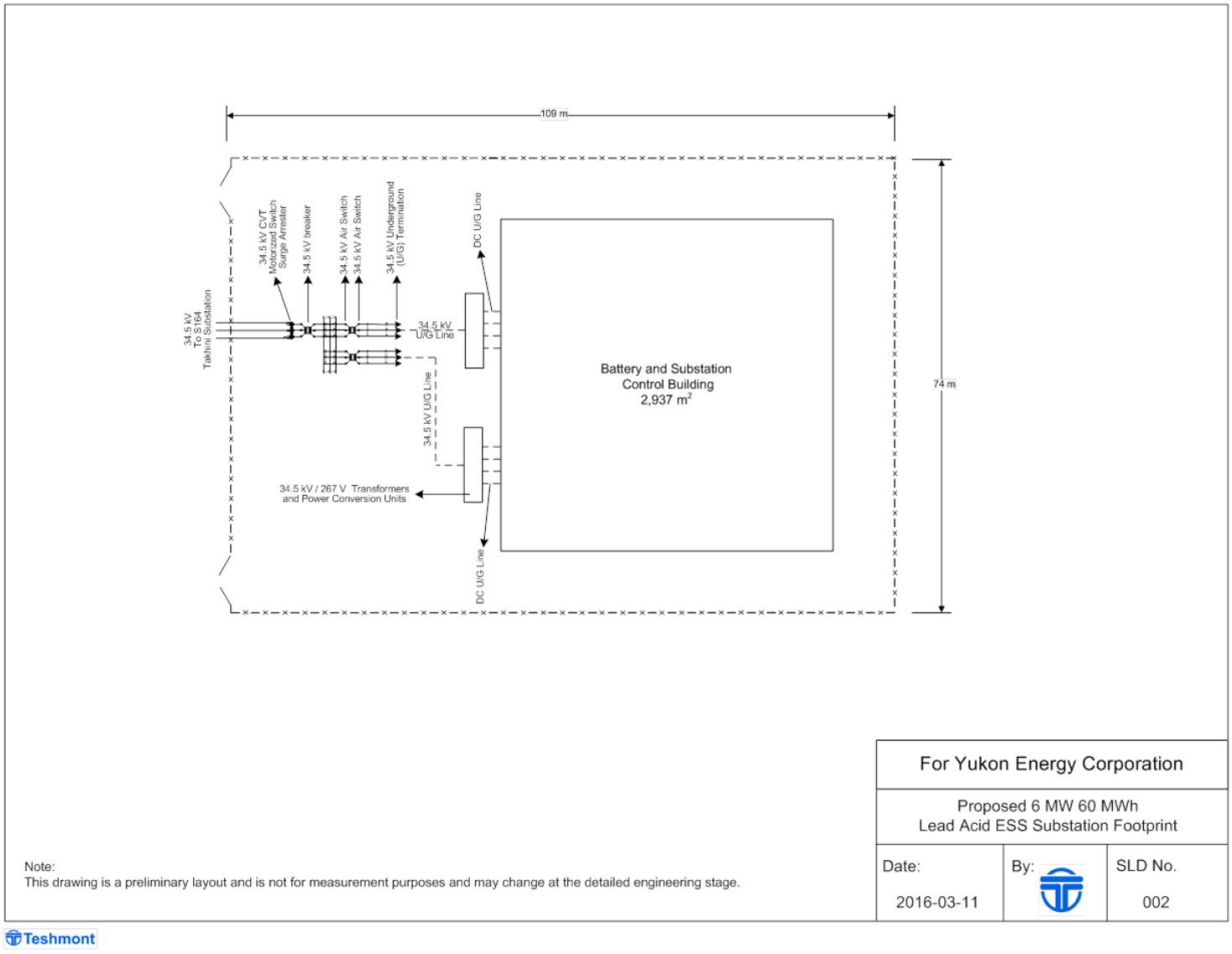

Figure 30 6 MW, 60 MWh Proposed Arrangement

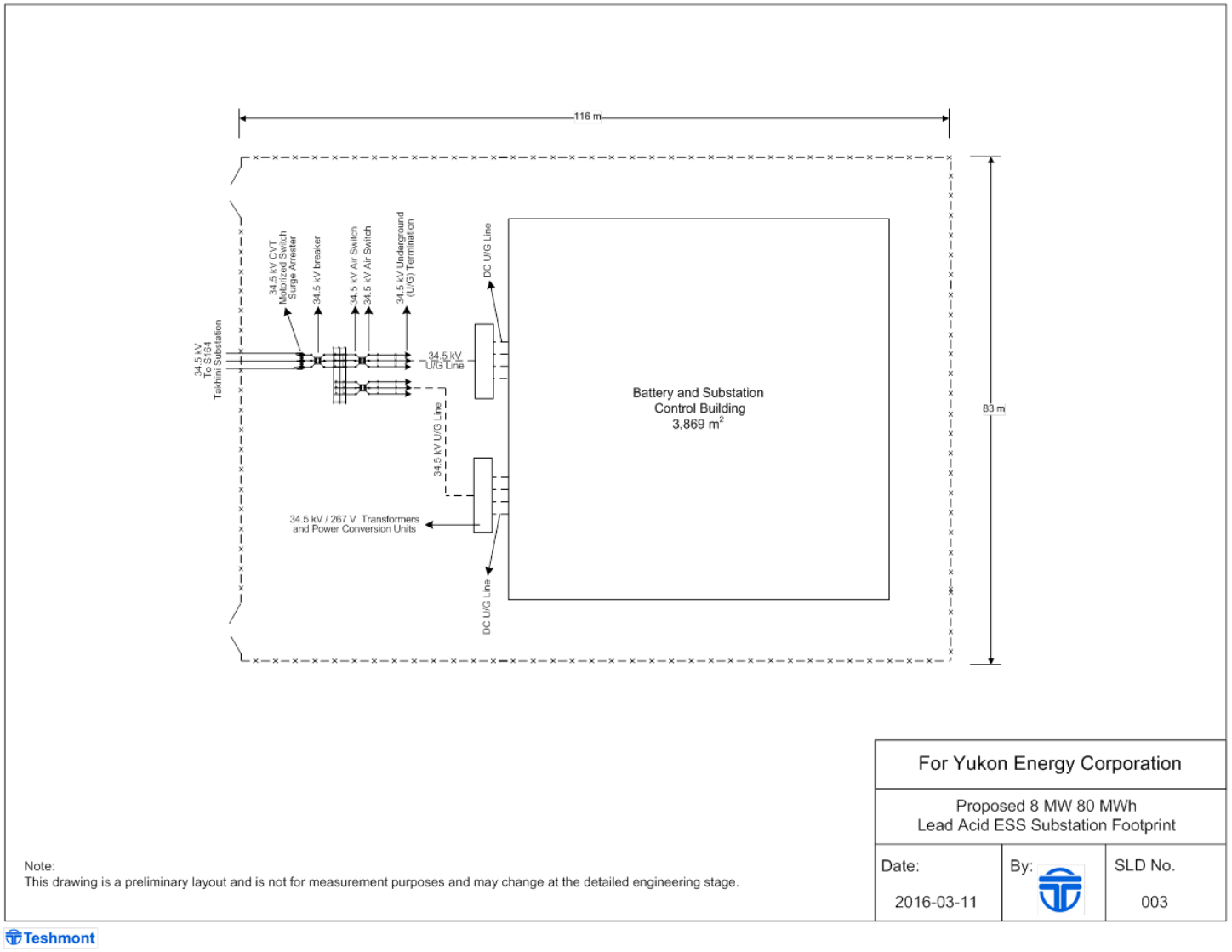

Figure 31 8 MW, 80 MWh Proposed Arrangement

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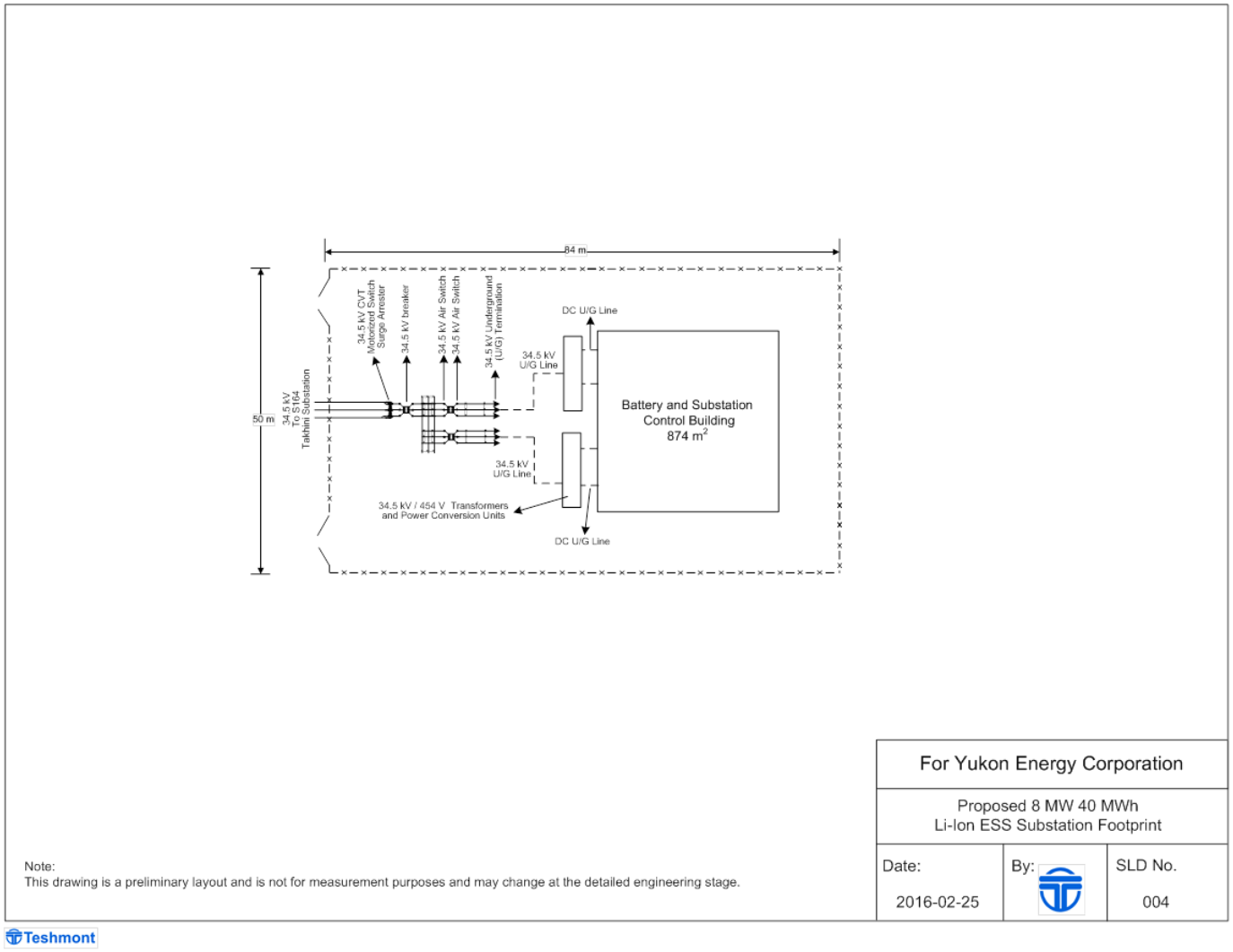

Figure 32 8 MW, 40 MWh Proposed Arrangement

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6.2 Development of Cost Schedule

The economic viability of implementing either of the BESS applications (lead acid or lithium ion) was explored by performing a 30 year life cycle cost-benefit analysis. The analysis was performed using an economic model developed especially for this purpose that detailed the estimated costs and expected benefits over the projected total life of the energy storage system. Future costs and benefits are converted to present value using a user defined discount rate. The total of all present value costs are then subtracted from the total of all present value benefits to provide a total Net Present Value (NPV) for the project. When the NPV value is negative, the project represents an overall economic burden to the system owner while a positive NPV provides an overall benefit to the owner.

The financial model takes into account the following costs and benefits:

- Capital cost of energy storage system equipment
- Capital cost of the building and auxiliary systems
- Capital cost of the civil works
- Operating and maintenance cost of the energy storage system and building
- Replacement cost of energy storage system components (primarily the batteries) after 15 years for lead acid batteries and after 20 years for lithium ion batteries
- Cost of power losses
- Cost of energy production differential benefit for using hydro power in place of diesel power

To evaluate different alternatives and scenarios, the model allows for certain economic parameters to be changed to assess the impact on the overall NPV. A base case was established based on current conditions and information obtained from Yukon Energy Corporation, summarized in Table 5.

Table 5 Economic Parameters

Financial Parameters	
Year for NPV and Currency Exchange Rates	2016
Study Period (years)	30
Nominal Discount Rate - annual	5.45%
Cost for Electric Power Losses (cents/kWh)	6.0
Electricity Cost Escalation rate - annual	2.0%
Owner's Portion of the Total Capital Cost	100%
Cost of Electricity Production from Hydro(cents/kWh)	6.00
Cost of Electricity Production from Diesel(cents/kWh)	30.80

The NPV was calculated to 2016 Canadian dollar values. The expected useful life for the energy storage system was set at 30 years, which required replacement of all batteries after 15 years for lead acid batteries and after 20 years for lithium ion batteries. No salvage value for the batteries was considered, nor was any anticipated decrease in future battery prices. The nominal discount rate used to calculate the Net Present Value of future costs was 5.45

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percent, provided by Yukon Energy Corp. YEC was assumed to provide 100 % of all costs, with no outside incentive funding. A 2.0 percent per year electricity escalation rate was assumed. The cost differential between utilizing diesel generation and hydro generation represented a savings of 24.80 cents/kWh.

The energy storage system parameters, shown in Table 6 , were obtained through consultation with Exide Technologies for lead acid batteries [9], LG Chem [10] for lithium ion batteries, ABB for the PCS [11], and Tru-Steel [12] for buildings that will house the batteries. Information provided included the efficiency of the system, the replacement period for the EST and cost parameters such as capital cost, operation and maintenance (O&M) costs and replacement costs. All other costs which are not included in the EST and PCS portion of the energy storage system costs are found in the Balance of Plant cost.

Table 6 Energy Storage System Parameters

BESS Parameters	**Lead Acid**			**Lithium Ion**
Energy Storage System Model	**4000 kW, 10h**	**6000 kW, 10h**	**8000 kW, 10h**	**8000 kW, 5h**
Power (kW)	4000	6000	8000	8000
Duration (h)	10	10	10	5
Power Discharge Efficiency (%)	80	80	80	90
Replacement period (years)	15	15	15	20
Capital Cost (PCS +EST)	$19,597,000	$30,086,000	$39,057,000	$25,670,000
Replacement Cost	$17,389,000	$26,084,000	$34,779,000	$22,082,000

Based on discussions with Exide Technologies and LG Chem., replacement of the energy storage technology (batteries) is expected to take place in the fifteenth year and twentieth year respectively, and have been estimated at the respective battery cost. The battery power discharge efficiency was quoted by Exide Technologies as 80 percent for lead acid and by LG Chem as 90 percent for lithium ion. The batteries costs included the engineering, installation and commissioning of the battery racks and enclosures. The PCS costs included the engineering, installation and commissioning of the units described in Table 4.

Table 7 shows the balance of plants parameters consisted of the building for the batteries and substation controls and the 34.5 kV substations.

Table 7 Balance of Plant Parameters

BESS Parameters	**Lead Acid**			**Lithium Ion**
Energy Storage System Model	**4000 kW, 10h**	**6000 kW, 10h**	**8000 kW, 10h**	**8000 kW, 5h**
EST Building Type /Size (m)	45 x 45 x 6.6	54 x 54 x 6.6	62 x 62 x 6.6	30 x 30 x 6.6
Building Costs	$820,000	$1,201,000	$1,583,000	$423,000
Substation Costs	$1,300,000			

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Based on the discussion with Tru-steel the cost included the installation and supply of a Pre-engineered building. The cost did not include soil conditions, site access, winter work, travel expenses and accommodations. The substation estimates were validated using in-house cost-estimating tools. The major equipment and requirements include all required site preparation, foundations, grounding, support structures, cabling, bus work, protection, controls, and SCADA at the substation, 3 three-phase 34.5 kV circuit breakers, 3 three-phase motor operated disconnects, 3 three-phase manual disconnects, Cabling between the substation and PCS and Cabling between the PCS and EST. Since the substation costs were negligible in the overall cost calculations, the 8000kW 10h was selected to represent all the different substation configurations costs.

Table 8 shows the operation and maintenance parameters as well as the annual energy savings.

Table 8 Operation and Maintenance Parameters

BESS Parameters	Lead Acid			Lithium Ion
Energy Storage System Model	**4000 kW, 10h**	**6000 kW, 10h**	**8000 kW, 10h**	**8000 kW, 5h**
Annual Energy production (MWh)	2443	2667	2780	2780
O&M Costs Escalation Rate (%)	2.00	2.00	2.00	2.00
Estimated Annual O&M Cost	$210,200	$321,300	$416,800	$260,900

The annual energy production for the different energy storage systems were calculated as the amount of energy required to replace the diesel energy production in 2015. For an example, the 40 MWh lead acid BESS is used to replace 2443 MWh of diesel energy production per year. Annual O&M assumed the facility heating and air conditioning, janitorial, storage system maintenance and general building upkeep. The cost for maintaining the different battery systems were also include in the annual O&M costs. The annual O&M cost for was subject to a 2.0 percent escalation rate.

The present value costs for the different energy storage systems included the capital costs of the battery technologies, the power conversion systems, and the balance of plant, the sum of the annual operation and maintenance cost, the sum of the annual costs of energy use to recharge the batteries and the replacement cost of the batteries. The equation used was as follows

$$PV_{Cost} = Cap_{Total} + \sum_{i=1}^{30} OM_{F\,i} * 1 + d^{-yr\,i} + \sum_{i=1}^{30} EL_{i} * (1+d)^{-yr(i)} + \mathrm{Rc} * (1+\mathrm{d})^{-Rp}$$

Where

Cap_{Total} = Capital Cost + BoP

OM_F = $Annual\ O\&M\ cost * (1 + O\&M\ Escalation\ rate)^{yr}$

EL = $Energy\ production * Electricity\ cost\ for\ losses * 0.01 * (1 + electricity\ Escalation\ rate)^{yr}$

Rc = Replacement cost

Rp = Replacement year

d = nominal discount rate

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The expenditure savings realized by utilizing the energy stored in the batteries was the net difference in energy production cost from replacing diesel energy with stored hydro energy. The net income from peak demand power was considered to be zero, as the power supplied by diesel was being directly replaced by the hydro power.

Based on all parameters in Table 5, Table 6, Table 7 and Table 8 the base case NPV value for the two energy storage systems being considered are shown in Table 9.

Table 9 Base Case NPV for Energy Storage Systems

	Lead Acid			Lithium Ion
Energy Storage System Model	**4000kW, 10h**	**6000kW, 10h**	**8000kW, 10h**	**8000kW, 5h**
Present Value – Benefits ($)	$11,085,000	$12,102,000	$12,615,000	$12,615,000
Present Value – Costs ($)	$35,981,000	$53,008,000	$68,119,000	$42,860,000
NPV ($)	-$24,896,000	-$40,906,000	-$55,504,000	-$30,245,000

Table 9 shows that over the lifetime of the four projects, all would have significantly higher costs compared with their respective benefits and hence a negative NPV. This evaluation considers only presently available technology. For the lead acid energy storage systems, the change in cost was directly related to the ratio of power. For example, the 6 MW and 8 MW lead acid energy storage systems costs 1.5 times and twice that of the 4 MW lead acid energy storage system.

Another way to evaluate and compare different energy technologies is to divide the total costs to construct, finance, operate and maintain a plant by its useful output. The costs are levelized using the cost of capital or discount rate to calculate a flat dost for energy in $/kWh and the capacity $/kW-yr over the life of the plant.

The primary basis for comparison of generation assets is the levelized cost of energy (LCOE) in $/MWh. The cost or value of capacity is levelized on an annual basis (LCOC) is expressed as $/kW-yr. The capital cost represents the cost of the plant being available to provide electrical generation whether or not it actually operates and is analogous to an insurance policy. The equations that were used for LCOE and LCOC were calculated as follows:

$$LCOE = \frac{PV_{Cost} * CRF}{\text{Annual Energy production}}$$

$$LCOC = \frac{PV_{Cost} * CRF}{\text{ESS Power (kW} - \text{yr)}}$$

Where

$$CRF = \frac{d * \ 1 + d\ ^{30}}{[\ 1 + d\ ^{30}] - 1}$$

Nominal discount rate is d = 5.45%

In Table 10 the LCOE and LCOC were determined for the different energy storage systems under evaluation.

Table 10 LCOE and LCOC

	Lead Acid			Lithium Ion
Energy Storage System Model	**4000kW, 10h**	**6000kW, 10h**	**8000kW, 10h**	**8000kW, 5h**
LCOE ($/MWh)	$1,010	$1,360	$1,680	$1,060
LCOC ($/kW-yr)	$620	$600	$580	$710

Since the operation of the Lithium ion is expected to operate at half its rated value the ESS power is 4000 kW in the LCOC calculation.

6.3 System Cost vs Utilization Sensitivity Study

To realize a positive NPV from any of the BESS, the system must be utilized more than it would be for only intermittently replacing up to 4 MW of diesel power production. As an example, the 40 MWh lead acid BESS is used to replace 2443 MWh (approximately 60 days of operation per year) of diesel energy production per year (based on the year 2015). Table 11shows the approximately number of days in operation per year based on the year 2015 for the different BESS.

Table 11 Operation Parameters

BESS Parameters	Lead Acid			**Lithium Ion**
Energy Storage System Model	**4000 kW, 10h**	**6000 kW, 10h**	**8000 kW, 10h**	**8000 kW, 5h**
Annual Energy production (MWh)	2443	2667	2780	2780
Approximate Days of operation	60	45	35	70

It was assumed the efficiency losses as the energy consumed during the charging cycle but not delivered to the loads during the discharge cycle. If the BESS can be used for providing more of a base load, either by load shifting or by load growth, then this unused capacity can generate more revenue or hence increase the NPV. Figure 33 shows the resulting increase in NPV for all 4 BESS with increased utilization.

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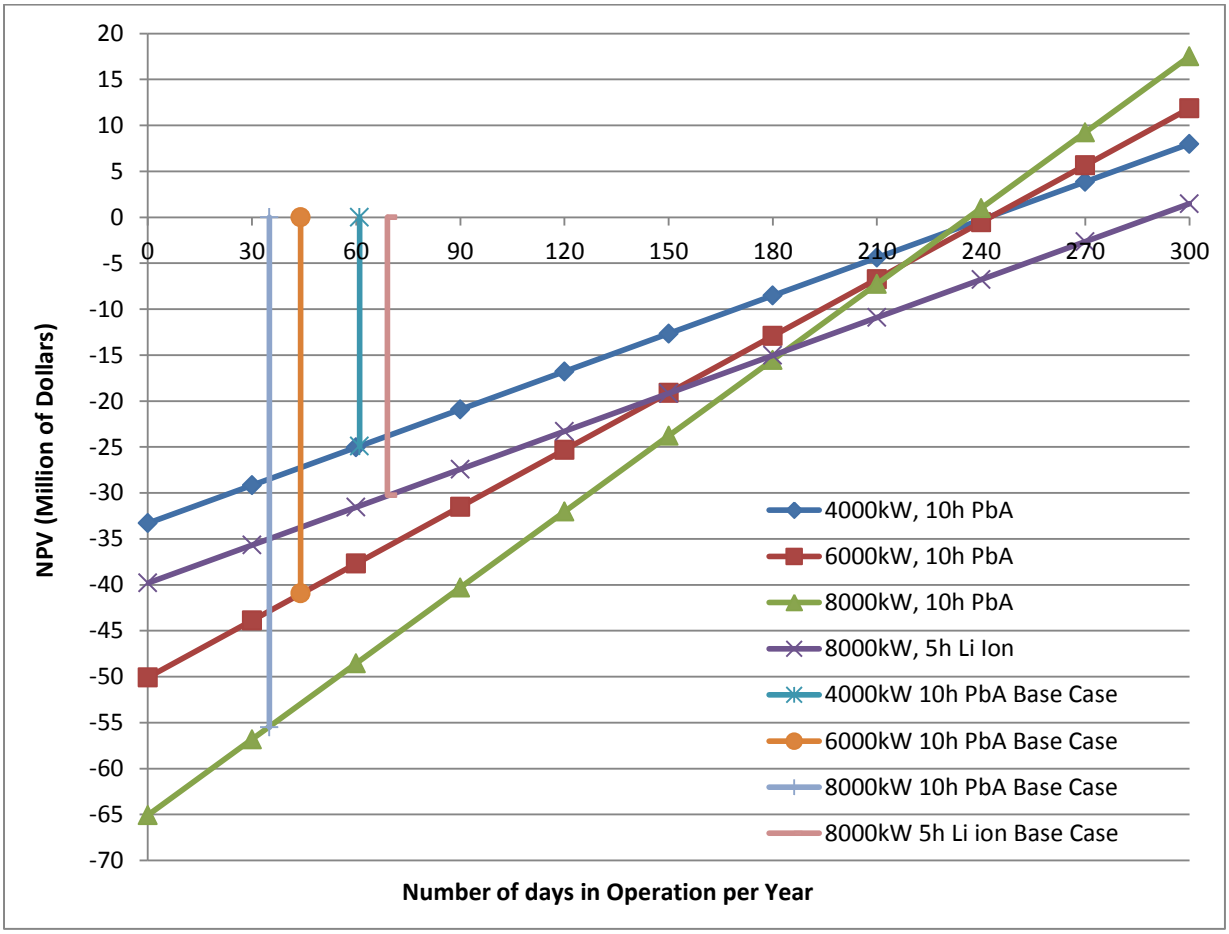

Figure 33 Battery Energy Storage System vs NPV Utilization

A day in operation, shown in Figure 33 , was represented by 10 hours of discharge and approximately 12 to 14 hours of recharge. As the number of days increased the NPV values improved. For the Lead Acid BESS would need approximately 240 days (approximately 8 months, 7 days a week) to the break-even. The Lithium Ion BESS would need approximately 290 days (approximately 9.5 months, 7 days a week) to the break-even.

6.4 Generation of high level project schedule

The high level project timeline was based on contributions from the manufactures of the different components for the energy storage systems. Figure 34 shows the time in weeks for each energy storage component; project planning and engineering, construction and site improvement and testing and commissioning. The duration of the total project is also shown.

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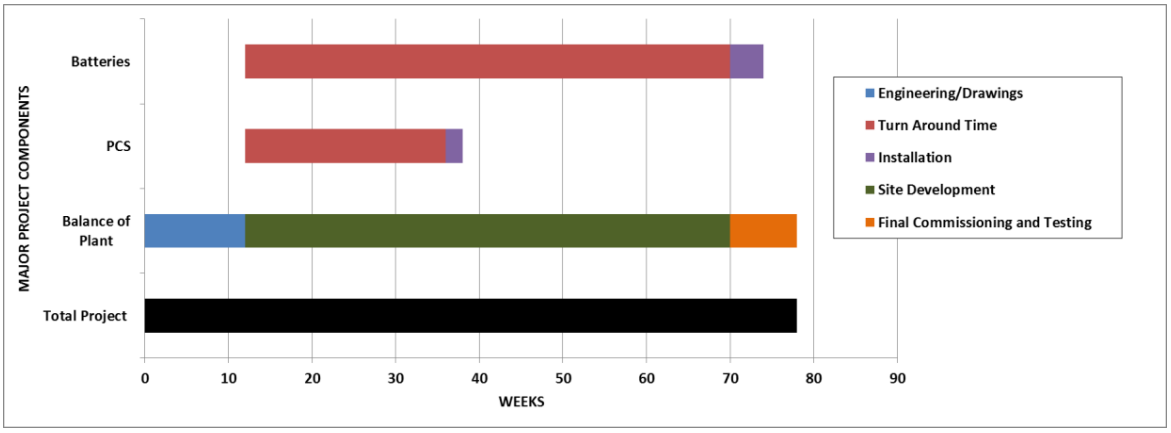

Figure 34 Battery Energy Storage System Timeline

Turnaround time includes procurement, manufacturing, and delivery. The estimated time to build the battery energy storage system from start to finish is 78 weeks (approximately 1.5 years).

6.5 Environmental and Societal Considerations

Although the life cycle costs are a major part of selecting any energy storage system, one must also consider the impact these energy storage systems will have on the environment and society.

Most of the chemicals used for creating the selected battery technologies are mined. The process from mining to manufacturing the batteries is energy intensive. Lead, when mined in large quantities produces a large amount of pollution within its mining areas. Lead, by itself, is also hazardous to human health. The chemical Lithium, on the other hand, is minor component when building lithium ion cells. The major chemicals required for these cells are copper and aluminum and the environmental impacts are more significant [8].

Furthermore, disposal of both battery technologies are an important part of the life cycle. There a number of regulations and safety concerns when handling and disposing of lead-acid batteries. Lead-acid batteries are among the most recycled products in the world [1]. Many lead acid manufactures accept old batteries and recycle the batteries. Recycling lithium ion batteries is still a challenge due to cells not having the ability to recharge. However, the newer lithium ion batteries are showing signs of recovering [8]. Therefore the recyclability of lithium ion batteries should rise.

In addition, battery layouts of this size are not common in utility systems. Both batteries have been known to have incidents of “thermal runaway” where the batteries rapidly increase in temperature causing fire and dangerous gases. During the design, construction and operation of the energy storage system, the utility and local authorities should familiarize themselves with the handling, operation and the chemical contents of the batteries. Since the battery facilities are large buildings, they should also be aware the location of emergency and critical components in the building and around the project site. Manufacturers should provide Material Safety Data Sheets to utility and local authorities.

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6.6 Spinning Reserve

The definition of spinning reserve is the online capacity that is synchronized to the grid and ready to supply the electrical demand within 10 minutes of a dispatch instruction by the independent system operator. Spinning reserve is required to maintain system frequency stability during emergency type operating conditions and random load swings.

Earlier research indicated that large energy storage systems could be designed to accommodate a utilities' spinning reserve by installing extra power capacity into its dc to ac advanced power converter system. The rating of the converter could be sized about 20% greater than the normal output rating. With the recent technology advancements involving a BESS with an advanced PCS, some power markets may assign a value to this function and allow the BESS facility with this characteristic to acquire monetary benefits.

However for the type of BESS being considered in this report, the cost of the converter is a very small portion of the overall cost. With oversizing the inverter, it would be difficult to find enough benefits to evaluate and justify the advantage of having the increased spinning reserve.

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7. Conclusions

Several Energy Storage System (ESS) options were considered to:

a. provide additional power to the YEC transmission system for “load levelling” purposes, and

b. avoid additional environmentally unfriendly diesel generation

From the extensive list of ESS options, the most technically viable were chosen based on the calculated power, energy, and discharge time characteristics required. Maturity of the ESS was also considered; as this is not an academic R&D project, using a proven, mature technology was important. This brought battery energy storage systems (BESS) to the forefront, and in particular lead acid and lithium ion batteries.

These two types of BESS, besides meeting the technical operational requirements, have other advantages. As they are a modular system, BESS power capacity can be added in small incremental steps to meet future power demand. This allows for easier financial planning, as well as taking advantage of future improvements in battery technology.

Using the known diesel power generation profile for the year 2015, the operational requirements of the BESS were determined to be:

a. Power rating = 4 MW

b. Energy rating = 40 MWh

c. Discharge time = 10 hours

The above BESS power rating of 4 MW, plus an anticipated 8 MW of natural gas reciprocating engines generation in the near future, provides a total of 12 MW of available power. 95% of the diesel power generation for 2015 was equal to or less than 12 MW, so the BESS plus NG solution can fully replace the present demand for diesel power 95% of the time. Future load growth can be met incrementally by adding modules of the BESS.

For cost comparison, four options of a BESS were considered:

a. 4 MW, 40 MWh, 10 hour discharge time, lead acid battery system

b. 6 MW, 60 MWh, 10 hour discharge time, lead acid battery system

c. 8 MW, 80 MWh, 10 hour discharge time, lead acid battery system

d. 8 MW, 40 MWh, 5 hour discharge time, lithium ion battery system

Budgetary prices of all major components of each BESS were provided directly by vendors. The financial model and approximate cost of civil works was provided by Yukon Electric Corp. A thorough consideration of costs and income was made over the next 30 years to arrive at the lowest total cost option for a BESS.

Based on the information provided from Yukon Energy, the power and energy determined from the load data and the total cost of a completely installed BESS system under study, the net present value was calculated for each option. Over the lifetime of the projects, all 4 options would have significantly higher costs compared with their respective benefits and hence a negative NPV. The lead acid 4 MW, 40 MWh BESS had the best NPV followed by the lithium ion 8 MW, 40 MWh BESS.

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The timeline for bringing this system online is approximately 18 months. This includes engineering and drawing, preparatory civil works, purchase and delivery of the system components, construction, and testing.

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Appendix 5.20
Updates to Yukon Electricity Conservation and Demand Management Potential Review
(ICF 2016)

MEMORANDUM

To: Stephanie Whitehead and Marc-Andre Lavigne, Yukon Energy Corporation

From: ICF International

Date: October 25, 2016

Re: Updates to Yukon Electricity Conservation and Demand Management Potential Review (CPR 2011)

Table of Contents

1 Introduction....2
2 Assumptions....3
2.1 General Assumptions....3
2.2 Residential Assumptions....3
2.2.1 Residential Measure-Level Assumptions....3
2.2.2 Changes to Residential Penetration & Participation Rates....4
2.3 Commercial Assumptions....4
2.3.1 Commercial Measure-Level Assumptions....4
2.3.2 Changes to Commercial Penetration & Participation Rates....5
3 Results....6
3.1 Residential Results....6
Base Year....6
Technology Screening....9
Energy-efficiency Supply Curves....11
Summary of Potential Electric Energy Savings....14
Summary of Electric Peak Load Reductions: Electric Energy Measures....17
Summary of Electric Peak Load Reductions: Capacity Measures....22
Summary of Lower Achievable Electric Peak Load Reductions: Capacity Measures....24
3.2 Commercial Results....25
Base Year....25
Technology Screening....28
Energy-efficiency Supply Curves....30
Summary of Potential Electric Energy Savings....33
Summary of Electric Peak Load Reductions: Electric Energy Measures....36
Summary of Electric Peak Load Reductions: Capacity Measures....41
Summary of Lower Achievable Electric Peak Load Reductions: Capacity Measures....43
3.3 Discussion....44
Cost of Conserved Energy (CCE)....44
Achievable Potential....45

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1 Introduction

This objective of this report is to update the assumptions and results of 2011 Conservation Potential Review (CPR) for the Yukon Energy Corporation (YEC). YEC updates their 20-year resource plan every five years, with the next update planned for 2016. In preparation for YEC's upcoming Resource Plan, YEC is seeking to update some of the CPR model input assumptions to better reflect the current state of the modeled technologies and more accurately project the conservation potential. Following the 2011 study and subsequent program design work, YEC was able to obtain more accurate information on the penetration of certain technologies and the participation rate of certain program implementations. The scope of this update is summarized below:

- **Base year:** Updated base year with 2014 energy sales data
- **Reference case:** Updated reference case with new load forecast
- **Measure-level assumptions:** Updated avoided cost, discount rate and measure-level assumptions such as cost, energy savings, measure life, current penetration and applicability
- **Participation rates:** Updated participation for certain measures, including showerheads, pipe and tank insulation

The scope of the updates to the assumptions were limited to the hydro grid-connected region. The large diesel, small diesel, and Old Crow regional models were omitted. Dwelling types, commercial building types, and energy end uses definitions remained unchanged from the 2011 study. Further information on these definitions can be found in the 2011 report.

The overall analysis approach and methodology for this study remains unchanged from the original 2011 study. For further information on the major analytical steps and modelling approach please refer back to the 2011 report. The following sections of this report are organized as follows:

- **Section 2** presents the revised assumptions for the update of the 2011 study. This includes changes to measure level assumptions, applicability and participation assumptions.
- **Section 3** presents the revised energy savings results for the residential and commercial sectors.

2 Assumptions

2.1 General Assumptions

This section presents the details of all changes that were made to the study assumptions. The following changes were made across both sectors:

- **Base year:** 2014 sales data provided by YEC was used to update the base year and the base year was changed from 2010 to 2014
- **Reference case:** YEC provided load forecast insights to inform a revised reference case and the reference case was extended to 2035 (i.e. the last milestone year for the 2011 study was 2030)
- **Avoided cost and discount rate:** The avoided costs were changed to $0.2871/kWh and the real discount rate was changed to 3.38%.

2.2 Residential Assumptions

2.2.1 Residential Measure-Level Assumptions

The following list of measure-level assumption changes were made in the residential sector measures:

- **Cold Climate Air Source Heat Pumps:** Costs updated to $12,000 based on Zuba model pricing provided from client consultation with HVAC specialists.
- **Programmable Thermostats (Central Heating):** Updated to Smart Learning Thermostats
  - Savings: Savings percentage was increased to 8%
  - Costs: Upgrade costs set to $300.00 based on cost of average nest/ecobee cost.
- **CFLs – Indoor:** Measure was deleted (superseded by LED measure)
- **CFLs – Outdoor:** Replaced measure with LED Lamps – Outdoor
  - Upgrade: Changed to 15 W PAR38 LED lamp
  - Savings: Measure savings percentage increased to 83.3% due to lower wattage of outdoor LED lamps
  - Costs: Set to $51.75 based on a retail scan of outdoor LED Lamps
  - Lifetime: Set to 25,000 hours (14.4 years based on 4.75 hours of use per day)
- **PAR CFLs:** Replaced measure with Dimmable PAR LED Lamps
  - Upgrade: Changed to 8 W dimmable PAR LED lamp
  - Savings: Measure savings percentage increased to 87%
  - Cost: Set upgrade costs to $15.00 based on a retail scan of PAR LED lamps.
  - Lifetime: Measure lifetime set to 25 years
- **Dimmable CFLs:** Measure was deleted (superseded by LED measure)
- **LED Lamps:**
  - Baseline: Changed baseline to a blended baseline of incandescent and CFL lamps
  - Savings: Savings assumptions were decreased from 80% to 76% relative to the new blended baseline of CFLs and incandescent lamps.
  - Costs: Reduced cost per lamp to $11.00 based upon retail scan of globe-type, screw-in 8 W LED lamps
- **High Performance New Homes:**
  - Baseline: Changed baseline from EGH rating of 80 to EGH rating of 82
  - Cost: Updated to $6,570 with 33% cost factor

- Savings: Savings assumptions were updated to 15% based on change in baseline scenario

2.2.2 Changes to Residential Penetration & Participation Rates

The following changes were made to penetration and participation rates in the residential sector measures:

- **LED Lamps:**
  - Reference penetration: Estimated at 50% by the end of the study period
- **LED Lamps – Outdoor:**
  - Reference penetration: Estimated at 50% by the end of the study period
  - Participation rates: Updated to match LED Lamps
- **PAR LED Lamps:**
  - Reference penetration: Estimated at 35% by the end of the study period
  - Participation rates: Updated to match LED Lamps
- **Smart Learning Thermostats:**
  - Reference penetration: Estimated at 10% by the end of the study period based on decrease in natural adoption compared to programmable thermostats

2.3 Commercial Assumptions

2.3.1 Commercial Measure-Level Assumptions

The following measure-level assumption changes were made to the commercial sector measures:

- **T8 Lighting:** Switched to LED Fluorescent Fixtures measure
  - Baseline: Standard 2-lamp F32T8 fixture consuming 58 W
  - Upgrade: Upgrade is a 2-lamp LED Fluorescent Fixture consuming 18 W
  - Cost: Upgrade cost set to $120 per fixture based upon client data
- **CFL Lamps (Indoor):** Measure was deleted (superseded by LED measure)
- **White LED Lamps:**
  - Cost: Upgrade costs set to $23.00 based on ICF's database of average LED lighting costs for previous lighting program implementations
- **Pulse-Start Metal Halide Lamps:** Changed measure to LED High Bay Fixtures
  - Upgrade: Changed to 125 W LED High Bay Fixture
  - Costs: Upgrade cost adjusted to $300 per fixture and baseline material cost adjusted to $200/fixture based upon costing data provided by the client
  - Lifetime: Adjusted to 50,000 hours based upon the average life expectancy of LED fixtures
- **T5HO High Bay:** Measure was deleted (superseded by LED measure)
- **CFL Lamps (Outdoor):** Changed this measure to LED Lamps (Outdoor)
  - Upgrade: 10 W LED Lamp
  - Costs: Updated cost to $28.45 per lamp based on ICF's database of average LED lighting costs for previous lighting program implementations
  - Lifetime: Updated to 20,000 hours
- **Induction (Outdoor):** Measure was deleted (superseded by LED measure)
- **Pulse Start Metal Halide Lamps (Outdoor):** Changed to LED Wallpack Outdoor Fixtures
  - Baseline: Standard 230 W metal halide wallpack
  - Upgrade: 50 W LED wallpack

  - Costs: Upgrade costs updated to $460/fixture, baseline cost of $345/fixture
  - Lifetime: Upgraded to 50,000 hours for LED fixture
- **Digital HID Street Lighting:** Measure was deleted (superseded by LED measure)
- **LED Street lighting:**
  - Cost: Costs were updated with a $185/fixture cost for LED Streetlight and a cost of $250/fixture for the baseline HPS streetlight
- **HP Glazing:**
  - Cost: Updated costs based on pricing list provided by Northerm. Unit window costs provided were used to derive incremental cost of approximately $5.03/ft^2
- **Super HP Glazing:**
  - Cost: Updated costs based on pricing list provided by Northerm. Unit window costs provided were used to derive incremental cost of approximately $13.32/ft^2
- **Programmable Thermostat:** Changed to Adaptive Thermostat measure
  - Savings: Upgraded savings to 15% based on average adaptive thermostat savings from case studies
  - Costs: Updated costs to $700/thermostat per 2000 ft^2 plus location factor

2.3.2 Changes to Commercial Penetration & Participation Rates

The following changes were made to penetration and participation rates in the commercial sector measures:

- **LED fluorescent fixtures:**
  - Reference penetration: Estimated at 15% by the end of the study period
  - Participation rate: The participation rate was decreased up to a maximum participation of 46%
- **LED High Bay Fixtures:**
  - Reference penetration: Estimated at 15% by the end of the study period
- **LED Lamps (Outdoor):**
  - Reference penetration: Estimated at 8% by the end of the study period
  - Participation rate: Updated to match white LED Lamps measure
- **LED Wallpack Outdoor Fixtures:**
  - Reference penetration: Estimated at 19% by the end of the study period
- **LED Streetlighting:**
  - Reference penetration: Estimated at 30% by the end of the study period
- **Adaptive Thermostats:**
  - Reference penetration: Estimated at 10% by the end of the study period

3 Results

The following section provides the updated results for the residential and commercial sector. Note that all results presented in this section represent the electrical consumption and savings only in the hydro grid connected region of Yukon. Below is a summary of the exhibit updates with the corresponding exhibit numbers from the 2011 Yukon Residential and Commercial sector reports:

- Residential (R) Exhibit Updates:
  - Exhibit 7R: Base Year Consumption by Dwelling Type & End Use
  - Exhibit 25R: Technology Screening
  - Exhibits 35R and 36R: Energy Efficiency Supply Curves
  - Exhibits 54R and 58R: Achievable Potential Energy Savings
  - Exhibits 62R, 62-2R, 65R, 65-2R: Achievable Electric Peak Load Reductions
  - Exhibits 41R and 42R: Electric Peak Load Reductions from Capacity Measures
  - Exhibits 42-2R and 42-3R: Lower Achievable Electric Peak Load Reductions from Capacity Measures
- Commercial (C) Exhibit Updates:
  - Exhibit 10C: Base Year Consumption by Sub Sector & End Use
  - Exhibit 25C: Technology Screening
  - Exhibits 35C and 36C: Energy Efficiency Supply Curve
  - Exhibits 54C and 58C: Achievable Potential Energy Savings (commercial sector equivalent to residential)
  - Exhibits 62C, 62-2C, 65C, 65-2C: Achievable Electric Peak Load Reductions (commercial sector equivalent to residential)
  - Exhibits 40C and 41C: Electric Peak Load Reductions from Capacity Measures
  - Exhibits 41-2C and 41-3C: Lower Achievable Electric Peak Load Reductions from Capacity Measures

3.1 Residential Results

Base Year

This section presents the results of the analysis of electricity consumption for the Base Year 2014. Electricity consumption is measured at the customer's point-of-use and does not include line losses.

Exhibit 7R presents total residential sector hydro grid electricity consumption by dwelling type and end use.

Base Year Electricity Use by Dwelling Type

Single detached dwellings account for the majority of residential electricity use in Yukon, with approximately 73% of residential hydro grid electricity consumed. Apartment buildings, including both the suites and common areas, account for the next largest share, using 11% of residential hydro grid electricity. Attached houses (duplexes, row houses, and townhouses) and mobile homes each account for 7% of residential hydro grid electricity.

Seasonal houses (using less than 3,000 kWh/yr. each) account for 2% of total residential hydro grid electricity consumption. Residential garages and sentinel lighting each consume less than 0.5% of residential hydro grid electricity.

Base Year Electricity Use by End Use

HVAC accounts for 33% of consumption, with 29% of that being electric space heating and the remainder being fans and pumps, including furnace fans, boiler circulation pumps, HRV fans, and bathroom and kitchen exhaust.

Domestic appliances (white goods) consume approximately 17% of total residential hydro grid electricity. Of this, clothes dryers account for 6% and refrigerators for 4%. Cooking appliances consume 4% and freezers each consume approximately 3%. Dishwashers and clothes washers consume less than 1% each, but this does not include the associated DHW consumption if DHW is heated electrically.

Domestic water heating accounts for approximately 15% of residential hydro grid electricity consumption.

Household electronics consume approximately 15% of residential hydro grid electricity, including 9% by computers and their peripherals, 3% by televisions, 1% by the various set-top boxes associated with televisions, and 3% by other home entertainment electronics.

Indoor, outdoor, and holiday lighting together account for 6% of residential hydro grid electricity consumption; 5% of this is indoor lighting and 1% is outdoor lighting. Holiday lighting is well under 1%.

Other end uses account for 13% of residential electricity consumption. Of this, 6% is consumed by spa heaters and pumps and 2% is consumed by block heaters and car warmers.

Exhibit 7R Base Year Annual Residential Electricity Consumption by Dwelling Type and End Use (MWh/yr.)

Dwelling Types	Space heating	Ventilation & circulation	Domestic hot water (DHW)	Indoor lighting	Outdoor lighting	Holiday lighting	Cooking appliances	Refrigerator	Freezer	Dishwasher
1980 & newer non-electrically heated single detached homes	19,773	11,737	46,057	14,306	3,801	282	11,115	15,631	10,505	1,671
Pre-1980 non-electrically heated single detached homes	23,104	9,875	38,467	11,969	3,181	237	9,281	11,890	7,988	1,272
1980 & newer electrically heated single detached homes	136,425	862	24,409	5,566	1,443	91	5,203	6,234	4,269	656
Pre-1980 electrically heated single detached homes	51,511	260	7,783	1,926	512	38	1,641	1,752	1,177	187
1980 & newer non-electrically heated attached/row housing	1,675	1,198	4,815	1,238	308	19	982	1,557	1,046	136
Pre-1980 non-electrically heated attached/row housing	1,911	1,006	4,013	1,034	258	16	818	1,178	791	103
1980 & newer electrically heated attached/row housing	8,960	103	2,322	438	105	6	418	569	389	49
Pre-1980 electrically heated attached/row housing	4,222	35	826	169	42	3	147	178	119	16
Non-electrically heated apartment units	4,159	2,891	8,244	2,677	248	24	2,303	3,179	2,126	237
Non-electrically heated apartment common areas	1,117	3,895	-	3,606	335	32	-	-	-	-
Electrically heated apartment units	26,791	177	4,298	999	85	8	1,045	1,307	892	96
Electrically heated apartment common areas	7,153	237	-	1,341	114	10	-	-	-	-
Non-electrically heated mobile/other	4,067	2,274	9,031	2,413	622	36	2,630	2,369	1,390	160
Electrically heated mobile/other	18,053	150	3,396	682	173	9	878	782	426	47
Seasonal housing	873	374	3,862	2,306	613	-	900	928	623	99
Residential garages	1,059	583	-	700	186	-	-	-	-	-
Sentinel Lighting	-	-	-	-	3,006	-	-	-	-	-
Grand Total	310,852	35,655	157,524	51,372	15,032	810	37,362	47,553	31,741	4,729

Dwelling Types	Clothes washer	Clothes dryer	Spa heaters and pumps	Computer and peripherals	Television	Set-top boxes	Home entertainment electronics	Block heaters & car warmers	Heat tape, propane htrs, circ pumps	Small appliance & other	Total	Percentage of Total
1980 & newer non-electrically heated single detached homes	1,107	20,933	22,626	27,472	9,467	4,202	7,613	5,506	1,386	13,435	248,624	23%
Pre-1980 non-electrically heated single detached homes	844	15,918	17,273	20,857	7,193	3,198	6,314	4,187	1,054	11,142	205,242	19%
1980 & newer electrically heated single detached homes	401	8,640	8,532	11,735	3,925	1,633	4,186	2,213	557	7,387	234,369	22%
Pre-1980 electrically heated single detached homes	123	2,399	2,852	3,045	1,051	467	1,008	612	154	1,778	80,276	8%
1980 & newer non-electrically heated attached/row housing	93	1,759	2,852	3,464	1,193	530	684	694	175	1,208	25,626	2%
Pre-1980 non-electrically heated attached/row housing	69	1,296	2,110	2,548	879	391	566	511	129	999	20,625	2%
1980 & newer electrically heated attached/row housing	31	658	1,001	1,328	446	187	330	253	64	582	18,238	2%
Pre-1980 electrically heated attached/row housing	10	199	354	379	131	58	92	76	19	162	7,238	1%
Non-electrically heated apartment units	85	1,594	-	8,408	2,898	1,287	1,815	-	-	3,204	45,380	4%
Non-electrically heated apartment common areas	94	1,717	1,534	-	-	-	-	2,271	572	-	15,172	1%
Electrically heated apartment units	33	704	-	3,906	1,308	544	983	-	-	1,736	44,910	4%
Electrically heated apartment common areas	35	732	625	-	-	-	-	987	249	-	11,482	1%
Non-electrically heated mobile/other	107	1,983	2,127	5,045	1,739	773	1,278	1,012	255	2,256	41,566	4%
Electrically heated mobile/other	30	613	635	1,634	551	233	465	313	79	821	29,969	3%
Seasonal housing	65	1,239	4,079	1,615	557	248	1,221	-	-	2,155	21,756	2%
Residential garages	-	-	-	-	-	-	-	372	94	1,741	4,734	0.4%
Sentinel Lighting	-	-	-	-	-	-	-	-	-	-	3,006	0.3%
Grand Total	3,127	60,382	66,600	91,433	31,339	13,750	26,556	19,007	4,785	48,603	1,058,214	100%

Technology Screening

A summary of the technology screening results is provided in Exhibit 25R. For each of the measures, the exhibit shows:

- The name of the measure
- The cost basis[1] for the CCE (cost of conserved energy) that is shown, e.g., full versus incremental
- The measure's average CCE when applied to all sub sectors.

Measures analyzed on the basis of full cost have been placed towards the top of the exhibit below because they are qualitatively different from the measures that pass only on an incremental basis. A measure that passes on a full-cost basis can be applied immediately, even if the piece of equipment it replaces or improves is currently working properly. That means the rate at which the measure can be implemented as a utility DSM measure is limited by market and program constraints. A measure that passes only on an incremental basis, on the other hand, is limited by the rate of natural replacement (due to failure or obsolescence) or purchase of the piece of equipment it replaces.

Exhibit 25R Residential Sector Energy-efficiency Technology Measures, Screening Results[2]

Measure Name	Basis (Full/ Incremental)	Average CCE (¢/kWh)	
		Existing Homes	New Homes
DHW Pipe Insulation	Full	0.20	0.25
Ultra Low-Flow Showerheads	Full	0.71	1.01
Hot Tub Pump Timers	Full	0.82	0.87
Insulating Hot Tub Covers	Full	1.29	1.36
LED Lamps	Full	1.44	1.44
PAR LED Lamps	Full	1.72	1.72
LED Lamps - Outdoor	Full	1.79	1.79
Timers for Electric Car Warmers	Full	2.21	2.22
Smart Learning Thermostats	Full	2.81	3.25
Solar Spa Pre-heat	Full	3.05	3.21
Programmable Thermostats (Baseboard Heating)	Full	3.13	3.52
Heat Pump Spa Heaters	Full	3.72	3.90
Motion Detectors for Outdoor Lighting	Full	4.38	4.38
Motion Detectors for Indoor Lighting	Full	4.61	4.61
Timer/Thermostat for Block Heaters	Full	5.05	5.00
Attic Insulation	Full	5.48	-
Outdoor Temperature Reset	Full	5.59	6.47
DHW Tank Insulation	Full	6.10	8.00
Basement (Foundation) Insulation	Full	6.27	-
LED Holiday Lighting (Outdoor)	Full	7.39	6.31
LEED Certified Apartment Buildings	Full		6.90
Spot/Task Lighting	Full	7.55	7.55
Air Leakage Sealing and Insulation (Old Homes)	Full	7.55	-

[1] See Step 3 in Section 7.2 of the 2011 Yukon Residential Report for a complete description.
[2] Average CCE does not include program costs.

Updates to Yukon Electricity CPR 2011

Measure Name	Basis (Full/ Incremental)	Average CCE (¢/kWh)	
		Existing Homes	New Homes
Smart Power Bars (Computers and Peripherals)	Full	7.59	7.72
Ductless Mini-Split Systems	Full	8.62	8.77
Air Sealing/Weather Stripping/Caulking	Full	8.88	-
Zone Heating	Full	9.38	10.85
Cold Climate Air Source Heat Pumps	Full	9.42	10.54
DHW Recirculation Systems (e.g. Metlund D'MAND)	Full	10.79	14.56
Wastewater Heat Recovery Systems	Full	11.25	14.51
Smart Power Bars (Televisions and Home Entertainment)	Full	13.35	12.96
Wall Insulation	Full	13.27	-
Crawlspace Insulation	Full	14.87	-
SuperGreen Homes (EGH rating of 85)	Full		16.05
DHW Piping Optimization	Full	18.37	16.19
Slab Insulation (Unfinished Basements)	Full	16.53	-
Solar Pre-heated Make-Up Air Systems (e.g., SolarWall®)	Full	18.60	20.80
High-efficiency Spa Pumps	Full	19.33	20.38
Timers for Electric Battery Blankets	Full	24.39	24.13
Near-zero/Net-zero Energy Homes	Full		26.09
LED Holiday Lighting (Indoor)	Full	27.58	27.58
Timers for Outdoor Lighting	Full	59.01	59.01
High-Efficiency Furnace Blower Motors (ECPM)	Full/Incr.	18.52	13.63
High-Efficiency (ENERGY STAR) Clothes Washers	Full/Incr.	15.44	15.67
Ground Source Heat Pumps (Closed Loop)	Full/Incr.	24.45	26.96
High-Efficiency (ENERGY STAR) Refrigerators	Incr.	5.60	5.80
Triple-glazed Windows	Incr.	14.65	6.78
Future Improvements to Electronics	Incr.	10.60	10.55
High-Efficiency (ENERGY STAR) Dishwashers	Incr.	11.23	14.88
High-Efficiency (ENERGY STAR) Freezers	Incr.	11.29	11.71
Quadruple-glazed Windows	Incr.	21.29	12.74
Efficient Fluorescent Fixtures (Replace T12s with T8s)	Incr.	12.80	12.80
Energy Efficient (ENERGY STAR) Printers and Faxes	Incr.	14.84	15.10
Optimizing of Glazing for Passive Solar Heating	Incr.	18.29	55.34
High-efficiency Heat Recovery Ventilators (HRVs)	Incr.	18.86	21.31
Energy Efficient (ENERGY STAR) Televisions	Incr.	21.83	21.83
Convection Ovens - Electric	Incr.	41.25	52.52
ENERGY STAR Ceiling Fans	Incr.	162.54	162.54
High-Efficiency Cooktops (Induction)	Incr.	421.30	536.44

Energy-efficiency Supply Curves

A supply curve was constructed based on the approximate Economic Potential savings associated with the above measures. The following approach was followed:

- Measures are introduced in sequence to show incremental impact and cost
- Sequence was determined by listing first the items that reduce the electrical load, then those that meet residual load with the most efficient technology
- Items appear in order, beginning with those that have the lowest average CCE

Exhibit 35R shows the measures included in the supply curve and Exhibit 36R shows the supply curve for Yukon as a whole in the 2030 milestone year. Since the 2035 results are based off of an extrapolation of 2030 results without any further achievable workshop consultations, the penetration and participation values for all measures were held constant over this period. Therefore, the 2030 supply curve results are presented below as this milestone year has the most reliable data.

Exhibit 35R Summary of Residential Sector Energy-Efficiency Measures, 2030

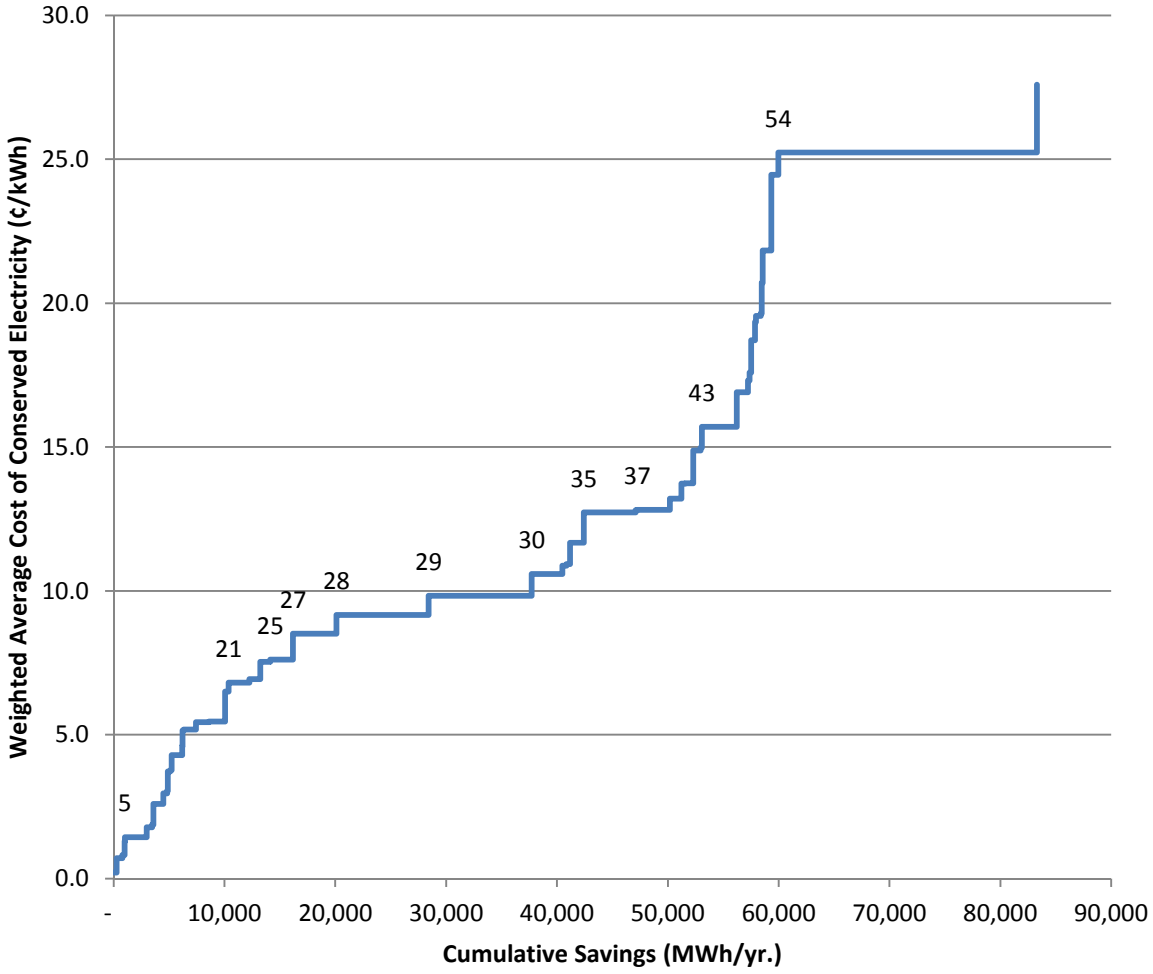
Ref #	Measure	Economic Potential Savings (MWh/yr.)	Accumulated CCE ($)	Weighted Average CCE (¢/kWh)
1	DHW Pipe Insulation	258	546	0.2
2	Showerheads	544	3,845	0.7
3	Hot Tub Pump Timers	194	1,596	0.8
4	Hot Tub Covers	16	213	1.3
5	LED Lamps	1,957	28,278	1.4
6	LED Lamps - Outdoor	497	8,876	1.8
7	Car Warmer Timers	119	2,221	1.9
8	Smart Learning Thermostats	904	23,453	2.6
9	Prog. Thermostats	347	10,267	3.0
10	Solar Spa Pre-heat	63	1,933	3.0
11	Heat Pump Spa Heaters	222	8,268	3.7
12	Pulse start metal halide sentinel lights	101	3,819	3.8
13	Block Heater Timers	952	40,858	4.3
14	Motion Detectors - Outdoor	11	476	4.4
15	Motion Detectors - Indoor	29	1,321	4.6
16	Basement Insulation	110	5,668	5.2
17	Attic Insulation	1,094	56,691	5.2
18	ENERGY STAR Refrigerators	1,190	64,763	5.4
19	Outdoor Temp Reset	1,435	78,438	5.5
20	DHW Tank Insulation	328	21,304	6.5
21	LEED Apartments	1,869	127,306	6.8
22	Sealing & Insul. - Old Homes	995	68,997	6.9
23	Air Sealing	854	64,362	7.5
24	Spot or Task Lighting	34	2,600	7.5

Updates to Yukon Electricity CPR 2011

Ref #	Measure	Economic Potential Savings (MWh/yr.)	Accumulated CCE ($)	Weighted Average CCE (¢/kWh)
25	Power Bars (PCs)	2,060	156,805	7.6
26	LED Holiday - Outdoor	4	341	7.8
27	Ductless Mini-Splits	3,911	332,892	8.5
28	Zone Heating	8,318	762,693	9.2
29	Cold Temp Heat Pumps	9,301	914,389	9.8
30	Future Elec Improvement	2,759	292,148	10.6
31	ENERGY STAR Dishwashers	385	41,916	10.9
32	ENERGY STAR Freezers	301	32,934	10.9
33	DHW Recirculation	1,248	145,605	11.7
34	Crawl Space Insulation	9	1,158	12.5
35	ENERGY STAR Clothes Washers	4,672	594,515	12.7
36	T8 Fixtures	147	18,783	12.8
37	Wall Insulation	2,952	378,288	12.8
38	Power Bars (TVs)	1,028	135,755	13.2
39	Triple-glazed Windows	365	50,077	13.7
40	Wastewater Heat Recovery	697	95,692	13.7
41	ENERGY STAR Printers and Fax	687	102,189	14.9
42	Slab Insulation	117	17,456	15.0
43	High-Perf. New Homes	3,143	493,576	15.7
44	DHW Piping Optimization	992	167,618	16.9
45	Optimizing Glazing for Passive	165	28,656	17.3
46	HRVs	133	23,358	17.6
47	Furnace Motors	338	63,302	18.7
48	Spa Pumps	94	18,161	19.3
49	Solar Pre-heat Makeup Air	419	81,948	19.6
50	Quadruple-glazed Windows	101	19,915	19.6
51	Battery Blanket Timers	91	18,866	20.7
52	ENERGY STAR TVs	784	171,064	21.8
53	Ground Heat Pumps - Closed	617	151,056	24.5
54	Net Zero Homes	23,336	5,890,246	25.2
55	LED Holiday - Indoor	3	831	27.6
	Grand Total	83,300	11,828,327	14.2

Updates to Yukon Electricity CPR 2011

Exhibit 36R Energy-efficiency Supply Curve, Residential Sector, 2030



Summary of Potential Electric Energy Savings

Exhibit 54R and Exhibit 58R present the residential achievable potential results for the total hydro grid connected Yukon service territory by technology and milestone year.

The Achievable Potential is defined as the proportion of the savings identified in the Economic Potential that could realistically be achieved within the study period. The achievable potential recognizes that it is difficult to induce customers to purchase and install all the electrical efficiency technologies that are economically feasible. The results are presented as a range, defined as lower and upper. The rate at which customers accept and purchase energy-efficiency products will be influenced by the level of financial incentives, information and other measures put in place by YEC.

The most significant savings in the Achievable Potential come from the following measures:

- Cold temperature heat pumps, which account for 24% of the upper Achievable Potential savings in 2035 and 20% of the lower Achievable Potential savings in 2035
- Zone heating systems, which account for 13% of the upper Achievable Potential savings in 2035 and 10% of the lower Achievable Potential savings in 2035
- ENERGY STAR clothes washers, which account for 9% of the upper Achievable Potential savings in 2035 and 13% of the lower Achievable Potential savings in 2035
- High-performance new homes, which account for 7% of the upper Achievable Potential savings in 2035 and 14% of the lower Achievable Potential savings in 2035
- Ductless mini-split systems, which account for 7% of the upper Achievable Potential savings in 2035 and 6% of the lower Achievable Potential savings in 2035
- LEED certified apartment buildings, which account for 4% of the upper Achievable Potential savings in 2035 and 4% of the lower Achievable Potential savings in 2035
- LED Lamps, which account for 3% of the upper Achievable Potential savings in 2035 and 4% of the lower Achievable Potential savings in 2035

There are numerous other smaller measures that contribute to the overall Achievable Potential results.

Updates to Yukon Electricity CPR 2011

Exhibit 54R Upper Achievable Residential Electricity Savings by Technology and Milestone Year (MWh/yr.)

End Use	Measure	2015	2020	2025	2030	2035	Adoption Curve	Weighted Average CCE (¢/kWh)
Space heating	Cold Temp Heat Pumps	403	2,035	5,402	9,807	9,653	B	9.8
Space heating	Zone Heating	185	986	2,761	5,292	5,196	B	9.0
Clothes dryer	ESTAR Clothes Washers	1,286	2,324	3,225	3,671	3,592	C	12.8
Space heating	High-Perf. New Homes	220	1,392	2,457	2,993	2,978	D-2017	15.7
Space heating	Ductless Mini-Splits	113	581	1,556	2,836	2,792	B	8.5
Indoor lighting	LED Lamps	299	938	1,573	1,664	1,088	B	1.4
Space heating	LEED Apartments	10	199	813	1,782	1,773	B	6.8
Space heating	Smart Learning Thermostats	357	673	946	1,175	1,135	A	2.5
Computer and peripherals	Power Bars (PCs)	119	310	563	824	882	A/B	7.6
Computer and peripherals	Future Elec Improvement	-	-	278	1,004	1,286	B	10.6
Space heating	Outdoor Temp Reset	31	165	465	899	883	B	5.4
Refrigerator	ESTAR Refrigerators	21	217	506	734	752	C	5.4
Television	ESTAR TVs	22	268	622	662	597	C	21.8
Computer and peripherals	ESTAR Printers and Fax	33	396	527	577	621	C	14.9
Block heaters & car warmers	Block Heater Timers	86	221	412	649	646	A/B	4.4
Domestic hot water (DHW)	Showerheads	209	337	433	475	439	A	0.7
Ventilation & circulation	Furnace Motors	270	431	463	333	332	A	18.7
Space heating	Wall Insulation	34	131	282	476	464	B	12.7
Television	Power Bars (TVs)	49	136	262	411	479	A/B	13.2
Space heating	Prog. Thermostats	92	180	262	338	327	A	2.9
Domestic hot water (DHW)	DHW Recirculation	19	83	213	393	373	B	11.5
Domestic hot water (DHW)	ESTAR Dishwashers	14	127	283	308	309	C	10.8
Domestic hot water (DHW)	DHW Tank Insulation	74	141	217	287	265	A	6.5
Space heating	Ground Heat Pumps - Closed	17	84	204	319	314	B	24.2
Domestic hot water (DHW)	DHW Piping Optimization	17	72	184	334	317	B	16.6
Indoor lighting	PAR LEDs	290	410	88	-	-	F	1.7
Space heating	Attic Insulation	20	75	159	265	258	B	5.2
Domestic hot water (DHW)	DHW Pipe Insulation	58	111	171	226	209	A	0.2
Freezer	ESTAR Freezers	5	55	129	215	300	C	10.9

End Use	Measure	2015	2020	2025	2030	2035	Adoption Curve	Weighted Average CCE (¢/kWh)
Space heating	Solar Pre-heat Makeup Air	7	40	110	201	198	B	19.3
Spa heaters and pumps	Heat Pump Spa Heaters	66	109	105	132	129	A/B	3.7
Spa heaters and pumps	Hot Tub Pump Timers	50	90	96	135	132	A/B	0.8
Space heating	Sealing & Insul. - Old Homes	11	44	96	165	160	B	6.9
Space heating	Air Sealing	10	37	80	138	137	B	7.4
Outdoor lighting	LEDs - Outdoor	90	155	50	-	-	F	1.8
Outdoor lighting	Pulse start metal halide sentinel lights	6	25	57	101	101	A	3.8
Domestic hot water (DHW)	Wastewater Heat Recovery	3	18	53	104	100	B	13.8
Block heaters & car warmers	Car Warmer Timers	11	28	51	81	81	A/B	1.9
Spa heaters and pumps	Spa Pumps	25	44	47	66	65	A/B	19.4
Block heaters & car warmers	Battery Blanket Timers	8	21	39	62	62	A/B	21.2
Space heating	HRVs	0	8	26	55	71	B	16.5
Indoor lighting	T8 Fixtures	1	15	37	52	52	B	12.8
Space heating	Triple-glazed Windows	0	7	22	49	78	B	13.5
Space heating	Basement Insulation	9	26	37	27	27	B	5.1
Space heating	Slab Insulation	3	9	18	28	28	B	14.6
Spa heaters and pumps	Solar Spa Pre-heat	8	15	16	22	22	A/B	3.1
Holiday lighting	LED Holiday - Outdoor	18	25	19	4	4	A	7.8
Indoor lighting	Spot or Task Lighting	9	15	17	15	10	A/B	7.5
Holiday lighting	LED Holiday - Indoor	13	17	14	3	3	A	27.6
Indoor lighting	Motion Detectors - Indoor	5	9	12	12	10	A/B	4.6
Spa heaters and pumps	Hot Tub Covers	4	8	8	11	11	A/B	1.3
Space heating	Optimizing Glazing for Passive	0	2	6	14	21	B	16.3
Outdoor lighting	Motion Detectors - Outdoor	2	5	6	7	4	A/B	4.4
Space heating	Quadruple-glazed Windows	0	1	2	5	7	B	16.1
Space heating	Crawl Space Insulation	0	1	1	2	1	B	12.3
Grand Total		4,715	13,852	26,482	40,441	39,773		9.7

Exhibit 58R Lower Achievable Residential Electricity Savings by Technology and Milestone Year (MWh/yr.)

End Use	Measure	2015	2020	2025	2030	2035	Adoption Curve	Weighted Average CCE (¢/kWh)
Domestic hot water (DHW)	DHW Pipe Insulation	45	86	132	174	161	A	0.2
Domestic hot water (DHW)	Showerheads	162	260	334	367	339	A	0.7
Spa heaters and pumps	Hot Tub Pump Timers	14	43	58	96	94	B	0.8
Spa heaters and pumps	Hot Tub Covers	1	4	5	8	8	B	1.3
Indoor lighting	LED Lamps	248	779	1,298	1,370	896	B	1.4
Indoor lighting	PAR LEDs	232	328	71	-	-	F	1.7
Outdoor lighting	LEDs - Outdoor	72	124	40	-	-	F	1.8
Block heaters & car warmers	Car Warmer Timers	3	13	31	57	57	B	1.9
Space heating	Smart Learning Thermostats	134	255	363	458	444	A	2.5
Space heating	Prog. Thermostats	31	61	90	117	114	A	2.9
Spa heaters and pumps	Solar Spa Pre-heat	2	7	10	16	16	B	3.1
Spa heaters and pumps	Heat Pump Spa Heaters	18	48	60	88	86	B	3.7
Outdoor lighting	Pulse start metal halide sentinel lights	6	25	57	101	101	A	3.8
Outdoor lighting	Motion Detectors - Outdoor	1	2	3	3	2	A/B	4.4
Block heaters & car warmers	Block Heater Timers	24	104	250	459	457	B	4.4
Indoor lighting	Motion Detectors - Indoor	3	5	6	7	5	A/B	4.6
	Subtotal (CCE up to 5 ¢/kWh)	**996**	**2,144**	**2,808**	**3,322**	**2,780**		**2.0**
Space heating	Basement Insulation	2	5	6	5	5	B	5.1
Space heating	Attic Insulation	4	13	28	47	46	B	5.2
Refrigerator	ESTAR Refrigerators	3	60	209	390	404	B	5.4
Space heating	Outdoor Temp Reset	11	63	187	373	367	B	5.5
Domestic hot water (DHW)	DHW Tank Insulation	57	109	167	221	204	A	6.5
Space heating	LEED Apartments	5	100	408	894	889	B	6.8
Space heating	Sealing & Insul. - Old Homes	2	8	17	29	28	B	6.9
Space heating	Air Sealing	2	7	14	24	24	B	7.4
Indoor lighting	Spot or Task Lighting	4	8	9	8	5	A/B	7.5
Computer and peripherals	Power Bars (PCs)	60	155	282	412	441	A/B	7.6
Holiday lighting	LED Holiday - Outdoor	18	25	19	4	4	A	7.8
Space heating	Ductless Mini-Splits	40	227	650	1,266	1,249	B	8.5
Space heating	Zone Heating	65	380	1,118	2,222	2,187	B	9.2
Space heating	Cold Temp Heat Pumps	140	768	2,162	4,179	4,120	B	9.8
	Subtotal (CCE between 5 -10 ¢/kWh)	**412**	**1,926**	**5,276**	**10,074**	**9,974**		**8.7**
Computer and peripherals	Future Elec Improvement	-	-	145	531	686	B	10.6
Freezer	ESTAR Freezers	1	16	55	125	195	B	10.9
Domestic hot water (DHW)	ESTAR Dishwashers	2	33	111	132	133	B	11.0
Domestic hot water (DHW)	DHW Recirculation	3	14	37	68	64	B	11.6
Space heating	Crawl Space Insulation	0	0	0	0	0	B	12.3
Space heating	Wall Insulation	6	23	50	84	82	B	12.7
Indoor lighting	T8 Fixtures	1	12	31	43	43	B	12.8
Television	Power Bars (TVs)	25	68	131	206	240	A/B	13.2
Clothes dryer	ESTAR Clothes Washers	149	627	1,525	2,746	2,682	B	13.4
Space heating	Triple-glazed Windows	0	1	4	9	14	B	13.5
Domestic hot water (DHW)	Wastewater Heat Recovery	1	3	9	18	17	B	13.8
Space heating	Slab Insulation	0	2	3	5	5	B	14.6
Computer and peripherals	ESTAR Printers and Fax	4	102	160	210	265	B	14.9
	Subtotal (CCE between 10 -15 ¢/kWh)	**191**	**901**	**2,261**	**4,177**	**4,427**		**12.9**
Space heating	High-Perf. New Homes	128	1,164	2,468	3,007	2,992	D-2022	15.7
Space heating	Quadruple-glazed Windows	0	0	0	1	1	B	16.1
Space heating	Optimizing Glazing for Passive	0	0	1	2	4	B	16.3
Space heating	HRVs	0	3	9	20	25	B	16.5
Domestic hot water (DHW)	DHW Piping Optimization	3	12	32	59	56	B	16.6
Ventilation & circulation	Furnace Motors	101	162	174	127	126	A	18.7
Spa heaters and pumps	Spa Pumps	7	21	29	47	46	B	19.4
Space heating	Solar Pre-heat Makeup Air	3	16	50	98	97	B	19.4
	Subtotal (CCE between 15 -20 ¢/kWh)	**242**	**1,379**	**2,764**	**3,361**	**3,348**		**16.0**
Block heaters & car warmers	Battery Blanket Timers	2	10	24	44	44	B	21.4
Television	ESTAR TVs	3	69	238	288	317	B	21.8
Space heating	Ground Heat Pumps - Closed	6	36	100	185	183	B	24.3
Holiday lighting	LED Holiday - Indoor	10	13	10	2	2	A	27.6
	Subtotal (CCE greater than 20	**21**	**128**	**372**	**519**	**545**		**22.7**
	Grand Total	**1,862**	**6,477**	**13,481**	**21,454**	**21,073**		**10.0**

Summary of Electric Peak Load Reductions: Electric Energy Measures

Exhibits 62R and 65R show the demand reductions associated with each residential sector electric energy savings measure in 2030. The 2030 results are presented in Exhibits 62R and 65R place of the 2035 results as they are more reliable results. With the absence of new achievable potential workshops, the results from 2035 were extrapolated from 2030 results with penetration and participation rates held constant. The results by milestone year are presented for the upper and lower achievable peak period 1 reductions in exhibits 62-2R and 65-2R respectively.

Most measures contribute to the peak demand reductions approximately in proportion to their electric energy savings. There are some notable exceptions. Block heaters are used at times that coincide closely with the utility peak, so their demand reduction would be disproportionate to their share of the electricity consumption savings. The potential reduction from block heater timers is even more significant than this would suggest, however, because the timer measure changes the load shape by moving the consumption almost entirely off the utility peak. Block heater timers offer the second largest potential for reducing peak demand in the Residential sector.

In contrast, the central heat pump and ductless mini-split systems, which both offer considerable electric energy savings potential, provide no reduction in peak electrical demand. This is because the utility peak occurs during the coldest period of the heating season, when these systems cease to operate as heat pumps and make use of their electric resistance backup heating elements.

Updates to Yukon Electricity CPR 2011

Exhibit 62R Electric Peak Load Reductions Upper Achievable Energy Savings Measures, 2030 (MW)

Measure	Period 1 Annual Peak Hour	Period 2 Evening Peak Period	Period 3 Morning Peak Period
Zone Heating	1.89	1.85	1.25
Block Heater Timers	1.18	1.48	0.00
High-Perf. New Homes	0.96	0.94	0.72
ESTAR Clothes Washers	0.80	0.68	0.36
LEED Apartments	0.58	0.58	0.38
Smart Learning Thermostats	0.42	0.41	0.28
LED Lamps	0.40	0.45	0.18
Outdoor Temp Reset	0.32	0.31	0.21
Wall Insulation	0.17	0.17	0.11
Future Elec Improvement	0.15	0.15	0.11
Power Bars (PCs)	0.12	0.12	0.09
Prog. Thermostats	0.12	0.12	0.08
Ground Heat Pumps - Closed	0.11	0.11	0.08
ESTAR TVs	0.10	0.10	0.08
Attic Insulation	0.09	0.09	0.06
ESTAR Refrigerators	0.09	0.09	0.07
ESTAR Printers and Fax	0.09	0.09	0.06
Solar Pre-heat Makeup Air	0.07	0.07	0.05
Power Bars (TVs)	0.06	0.06	0.05
Sealing & Insul. - Old Homes	0.06	0.06	0.04
Car Warmer Timers	0.05	0.07	0.00
Furnace Motors	0.05	0.05	0.05
Air Sealing	0.05	0.05	0.03
Showerheads	0.04	0.05	0.12
Battery Blanket Timers	0.04	0.05	0.00
DHW Recirculation	0.03	0.04	0.10
ESTAR Dishwashers	0.03	0.04	0.07
DHW Piping Optimization	0.03	0.03	0.08
ESTAR Freezers	0.03	0.03	0.02
DHW Tank Insulation	0.03	0.03	0.07
Pulse start metal halide sentinel lights	0.02	0.02	0.02
Hot Tub Pump Timers	0.02	0.02	0.02
Heat Pump Spa Heaters	0.02	0.02	0.02
DHW Pipe Insulation	0.02	0.02	0.06
HRVs	0.02	0.02	0.01
Triple-glazed Windows	0.02	0.02	0.01
LED Holiday - Outdoor	0.02	0.02	0.00
T8 Fixtures	0.01	0.01	0.01
LED Holiday - Indoor	0.01	0.01	0.00
Slab Insulation	0.01	0.01	0.01
Spa Pumps	0.01	0.01	0.01
Basement Insulation	0.01	0.01	0.01
Wastewater Heat Recovery	0.01	0.01	0.03
Optimizing Glazing for Passive	0.00	0.00	0.00
Spot or Task Lighting	0.00	0.00	0.00
Solar Spa Pre-heat	0.00	0.00	0.00
Motion Detectors - Indoor	0.00	0.00	0.00
Hot Tub Covers	0.00	0.00	0.00
Quadruple-glazed Windows	0.00	0.00	0.00
Motion Detectors - Outdoor	0.00	0.00	0.00
Crawl Space Insulation	0.00	0.00	0.00
Grand Total	8.41	8.58	5.02

Exhibit 62-2R Upper Achievable Electric Peak Load Reductions (Peak Period 1 - Annual Peak Hour) (MW)

Measure	2015	2020	2025	2030	2035
Zone Heating	0.07	0.35	0.99	1.89	1.85
Block Heater Timers	0.18	0.44	0.77	1.18	1.18
High-Perf. New Homes	0.07	0.44	0.78	0.96	0.95
ESTAR Clothes Washers	0.27	0.50	0.70	0.80	0.79
LEED Apartments	0.00	0.06	0.26	0.58	0.58
Smart Learning Thermostats	0.13	0.24	0.34	0.42	0.41
Outdoor Temp Reset	0.01	0.06	0.17	0.32	0.32
LED Lamps	0.07	0.23	0.38	0.40	0.26
Future Elec Improvement	0.00	0.00	0.04	0.15	0.20
Wall Insulation	0.01	0.05	0.10	0.17	0.17
Power Bars (PCs)	0.02	0.05	0.08	0.12	0.13
Prog. Thermostats	0.03	0.06	0.09	0.12	0.12
Ground Heat Pumps - Closed	0.01	0.03	0.07	0.11	0.11
ESTAR Refrigerators	0.00	0.03	0.06	0.09	0.09
ESTAR TVs	0.00	0.04	0.10	0.10	0.09
Attic Insulation	0.01	0.03	0.06	0.09	0.09
ESTAR Printers and Fax	0.00	0.06	0.08	0.09	0.09
Power Bars (TVs)	0.01	0.02	0.04	0.06	0.07
Solar Pre-heat Makeup Air	0.00	0.01	0.04	0.07	0.07
Sealing & Insul. - Old Homes	0.00	0.02	0.03	0.06	0.06
Car Warmer Timers	0.01	0.02	0.03	0.05	0.05
Furnace Motors	0.04	0.07	0.07	0.05	0.05
Air Sealing	0.00	0.01	0.03	0.05	0.05
Battery Blanket Timers	0.01	0.01	0.03	0.04	0.04
Showerheads	0.02	0.03	0.04	0.04	0.04
ESTAR Freezers	0.00	0.01	0.02	0.03	0.04
DHW Recirculation	0.00	0.01	0.02	0.03	0.03
ESTAR Dishwashers	0.00	0.01	0.03	0.03	0.03
DHW Piping Optimization	0.00	0.01	0.02	0.03	0.03
Triple-glazed Windows	0.00	0.00	0.01	0.02	0.03
HRVs	0.00	0.00	0.01	0.02	0.03
Pulse start metal halide sentinel lights	0.00	0.01	0.01	0.02	0.02
DHW Tank Insulation	0.01	0.01	0.02	0.03	0.02
Hot Tub Pump Timers	0.01	0.01	0.01	0.02	0.02
Heat Pump Spa Heaters	0.01	0.02	0.02	0.02	0.02
DHW Pipe Insulation	0.01	0.01	0.02	0.02	0.02
LED Holiday - Outdoor	0.07	0.09	0.07	0.02	0.02
T8 Fixtures	0.00	0.00	0.01	0.01	0.01
LED Holiday - Indoor	0.05	0.06	0.05	0.01	0.01
Slab Insulation	0.00	0.00	0.01	0.01	0.01
Spa Pumps	0.00	0.01	0.01	0.01	0.01
Basement Insulation	0.00	0.01	0.01	0.01	0.01
Wastewater Heat Recovery	0.00	0.00	0.00	0.01	0.01
Optimizing Glazing for Passive	0.00	0.00	0.00	0.00	0.01
Solar Spa Pre-heat	0.00	0.00	0.00	0.00	0.00
Quadruple-glazed Windows	0.00	0.00	0.00	0.00	0.00
Spot or Task Lighting	0.00	0.00	0.00	0.00	0.00
Motion Detectors - Indoor	0.00	0.00	0.00	0.00	0.00
Hot Tub Covers	0.00	0.00	0.00	0.00	0.00
Motion Detectors - Outdoor	0.00	0.00	0.00	0.00	0.00
Crawl Space Insulation	0.00	0.00	0.00	0.00	0.00
LEDs - Outdoor	0.02	0.04	0.01	-	-
PAR LEDs	0.07	0.10	0.02	-	-
Grand Total	1.24	3.28	5.78	8.41	8.25

Exhibit 65R Electric Peak Load Reductions Lower Achievable Energy Savings Measures, 2030 (MW)

Measure	Period 1 Annual Peak Hour	Period 2 Evening Peak Period	Period 3 Morning Peak Period
High-Perf. New Homes	0.96	0.94	0.73
Block Heater Timers	0.84	1.05	0.00
Zone Heating	0.79	0.78	0.52
ESTAR Clothes Washers	0.60	0.51	0.27
LED Lamps	0.33	0.37	0.15
LEED Apartments	0.29	0.29	0.19
Smart Learning Thermostats	0.16	0.16	0.11
Outdoor Temp Reset	0.13	0.13	0.09
Future Elec Improvement	0.08	0.08	0.06
Ground Heat Pumps - Closed	0.07	0.06	0.04
Power Bars (PCs)	0.06	0.06	0.05
ESTAR Refrigerators	0.05	0.05	0.04
ESTAR TVs	0.05	0.04	0.03
Prog. Thermostats	0.04	0.04	0.03
Car Warmer Timers	0.04	0.05	0.00
Solar Pre-heat Makeup Air	0.03	0.03	0.02
Showerheads	0.03	0.04	0.09
Power Bars (TVs)	0.03	0.03	0.02
ESTAR Printers and Fax	0.03	0.03	0.02
Wall Insulation	0.03	0.03	0.02
Battery Blanket Timers	0.03	0.04	0.00
Pulse start metal halide sentinel lights	0.02	0.02	0.02
Furnace Motors	0.02	0.02	0.02
DHW Tank Insulation	0.02	0.02	0.06
Attic Insulation	0.02	0.02	0.01
LED Holiday - Outdoor	0.02	0.02	0.00
ESTAR Freezers	0.02	0.01	0.01
DHW Pipe Insulation	0.02	0.02	0.04
Hot Tub Pump Timers	0.01	0.01	0.01
ESTAR Dishwashers	0.01	0.02	0.03
Heat Pump Spa Heaters	0.01	0.01	0.01
T8 Fixtures	0.01	0.01	0.00
Sealing & Insul. - Old Homes	0.01	0.01	0.01
Air Sealing	0.01	0.01	0.01
LED Holiday - Indoor	0.01	0.01	0.00
Spa Pumps	0.01	0.01	0.01
HRVs	0.01	0.01	0.00
DHW Recirculation	0.01	0.01	0.02
DHW Piping Optimization	0.01	0.01	0.01
Triple-glazed Windows	0.00	0.00	0.00
Solar Spa Pre-heat	0.00	0.00	0.00
Spot or Task Lighting	0.00	0.00	0.00
Slab Insulation	0.00	0.00	0.00
Basement Insulation	0.00	0.00	0.00
Motion Detectors - Indoor	0.00	0.00	0.00
Wastewater Heat Recovery	0.00	0.00	0.00
Hot Tub Covers	0.00	0.00	0.00
Optimizing Glazing for Passive	0.00	0.00	0.00
Motion Detectors - Outdoor	0.00	0.00	0.00
Quadruple-glazed Windows	0.00	0.00	0.00
Crawl Space Insulation	0.00	0.00	0.00
Grand Total	4.92	5.06	2.78

Updates to Yukon Electricity CPR 2011

Exhibit 65-2R Lower Achievable Electric Peak Load Reductions (Peak Period 1 - Annual Peak Hour) (MW)

Measure	2015	2020	2025	2030	2035
High-Perf. New Homes	0.04	0.37	0.78	0.96	0.95
Block Heater Timers	0.05	0.21	0.47	0.84	0.83
Zone Heating	0.02	0.14	0.40	0.79	0.78
ESTAR Clothes Washers	0.03	0.13	0.33	0.60	0.59
LEED Apartments	0.00	0.03	0.13	0.29	0.29
LED Lamps	0.06	0.19	0.31	0.33	0.22
Smart Learning Thermostats	0.05	0.09	0.13	0.16	0.16
Outdoor Temp Reset	0.00	0.02	0.07	0.13	0.13
Future Elec Improvement	0.00	0.00	0.02	0.08	0.10
Ground Heat Pumps - Closed	0.00	0.01	0.04	0.07	0.07
Power Bars (PCs)	0.01	0.02	0.04	0.06	0.07
ESTAR Refrigerators	0.00	0.01	0.03	0.05	0.05
ESTAR TVs	0.00	0.01	0.04	0.05	0.05
Prog. Thermostats	0.01	0.02	0.03	0.04	0.04
ESTAR Printers and Fax	0.00	0.02	0.02	0.03	0.04
Car Warmer Timers	0.00	0.01	0.02	0.04	0.04
Power Bars (TVs)	0.00	0.01	0.02	0.03	0.04
Solar Pre-heat Makeup Air	0.00	0.01	0.02	0.03	0.03
Showerheads	0.01	0.02	0.03	0.03	0.03
Battery Blanket Timers	0.00	0.01	0.02	0.03	0.03
Wall Insulation	0.00	0.01	0.02	0.03	0.03
ESTAR Freezers	0.00	0.00	0.01	0.02	0.02
Pulse start metal halide sentinel lights	0.00	0.01	0.01	0.02	0.02
Furnace Motors	0.02	0.03	0.03	0.02	0.02
DHW Tank Insulation	0.01	0.01	0.01	0.02	0.02
Attic Insulation	0.00	0.00	0.01	0.02	0.02
LED Holiday - Outdoor	0.07	0.09	0.07	0.02	0.02
Hot Tub Pump Timers	0.00	0.01	0.01	0.01	0.01
DHW Pipe Insulation	0.00	0.01	0.01	0.02	0.01
ESTAR Dishwashers	0.00	0.00	0.01	0.01	0.01
Heat Pump Spa Heaters	0.00	0.01	0.01	0.01	0.01
T8 Fixtures	0.00	0.00	0.01	0.01	0.01
Sealing & Insul. - Old Homes	0.00	0.00	0.01	0.01	0.01
HRVs	0.00	0.00	0.00	0.01	0.01
Air Sealing	0.00	0.00	0.00	0.01	0.01
LED Holiday - Indoor	0.04	0.05	0.04	0.01	0.01
Spa Pumps	0.00	0.00	0.00	0.01	0.01
DHW Recirculation	0.00	0.00	0.00	0.01	0.01
DHW Piping Optimization	0.00	0.00	0.00	0.01	0.00
Triple-glazed Windows	0.00	0.00	0.00	0.00	0.00
Solar Spa Pre-heat	0.00	0.00	0.00	0.00	0.00
Slab Insulation	0.00	0.00	0.00	0.00	0.00
Basement Insulation	0.00	0.00	0.00	0.00	0.00
Wastewater Heat Recovery	0.00	0.00	0.00	0.00	0.00
Optimizing Glazing for Passive	0.00	0.00	0.00	0.00	0.00
Spot or Task Lighting	0.00	0.00	0.00	0.00	0.00
Motion Detectors - Indoor	0.00	0.00	0.00	0.00	0.00
Hot Tub Covers	0.00	0.00	0.00	0.00	0.00
Motion Detectors - Outdoor	0.00	0.00	0.00	0.00	0.00
Quadruple-glazed Windows	0.00	0.00	0.00	0.00	0.00
Crawl Space Insulation	0.00	0.00	0.00	0.00	0.00
LEDs - Outdoor	0.02	0.03	0.01	-	-
PAR LEDs	0.06	0.08	0.02	-	-
Grand Total	0.52	1.68	3.26	4.92	4.82

Summary of Electric Peak Load Reductions: Capacity Measures

Exhibits 41R and 42R show the economic demand reductions associated with each residential sector peak load reduction measure in 2015. Exhibit 41R shows the name of the measure, the cost basis for the CEPR that the shown (full versus incremental) and the measure's average CEPR. The following approach was taken in updating these exhibits from the 2011 study:

- The discount rate was updated to 3.38% from 7.5%, thus impacting the CEPR values.
- The applicable dwellings count was updated from the 2010 base year to the new 2015 milestone year data, thus impacting the dwelling saturation and MW reduction for each capacity measure.
- Costing assumptions for each measure were left unchanged from the 2011 CPR study.

Measures analyzed on the basis of full cost have been placed towards the top of Exhibit 41R as they are qualitatively different from the measures that pass only on an incremental basis. A measure that passes on a full-cost basis can be applied immediately, while incremental measures presume the adoption of other technologies as a condition of their cost effectiveness (e.g., facility network gateways).

Exhibit 42R shows a list of the capacity electric peak load reduction measures grouped by applicable end use category. This exhibit shows the measure name, dwelling saturation, applicable count in 2015, average demand reduction and average CEPR. Note that since there was no threshold established for maximum cost effective CEPR, all measures are listed and there are no exclusions based on cost effectiveness.

Exhibit 41R Residential Sector Electric Peak Load Reduction Measures, Screening Results

Measure Name	Basis (Full/Incremental)	CEPR Ranges ($/kW)
One-way switch for engine block heater	Full	$55 - $68
Electric central thermal storage	Full	$109 - $111
One-way switch for pools and spas	Full	$77 - $82
One-way switch for water heating control	Full	$105 - $117
Electric room thermal storage for supplemental heat	Full	$96 - $99
One-way switch for plug loads	Full	$172 - $234
One-way switch for lighting control	Full	$270 - $300
One-way switch for engine block heater	Incremental	$48 - $60
One-way switch for pools and spas	Incremental	$37 - $39
One-way switch for plug loads	Incremental	$51 - $69
One-way switch for lighting control	Incremental	$80 - $89
One-way switch for water heating control	Incremental	$77 - $86

Exhibit 42R Total Applicable Dwelling Types and MW Impact by Measure

Electric Peak Reduction Measures	Dwelling Saturation	Applicable Count 2015	Avg MW	Avg CEPR $/kW/yr.
Space Heating				
One-way switch for engine block heater - utility load control – stand-alone	52%	7,897	1.5	$55 - $68
One-way switch for engine block heater - utility load control - incremental	52%	7,897	1.5	$48 - $60
Electric thermal storage (central)	13%	1,982	6.8	$109 - $111
Electric thermal storage (room/supplemental)	9.3%	1,418	1.7	$96 - $99
Electric Water Heating				
One-way switch-based utility load control – stand-alone	68%	10,267	2.7	$105 - $117
One-way switch-based utility load control - incremental	68%	10,267	2.7	$77 - $86
Lighting				
One-way switch-based utility load control - stand-alone	95%	14,379	1.2	$270 - $300
One-way switch-based utility load control - incremental	95%	14,379	1.2	$80 - $89
Plug Loads				
One-way switch-based utility load control - stand-alone	95%	14,379	1.0	$172 - $234
One-way switch-based utility load control – incremental	95%	14,379	1.0	$51 - $69
Electric Pools and Spas				
One-way switch-based utility load control - stand-alone	6.3%	949	0.6	$77 - $82
One-way switch-based utility load control – incremental	6.3%	949	0.6	$37 - $39

Summary of Lower Achievable Electric Peak Load Reductions: Capacity Measures

Exhibit 42-2R below shows the residential lower achievable demand reduction for peak period 1 and the average full cost CEPR value by end use category for each milestone year until 2035. The demand curve showing the lower achievable demand with EE measures only versus the lower achievable demand with both EE and capacity measures is shown in Exhibit 42-3R. The following approach was taken in developing these exhibits:

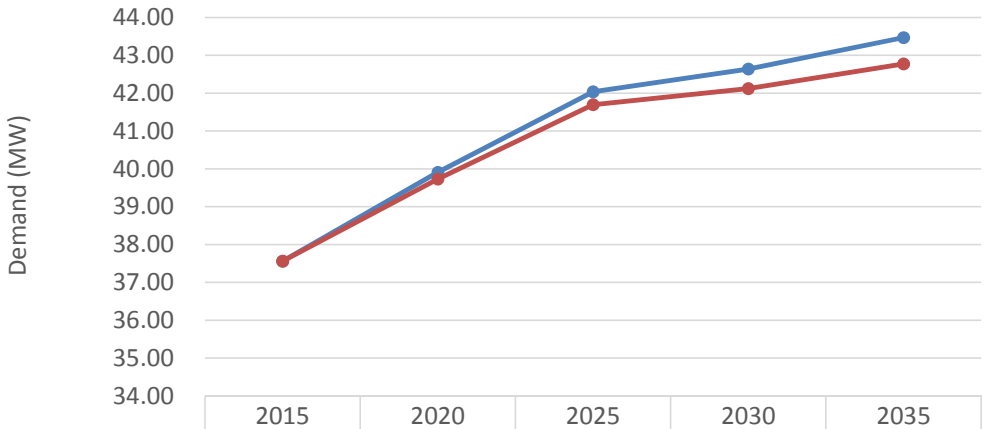
- The demand for each end use category after EE measures are applied was used as the baseline demand from which peak reductions occur due to capacity measures
- A lower achievable potential of 5% was assumed for all capacity measures, and was linearly extrapolated to all milestone years from a starting uptake of 0% in 2015 (due to lack of utility programs) up to a maximum of 5% in the year 2035.

Note that results of the achievable reduction due to capacity measures presented below are based upon the *lower* achievable potential and are subject to variation as they are highly jurisdiction-specific and dependent upon the structure of the utility programs. It is recommended that additional research be conducted in order to account for these limitations.

Exhibit 42-2R Lower Achievable Potential Peak Load Reductions by End Use (MW) – Capacity Measures

	2020	2025	2030	2035	Average CEPR ($/kW/yr.)
Space Heating	0.10	0.21	0.31	0.41	$100
Electric Water Heating	0.03	0.07	0.10	0.14	$111
Lighting	0.02	0.03	0.04	0.06	$285
Plug Loads	0.01	0.03	0.04	0.05	$203
Electric Pools and Spas	0.01	0.01	0.02	0.03	$80
TOTAL	**0.17**	**0.35**	**0.52**	**0.69**	

Exhibit 42-3R Lower Achievable Potential Demand (MW) – EE Measures only vs. EE & Capacity Measures



	2015	2020	2025	2030	2035
Demand with Lower Achievable EE Measures Applied (MW)	37.56	39.90	42.04	42.64	43.47
Lower Achievable Potential Demand (MW)	37.56	39.73	41.69	42.12	42.78

3.2 Commercial Results

Base Year

This section presents the results of the analysis of electricity consumption for the Base Year 2014. Electricity consumption is measured at the customer's point-of-use and does not include line losses.

Exhibit 10C presents total commercial sector hydro grid electricity consumption by sub sector and end use.

Base Year Electricity Use by Sub Sector

Other General Service Buildings account for the largest share of electricity use within the building sub sectors (19%), followed by Office (15%), and Education, Warehouse/Wholesale and Non-food Retail at 9% each.

Non-buildings account for 12% of Base Year Commercial sector hydro grid electricity use.

Base Year Electricity Use by End Use

Lighting is the largest Commercial sector end use, accounting for approximately 37% of total Commercial sector hydro grid electricity use. Indoor lighting, which consists of general, architectural and high-bay lighting, accounts for approximately 34%, while outdoor lighting accounts for the remaining 3%.

Space heating is the second largest end use, accounting for 14% of Commercial sector hydro grid electricity use, followed by refrigeration (9%), HVAC fans & pumps (8%), and computer equipment (6%). Cooking equipment, domestic water heating and a number of smaller end uses account for the remaining Commercial sector hydro grid electricity use.

Non-building loads are treated as both an end use and sub sector in this analysis. These loads account for 12% of Commercial sector end use hydro grid electricity consumption. Energy consumption for street lighting and block heaters is broken out separately as well.

Updates to Yukon Electricity CPR 2011

Exhibit 10C Base Year Annual Commercial Electricity Consumption by Sub Sector and End Use (MWh/yr.)

Sub Sector	General Lighting	Architectural Lighting	High Bay Lighting	Outdoor Lighting	Space Heating	Space Cooling	HVAC Fans and Pumps	Water Heating	Computer Equipment	Other Plug Loads	Food Service Equipment	Refrigeration	Elevators	Miscellaneous	Non Buildings	Street Lighting	Block Heater	Grand Total
Office	6,421	2,127	-	642	6,135	621	2,882	478	4,091	1,055	144	151	146	756	-	-	-	25,650
Food Retail	628	620	1,064	275	604	41	510	110	185	177	130	6,498	-	54	-	-	-	10,896
Non-food Retail	4,959	2,642	996	865	2,150	167	1,377	148	530	635	253	379	-	253	-	-	-	15,354
Hotel / Motel	860	1,543	-	291	2,225	148	980	721	365	330	214	514	66	174	-	-	-	8,430
Healthcare	1,246	458	-	196	723	46	1,315	81	251	392	116	87	45	58	-	-	-	5,013
Education	3,820	1,504	585	410	3,313	52	1,650	1,069	1,158	942	483	479	-	241	-	-	-	15,707
Recreation Centres	511	273	1,921	587	190	3	350	145	27	224	312	2,570	-	138	-	-	-	7,252
Restaurant	461	1,660	-	593	1,239	67	669	379	103	135	877	1,888	-	54	-	-	-	8,124
Warehouse / Wholesale	885	728	6,425	677	1,221	6	919	126	712	646	160	2,793	-	399	-	-	-	15,696
Other General Service Buildings	9,038	3,970	973	1,264	5,958	535	3,227	442	3,190	1,309	337	469	96	741	-	-	-	31,550
Non-Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20,562	-	-	20,562
Street lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,714	-	3,714
Parking Lot Plug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	360	360
Grand Total	28,830	15,524	11,962	5,799	23,757	1,687	13,878	3,700	10,613	5,846	3,024	15,828	353	2,869	20,562	3,714	360	168,308

Technology Screening

A summary of the technology screening results is provided in Exhibit 25C. For each of the measures, the exhibit shows:

- The name of the measure
- The cost basis[3] for the CCE that is shown, e.g., full versus incremental
- The measure's average CCE when applied to all sub sectors.

Measures analyzed on the basis of full cost have been placed towards the top of the exhibit below because they are qualitatively different from the measures that pass only on an incremental basis. A measure that passes on a full-cost basis can be applied immediately, even if the piece of equipment it replaces or improves is currently working properly. That means the rate at which the measure can be implemented as a utility DSM measure is limited by market and program constraints. A measure that passes only on an incremental basis, on the other hand, is limited by the rate of natural replacement (due to failure or obsolescence) or purchase of the piece of equipment it replaces.

Exhibit 25C Commercial Sector Energy-efficiency Technology Measures, Screening Results[4] - Hydro Region

Measure Name	Basis (Full/[5] Incremental)	Average CCE (¢/kWh)
Low Flow Faucets	Full	0.22
Lighting Controls (Outdoor)	Full	0.39
Low Flow Showerheads	Full	0.48
Demand-Controlled Kitchen Ventilation	Full	0.64
Domestic Hot Water Tank Insulation	Full	1.72
Brine Pump Control	Full	1.84
Infrared Electric Radiant Heaters	Full	1.90
LED High Bay Fixtures	Full	2.15
Air Sealing	Full	2.26
Adjustable Speed Drive (Fan Application)	Full	2.32
Demand-Controlled Ventilation	Full	2.33
High-Volume Low-Speed Destratification Fans	Full	2.39
Building Recommissioning	Full	2.80
High Performance T8 (T12 Retrofit)	Full	2.92
LED Lamps (Outdoor)	Full	3.18
LED Street Lighting	Full	3.46
Block Heater Controls	Full	3.58
Air-to-Air Heat Recovery	Full	3.70
White LED Lamps	Full	4.40
Occupancy Controls	Full	4.74
Drainwater Heat Recovery	Full	4.85
LED Fluorescent Fixtures	Full	5.77
Ceramic Metal Halide Lamps	Full	6.04

[3] See Step 3 in Section 7.2 for a complete description.
[4] Average CCE does not include program costs.
[5] Due to the high avoided cost of new supply in Yukon many measures pass at full cost. The CCEs for energy-efficient equipment upgrades at time of failure (incremental) are typically significantly lower.

Updates to Yukon Electricity CPR 2011

Measure Name	Basis (Full/[5] Incremental)	Average CCE (¢/kWh)
High Performance T8 (Redesign)	Full	6.61
Low Flow Pre-Rinse Spray Valves	Full	6.81
LED Wallpack Outdoor Fixtures	Full	7.18
Ground-Source Heat Pump	Full	7.68
Refrigeration Plant Controls	Full	8.61
High Performance T8 (T8 Retrofit)	Full	9.62
Adaptive Thermostats	Full	9.70
High Efficiency Refrigeration Equipment - Full Cost Measures	Full	10.79
Refrigeration Plant Heat Recovery	Full	16.15
Premium Efficiency Motors	Full	17.42
Dimming Controls (Daylighting)	Full	18.21
T5 High Output Arena Lighting	Full	24.31
Low Emissivity Ceiling	Full	34.36
New Building Construction - 25% Better than Current Practice	Incr.	1.95
New Building Construction - 40% Better than Current Practice	Incr.	3.66
ENERGY STAR Computers	Incr.	4.56
High Performance Glazing	Incr.	5.23
ENERGY STAR Servers	Incr.	6.34
ENERGY STAR Refrigerators and Freezers	Incr.	6.84
Halogen IR Lamps	Incr.	7.26
ENERGY STAR Office Equipment	Incr.	7.78
New Building Construction - 60% Better than Current Practice	Incr.	8.13
Wall Insulation Upgrade	Incr.	9.60
High-Efficiency Cooking Equipment	Incr.	10.49
Super High Performance Glazing	Incr.	10.65
Roof Insulation Upgrade	Incr.	11.86
High Efficiency Refrigeration Equipment - Incremental Cost Measures	Incr.	12.84
High Efficiency Chillers	Incr.	53.64
High Efficiency Packed Direct-Expansion (DX) Cooling	Incr.	94.29
Low Flow Faucets	Full	0.22
Lighting Controls (Outdoor)	Full	0.39
Low Flow Showerheads	Full	0.48
Demand-Controlled Kitchen Ventilation	Full	0.64
Domestic Hot Water Tank Insulation	Full	1.72
Brine Pump Control	Full	1.84

Energy-efficiency Supply Curves

A supply curve was constructed based on the approximate Economic Potential savings associated with the above measures. The following approach was followed:

- Measures are introduced in sequence to show incremental impact and cost
- Sequence was determined by listing first the items that reduce the electrical load, then those that meet residual load with the most efficient technology
- Items appear in order, beginning with those that have the lowest average CCE

Exhibit 35C shows the measures included in the supply curve and Exhibit 36C shows the supply curve for Yukon as a whole in the 2030 milestone year. Since the 2035 results are based off of an extrapolation of 2030 results without any further achievable workshop consultations, the penetration and participation values for all measures were held constant over this period. Therefore, the 2030 supply curve results are presented below as this milestone year has the most reliable data.

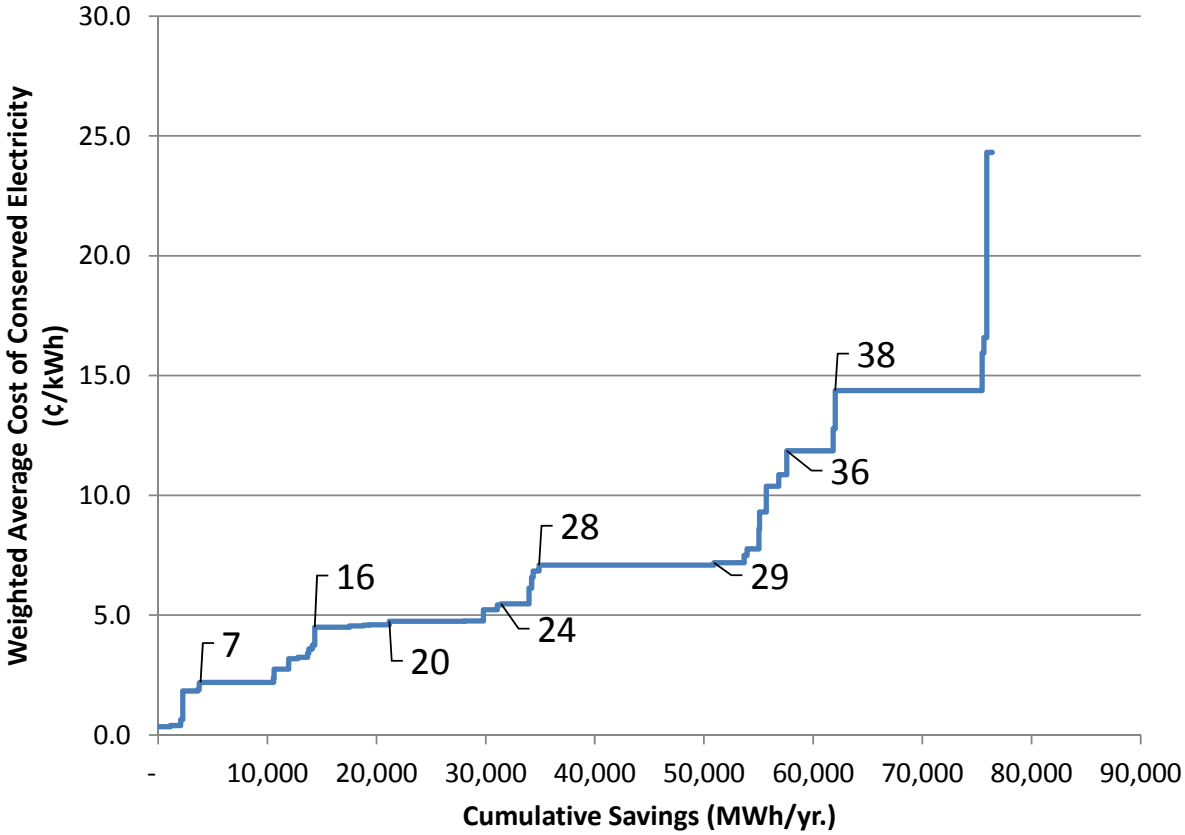
Exhibit 35C Summary of Commercial Sector Energy-efficiency Measures, 2030

Ref #	Measure	Economic Potential Savings (MWh/yr.)	Cost of Savings ($)	Weighted Average CCE (¢/kWh)
1	Low Flow Faucets	1,095	3,758	0.3
2	Lighting Controls (Outdoor)	965	3,788	0.4
3	Demand Controlled Kitchen Ventilation	188	1,198	0.6
4	Brine Pump Control	1,374	25,246	1.8
5	Infrared Electric Radiant Heaters	131	2,490	1.9
6	Low Flow Pre Rinse Spray Valves	114	2,478	2.2
7	LED High Bay Fixtures	6,710	147,050	2.2
8	High-Volume Low-Speed Destratification Fans	50	1,190	2.4
9	Adjustable Speed Drive (Fan Application)	1,324	36,390	2.7
10	LED Lamps (Outdoor)	850	27,021	3.2
11	Air Sealing	898	29,169	3.2
12	Tank Insulation	98	3,346	3.4
13	Block Heater Controls	234	8,390	3.6
14	Drainwater Heat Recovery	93	3,351	3.6
15	Adaptive Thermostats	213	7,975	3.7
16	ENERGY STAR Computers	3,207	144,419	4.5
17	HP to redesign increment	1256	57208	4.6
18	DC Ventilation	523	24,026	4.6
19	High Efficiency Refrigeration - Full Cost	1,840	84,617	4.6
20	Building Recommissioning	6,889	326,795	4.7
21	Air to Air HR	1,744	82,959	4.8

Updates to Yukon Electricity CPR 2011

Ref #	Measure	Economic Potential Savings (MWh/yr.)	Cost of Savings ($)	Weighted Average CCE (¢/kWh)
22	HP Glazing	1,270	66,443	5.2
23	HP to SHP Glazing increment	359	19,480	5.4
24	HE Refrigeration - Incr. Cost	2,545	139,235	5.5
25	Low Flow Showerheads	233	14,279	6.1
26	Occupancy Controls	139	9,141	6.6
27	ENERGY STAR Fridges, Freezers	544	37223	6.8
28	LED Fluorescent Fixtures	16,040	1,137,413	7.1
29	LED Wallpack Outdoor Fixtures	2,762	198,398	7.2
30	ENERGY STAR Office Equipment	261	19,608	7.5
31	Ground-Source Heat Pumps	1,075	83,489	7.8
32	Refrigeration Plant Controls	58	5,003	8.6
33	ENERGY STAR Servers	632	58,851	9.3
34	Wall Insulation	1,124	116,721	10.4
35	Roof Insulation	754	81,917	10.9
36	High Performance T8 (T8 Retrofit)	4,260	505,173	11.9
37	PE Motors	176	22,446	12.8
38	Whole Building - 60% More Efficient than Current	13449	1933922	14.4
39	High Efficiency Cooking Equipment	171	27,252	15.9
40	Dimming Controls (Daylighting)	258	42,702	16.6
41	T5HO Arena Lighting	488	118,717	24.3
	Total	76,395	5,660,277	7.4

Exhibit 36C Energy-efficiency Supply Curve, Commercial Sector, 2030



Summary of Potential Electric Energy Savings

Exhibits 54C and 58C present the achievable potential results for the total hydro grid connected Yukon service territory by technology and milestone year.[6] The most significant savings in the Achievable Potential come from the following measures:

- Building recommissioning, which accounts for 16% of the upper Achievable Potential savings in 2035 and 15% of the lower Achievable Potential savings in 2035
- LED fluorescent fixtures, which account for 14% of the upper Achievable Potential savings in 2035 and 12% of the lower Achievable Potential savings in 2035
- LED high bay fixtures, which account for 11% of the upper Achievable Potential savings in 2035 and 9% of the lower Achievable Potential savings in 2035
- High performance new buildings (whole building – 60% more efficient than current), which account for 9% of the upper Achievable Potential savings in 2035 and 11% of the lower Achievable Potential savings in 2035
- High efficiency refrigeration measures (both full and incremental cost), which account for 8% of the upper Achievable Potential savings in 2035 and 15% of the lower Achievable Potential savings in 2035
- ENERGY STAR computers, which account for 5% of the upper Achievable Potential savings in 2035 and 7% of the lower Achievable Potential savings in 2035
- LED wallpack outdoor fixtures, which account for 4% of the upper Achievable Potential savings in 2035 and 4% of the lower Achievable Potential savings in 2035

There are numerous other smaller measures that contribute to the overall Achievable Potential results.

[6] Note that these exhibits were not present in the original commercial sector report. However, they are equivalent to Exhibits 54 and 58 in the original residential sector report.

Exhibit 54C Upper Achievable Electricity Savings by Technology and Milestone Year (MWh/yr.)

End Use	Measure	2015	2020	2025	2030	2035	Adoption Curve	Weighted Average CCE (¢/kWh)
General Lighting	LED Fluorescent Fixtures	1,279	2,813	4,561	6,481	6,350	A/B	3.7
General Lighting	Building Recommissioning	558	2,107	4,398	7,128	7,059	B	2.7
High Bay Lighting	LED High Bay Fixtures	799	1,890	3,257	4,881	4,881	A/B	1.2
Space Heating	Whole Building - 60% More Efficient than Current	30	523	2,076	4,518	3,981	B	11.2
Refrigeration	High Efficiency Refrigeration - Full Cost	1,805	1,805	1,805	1,805	1,805	D	4.5
Computer Equipment	Energy Star ® Computers	256	1,594	1,948	2,294	2,331	B	3.6
Outdoor Lighting	LED Wallpack Outdoor Fixtures	346	802	1,349	1,965	1,965	A/B	3.8
General Lighting	High Performance T8 (T8 Retrofit)	321	718	1,186	1,720	1,685	A/B	6.2
Refrigeration	HE Refrigeration - Incr. Cost	39	468	1,126	1,843	1,843	A/B	6.3
Space Heating	Air to Air HR	115	446	946	1,546	1,521	B	2.6
Outdoor Lighting	Lighting Controls (Outdoor)	274	577	846	1,016	1,016	A/B	0.3
HVAC Fans and Pumps	Adjustable Speed Drive (Fan Application)	64	255	573	1,019	1,019	B	1.4
Water Heating	Low Flow Faucets	207	415	622	829	829	A/B	0.2
General Lighting	Dimming Controls (Daylighting)	103	309	528	685	671	A/B	10.7
Space Heating	Air Sealing	51	203	448	772	759	B	1.7
Outdoor Lighting	LED Lamps (Outdoor)	134	297	475	653	653	B	2.0
Space Heating	Ground-Source Heat Pumps	163	306	414	473	465	A	2.7
Computer Equipment	Energy Star ® Servers	165	310	380	449	456	B	7.3
Refrigeration	Brine Pump Control	120	241	361	481	481	A	0.5
Space Heating	HP Glazing	7	85	234	453	595	A	1.5
Space Heating	DC Ventilation	35	134	284	464	456	B	2.5
General Lighting	Occupancy Controls	86	185	285	370	362	A/B	3.8
High Bay Lighting	T5HO Arena Lighting	64	151	261	391	391	A/B	13.4
Space Heating	Wall Insulation	7	81	220	420	521	A	3.0
Space Heating	Roof Insulation	5	57	155	294	362	A	3.2
General Lighting	HP to redesign increment	47	106	175	254	248	A/B	2.4
Computer Equipment	Energy Star ® Office Equipment	22	136	164	192	195	B	6.1
Space Heating	Adaptive Thermostats	57	110	154	190	187	A/B	2.0
Water Heating	Low Flow Showerheads	47	93	140	186	186	A/B	2.9
Refrigeration	Energy Star ® Fridges, Freezers	5	57	150	204	201	A/B	3.4
Space Heating	Demand Controlled Kitchen Ventilation	14	53	112	183	179	B	0.4
Other Plug Loads	Block Heater Controls	23	58	107	171	174	A/B	1.9
Space Heating	HP to SHP Glazing increment	2	25	69	133	174	A	1.6
HVAC Fans and Pumps	PE Motors	7	30	74	139	139	B	6.7
Water Heating	Low Flow Pre Rinse Spray Valves	23	46	68	91	91	A/B	1.1
Water Heating	Tank Insulation	21	40	59	77	77	A/B	1.7
Space Heating	Infrared Electric Radiant Heaters	17	32	46	56	55	A	0.6
Food Service Equipment	High Efficiency Cooking Equipment	1	17	45	61	60	A	4.6
Refrigeration	Refrigeration Plant Controls	11	20	29	36	36	A	2.9
Water Heating	Drainwater Heat Recovery	10	19	27	34	34	A	1.2
Space Heating	High-Volume Low-Speed Destratification Fans	8	14	20	24	24	A	0.8
Grand Total		7,345	17,628	30,178	44,983	44,518		4.0

Exhibit 58C Lower Achievable Electricity Savings by Technology and Milestone Year (MWh/yr.)

End Use	Measure	2015	2020	2025	2030	2035	Adoption Curve	Weighted Average CCE (¢/kWh)
Water Heating	Low Flow Faucets	104	207	311	415	415	A/B	0.3
Outdoor Lighting	Lighting Controls (Outdoor)	152	341	547	748	748	A/B	0.4
Space Heating	Demand Controlled Kitchen Ventilation	7	28	61	105	105	B	0.6
Refrigeration	Brine Pump Control	34	69	103	137	137	A	1.8
Space Heating	Infrared Electric Radiant Heaters	5	10	14	18	18	A	1.9
Water Heating	Low Flow Pre Rinse Spray Valves	11	23	34	46	46	A/B	2.2
High Bay Lighting	LED High Bay Fixtures	420	995	1,714	2,569	2,569	A/B	2.2
Space Heating	High-Volume Low-Speed Destratification Fans	2	4	6	8	8	A	2.4
HVAC Fans and Pumps	Adjustable Speed Drive (Fan Application)	32	127	287	509	509	B	2.7
Outdoor Lighting	LED Lamps (Outdoor)	33	124	254	408	408	B	3.2
Space Heating	Air Sealing	26	102	229	403	401	B	3.2
Water Heating	Tank Insulation	10	21	30	40	40	A/B	3.3
Other Plug Loads	Block Heater Controls	12	30	56	90	92	A/B	3.6
Water Heating	Drainwater Heat Recovery	3	6	8	11	11	A	3.6
Space Heating	Adaptive Thermostats	29	56	80	101	101	A/B	3.7
Space Heating	DC Ventilation	17	68	150	258	257	B	4.5
Refrigeration	High Efficiency Refrigeration - Full Cost	903	1,805	1,805	1,805	1,805	D	4.5
Computer Equipment	Energy Star ® Computers	224	1,297	1,544	1,837	1,867	B	4.5
General Lighting	HP to redesign increment	25	56	92	133	131	A/B	4.5
Space Heating	Air to Air HR	58	228	501	859	855	B	4.6
General Lighting	Building Recommissioning	284	1,099	2,376	4,030	3,999	B	4.8
	Subtotal (CCE up to 5 ¢/kWh)	**2,391**	**6,696**	**10,205**	**14,532**	**14,522**		**3.6**
Space Heating	HP Glazing	2	24	67	129	170	A	5.2
Refrigeration	HE Refrigeration - Incr. Cost	78	702	1,430	2,184	2,184	A/B	5.3
Space Heating	HP to SHP Glazing increment	1	7	20	39	51	A	5.4
Water Heating	Low Flow Showerheads	23	47	70	93	93	A/B	5.8
General Lighting	Occupancy Controls	46	105	171	239	234	A/B	5.9
Refrigeration	Energy Star ® Fridges, Freezers	1	14	56	102	101	A/B	6.8
General Lighting	LED Fluorescent Fixtures	673	1,480	2,400	3,411	3,342	A/B	7.1
Outdoor Lighting	LED Wallpack Outdoor Fixtures	182	422	710	1,034	1,034	A/B	7.2
Computer Equipment	Energy Star ® Office Equipment	20	113	133	157	159	B	7.4
Space Heating	Ground-Source Heat Pumps	47	91	131	163	162	A	7.8
Refrigeration	Refrigeration Plant Controls	3	6	9	12	12	A	8.6
Computer Equipment	Energy Star ® Servers	142	251	299	357	363	B	9.2
	Subtotal (CCE between 5 -10 ¢/kWh)	**1,218**	**3,263**	**5,496**	**7,921**	**7,906**		**6.6**
Space Heating	Wall Insulation	2	23	63	122	153	A	10.4
Space Heating	Roof Insulation	1	17	45	87	108	A	10.8
General Lighting	High Performance T8 (T8 Retrofit)	169	378	624	905	887	A/B	11.8
HVAC Fans and Pumps	PE Motors	3	15	38	72	72	B	12.9
Space Heating	Whole Building - 60% More Efficient than Current	24	408	1,619	3,523	3,104	B	14.4
	Subtotal (CCE between 10 -15 ¢/kWh)	**199**	**841**	**2,390**	**4,710**	**4,324**		**13.6**
Food Service Equipment	High Efficiency Cooking Equipment	0	5	13	17	17	A	16.1
General Lighting	Dimming Controls (Daylighting)	56	175	316	443	434	A/B	16.6
High Bay Lighting	T5HO Arena Lighting	34	81	142	215	215	A/B	24.3
	Subtotal (CCE greater than 15 ¢/kWh)	**90**	**261**	**470**	**675**	**666**		**19.1**
	Grand Total	**3,899**	**11,060**	**18,561**	**27,838**	**27,417**		**6.4**

Summary of Electric Peak Load Reductions: Electric Energy Measures

Exhibits 62C and 65C show the demand reductions associated with each electric energy savings measure in 2030. The 2030 results are presented in place of the 2035 results as they are more reliable results. With the absence of new achievable potential workshops, the results from 2035 were extrapolated from 2030 results with penetration and participation rates held constant. Most measures contribute to the peak demand reductions approximately in proportion to their electric energy savings. The results by milestone year are presented for the upper and lower achievable peak period 1 reductions in exhibits 62-2C and 65-2C respectively.

Exhibit 62C Electric Peak Load Reductions from Upper Achievable Energy Savings Measures, 2030 (MW)

Measure	Period 1 Annual Peak Hour	Period 2 Evening Peak Period	Period 3 Morning Peak Period
Building Recommissioning	1.26	1.17	0.94
LED Fluorescent Fixtures	1.04	0.99	0.70
Whole Building - 60% More Efficient than Current	0.99	0.89	0.71
LED High Bay Fixtures	0.86	0.75	0.57
LED Wallpack Outdoor Fixtures	0.53	0.55	0.53
Air to Air HR	0.48	0.41	0.33
Energy Star ® Computers	0.32	0.31	0.16
High Performance T8 (T8 Retrofit)	0.28	0.26	0.19
Lighting Controls (Outdoor)	0.28	0.28	0.28
Air Sealing	0.24	0.20	0.16
HE Refrigeration - Incr. Cost	0.21	0.21	0.20
High Efficiency Refrigeration - Full Cost	0.21	0.21	0.20
LED Lamps (Outdoor)	0.18	0.18	0.18
Adjustable Speed Drive (Fan Application)	0.16	0.15	0.11
DC Ventilation	0.14	0.12	0.10
Ground-Source Heat Pumps	0.14	0.12	0.10
HP Glazing	0.14	0.12	0.10
Wall Insulation	0.13	0.11	0.09
Dimming Controls (Daylighting)	0.11	0.10	0.07
Roof Insulation	0.09	0.08	0.06
Low Flow Faucets	0.08	0.08	0.07
T5HO Arena Lighting	0.07	0.06	0.04
Brine Pump Control	0.07	0.07	0.06
Energy Star ® Servers	0.06	0.06	0.03
Occupancy Controls	0.06	0.06	0.04
Demand Controlled Kitchen Ventilation	0.06	0.05	0.04
Adaptive Thermostats	0.05	0.04	0.03
HP to SHP Glazing increment	0.04	0.04	0.03
HP to redesign increment	0.04	0.04	0.03
Low Flow Showerheads	0.03	0.03	0.02
Energy Star ® Office Equipment	0.03	0.03	0.01
Energy Star ® Fridges, Freezers	0.02	0.02	0.02
PE Motors	0.02	0.02	0.02
Block Heater Controls	0.02	0.02	0.02
Infrared Electric Radiant Heaters	0.02	0.02	0.01
Low Flow Pre Rinse Spray Valves	0.02	0.02	0.01
Tank Insulation	0.01	0.01	0.01
High-Volume Low-Speed Destratification Fans	0.01	0.01	0.00
High Efficiency Cooking Equipment	0.01	0.01	0.01
Drainwater Heat Recovery	0.01	0.01	0.00
Refrigeration Plant Controls	0.00	0.01	0.00
Grand Total	8.53	7.90	6.28

Exhibit 62-2C Upper Achievable Electric Peak Load Reductions (Peak Period 1 - Annual Peak Hour) (MW)

Measure	2015	2020	2025	2030	2035
Building Recommissioning	0.10	0.37	0.78	1.26	1.25
LED Fluorescent Fixtures	0.21	0.45	0.73	1.04	1.02
LED High Bay Fixtures	0.14	0.33	0.57	0.86	0.86
Whole Building - 60% More Efficient than Current	0.01	0.11	0.45	0.99	0.87
LED Wallpack Outdoor Fixtures	0.09	0.22	0.37	0.53	0.53
Air to Air HR	0.04	0.14	0.29	0.48	0.47
Energy Star ® Computers	0.04	0.22	0.27	0.32	0.33
High Efficiency Refrigeration - Full Cost	0.21	0.21	0.21	0.21	0.21
Lighting Controls (Outdoor)	0.07	0.16	0.23	0.28	0.28
High Performance T8 (T8 Retrofit)	0.05	0.12	0.19	0.28	0.27
Air Sealing	0.02	0.06	0.14	0.24	0.24
HE Refrigeration - Incr. Cost	0.00	0.05	0.13	0.21	0.21
LED Lamps (Outdoor)	0.04	0.08	0.13	0.18	0.18
Ground-Source Heat Pumps	0.05	0.09	0.12	0.14	0.14
Adjustable Speed Drive (Fan Application)	0.01	0.04	0.09	0.16	0.16
HP Glazing	0.00	0.03	0.07	0.14	0.18
DC Ventilation	0.01	0.04	0.09	0.14	0.14
Wall Insulation	0.00	0.03	0.07	0.13	0.17
Dimming Controls (Daylighting)	0.02	0.05	0.08	0.11	0.11
Low Flow Faucets	0.02	0.04	0.06	0.08	0.08
Roof Insulation	0.00	0.02	0.05	0.09	0.12
Energy Star ® Servers	0.02	0.04	0.05	0.06	0.06
Brine Pump Control	0.02	0.03	0.05	0.07	0.07
T5HO Arena Lighting	0.01	0.03	0.04	0.07	0.07
Occupancy Controls	0.01	0.03	0.05	0.06	0.06
Adaptive Thermostats	0.01	0.03	0.04	0.05	0.05
Demand Controlled Kitchen Ventilation	0.00	0.02	0.04	0.06	0.06
HP to redesign increment	0.01	0.02	0.03	0.04	0.04
HP to SHP Glazing increment	0.00	0.01	0.02	0.04	0.05
Low Flow Showerheads	0.01	0.02	0.02	0.03	0.03
Energy Star ® Office Equipment	0.00	0.02	0.02	0.03	0.03
Energy Star ® Fridges, Freezers	0.00	0.01	0.02	0.02	0.02
Infrared Electric Radiant Heaters	0.01	0.01	0.01	0.02	0.02
PE Motors	0.00	0.00	0.01	0.02	0.02
Block Heater Controls	0.00	0.01	0.01	0.02	0.02
Low Flow Pre Rinse Spray Valves	0.00	0.01	0.01	0.02	0.02
Tank Insulation	0.00	0.00	0.01	0.01	0.01
High-Volume Low-Speed Destratification Fans	0.00	0.00	0.01	0.01	0.01
Drainwater Heat Recovery	0.00	0.00	0.00	0.01	0.01
High Efficiency Cooking Equipment	0.00	0.00	0.01	0.01	0.01
Refrigeration Plant Controls	0.00	0.00	0.00	0.00	0.00
Grand Total	1.25	3.16	5.61	8.53	8.46

Exhibit 65C Electric Peak Load Reductions from Lower Achievable Energy Savings Measures, 2030 (MW)

Measure	Period 1 Annual Peak Hour	Period 2 Evening Peak Period	Period 3 Morning Peak Period
Whole Building - 60% More Efficient than Current	0.77	0.69	0.56
Building Recommissioning	0.72	0.66	0.53
LED Fluorescent Fixtures	0.55	0.52	0.37
LED High Bay Fixtures	0.45	0.39	0.30
LED Wallpack Outdoor Fixtures	0.28	0.29	0.28
Air to Air HR	0.27	0.23	0.18
Energy Star ® Computers	0.26	0.25	0.13
HE Refrigeration - Incr. Cost	0.25	0.25	0.24
High Efficiency Refrigeration - Full Cost	0.21	0.21	0.20
Lighting Controls (Outdoor)	0.20	0.21	0.20
High Performance T8 (T8 Retrofit)	0.15	0.14	0.10
Air Sealing	0.13	0.11	0.08
LED Lamps (Outdoor)	0.11	0.11	0.11
Adjustable Speed Drive (Fan Application)	0.08	0.08	0.06
DC Ventilation	0.08	0.07	0.05
Dimming Controls (Daylighting)	0.07	0.07	0.05
Energy Star ® Servers	0.05	0.05	0.02
Ground-Source Heat Pumps	0.05	0.04	0.03
Low Flow Faucets	0.04	0.04	0.04
HP Glazing	0.04	0.03	0.03
Wall Insulation	0.04	0.03	0.03
Occupancy Controls	0.04	0.04	0.03
T5HO Arena Lighting	0.04	0.03	0.02
Demand Controlled Kitchen Ventilation	0.03	0.03	0.02
Roof Insulation	0.03	0.02	0.02
Adaptive Thermostats	0.03	0.02	0.02
Energy Star ® Office Equipment	0.02	0.02	0.01
HP to redesign increment	0.02	0.02	0.01
Brine Pump Control	0.02	0.02	0.02
Low Flow Showerheads	0.02	0.01	0.01
Energy Star ® Fridges, Freezers	0.01	0.01	0.01
HP to SHP Glazing increment	0.01	0.01	0.01
PE Motors	0.01	0.01	0.01
Block Heater Controls	0.01	0.01	0.01
Low Flow Pre Rinse Spray Valves	0.01	0.01	0.01
Infrared Electric Radiant Heaters	0.01	0.01	0.00
Tank Insulation	0.00	0.00	0.00
High-Volume Low-Speed Destratification Fans	0.00	0.00	0.00
High Efficiency Cooking Equipment	0.00	0.00	0.00
Drainwater Heat Recovery	0.00	0.00	0.00
Refrigeration Plant Controls	0.00	0.00	0.00
Grand Total	5.11	4.76	3.80

Exhibit 65-2C Lower Achievable Electric Peak Load Reductions (Peak Period 1 - Annual Peak Hour) (MW)

Measure	2015	2020	2025	2030	2035
Building Recommissioning	0.05	0.20	0.42	0.72	0.71
Whole Building - 60% More Efficient than Current	0.01	0.09	0.35	0.77	0.68
LED Fluorescent Fixtures	0.11	0.24	0.39	0.55	0.54
LED High Bay Fixtures	0.07	0.18	0.30	0.45	0.45
Energy Star ® Computers	0.03	0.18	0.22	0.26	0.26
High Efficiency Refrigeration - Full Cost	0.10	0.21	0.21	0.21	0.21
LED Wallpack Outdoor Fixtures	0.05	0.11	0.19	0.28	0.28
Air to Air HR	0.02	0.07	0.16	0.27	0.27
HE Refrigeration - Incr. Cost	0.01	0.08	0.17	0.25	0.25
Lighting Controls (Outdoor)	0.04	0.09	0.15	0.20	0.20
High Performance T8 (T8 Retrofit)	0.03	0.06	0.10	0.15	0.14
Air Sealing	0.01	0.03	0.07	0.13	0.13
LED Lamps (Outdoor)	0.01	0.03	0.07	0.11	0.11
Adjustable Speed Drive (Fan Application)	0.01	0.02	0.05	0.08	0.08
DC Ventilation	0.01	0.02	0.05	0.08	0.08
Dimming Controls (Daylighting)	0.01	0.03	0.05	0.07	0.07
Energy Star ® Servers	0.02	0.04	0.04	0.05	0.05
Ground-Source Heat Pumps	0.01	0.03	0.04	0.05	0.05
Low Flow Faucets	0.01	0.02	0.03	0.04	0.04
Occupancy Controls	0.01	0.02	0.03	0.04	0.04
HP Glazing	0.00	0.01	0.02	0.04	0.05
T5HO Arena Lighting	0.01	0.01	0.02	0.04	0.04
Wall Insulation	0.00	0.01	0.02	0.04	0.05
Demand Controlled Kitchen Ventilation	0.00	0.01	0.02	0.03	0.03
Adaptive Thermostats	0.01	0.01	0.02	0.03	0.03
Roof Insulation	0.00	0.01	0.01	0.03	0.03
Energy Star ® Office Equipment	0.00	0.02	0.02	0.02	0.02
HP to redesign increment	0.00	0.01	0.01	0.02	0.02
Brine Pump Control	0.00	0.01	0.01	0.02	0.02
Low Flow Showerheads	0.00	0.01	0.01	0.02	0.02
HP to SHP Glazing increment	0.00	0.00	0.01	0.01	0.02
Energy Star ® Fridges, Freezers	0.00	0.00	0.01	0.01	0.01
PE Motors	0.00	0.00	0.01	0.01	0.01
Block Heater Controls	0.00	0.00	0.01	0.01	0.01
Low Flow Pre Rinse Spray Valves	0.00	0.00	0.01	0.01	0.01
Infrared Electric Radiant Heaters	0.00	0.00	0.00	0.01	0.01
Tank Insulation	0.00	0.00	0.00	0.00	0.00
High-Volume Low-Speed Destratification Fans	0.00	0.00	0.00	0.00	0.00
Drainwater Heat Recovery	0.00	0.00	0.00	0.00	0.00
High Efficiency Cooking Equipment	0.00	0.00	0.00	0.00	0.00
Refrigeration Plant Controls	0.00	0.00	0.00	0.00	0.00
Grand Total	0.65	1.87	3.30	5.11	5.03

Summary of Electric Peak Load Reductions: Capacity Measures

Exhibits 40C and 41C show the economic demand reductions associated with each commercial sector peak load reduction measure in 2015. Exhibit 40C shows the name of the measure, the cost basis for the CEPR that the shown (full versus incremental) and the measure's average CEPR. The following approach was taken in updating these exhibits from the 2011 study:

- The discount rate was updated to 3.38% from 7.5%, thus impacting the CEPR values.
- The applicable count was updated from the 2010 base year to the new 2015 milestone year data, thus impacting the MW reduction for each capacity measure.
- Costing assumptions for each measure were left unchanged from the 2011 CPR study.

Measures analyzed on the basis of full cost have been placed towards the top of Exhibit 40C as they are qualitatively different from the measures that pass only on an incremental basis. A measure that passes on a full-cost basis can be applied immediately, while incremental measures presume the adoption of other technologies as a condition of their cost effectiveness (e.g., facility network gateways).

Exhibit 41C shows a list of the capacity electric peak load reduction measures grouped by applicable end use category. This exhibit shows the measure name, applicable count in 2015, average demand reduction and average CEPR. Note that since there was no threshold established for maximum cost effective CEPR, all measures are listed and there are no exclusions based on cost effectiveness.

Exhibit 40C Commercial Sector Capacity Reduction Measures, Screening Results

Measure Name	Basis (Full/Incremental)	CEPR Ranges ($/kW)
Engine block heater switch-timer	Full	$36 - $45
Lighting switch load control	Full	$19 - $21
Multiple whole facility elevator/HVAC switches	Full	$41
Electric heat switch control for Hotels	Full	$60 - $68
Electric water heater control switches	Full	$49 - $55
Multiple whole facility refrigeration switches	Full	$56
Multiple whole facility plug load switches	Full	$31 - $42
Electric thermal storage room units	Full	$142 - $159
Multiple whole facility elevator/HVAC switches	Incremental	$34
Electric heat switch control for Hotels	Incremental	$46 - $52
Multiple whole facility refrigeration switches	Incremental	$42
Electric water heater control switches	Incremental	$36 - $41
Multiple whole facility plug load switches	Incremental	$18 - $25

Exhibit 41C Economic Potential Electric Capacity measures and MW Impact

Electric Peak Reduction Measures	Applicable Count 2015	Avg. kW/unit	Avg kW	Avg CEPR $/kW/yr.
Space Heating				
One-way switch for engine block heater - utility load control – stand-alone (assumes 10,000 units)	1,395	0.17 - 0.22	271	$36 - $45
Electric thermal storage (10% of Hotel/Health Offices)	792	0.73 - 0.82	617	$142 - $159
One-way switch for control (Hotels) – stand alone	74	5.15 - 5.77	404	$60 - $68
One-way switch for control (Hotels) - incremental	74	5.15 - 5.77	404	$46 - $52
Electric Water Heating				
One-way switch-based utility load control – stand alone	925	0.52 - 0.59	514	$49 - $55
One-way switch-based utility load control – incremental	925	0.52 - 0.59	514	$36 - $41
Lighting				
One-way switch-based utility load control – stand alone	1,344	1.6 - 1.77	2,267	$19 - $21
One-way switch-based utility load control - incremental	1,344	1.6 - 1.77	2,267	$19 - $21
Plug Loads				
One-way switch-based utility load control – stand alone	823	0.72 - 0.97	694	$31 - $42
One-way switch-based utility load control – incremental	823	0.72 - 0.97	694	$18 - $25
Other Loads				
One-way switch-based Refrigeration – stand alone	75	1.75	131	$56
One-way switch-based Refrigeration – incremental	75	1.75	131	$42
One-way switch-based Elevators & HVAC Fans – stand alone	60	5.25	315	$41
One-way switch-based Elevators & HVAC Fans – incremental	60	5.25	315	$34

Summary of Lower Achievable Electric Peak Load Reductions: Capacity Measures

Exhibit 41-2C below shows the lower achievable demand reduction for peak period 1 and the average full cost CEPR value by end use category for each milestone year until 2035. The demand curve showing the lower achievable demand with EE measures only versus the lower achievable demand with both EE & capacity measures is show in Exhibit 41-3C. The following approach was taken in developing these exhibits:

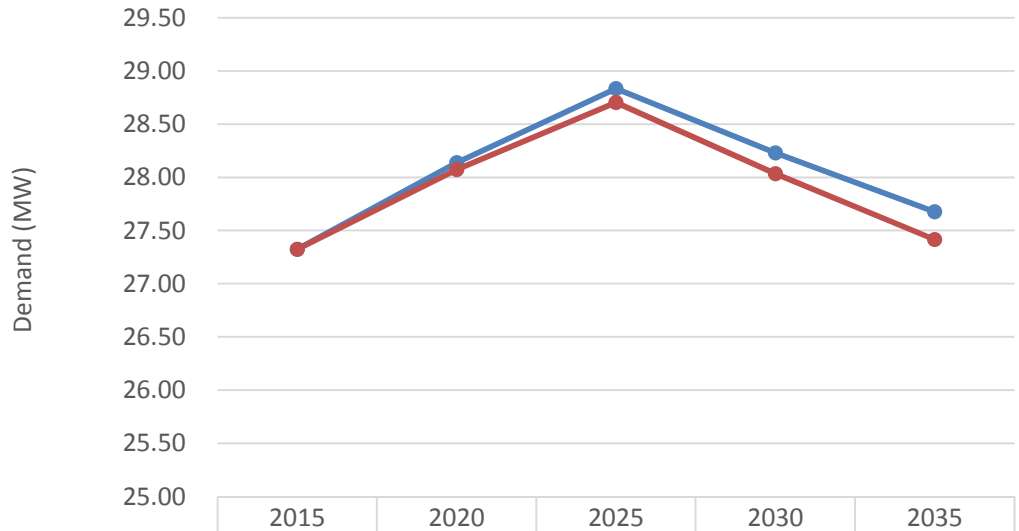
- The demand for each end use category after EE measures are applied was used as the baseline demand from which peak reductions occur due to capacity measures
- A lower achievable potential of 5% was assumed for all capacity measures, and was linearly extrapolated to all milestone years from a starting uptake of 0% in 2015 (due to lack of utility support) up to a maximum of 5% in the year 2035.

Note that results of the achievable reduction due to capacity measures presented below are based upon the *lower* achievable potential and are subject to variation as they are highly jurisdiction-specific and dependent upon the structure of the utility programs. It is recommended that additional research be conducted in order to account for these limitations.

Exhibit 41-2C Lower Achievable Potential Peak Load Reductions by End Use (MW) – Capacity Measures

	2020	2025	2030	2035	Average CEPR ($/kW/yr.)
Space Heating	0.02	0.03	0.05	0.06	$100
Electric Water Heating	0.01	0.01	0.02	0.03	$52
Lighting	0.03	0.06	0.09	0.11	$20
Plug Loads	0.01	0.02	0.03	0.03	$37
Refrigeration	0.00	0.00	0.00	0.01	$56
Elevators & HVAC Fans	0.00	0.01	0.01	0.02	$41
TOTAL	**0.07**	**0.13**	**0.20**	**0.26**	

Exhibit 41-3C Lower Achievable Potential Demand (MW) – EE Measures only vs. EE & Capacity Measures



	2015	2020	2025	2030	2035
Demand with Lower Achievable EE Measures Applied (MW)	27.32	28.14	28.84	28.23	27.68
Lower Achievable Potential Demand (MW)	27.32	28.07	28.70	28.03	27.42

3.3 Discussion

Cost of Conserved Energy (CCE)

The CCE values in this study do not account for program costs. In addition, parameters that affect the NTG (net-to-gross) ratio (e.g. free-ridership, spillover, etc.) are highly dependent on the design of programs and other jurisdiction-specific features. Since the CCE values for the study do not assume a NTG ratio (i.e. distortion effects, such as free ridership, are ignored since they are program constructs), the CCE values are closer to being gross values.

However, the reference case assumes natural efficiency. This means that the reference case incorporates assumptions for changes to the penetration of energy efficiency measures in absence of utility support over the timeframe of the study. As such, the measure savings values are closer to being net of free ridership.

ICF expects that the CCE can be used as a proxy of utility program costs for YEC, since only a portion of the measure costs are covered by the utility. A recent study by the Lawrence Berkeley National Lab (LBNL) assessed the total cost of electric energy efficiency programs and the relative investments by program administrators versus program participants. Investments by program participants were net of incentives and/or rebates by utilities. The study found that the cost per unit savings varied significantly by jurisdiction and program type, as did the relative investment by program administrators versus participants. However, the study found that, on average, “program administrators and participants split the cost of saving electricity almost

exactly in half".[7] Since the CCE includes all measure costs and the average utility incentive for many energy efficiency programs is no more than 30% of measure costs, the CCE is a reasonable proxy of overall utility program costs for implementing energy efficiency; especially in a jurisdiction with a relatively small number of customers.

An ACEEE study, which focuses on utility costs (program spending) per unit savings and includes only electric DSM programs, is a useful point of reference as well.[8] This study profiled 14 leading EE program administrators in the US and a total of 107 program years. The study found that the levelized cost of saved energy (LCSE) ranged between 1 and 8 cents/kWh and the median was $0.035/kWh for their sample (i.e. all values in $USD). YEC would be expected to be on the higher end of this range based on the size of your jurisdiction and the fact that DSM programs are fairly new.

Achievable Potential

As noted earlier in this memo, the achievable potential results are presented as a range, defined as lower and upper. This is because any estimate of Achievable Potential over a long-term period is necessarily subject to uncertainty.

The lower Achievable Potential assumes Yukon market conditions that are similar to those contained in the Reference Case. That is, the customers' awareness of energy-efficiency options and their motivation levels remain similar to those in the recent past, technology improvements continue at historical levels, and new energy performance standards continue as per current known schedules. It also assumes that the ability of the Yukon utilities and government to influence customers' decisions towards increased investments in energy-efficiency options remains roughly in line with previous company DSM experience.

The upper Achievable Potential assumes Yukon market conditions that aggressively support investment in energy efficiency. For example, this scenario assumes that real energy prices increase over the study period. It also assumes that federal and territorial government actions to mitigate climate change result in increased levels of complementary energy-efficiency initiatives. The upper Achievable Potential typically does not reach Economic Potential levels; this recognizes that some portion of the market is typically constrained by barriers that cannot realistically be affected by DSM programs within the study period.

It should also be emphasized that the estimation of Achievable Potential is not synonymous with either the setting of specific program targets or with program design. While both are closely linked to the discussion of Achievable Potential, they involve more detailed analysis that is beyond the scope of this study. Nonetheless, ICF is aware that achievable potential results are often used to guide targets in some jurisdictions. The lower Achievable Potential often represents a "business-as-usual" scenario in many jurisdictions, while it may represent a more aggressive target in jurisdictions with less DSM experience, such as Yukon.

[7] "The Total Cost of Saving Electricity through Utility Customer-Funded Energy Efficiency Programs: Estimates at the National, State, Sector and Program Level". Lawrence Berkeley National Lab, 2015.
[8] "Big Savers: Experiences and Recent History of Program Administrators Achieving High Levels of Electric Savings". ACEEE, Report Number U1601, April 2016.

Appendix 5.21 Transmission Options Evaluation (Midgard 2016)

Yukon Energy Corporation

Transmission Options Evaluation

(11 Routes of Interest)

Submitted By: Midgard Consulting Incorporated

Date: November 8, 2016

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Document Control & Signoff

DOCUMENT NUMBER

P0239-D033-RPT-R01-EXT

REVISION CONTROL

Revision	Description	Date
00	First draft version of report for client review and comment	Aug 9, 2016
01	Incorporating YEC feedback and edits	Nov 8, 2016

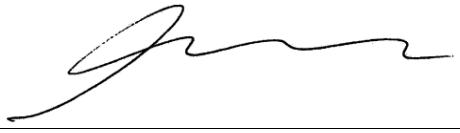
REPORT SIGN-OFF

Prepared By: Nov 8, 2016

Scott Seifert, Midgard Consulting Inc. ***Date***

Checked By: Nov 8, 2016

Scott Seifert, Midgard Consulting Inc. ***Date***

Approved By:  Nov 8, 2016

Chris Oakley, Midgard Consulting Inc. ***Date***

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Executive Summary

The Yukon Energy Corporation ("YEC") has commissioned Midgard Consulting Incorporated ("Midgard") and its team of sub-consultants to complete a Transmission Options Evaluation of eleven potential Yukon transmission line corridors. The assignment scope comprises:

- Detailed transmission corridor optimization (Section 2)
- Estimate of capital expenditures ("CAPEX") (Section 3)
- Estimate of operating expenditures ("OPEX") (Section 4)
- Calculation of power transfer capacities (Section 5)
- Overview of transmission corridor development schedules (Section 6)
- Assessment of corridor risks (Section 7)

Figure 1 below illustrates the eleven routes of interest on a map of the Yukon.

Figure 1: Map of Studied Routes

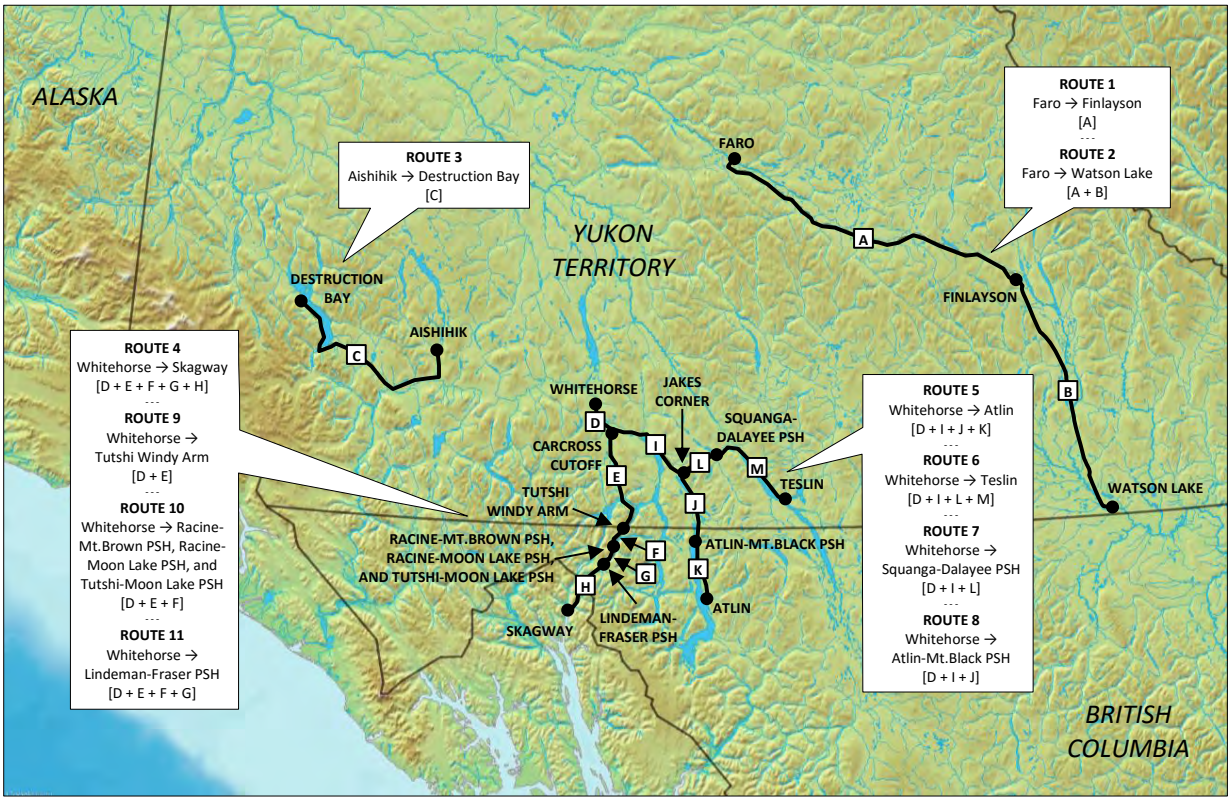

Table 1 below provides a high level summary of the study results for each transmission option, listing the line voltage, line length, maximum reliable transfer capacity, estimated CAPEX, estimated annual OPEX, and earliest In-Service-Date ("ISD").

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The estimated CAPEX and OPEX costs shown in Table 1 represent a Class 5 estimate (-50%/+100% range of cost accuracy) as set out in Standard 17R-97 of the Association of the Advancement of Cost Engineering.

Table 1: Summary of Results (Costs Stated in $2016)

#	Transmission Route	Voltage	Length	Reliable Transfer Capacity[1]	CAPEX	OPEX	Earliest Possible ISD
1	Faro → Finlayson	138 kV	233 km	84 MW	$221M	$351k/yr	Jan 2021
2	Faro → Watson Lake	230 kV	414 km	190 MW	$597M	$613k/yr	Sep 2022
3	Aishihik → Destruction Bay	138 kV	157 km	122 MW	$167M	$217k/yr	Jul 2020
		230 kV		484 MW	$241M		
4	Whitehorse → Skagway	138 kV	170 km	114 MW	$166M	$285k/yr	Oct 2020
		230 kV		443 MW	$251M		
5	Whitehorse → Atlin	138 kV	172 km	97 MW	$158M	$236k/yr	Oct 2020
6	Whitehorse → Teslin	138 kV	174 km	95 MW	$165M	$239k/yr	Oct 2020
7	Whitehorse → Squanga-Dalayee PSH	138 kV	105 km	134 MW	$100M	$143k/yr	Dec 2019
8	Whitehorse → Atlin-Mt.Black PSH	138 kV	127 km	131 MW	$119M	$174k/yr	May 2020
9	Whitehorse → Tutshi Windy Arm	138 kV	96 km	135 MW	$94M	$143k/yr	Nov 2019
10	Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	138 kV	112 km	132 MW	$108M	$168k/yr	Jan 2020
11	Whitehorse → Lindeman-Fraser PSH	138 kV	129 km	129 MW	$125M	$200k/yr	Jun 2020

[1] These values represent the most restricted transfer capacity that is expected in either summer or winter. Thermally limited transmission options may demonstrate a higher Winter Capacity. See Table 8 for more details.

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TABLE OF CONTENTS

Document Control & Signoff 2
Executive Summary 3
1 Introduction 6
2 Corridor Routing & Descriptions 8
3 CAPEX Analysis 13
3.1 CAPEX Estimation Methodology 13
3.2 CAPEX Results 14
3.3 CAPEX Benchmarking Analysis 15
4 OPEX Analysis 17
4.1 OPEX Estimation Methodology 17
4.2 OPEX Results 18
5 Power Transfer Capacity Analysis 19
5.1 Assumptions 19
5.2 Methodology 21
5.3 Route Characteristics and Transfer Capacity Results 21
6 Project Scheduling 24
6.1 Phase-By-Phase Discussion 24
6.2 Schedule Results 26
7 Risk Assessment 28
7.1 Defining Risk Metrics 28
7.2 Universal Risks (Affecting All Routes) 28
7.3 Route Specific Risks 31
8 Summary & Conclusions 36
Appendix A: PSSE Simulation Details 37
Appendix B: Transmission Option Schedules 65
Appendix C: JDMA Transmission Routing Report 67
Appendix D: 69 kV Alternative Routing Analysis 114

LIST OF ACRONYMS & ABBREVIATIONS

CAPEX	Capital Expenditure
ISD	In-Service Date
JDMA	J.D. Mollard and Associates (“JDMA”) Limited
Midgard	Midgard Consulting Inc.
OPEX	Operating Expenditure
PSH	Pumped Storage Hydro
ROW	Right of Way

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1 Introduction

The Yukon Energy Corporation ("YEC") has commissioned Midgard Consulting Incorporated ("Midgard") and its sub-consultant, J.D. Mollard and Associates (2010) Limited ("JDMA") to evaluate eleven potential Yukon transmission line options.

1) **Midgard Consulting Incorporated ("Midgard"):** Midgard has been providing consulting services to the electrical power and utility industry since 2009, specializing in utility resource planning, renewable generation development, transmission & distribution planning and design, and providing expert strategic services including business case development, project due diligence & financing, system modelling and regulatory support.
2) **J.D. Mollard and Associates (2010) Limited ("JDMA"):** JDMA is a private consulting firm of professional engineers, geoscientists, geographers, and environmental scientists based in Regina, Saskatchewan, Canada. The company has a long tradition of excellence in applied civil and geological engineering, geology, hydrogeology, geography, biology, remote sensing, GIS, terrain analysis, and environmental studies.

The scope of work includes evaluating and optimizing the transmission corridors, estimating capital expenditures ("CAPEX"), estimating operating expenditures ("OPEX"), calculating the maximum reliable power transfer capacities, preparing high-level transmission development schedules, and assessing development risks for each of the identified transmission options.

Table 2 lists the eleven transmission line options evaluated in this report.

Table 2: Overview of Transmission Options

#	Transmission Option	Voltage	Length
1	Faro → Finlayson	138 kV	233 km
2	Faro → Watson Lake	230 kV	414 km
3	Aishihik → Destruction Bay	138 & 230 kV	157 km
4	Whitehorse → Skagway	138 & 230 kV	170 km
5	Whitehorse → Atlin	138 kV	172 km
6	Whitehorse → Teslin	138 kV	174 km
7	Whitehorse → Squanga-Dalayee PSH	138 kV	105 km
8	Whitehorse → Atlin-Mt.Black PSH	138 kV	127 km
9	Whitehorse → Tutshi Windy Arm	138 kV	96 km
10	Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	138 kV	112 km
11	Whitehorse → Lindeman-Fraser PSH	138 kV	129 km

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The following assumptions were utilized in preparing this report:

1) The line voltage for each transmission option was defined by YEC in the scope of work.
2) 34.5 kV distribution underbuild has been incorporated on portions of several routes, including:
    a. Whitehorse → Teslin
    b. Whitehorse → Carcross
    c. Aishihik → Haines Junction
3) The following standard phase conductor and bundling selections have been used throughout:
    a. 138 kV Options: Single 397.5 MCM[2] Ibis ACSR conductor
    b. 230 KV Options: Double Bundle[3] 477 MCM Hawk ACSR conductor

[2] MCM = Thousand circular mils. A circular mil is the cross-sectional area of a wire with a 1/1000 inch diameter (approximately 0.0005 mm^2)

[3] Double bundle 477 MCM Hawk has been selected to mitigate corona inception at 230 kV. In this conductor bundling configuration, each phase comprises two separate Hawk conductors.

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2 Corridor Routing & Descriptions

JDMA, with input from Midgard and YEC, carried out route analysis and refinement for the transmission corridors of interest. JDMA completed the corridors evaluations using ESRI ArcGIS and MicroImages TNT MIPS, with data sourced from various territorial, provincial, and national sources (for a detailed breakdown of data sourcing, please see Section 2.1 of JDMA's report attached in Appendix C). The general methodology of route selection was as follows:

- Transmission line span length between poles/structures/towers targeted to be 200 to 230 m with longer spans as needed
- Where practical, the transmission line corridor was placed adjacent to roadways
- The target corridor width of 500m, but narrowed to less than 500 m when necessary to avoid major terrain constrictions adjacent to the corridor (e.g.: next to a steep slope, river, etc.)
- Avoided crossing privately held land wherever possible
- Where practical, line deflections were kept to <15° to avoid more complex and costly structures

In addition to these specific criteria, JDMA also considered surficial geology and surface materials, terrain and slope, total length, as well as stream and wetland crossings to help identify potentially feasible corridors. The full JDMA study is attached in Appendix C. Figure 2 shows all of the transmission routes considered.

Figure 2: Map of Studied Routes

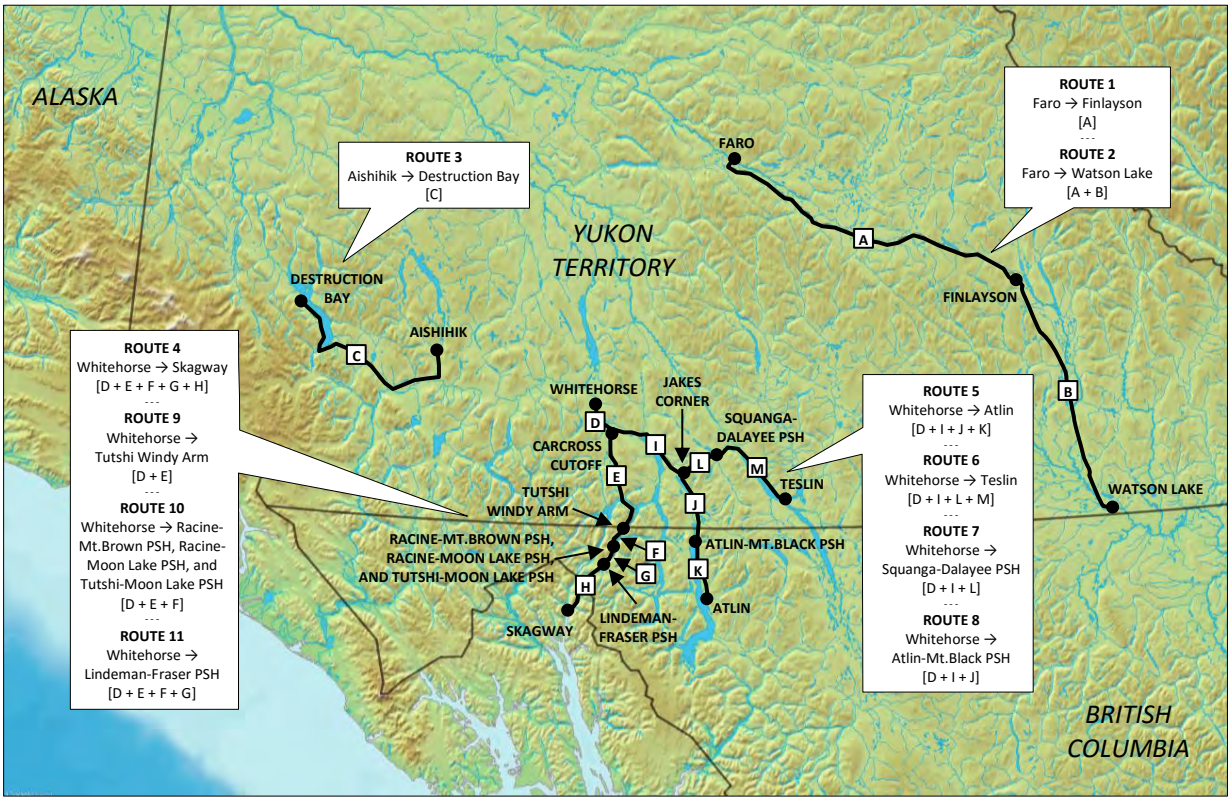

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Table 3 provides a brief overview of the analyzed routes.

Table 3: Description of Studied Routes

#	Transmission Route	Description of Route
1	Faro ↓ Finlayson	▪ **Start:** Town of Faro ▪ **End:** Finlayson Project Interconnection ▪ **Length:** 233 km ▪ Follows the "Faro → Watson Lake" route from Faro for 233 km until reaching the Finlayson project interconnection point.
2	Faro ↓ Watson Lake	▪ **Start:** Town of Faro ▪ **End:** Town of Watson Lake ▪ **Length:** 414 km ▪ Parallels the Pelley River for 56 km at the north end and then follows Highway 4 (Robert Campbell Highway) to Watson Lake. ▪ Crosses several major rivers at the south end, including the Frances and Liard Rivers.
3	Aishihik ↓ Destruction Bay	▪ **Start:** Aishihik Generating Station ▪ **End:** Town of Destruction Bay ▪ **Length:** 157 km ▪ From Aishihik the corridor heads south to Canyon, paralleling existing access and transmission used for the Aishihik project. ▪ From Canyon the corridor generally follows Highway 1 westwards (Alaska Highway) to Destruction Bay. ▪ The corridor detours off of Highway 1 at the Slims River crossing to take advantage of a narrower river crossing location further upstream, but even this upstream location may involve a crossing span of up to 500 m. ▪ After crossing Slims River, the corridor continues to follow Highway 1 to Destruction Bay, making use of an abandoned pipeline right-of-way. ▪ 49 km of 34.5 kV distribution underbuild is included from Aishihik to Haines Junction
4	Whitehorse ↓ Skagway	▪ **Start:** Whitehorse Generating Station ▪ **End:** Town of Skagway, AK ▪ **Length:** 170 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1 southeast for 17 km to Carcross Cutoff (the junction of Highways 1 and 2). ▪ From Carcross Cutoff the corridor follows Highway 2 southwards through the town of Carcross for 77 km to the BC-Yukon border. ▪ Once in BC the corridor continues along Highway 2 for an additional 56 km to the BC-Alaska border. ▪ Once in Alaska the corridor continues along the same highway (now named Highway 98) for an additional 21 km to Skagway, Alaska. ▪ 68 km of 34.5 kV distribution underbuild is included from Whitehorse to Carcross

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#	Transmission Route	Description of Route
5	Whitehorse ↓ Atlin	▪ **Start:** Whitehorse Generating Station ▪ **End:** Town of Atlin, BC ▪ **Length:** 172 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1 southeast for 17 km to Carcross Cutoff. ▪ The corridor then follows Highway 1 eastwards for 62 km to Jakes Corner where Highway 1 meets Highway 8. On this stretch the corridor crosses the Yukon River, a span of approximately 250 m. ▪ From Jakes Corner the corridor turns south and follows Highway 7 for 42 km to the BC-Yukon border. ▪ Once in BC the corridor continues along Highway 7 for an additional 50 km to Atlin, BC. ▪ 79 km of 34.5 kV distribution underbuild is included from Whitehorse to Jakes Corner
6	Whitehorse ↓ Teslin	▪ **Start:** Whitehorse Generating Station ▪ **End:** Town of Teslin ▪ **Length:** 174 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1/2 southeast for 17 km to Carcross Cutoff (the junction of Highways 1 and 2). ▪ The corridor then follows Highway 1 eastwards for 62 km to Jakes Corner, where Highway 1 meets Highway 8. On this stretch the corridor crosses the Yukon River, a span of approximately 250 m. ▪ From Jakes Corner the corridor follows Highway 1 eastwards for 95 km to Teslin, crossing the Teslin River (a span of approximately 400 m) and passing through the communities of Johnson's Crossing, Brooks Brook, and Teslin Lake. ▪ 34.5 kV distribution underbuild is included for the entire corridor (174 km)
7	Whitehorse ↓ Squanga-Dalayee PSH	▪ **Start:** Whitehorse Generating Station ▪ **End:** Squanga-Dalayee PSH Project Interconnection ▪ **Length:** 105 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1/2 southeast for 17 km to Carcross Cutoff (the junction of Highways 1 and 2). ▪ The corridor then follows Highway 1 eastwards for 62 km to Jakes Corner, where Highway 1 meets Highway 8. On this stretch the corridor crosses the Yukon River, a span of approximately 250 m. ▪ From Jakes Corner the corridor follows Highway 1 eastwards for 26 km to the Squanga-Dalayee PSH interconnection point. ▪ 34.5 kV distribution underbuild is included for the entire corridor (105 km)

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#	Transmission Route	Description of Route
8	Whitehorse ↓ Atlin-Mt.Black PSH	▪ **Start:** Whitehorse Generating Station ▪ **End:** Atlin-Mt.Black PSH Project Interconnection ▪ **Length:** 127 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1 southeast for 17 km to Carcross Cutoff. ▪ The corridor then follows Highway 1 eastwards for 62 km to Jakes Corner where Highway 1 meets Highway 8. On this stretch the corridor crosses the Yukon River, a span of approximately 250 m. ▪ From Jakes Corner the corridor turns south and follows Highway 7 for 42 km to the BC-Yukon border. ▪ Once in BC the corridor continues along Highway 7 for an additional 6 km to the Atlin-Mt.Black PSH interconnection point. ▪ 79 km of 34.5 kV distribution underbuild is included from Whitehorse to Jakes Corner ▪ Note that given the proximity of the termination point of this line, it likely makes sense to complete the remaining 45 km stretch into Atlin.
9	Whitehorse ↓ Tutshi Windy Arm	▪ **Start:** Whitehorse Generating Station ▪ **End:** Tutshi Windy Arm Project Interconnection ▪ **Length:** 96 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1 southeast for 17 km to Carcross Cutoff (the junction of Highways 1 and 2). ▪ From Carcross Cutoff the corridor follows Highway 2 southwards through the town of Carcross for 77 km to the BC-Yukon border. ▪ Once in BC the corridor continues along Highway 2 for an additional 2 km to reach the Tutshi Windy Arm project interconnection point. ▪ 68 km of 34.5 kV distribution underbuild is included from Whitehorse to Carcross
10	Whitehorse ↓ Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	▪ **Start:** Whitehorse Generating Station ▪ **End:** Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH Project Interconnections ▪ **Length:** 112 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1 southeast for 17 km to Carcross Cutoff (the junction of Highways 1 and 2). ▪ From Carcross Cutoff the corridor follows Highway 2 southwards through the town of Carcross for 77 km to the BC-Yukon border. ▪ Once in BC the corridor continues along Highway 2 for an additional 18 km to reach the interconnection point for several different PSH projects (Racine-Mt.Brown PSH, Racine-Moon Lake PSH, & Tutshi-Moon Lake PSH) ▪ 68 km of 34.5 kV distribution underbuild is included from Whitehorse to Carcross

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#	Transmission Route	Description of Route
11	Whitehorse ↓ Lindeman-Fraser PSH	▪ **Start:** Whitehorse Generating Station ▪ **End:** Lindeman-Fraser PSH Project Interconnection ▪ **Length:** 129 km ▪ From the Whitehorse Generating Station the corridor follows Highway 1 southeast for 17 km to Carcross Cutoff (the junction of Highways 1 and 2). ▪ From Carcross Cutoff the corridor follows Highway 2 southwards through the town of Carcross for 77 km to the BC-Yukon border. ▪ Once in BC the corridor continues along Highway 2 for an additional 35 km to reach the Lindeman-Fraser PSH project interconnection point. ▪ 68 km of 34.5 kV distribution underbuild is included from Whitehorse to Carcross

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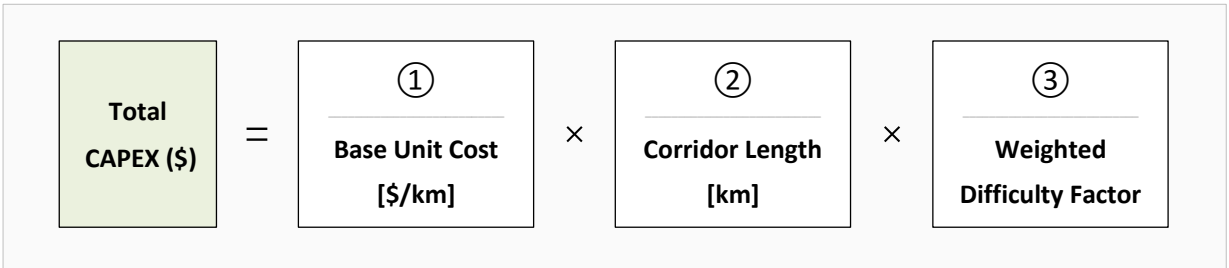
3 CAPEX Analysis

Midgard created a parametric model to estimate the all-in CAPEX required to implement each transmission line routing option. Midgard's costs represent total, all-in costs for the transmission lines, which includes owner's costs, development costs, stakeholder engagement costs, land costs, planning and engineering costs, construction costs, contractor profit margins, material costs, and commissioning costs. The CAPEX estimates do not include any provisions for new substations or substation related costs (e.g.: new bays, new breakers, or new bus work).

3.1 CAPEX Estimation Methodology

The factor-based CAPEX model is defined by the following logic (see Figure 3):

Figure 3: Midgard Parametric CAPEX Model



The following descriptions provide more information on each component of the parametric CAPEX model:

- **Component ① - Base Unit Costs:** Drawing upon both public and proprietary industry transmission project cost information, an average per kilometer project costs for the studied voltage classes (138 kV and 230 kV) was established. The source data covers a wide range of transmission projects (16 x 138 kV projects and 17 x 230 kV projects) and represents a reasonable estimate of the expected "base case" unit costs for both 138 kV and 230 kV voltages.
- **Component ② - Corridor Length:** The corridor length for each of the transmission line routes was extracted from the detailed corridor analysis.
- **Component ③ - Weighted Difficulty Factor:** Weighted Difficulty Factors are calculated based on the terrain information from the detailed corridor analysis. The corridor-specific difficulty factors are based on a variety of inputs that uniquely differentiate each route based on the expected difficulty of project execution. Factors considered include: vegetation cover, water features, surficial geology, permafrost, terrain slope, existing access, human settlements, land use and remoteness.

In addition to the factor-based workup of project costs (detailed above), sub-sections of several routes (Whitehorse → Teslin, Whitehorse → Carcross, and Aishihik → Haines Junction) include a provision for 34.5 kV distribution underbuild. Since the Base Unit Costs do not include allowance for distribution underbuild, an additional adder was included for the route segments requiring underbuild. It is worth noting

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that distribution underbuild cost is dependent on a variety of factors that have not yet been determined (e.g.: conductor type, number of taps/services, etc.), and therefore a consistent underbuild costs per kilometer was used. The following ranges are indicative of the incremental costs that could be expected to add distribution underbuild on different transmission line configurations:

1) Short spans, single pole structures, light distribution conductor: $80,000 per km
2) Short spans, single pole structures, heavy distribution conductor: $100,000 per km
3) Long spans, H-frame structures: $120,000 to $150,000 per km

Midgard considers that a $100,000 per km adder is a reasonable high-level allowance for the incremental all-in costs of adding 34.5 kV underbuild to the selected transmission route segments.

The level of accuracy of the factor-based CAPEX model is Class 5 as per standard 17R-97 by the Association of the Advancement of Cost Engineering, which represents a -50% / +100% range of accuracy.

3.2 CAPEX Results

Table 4 below provides the tabular details of each of the eleven transmission corridors (including voltage, length, and the amount of 34.5 kV distribution underbuild) as well as the estimated total CAPEX and estimated CAPEX per km.

Table 4: Summary of CAPEX Results (Costs Stated in $2016)

#	Transmission Route	Voltage	Length	34.5 kV Underbuild	CAPEX [Total]	CAPEX [Per KM]
1	Faro → Finlayson	138 KV	233 km	None	$221M	$0.95M/km
2	Faro → Watson Lake	230 kV	414 km	None	$597M	$1.44M/km
3	Aishihik → Destruction Bay	138 kV	157 km	49 km	$167M	$1.07M/km
		230 kV			$241M	$1.54M/km
4	Whitehorse → Skagway	138 kV	170 km	68 km	$166M	$0.98M/km
		230 kV			$251M	$1.48M/km
5	Whitehorse → Atlin	138 kV	172 km	79 km	$158M	$0.91M/km
6	Whitehorse → Teslin	138 kV	174 km	174 km	$165M	$0.95M/km
7	Whitehorse → Squanga-Dalayee PSH	138 KV	105 km	105 km	$100M	$0.96M/km
8	Whitehorse → Atlin-Mt.Black PSH	138 KV	127 km	79 km	$119M	$0.94M/km
9	Whitehorse → Tutshi Windy Arm	138 KV	96 km	68 km	$94M	$0.98M/km
10	Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	138 KV	112 km	68 km	$108M	$0.97M/km
11	Whitehorse → Lindeman-Fraser PSH	138 KV	129 km	68 km	$125M	$0.97M/km

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3.3 CAPEX Benchmarking Analysis

In addition to the above CAPEX estimates, Midgard has also completed a benchmarking exercise against several YEC cost numbers in the Yukon. The two data sets being compared are:

1) **The 138 kV Routes from This Report:** The 138 kV lines (10 in total) considered in this *Transmission Options Evaluation* are based on the average costs (plus some factor modification, see Section 3.1) of 16 recent projects across the Yukon, Alberta, and British Columbia.
2) **YEC Projects of Interest:** A 138 kV route cost workup for the Stewart-Keno Transmission Project provided by YEC on July 8, 2016.

A benchmarking comparison (on a $2016/km basis) of the two data sets is presented in Table 5 below.

Table 5: Benchmarking Results (Costs Stated in $2016)

Data Set	#	Cost Range ($2016)	Items Included in Cost Estimate
Transmission Options Evaluation 138 kV Results	10 Lines	$0.85M → $1.04M/km	Complete, All-In Costs (including project contingency, land costs, First Nation costs, development costs, permitting costs, engineering costs, salvage costs, and owner's overhead/admin costs, but not including distribution underbuild costs)
YEC Stewart-Keno Transmission Project Estimate	1 Line	$0.53M/km	Construction Cost Only

As seen in the table above, the results of this *Transmission Options Evaluation* are higher than YEC's Stewart-Keno Transmission Project. Midgard believes this difference is primarily due to the *Transmission Options Evaluation* costs being represented as **total, all-in** costs as opposed construction-only costs (an "apples-to-oranges" comparison). Some of the cost items missing from YEC's Stewart-Keno Transmission Project estimate include:

1) **Project Contingency:** A contingency is a budget allocation to compensate for unforeseen costs. Unforeseen costs can manifest in many forms, including weather induced delays, unplanned soil conditions, or changes in labour market rates.
2) **Land Costs:** Land costs can include Right-of-Way acquisition, long term land leases, settlements with private land owners, relocation costs, remediation efforts, and habitat compensation offsets.
3) **First Nation Costs:** First Nation costs can include consultation efforts, compensation packages (impact benefit agreements), granting equity in projects, etc.

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4) **Development Costs:** Development costs cover all early stage conceptual studies, preliminary engineering efforts, and environmental studies.
5) **Permitting Costs:** Permitting costs can include highway crossing permits, access permits, river crossing permits, aerodrome permits, pipeline crossing permits, etc.
6) **Engineering Costs:** Detailed engineering to design and issue the construction package for the transmission line.
7) **Salvage Costs:** Salvage costs includes any modification or removal of existing infrastructure to accommodate a new transmission line. For example, the removal of an old transmission line or wrecking out old distribution circuits.
8) **Owner's Overhead & Admin Costs:** Utility overhead includes the project's portion of all utility overhead. Utility overhead includes administration, office space, staffing costs, etc.

Typically the eight non-construction costs listed above can make up 30% to 50% of total, all-in project costs for a transmission line. Considering this fact, the benchmarking results do show overlap between the two sets of cost estimates.

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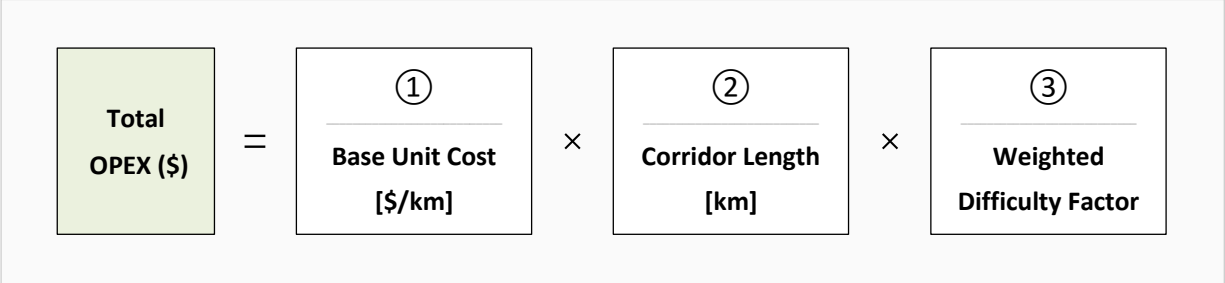
4 OPEX Analysis

Midgard calculated the annual OPEX required to maintain each transmission line option by drawing upon the average per unit costs of operating the existing YEC transmission system. Similar to the CAPEX modeling, the estimated OPEX costs represent the total all-in cost of transmission operations.

4.1 OPEX Estimation Methodology

The OPEX model is defined by the following logic (see Figure 4):

Figure 4: Midgard OPEX Model



The following descriptions provide more information on each component used in the calculations:

- **Component ① - Base Unit Cost:** The YEC 2012-2013 General Rate Application was used as the source for YEC's total transmission operational costs. The proposed OPEX cost estimate for YEC in 2013 was $1,293,000 (extracted from Table 3.6 on page 3-8 of "Supporting Documents: Tab 3 – Revenue Requirement"), which is comprised of labour costs, brushing costs, and other non-labour costs. This 2013 estimate was normalized to a $/km value using the total line length of the existing YEC transmission system. Finally, the resulting per unit operational costs were inflation-adjusted to give results in 2016 Canadian dollars.
- **Component ② - Corridor Length:** The corridor length for each of the transmission line routes was extracted from the detailed corridor analysis.
- **Component ③ - Weighted Difficulty Factor:** Weighted Difficulty Factors are calculated based on the terrain information from the detailed corridor analysis. The corridor-specific difficulty factors are based on four inputs that uniquely differentiate each route based on the expected difficulty of operations. Factors considered include: permafrost, remoteness, terrain slope, and an adder for projects that extend outside the Yukon jurisdiction. The factors were applied in a manner such that some routes had increased operating costs (above the Base Unit Cost) and some had decreased operating costs (below the Base Unit Cost). This approach was chosen as the Base Unit Costs are already representative of the different factors that influence Yukon operating costs, and that it is reasonable to assume the new routes under consideration would more or less average to a similar operating cost (some being higher than average, some being lower).

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4.2 OPEX Results

Table 6 below provides the estimated total annual OPEX for each of the evaluated transmission options.

Table 6: Summary of OPEX Results (Costs Stated in $2016)

#	Transmission Route	Length	Annual OPEX [Total]	Annual OPEX [per km]
1	Faro → Finlayson	233 km	$351,000	$1,509/km
2	Faro → Watson Lake	414 km	$613,000	$1,481/km
3	Aishihik → Destruction Bay	157 km	$217,000	$1,383/km
4	Whitehorse → Skagway	170 km	$285,000	$1,680/km
5	Whitehorse → Atlin	172 km	$236,000	$1,377/km
6	Whitehorse → Teslin	174 km	$239,000	$1,371/km
7	Whitehorse → Squanga-Dalayee PSH	105 km	$143,000	$1,363/km
8	Whitehorse → Atlin-Mt.Black PSH	127 km	$174,000	$1,376/km
9	Whitehorse → Tutshi Windy Arm	96 km	$143,000	$1,487/km
10	Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	112 km	$168,000	$1,509/km
11	Whitehorse → Lindeman-Fraser PSH	129 km	$200,000	$1,551/km

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5 Power Transfer Capacity Analysis

In order to estimate the maximum reliable power transfer capacity of each transmission line option, a steady state power system analysis was performed using the Siemens PSS®E power system simulation software. The maximum reliable power transfer tells you how much electricity can be safely sent through the transmission line and is a useful characteristic to determine the most appropriate voltage and conductor type for planning purposes. The potential transmission lines studied in this *Transmission Options Evaluation* could be used for a variety of purposes, including serving electricity to remove communities, interconnecting mining operations to the Yukon grid, and/or interconnecting new power generations projects to the Yukon grid.

The power transfer capacity limit for each transmission option was determined by calculating the expected conductor temperature and the voltage magnitudes and angles at the line terminals and one or more intermediate points across a range of power transfers. For any given line option the capacity limiting parameter may be the absolute voltage magnitude (voltage constraint), the voltage angle separation between line terminals (angular constraint), or reaching the temperature limit of the conductor (thermal constraint). Since public access is not available for the power system models used by YEC, simplifying assumptions based on publicly available information were utilized to approximate the Yukon electrical system as part of a simplified model. Additional detail regarding the simulation set-up can be found in Appendix A.

It is important to state that the methodology used to calculate the maximum reliable power transfer capacity remains preliminary in this *Transmission Options Evaluation* for the purposes of informing YEC's long term planning efforts. As the projects are further considered, modified, and iterated towards actual implementation, the requirements and ultimate use of these proposed transmission lines will become more concrete. Once the transmission line projects are in a later stage of development, a more comprehensive suite of system analyses (including transient and voltage stability studies covering a broad set of present and future system forecast load cases) would be necessary.

5.1 Assumptions

5.1.1 General

Some of the basic assumptions adopted for this study are as follows:

1) Swing Bus: A Swing Bus is a simulated generator bus that is used to balance power system loads and generators during system studies. The Swing Bus either absorbs surplus power or generates power to balance total power generation and consumption when solving system simulations. In the context of this study, the Swing Bus represents the cumulative Yukon grid, and the amount of power the Swing Bus absorbs represents the power transferred by the transmission line.

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2) Yukon Loads: Yukon communities that are already electrified (e.g.: Tagish, Carcross, Ross River, etc.) were assumed to remain connected via their existing electrical grid connections (i.e. they were not transferred from their existing grid connection to the potential transmission lines). Midgard reviewed a series of future mining loads[4], but determined that they would not be supplied by any of the eleven transmission corridors. All other electrical load values were provided by YEC.
3) Power Transferred to the Swing Bus = [Total generation along the new transmission line] – [Total loads along the new transmission line] - [Transmission line losses]
4) Voltage Stability: Steady state voltage stability implies maintaining voltage levels within 90% and 110% of the prescribed operating voltage (138 kV or 230 kV).
5) Angular Stability: Steady state angular stability is assumed to be achieved by maintaining a voltage angle difference of less than 33° between the generating end and the receiving end.

5.1.2 Operating Conditions

The following assumptions were made in order to model transmission line behaviour:

1) Wind Speed: 2 ft/s (0.61 m/s)
2) Winter Ambient Temperature: -10°C
3) Summer Ambient Temperature: +35°C
4) Altitude: Detailed in Table 7.

Table 7: Altitude of Transmission Line Terminal Locations

Location	Altitude (m)
Whitehorse	655
Faro	670
Aishihik	920
Mayo	504
Pelly Crossing	570
Destruction Bay	815
Watson Lake	685
Teslin	690

Location	Altitude (m)
Finlayson Lake	934
Squanga-Dalayee	778
Atlin	696
Tutshi Windy Arm	715
Racine	900
Lindeman	900
Skagway	0

5.1.3 Conductor Type

Conductor selection assumptions:

1) 138 kV Corridors: Single 397.5 MCM Ibis ACSR conductor
2) 230 KV Corridors: Double Bundle 477 MCM Hawk ACSR conductor

[4] Victoria Gold, Brewery Creek, Alexco Bellekeno and Carmacks Copper are the potential mines that may be operational in the future.

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5.2 Methodology

The following methodology was applied to determine the maximum reliable transfer capacity for each Transmission Option:

1) STEP 1: A steady state power flow model is developed for the PSS®E software using the following inputs:
    a. Transmission line information (resistance, reactance, charging susceptance, and thermal rating)
    b. Generation and load information
    c. Operating voltage
2) STEP 2: A full Newton-Raphson simulation is performed assuming a flat start condition utilizing an assumed base power transfer level.
3) STEP 3: The bus voltage, the voltage angle, and the conductor temperature are monitored to determine if they remain within their limiting conditions. The limiting conditions are as follows:
    a. Bus Voltage: Lower limit is 90% of the operating voltage, and the upper limit is 110% of the operating voltage
    b. Voltage Angle: The upper limit for sending & receiving end voltage angle separation is 33°
    c. Thermal Rating: The limits are dependent on the type of conductor, operating voltage and conditions such as line orientation, elevation, ambient temperature and wind speed.
4) STEP 4: If there are no violations of the monitored key parameters, the process is repeated from Step 2 at an incrementally higher line transfer capacity.
5) STEP 5: The simulation is stopped and the transmission line maximum power transfer limit (recorded as power flow into the swing bus end of the system) is identified when any one of the monitored parameters reaches a limiting value.

5.3 Route Characteristics and Transfer Capacity Results

Maximum power transfer capacity results are tabulated in Table 8 below. Table 8 lists the voltage class, conductor type, line length, size and location of loads, the maximum summer power transfer rate, the maximum winter power transfer rate, and the limiting condition for each of the evaluated transmission options.

Table 8: Electrical Description of Routes & Power Transfer Results

#	Option	Description	Results
1	Faro ↓ Finlayson	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 233 km ▪ Loads Modeled: o No Intermediate loads	Max Power Transfer: **84 MW** Limiting Factor: Voltage Angle Limit

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#	Option	Description	Results
2	Faro ↓ Watson Lake	▪ Voltage: 230 kV ▪ Conductor Type: Hawk 477 MCM (Double Bundle) ▪ Total Line Length: 414 km ▪ Loads Modeled: o Watson Lake (414 km from Faro; 3.2 MW)	Max Power Transfer: **190 MW** Limiting Factor: Voltage Angle limit
3	Aishihik ↓ Destruction Bay	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 157 km ▪ Loads Modeled: o Destruction Bay (157 km from Aishihik; 0.42 MW)	Max Power Transfer: **122 MW** Limiting Factor: Voltage Angle Limit
		▪ Voltage: 230 kV ▪ Conductor Type: Hawk 477 MCM (Double Bundle) ▪ Total Line Length: 157 km ▪ Loads Modeled: o Destruction Bay (157 km from Aishihik; 0.42 MW)	Max Power Transfer: **484 MW** Limiting Factor: Voltage Angle limit
4	Whitehorse ↓ Skagway	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 170 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **114 MW** Limiting Factor: Voltage Angle Limit
		▪ Voltage: 230 kV ▪ Conductor Type: Hawk 477 MCM (Double Bundle) ▪ Total Line Length: 170 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **443 MW** Limiting Factor: Voltage Angle limit
5	Whitehorse ↓ Atlin	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 172 km ▪ Loads Modeled: o Atlin (172 km from Whitehorse; 4 MW)	Max Power Transfer: **97 MW** Limiting Factor: Voltage Angle limit
6	Whitehorse ↓ Teslin	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 174 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **95 MW** Limiting Factor: Voltage Angle limit

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#	Option	Description	Results
7	Whitehorse ↓ Squanga-Dalayee PSH	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 105 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **169 MW (Winter)** **134 MW (Summer)** Limiting Factor: Thermal Rating
8	Whitehorse ↓ Atlin-Mt.Black PSH	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 127 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **154 MW (Winter)** **131 MW (Summer)** Limiting Factor: Voltage Angle Limit (Winter) Thermal Rating (Summer)
9	Whitehorse ↓ Tutshi Windy Arm	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 96 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **172 MW (Winter)** **135 MW (Summer)** Limiting Factor: Thermal Rating
10	Whitehorse ↓ Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 112 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **166 MW (Winter)** **132 MW (Summer)** Limiting Factor: Thermal Rating
11	Whitehorse ↓ Lindeman-Fraser PSH	▪ Voltage: 138 kV ▪ Conductor Type: Ibis 397.5 MCM (Single Bundle) ▪ Total Line Length: 129 km ▪ Loads Modeled: o No intermediate loads	Max Power Transfer: **147 MW (Winter)** **129 MW (Summer)** Limiting Factor: Voltage Angle Limit (Winter) Thermal Rating (Summer)

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6 Project Scheduling

High-level project schedules have been estimated for each of the transmission project options evaluated in this report. Each project schedule is broken down into the following general activity phases[5]:

1) Phase 1: Preliminary Engineering and Cost Estimation
2) Phase 2: Permitting
3) Phase 3: Detailed Design
4) Phase 4: Procurement and Logistics
5) Phase 5: Tendering and Construction
6) Phase 6: Commissioning

The schedule estimates draw upon recent Yukon transmission project results[6] and are augmented with Midgard's knowledge of recently completed and ongoing transmission project developments in nearby jurisdictions. The following subsections describe the project schedule phases listed above, and the assumptions related to each respective phase.

6.1 Phase-By-Phase Discussion

6.1.1 Phase 1: Preliminary Engineering and Cost Estimates

The Preliminary Engineering and Cost Estimates phase includes allowance for the required pre-feasibility and feasibility design, and cost estimation activities required to support business case decisions.

The duration of preliminary engineering and cost estimate studies will be strongly influenced by the total length of the specific transmission line being considered, but the relationship between duration and line length is not linear. For the purpose of this report a minimum duration of at least 3 months has been assumed for short projects, and a maximum duration of 12 months has been assumed for transmission projects over 200 km in length (based on a range of time durations extracted from recent transmission line builds).

The study results from the preliminary engineering activities will feed into YESAB and YUB permit applications.

[5] The scheduling estimates included in this report account for technical components only and do not include the time required for First Nation and stakeholder consultation activities. In reality, all First Nations and stakeholders will be consulted and engaged with throughout project development (from early stage development through to project completion and operation).

[6] YESSA Project Proposal, Oct 2015: Stewart – Keno 138 kV Transmission Project and YESAB Project Proposal - Carmacks – Stewart/Minto Spur Transmission Project, Chapter 5

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6.1.2 Phase 2: Permitting

The Permitting phase activities include preparing and filing the documents necessary to obtain environmental approvals from YESAB and regulatory permits from YUB.

Based upon the permitting duration allowance for the Carmacks – Stewart/Minto Transmission project and the Stewart Keno Transmission project, a minimum permitting duration of 13 months has been assumed. Assuming that there are no extraordinary issues identified during the permitting phase, a maximum permitting duration of 18 months is used for transmission options ranging from 150 km to 200 km, and for transmission options over 200 km the permitting duration is capped at 20 months (based on a range of time durations extracted from recent transmission line builds).

Issues that arise during the permitting phase may require line re-routing or other facility modifications to enable the necessary permits to be obtained. Any required modifications to the feasibility phase designs will cascade into the detailed design stage activities, and may extend expected timelines for permitting activities and all other project phases.

6.1.3 Phase 3: Detailed Design Engineering

The detailed design engineering phase builds on the results of the preliminary engineering and cost estimates, with further refinements being implemented throughout the permitting process as required to address any YESAB and YUB permit conditions.

The detailed design effort typically has a non-linear relationship to the line length. Certain design activities have a minimum duration even for very short lines, and significant external engineering resources are typically brought on for longer transmission projects, thereby mitigating the overall duration of detailed design activities. For the purpose of this report the estimated duration of detailed design engineering activities has been capped at 12 months for transmission projects over 200 km long (based on a range of time durations extracted from recent transmission line builds).

6.1.4 Phase 4: Procurement and Logistics

The procurement process for long lead-time equipment (e.g.: transformers) and bulk materials such as poles and conductor is often initiated prior to the issuance of final permits in order to avoid extended delays to construction start after the required permits have been obtained. Although the overall project duration can be shortened in this way, there is a risk of stranded investment if the project does not receive approval.

Similar to the design activities discussed above, the duration of procurement activities is not linearly proportional to line length. For the purpose of this report, procurement activities are assumed to last 16 months for lines 100 - 200 km long, and are capped at 20 months for lines longer than 200 km (based on a range of time durations extracted from recent transmission line builds).

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6.1.5 Phase 5: Tendering and Construction

In most cases, construction activities cannot begin until after the necessary permits and licenses have been obtained, although construction tendering can be initiated prior to receiving permits (with the assumption of the associated incremental risk).

Transmission line construction activities include right-of-way brushing and clearing, access road development, foundation and anchor installation, structure assembly and erection, conductor stringing, sagging and clipping in. Construction activities must be carried out in consideration of environmental restrictions, such as avoiding bird nesting seasons and not entering or disturbing streams except during approved fish windows. Most construction activities in wet or permafrost areas must be completed during the winter season to take advantage of frozen conditions to reduce damage to soils and wetlands and to enable access to structure sites using standard vehicles.

6.1.6 Phase 6: Commissioning

A duration of 3 months has been assumed for commissioning the transmission line for all the transmission options considered in this report (based on a range of time durations extracted from recent transmission line builds). It is assumed that line review and commissioning preparation activities will actually be ongoing during the construction phase, so the incremental duration of commissioning activities post-construction will not be proportional to overall line length.

6.2 Schedule Results

Table 9 below contains the total timeline (from preliminary engineering through to commissioning) of each of the transmission routes of interest as well as a stated In-Service Date, assuming the initial activities are started today. A more detailed phase-by-phase Gantt chart for each transmission route option is included in Appendix B.

Table 9: Schedule Highlights

#	Transmission Route	Total Timeline	Earliest Possible ISD
1	Faro → Finlayson	52 Months	Jan 2021
2	Faro → Watson Lake	72 Months	Sep 2022
3	Aishihik → Destruction Bay	46 Months	Jul 2020
4	Whitehorse → Skagway	49 Months	Oct 2020
5	Whitehorse → Atlin	49 Months	Oct 2020
6	Whitehorse → Teslin	49 Months	Oct 2020
7	Whitehorse → Squanga-Dalayee PSH	39 Months	Dec 2019
8	Whitehorse → Atlin-Mt.Black PSH	44 Months	May 2020

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#	Transmission Route	Total Timeline	Earliest Possible ISD
9	Whitehorse → Tutshi Windy Arm	38 Months	Nov 2019
10	Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	40 Months	Jan 2020
11	Whitehorse → Lindeman-Fraser PSH	45 Months	Jun 2020

With regards to project lifespans, the typical asset life for transmission lines can be expected to range from 40 to 45 years. However, with proper and regular maintenance, line life can be extended. YEC amortizes transmission line assets over a 55 year period.

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7 Risk Assessment

Potential risks must be identified and assessed whenever planning, budgeting, and scheduling any new transmission line projects. Different risks may be encountered during each phase of transmission project development, and the relative priority of risks will likely change between the different project phases.

7.1 Defining Risk Metrics

The first step in risk assessment involves creating a risk register that comprehensively identifies the risks that may credibly be encountered when developing an individual project (or portfolio of projects). Some risks are generic to transmission projects built anywhere, some apply to projects built within a particular geographical setting and climatic zone, and some risks are specific to the selected routing. Most of the projects discussed in this report are potentially exposed to a common set of risks that would be generally applicable to projects built anywhere in the Yukon.

Once the risks applicable to a particular project have been identified the probability and consequence of each risk is estimated. In this analysis, probabilities are assigned on a scale of 1 to 5, where 1 indicates a low probability (the risk is unlikely to happen on the project being evaluated) and 5 indicates a high probability (the risk will almost certainly be realized at some point during the project). Similarly, consequences are assigned a rating of 1 to 5 where 1 indicates a small consequence should the risk be incurred (minor cost impact or very brief schedule delay) and 5 indicates a significant consequence (major cost overruns, extended schedule delays, severe or widespread environmental or safety impacts).

Each risk is assigned a rank based upon the product of the probability and consequence of that risk:

- 1 to 5 = Low Risk (L)
- 6 to 10 = Moderate Risk (M)
- 11 to 15 = High Risk (H)
- 16 to 20 = Very High Risk (V)
- 21 to 25 = Extreme Risk (X)

7.2 Universal Risks (Affecting All Routes)

The first risk matrix shown below (Table 10) identifies and ranks risks to which all Yukon transmission line projects may be exposed. Each risk is identified as a development phase risk, a construction phase risk, and/or an operational phase risk. Some risks can impact more than one project phase.

In addition, the risk matrix also includes a “Potential Mitigation” column that lists some mitigation options identified by Midgard.

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Table 10: Universal Risks (Affecting All Routes)

#	Risk Description	Risk Rank	Potential Mitigation
1	Risk: Meteorological –Extended Extreme Cold ▪ Construction delays ▪ Labour inefficiency ▪ Crew standby costs ▪ Additional mob & de-mob costs for extended extreme cold periods Affects: Construction	**Prob:** 5 **Conseq.:** 2 **Rank:** M	▪ Schedule activities potentially impacted by extreme cold temperatures during spring, summer or fall ▪ Allow adequate schedule float for anticipated extreme cold days
2	Risk: Meteorological – Extreme Snow ▪ Construction delays ▪ Labour inefficiency ▪ Standby costs ▪ Additional mob & de-mob costs ▪ Additional snow clearing costs ▪ Operational impacts can include structure & conductor damage, inadequate clearance over roads, railways and pathways Affects: Construction, Operations	**Prob:** 3 **Conseq.:** 2 **Rank:** M	▪ Schedule construction activities in heavy snow-prone areas during summer ▪ Allow adequate schedule float for an appropriate number of anticipated extreme snow days ▪ Allow adequate safety factor when designing clearances above ground and obstacles
3	Risk: Meteorological – Extreme Wind ▪ Construction delays, especially if high winds occur during structure erection or stringing activities ▪ Operational impacts can include structure failure, contact between phases and transmission structure or guys, phase contact with trees or buildings, trees falling into line, forest fire ignition Affects: Construction, Operations	**Prob:** 3 **Conseq.:** 2 **Rank:** M	▪ Allow adequate schedule float for anticipated extreme wind days ▪ Allow for phase blow-out in RoW widths ▪ Clear all danger trees that could fall into line
4	Risk: Geotechnical – Permafrost ▪ Additional foundation costs ▪ Sub-optimal span lengths required to avoid placing structures in permafrost (in areas with discontinuous permafrost) ▪ Operational risk if foundations accelerate permafrost melting and structure fails Affects: Construction, Operations	**Prob:** 4 **Conseq.:** 3 **Rank:** H	▪ Avoid or span over permafrost areas to the greatest extent possible ▪ Utilize permafrost-friendly foundation designs
5	Risk: Geotechnical – Exposed Bedrock ▪ High foundation and guying costs (e.g.: grouted rock anchors, blasting) Affects: Construction	**Prob:** 3 **Conseq.:** 3 **Rank:** M	▪ Select centreline route to maximize opportunities to site structures in acceptable overburden ▪ Select structure types adaptable to cost effective use of rock foundations and anchors

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#	Risk Description	Risk Rank	Potential Mitigation
6	Risk: Geotechnical – Steep Sideslopes ▪ Difficult and costly foundation and structure erection ▪ Operational Risk of snow creep damaging structures sited on steep sideslopes in heavy snow zones ▪ Risk of snow avalanche damage ▪ Risk of slope instability/landslides, exacerbated by foundation excavation and access road construction Affects: Construction, Operations	**Prob:** 3 **Conseq.:** 3 **Rank:** M	▪ Avoid routing on steep sideslopes if possible ▪ Avoid placing structures in avalanche chutes or on unstable slopes ▪ Utilize existing access roads wherever possible ▪ Locate structures as close as possible to existing access roads ▪ Utilize snow creep resistant foundations and structure bases on steep slopes in heavy snow loading areas ▪ Utilize upslope avalanche guards or deflectors where necessary & practical
7	Risk: Geotechnical – Floodplains ▪ Expensive foundations ▪ Operational risk of flood damage or destruction of structures and resulting extended outages ▪ Construction difficult or impossible during freshet/snowmelt season Affects: Construction, Operations	**Prob:** 3 **Conseq.:** 3 **Rank:** M	▪ Avoid placing structures within floodplains to the greatest extent possible ▪ Schedule floodplain construction during late summer/fall/winter ▪ Use heavy rip-rap protection (large rock armour) for structures that must be placed in floodplains
8	Risk: Social – Permitting in Reserve Blocks ▪ Consultation with First Nations potentially impacted by new facilities in traditional lands or near communities ▪ Schedule delays or routing adjustments if route agreement is not achieved Affects: Development, Construction, Operations	**Prob:** 4 **Conseq.:** 4 **Rank:** V	▪ Begin comprehensive outreach activities with affected FN communities early
9	Risk: Social – Permitting near Urban Areas ▪ Avoiding populated areas may involve more complex line routing ▪ Possible cost increases due to additional route length, additional deflection structures, more difficult access roads ▪ Schedule delays if consultation does not achieve route agreement with landowners Affects: Development, Construction	**Prob:** 3 **Conseq.:** 4 **Rank:** H	▪ Where possible select routes that avoid densely populated areas ▪ Avoid siting structures close to residences

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#	Risk Description	Risk Rank	Potential Mitigation
10	Risk: Social – Permitting in Scenic Areas ▪ Siting routes parallel to scenic highways increases risk of obstructing viewscapes or impacting sight lines due to RoW clearing Affects: Development, Construction	**Prob:** 3 **Conseq.:** 3 **Rank:** M	▪ Avoid locating structures between scenic viewpoint areas and scenic vistas ▪ Align RoW to minimize visual impact of transmission RoW cutlines through forested areas impact viewscapes

7.3 Route Specific Risks

In addition to the universal risks identified above, project-specific risk matrices have been developed for the following routes:

- Faro → Finlayson / Watson Lake (see Table 11)
- Aishihik → Destruction Bay (see Table 12)
- Whitehorse → Skagway / Tutshi Windy Arm / Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH / Lindeman-Fraser PSH (see Table 13)
- Whitehorse → Atlin / Atlin-Mt.Black PSH (see Table 14)
- Whitehorse → Teslin / Squanga-Dalayee PSH (see Table 15)

Table 11: Route Specific Risks for Faro → Finlayson / Watson Lake

#	Risk Description	Risk Rank	Potential Mitigation
1	Risk: Logistics – Very Large Projects located in Remote Area with little local capacity ▪ Challenging to setup and supply camps ▪ Transportation and storage of very large amounts of construction materials in remote area ▪ Difficult to stage construction for such a long linear project in this region Affects: Development, Construction, Operations	**Prob:** 5 **Conseq.:** 2 **Rank:** M	▪ Logistics and camp planning at very early project stage ▪ Allow adequate schedule float to address logistical challenges

Table 12: Route Specific Risks for Aishihik → Destruction Bay

#	Risk Description	Risk Rank	Potential Mitigation
1	Risk: Geotechnical – Floodplains ▪ Extensive Floodplain where Slims River previously discharged into south end of Kluane Lake Affects: Construction, Operations	**Prob:** 5 **Conseq.:** 3 **Rank:** H	▪ Route line near Hwy 1 and cross the dried up Slims River at the narrow point between two well-treed and relatively stable alluvial fans

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#	Risk Description	Risk Rank	Potential Mitigation
2	Risk: Social – Permitting within Kluane National Park ▪ Proposed centerline lays within Kluane National Park ▪ Siting within the Park will likely impose moderate to severe restrictions on permitting, construction and operations Affects: Development, Construction, Operations	**Prob:** 5 **Conseq.:** 3 **Rank:** H	▪ Initiate routing discussions with Parks Canada and other stakeholders at very early stage ▪ If route through Park cannot be permitted, considering routing line on strip of non-park lands between Hwy 1 and Kluane Lake – note that scenic viewscape of lake will be impacted
3	Risk: Geotechnical – Permafrost ▪ Aishihik corridor features extensive areas of discontinuous permafrost, probably impossible to avoid placing a large number of structures into permafrost Affects: Construction, Operations	**Prob:** 5 **Conseq.:** 3 **Rank:** H	▪ Avoid or span over permafrost areas to the greatest extent possible ▪ Utilize permafrost-friendly foundation designs

Table 13: Route Specific Risks for Whitehorse → Skagway / Tutshi Windy Arm / Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH / Lindeman-Fraser PSH

#	Risk Description	Risk Rank	Potential Mitigation
1	Risk: Geotechnical – Exposed Bedrock ▪ Bedrock is unavoidable over substantial portions of this route, especially sections south of Tutshi Lake and in the White Pass area Affects: Construction	**Prob:** 5 **Conseq.:** 3 **Rank:** H	▪ Select centreline route to maximize opportunities to site structures in acceptable overburden ▪ Select structure types adaptable to cost effective use of rock foundations and anchors
2	Risk: Geotechnical – Steep Sideslopes ▪ Difficult to avoid building on sideslopes above the highway in the segments parallel with Tagish and Tutshi Lakes ▪ Risk is compounded since this is also an area of extreme snow loads and avalanches Affects: Construction, Operations	**Prob:** 5 **Conseq.:** 5 **Rank:** X	▪ Build on lake side of highway (may not be possible due to scenic highway restrictions) ▪ Install underground beside highway (very costly alternative)
3	Risk: Social – Permitting near Populated Areas ▪ Suburban residential development from Whitehorse to Carcross Cutoff ▪ Routing must pass through Carcross to cross narrows between Bennett Lake and Nares Lake Affects: Development	**Prob:** 3 **Conseq.:** 4 **Rank:** H	▪ Re-route south of developed area from Whitehorse to Carcross Cutoff ▪ Follow railway through Carcross

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#	Risk Description	Risk Rank	Potential Mitigation
4	Risk: Social – Permitting in scenic areas ▪ Whitehorse to Skagway is a national scenic route ▪ Particular areas of special concern include Emerald Lake (between Carcross Cutoff and Carcross), the narrows at Carcross, along the shores of Tagish and Tutshi Lakes, and across White Pass Affects: Development	**Prob:** 5 **Conseq.:** 3 **Rank:** H	▪ Avoid locating structures between scenic viewpoint areas and scenic vistas ▪ Align RoW to minimize visual impact of transmission RoW cutlines through forested areas impact viewscapes
5	Risk: Social – Permitting near National Parks ▪ Skagway to White Pass segment abuts the Klondike Gold Rush US National Historical Park ▪ Schedule delays or routing adjustments if route agreement is not achieved Affects: Development, Construction, Operations	**Prob:** 5 **Conseq.:** 3 **Rank:** H	▪ Assess any special construction or operational requirements, such as low-profile structures, specialized paints or non-specular conductors, limited construction windows and operating access constraints ▪ Begin permitting activities early
6	Risk: Political – Yukon/BC Border Crossing ▪ Permitting must satisfy BC regulations ▪ May trigger studies and require approval by BC Hydro ▪ May require YEC to apply for status as a BC utility Affects: Development, Construction, Operations	**Prob:** 5 **Conseq.:** 4 **Rank:** V	▪ Initiate discussions with BC Government, BC Hydro and BC Utilities Commission to determine applicable regulations and approval & permitting requirements
7	Risk: Political – Canada/United States Border Crossing ▪ Will require permits from Canadian National Energy Board and US Federal Energy Regulation Commission ▪ International powerline crossings require a US Presidential Permit ▪ Will likely require additional approvals from State of Alaska and Municipality of Skagway Affects: Development, Construction, Operations	**Prob:** 5 **Conseq.:** 5 **Rank:** X	▪ Initiate discussions with all Canadian and US entities to determine applicable regulations and permitting requirements

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#	Risk Description	Risk Rank	Potential Mitigation
8	Risk: Social, Geotechnical, Technical – Termination at Whitehorse Riverside ▪ Constrained access into open bay at Riverside substation ▪ Will require crossing under or relocating an existing 138 kV line ▪ Difficult access from south bank requires crossing Yukon River at a very congested location ▪ Two existing hydroelectric facilities, intake canal, tailrace canal and main stem of Yukon River Affects: Construction	**Prob:** 5 **Conseq.:** 3 **Rank:** H	▪ Relocate one of the existing 138 kV lines to the open north bay position ▪ Possibly double circuit existing 138 kV line located between the intake and tailrace canals ▪ Taking the new line underground/underwater at the river crossing may be an option (although very costly)

Table 14: Route Specific Risks for Whitehorse → Atlin / Atlin-Mt.Black PSH

#	Risk Description	Risk Rank	Potential Mitigation
1	Risk: Social – Permitting near Populated Areas ▪ Dense suburban residential development from Whitehorse to Carcross Cutoff Affects: Development, Construction	**Prob:** 3 **Conseq.:** 3 **Rank:** M	▪ Re-route south of developed area from Whitehorse to Carcross Cutoff
2	Risk: Social – Permitting in Reserve Blocks and First Nations traditional lands within BC ▪ BC has specific Provincial FN consultation requirements Affects: Development, Construction, Operations	**Prob:** 4 **Conseq.:** 4 **Rank:** V	▪ Assess BC-specific consultation requirements ▪ Begin comprehensive outreach activities with affected FN communities early
3	Risk: Political – Yukon/BC Border Crossing ▪ Permitting must satisfy BC regulations ▪ May trigger studies and require approval by BC Hydro ▪ May require YEC to apply for status as a BC utility Affects: Development, Construction, Operations	**Prob:** 5 **Conseq.:** 4 **Rank:** V	▪ Initiate discussions with BC Government, BC Hydro and BC Utilities Commission to determine applicable regulations and approval & permitting requirements

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Table 15: Route Specific Risks for Whitehorse → Teslin / Squanga-Dalayee PSH

#	Risk Description	Risk Rank	Potential Mitigation
1	Risk: Social – Permitting near Populated Areas ▪ Dense suburban residential development from Whitehorse to Carcross Cutoff Affects: Development, Construction	**Prob:** 3 **Conseq.:** 3 **Rank:** M	▪ Re-route south of developed area from Whitehorse to Carcross Cutoff
2	Risk: Safety – Proximity to Airports ▪ Line Route passes near runways at Teslin and Squanga Lake Affects: Development, Construction, Operations	**Prob:** 3 **Conseq.:** 3 **Rank:** M	▪ Use low-profile structures ▪ Obtain required Transport Canada Permits ▪ Avoid structure placement near end of runways

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8 Summary & Conclusions

This *Transmission Options Evaluation* report included several components:

- Detailed transmission corridor optimization (Section 2)
- Estimate of CAPEX (Section 3)
- Estimate of OPEX (Section 4)
- Calculation of power transfer capacities (Section 5)
- Overview of transmission corridor development schedules (Section 6)
- Assessment of corridor risks (Section 7)

Table 16 below provides a tabular summary of this report's findings. For each potential transmission route, the line voltage, line length, max transfer capacity, estimated CAPEX, estimated OPEX, and earliest In-Service-Date ("ISD") is stated.

Table 16: Summary of Results (Costs Stated in $2016)

#	Transmission Route	Voltage	Length	Transfer Capacity[7]	CAPEX[8]	OPEX[8]	Earliest ISD
1	Faro → Finlayson	138 kV	233 km	84 MW	$221M	$351k/yr	Jan 2021
2	Faro → Watson Lake	230 kV	414 km	190 MW	$597M	$613k/yr	Sep 2022
3	Aishihik → Destruction Bay	138 kV	157 km	122 MW	$167M	$217k/yr	Jul 2020
		230 kV		484 MW	$241M		
4	Whitehorse → Skagway	138 kV	170 km	114 MW	$166M	$285k/yr	Oct 2020
		230 kV		443 MW	$251M		
5	Whitehorse → Atlin	138 kV	172 km	97 MW	$158M	$236k/yr	Oct 2020
6	Whitehorse → Teslin	138 kV	174 km	95 MW	$165M	$239k/yr	Oct 2020
7	Whitehorse → Squanga-Dalayee PSH	138 kV	105 km	134 MW	$100M	$143k/yr	Dec 2019
8	Whitehorse → Atlin-Mt.Black PSH	138 kV	127 km	131 MW	$119M	$174k/yr	May 2020
9	Whitehorse → Tutshi Windy Arm	138 kV	96 km	135 MW	$94M	$143k/yr	Nov 2019
10	Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	138 kV	112 km	132 MW	$108M	$168k/yr	Jan 2020
11	Whitehorse → Lindeman-Fraser PSH	138 kV	129 km	129 MW	$125M	$200k/yr	Jun 2020

[7] These values represent the most restricted transfer capacity that would be expected in either summer or winter. Thermally limited transmission options may demonstrate a higher Winter Capacity. See Table 8 for more details.

[8] All cost information is stated in $2016 and is considered a Class 5 estimate as per standard 17R-97 by the Association of the Advancement of Cost Engineering, which represents a +100% / -50% range of accuracy.

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Appendix A:

PSSE Simulation Details

Appendix A: PSS®E Simulation Details

A simple PSS®E model was built and simulations were carried out to estimate the power transfer capability along the transmission line each of the transmission option being studied. This appendix provides the more in-depth details of the PSS®E modeling effort.

The voltage is maintained between a nominal range of 1.1 per unit to 0.9 per unit at all buses, and the maximum Sending End to Receiving End voltage angle difference is taken to be 33° to avoid angular instability for minor system perturbations. The term "*Transmission Line Capacity*" in the following tables represent available capacity at the Swing Bus after deducting intermediate loads (if connected) and peak transmission losses.

A.1 Conductor Characteristics

Table A-1 lists the conductor characteristics for the 138 kV and 230 kV transmission options.

Table A-1: Conductor Characteristics

Voltage Class (kV)	Conductor Type	GMR (ft.)	External Diameter (In)	Bundle	Phase Spacing (m)	Conductor Spacing (In)
138	Ibis 397.5 MCM	0.0264'	0.783"	1	4.6 m	N/A
230	Hawk 477 MCM	0.0289'	0.858"	2	6.7 m	18"

Assuming a wind speed of 2 ft/s and a maximum conductor temperature of 100°C, the thermal MVA rating of the conductors at different locations, for an ambient temperature of -10°C in winter and 35°C in summer is listed in the Table A-2 below.

Table A-2: Conductor Thermal Rating

Location	Altitude (ft)	Double Bundle 230 kV Hawk 477 MCM Thermal Rating (MVA)		Single Bundle 138 kV Ibis 397.5 MCM Thermal Rating (MVA)	
		@ -10°C	@ 35°C	@ -10°C	@ 35°C
Whitehorse	2149	765	575	204	153
Aishihik	3018	758	569	202	152
Destruction Bay	2674	761	571	203	153
Faro	2198	765	575	204	153
Watson Lake	2247	764	574	204	153
Teslin	2264	764	574	204	153
Mayo	1653	769	578	205	154
Pelly Crossing	1870	767	577	205	154

A.2 Route 1: Faro → Finlayson (138 kV)

Key physical parameters are listed in Table A-3.

Table A-3: Physical Parameters – Faro → Finlayson (138 kV)

Parameter	Value
From:	Faro
To:	Finlayson
Distance:	233 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	202 MVA in Winter 152 MVA in Summer

A.2.1 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-4 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-4: Transmission Line Characteristics – Faro → Finlayson (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Faro	Voltage Test 1	58.2	0.0540260634	0.1496790132	0.0367760150
Voltage Test 1	Voltage Test 2	58.2	0.0540260634	0.1496790132	0.0367760150
Voltage Test 2	Voltage Test 3	58.2	0.0540260634	0.1496790132	0.0367760150
Voltage Test 3	Finlayson	58.2	0.0540260634	0.1496790132	0.0367760150

A.2.2 PSSE Simulation

Table A-5 lists the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-5 and Figure A-1 shows that the Yukon system can receive 84 MW of power through the 138 kV transmission line between Faro and Finlayson, when an imaginary generator at Finlayson generates its maximum power while maintaining acceptable system conditions.

Figure A-1: PSS®E Single Line Diagram – Faro → Finlayson (138 kV)

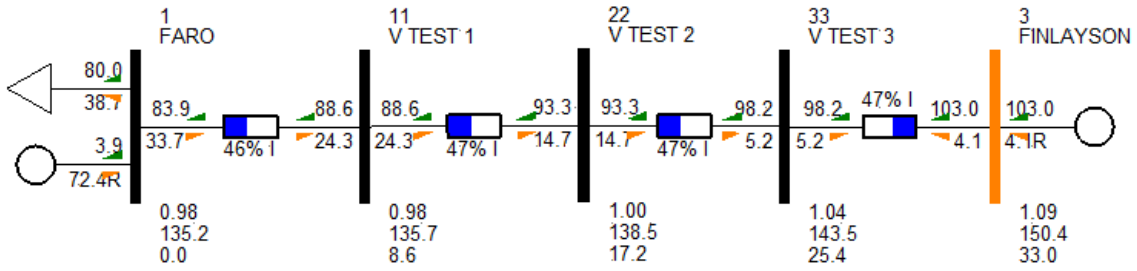

Table A-5: PSS®E Results – Faro → Finlayson (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Faro	-3.9	72.4	80	38.7	0.98	0.0
Voltage Test 1	-	-	-	-	0.98	8.6
Voltage Test 2	-	-	-	-	1.00	17.2
Voltage Test 3	-	-	-	-	1.04	25.4
Finlayson	103.0	4.1	-	-	1.09	33.0

A.2.3 Results

Analysis results are listed in Table A-6.

Table A-6: Analysis Results – Faro → Finlayson (138 kV)

Parameter	Value
Line Capacity:	84 MW
Limiting Issue:	33° Voltage Angle

A.3 Route 2: Faro → Watson Lake (230 kV)

A.3.1 Transmission Line Characteristics

Key physical parameters are listed in Table A-7.

Table A-7: Physical Parameters – Faro → Watson Lake (230 kV)

Parameter	Value
From:	Faro
To:	Watson Lake
Distance:	414 km
Transmission Voltage:	230 kV
Transmission Conductor:	Hawk 477 MCM
Conductor Thermal Rating:	764 MVA in Winter 564 MVA in Summer

Using a 100 MVA system base and 230 kV line voltage, Table A-8 was tabulated based on Table A-1 and tower structure assumptions for phase spacing. Voltage Test 1, Voltage test 2 and Voltage Test 3 are hypothetical test buses to measure midpoint line parameters.

Table A-8: Transmission Line Characteristics – Faro → Watson Lake (230 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Faro	Voltage Test 1	103.5	0.007358071	0.071937675	0.24036989
Voltage Test 1	Voltage Test 2	103.5	0.007358071	0.071937675	0.24036989
Voltage Test 2	Voltage Test 3	103.5	0.007358071	0.071937675	0.24036989
Voltage Test 3	Watson Lake	103.5	0.007358071	0.071937675	0.24036989

A.3.2 PSSE Simulation

Table A-9 lists the generation and load parameters for all the buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-9 and Figure A-2 shows that the Yukon system can receive 190 MW of power through the 230 kV transmission line between Faro and Watson Lake, when an imaginary generator at Watson Lake generates its maximum power while maintaining acceptable system conditions.

Figure A-2: PSS®E Single Line Diagram – Faro → Watson Lake (230 kV)

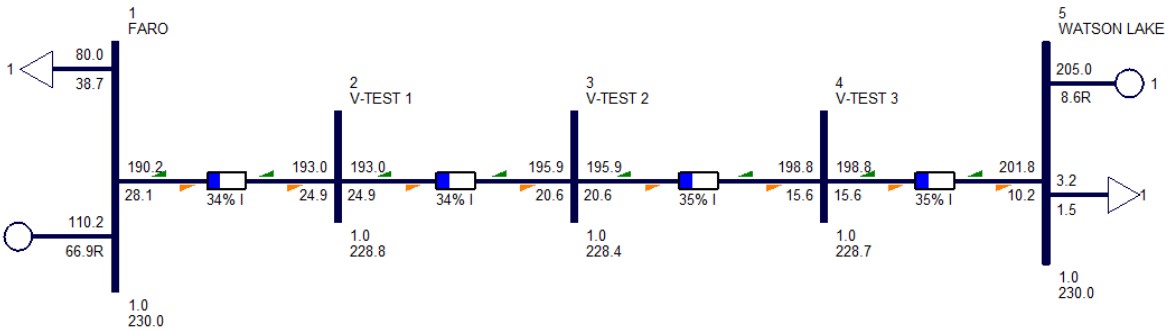

Table A-9: PSS®E Results – Faro → Watson Lake (230 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Faro	-110.2	66.9	80	38.7458	1.000	0.000
Voltage Test 1	-	-	-	-	0.995	8.080
Voltage Test 2	-	-	-	-	0.993	16.310
Voltage Test 3	-	-	-	-	0.994	24.660
Watson Lake	205.0	-8.6	3.2	1.6	1.000	33.040

A.3.3 Results

Analysis results are listed in Table A-10.

Table A-10: Analysis Results – Faro → Watson Lake (230 kV)

Parameter	Value
Line Capacity:	190 MW
Limiting Issue:	33° Voltage Angle

A.4 Route 3: Aishihik → Destruction Bay (230 kV)

A.4.1 Transmission Line Characteristics

Key physical parameters are listed in Table A-11.

Table A-11: Physical Parameters – Aishihik → Destruction Bay (230 kV)

Parameter	Value
From:	Aishihik
To:	Destruction Bay
Distance:	157 km
Transmission Voltage:	230 kV
Transmission Conductor:	Hawk 477 MCM
Conductor Thermal Rating:	758 MVA in winter 569 MVA in summer

Using a 100 MVA system base and 230 kV line voltage, Table A-12 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-12: Transmission Line Characteristics – Aishihik → Destruction Bay (230 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Aishihik	Voltage Test 1	78.6	0.005559094	0.054280891	0.181035243
Voltage Test 1	Destruction Bay	78.6	0.005559094	0.054280891	0.181035243

A.4.2 PSSE Simulation

Table A-13 lists the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-13 and Figure A-3 shows that the Yukon system can receive 484 MW of power through the 230 kV transmission line between Aishihik and Destruction Bay, when an imaginary generator at Destruction Bay generates its maximum power while maintaining acceptable system conditions.

Figure A-3: PSS®E Single Line Diagram – Aishihik → Destruction Bay (230 kV)

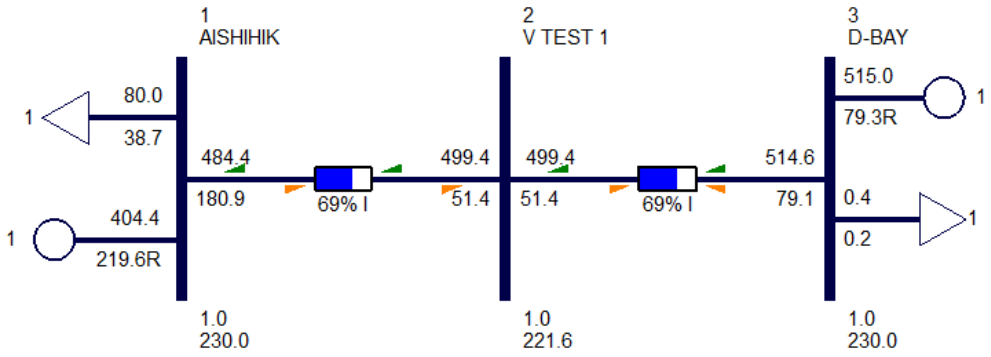

Table A-13: PSS®E Results – Aishihik → Destruction Bay (230 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Aishihik	-404.4	219.6	80	38.7458	1.000	0.000
Voltage Test 1	-	-	-	-	0.964	16.490
Destruction Bay	515.0	79.3	0.415	0.2	1.000	33.040

A.4.3 Results

Analysis results are listed in Table A-14.

Table A-14: Analysis Results – Aishihik → Destruction Bay (230 kV)

Parameter	Value
Line Capacity:	484 MW
Limiting Issue:	33° Voltage Angle

A.5 Route 3: Aishihik → Destruction Bay (138 kV)

A.5.1 Transmission Line Characteristics

Key physical parameters are listed in Table A-15.

Table A-15: Physical Parameters – Aishihik → Destruction Bay (138 kV)

Parameter	Value
From:	Aishihik
To:	Destruction Bay
Distance:	157 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	202 MVA in Winter 152 MVA in Summer

Using a 100 MVA system base and 138 kV line voltage, Table A-16 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-16: Transmission Line Characteristics – Aishihik → Destruction Bay (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Aishihik	Voltage Test 1	52.4	0.04937811	0.13553595	0.03293529
Voltage Test 1	Voltage Test 2	52.4	0.04937811	0.13553595	0.03293529
Voltage Test 2	Destruction Bay	52.4	0.04937811	0.13553595	0.03293529

A.5.2 PSSE Simulation

Table A-17 lists the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-17 and Figure A-4 shows that the Yukon system can receive 122 MW of power through the 138 kV transmission line between Aishihik and Destruction Bay, when an imaginary generator at Destruction Bay generates its maximum power while maintaining acceptable system conditions.

Figure A-4: PSS®E Single Line Diagram – Aishihik → Destruction Bay (138 kV)

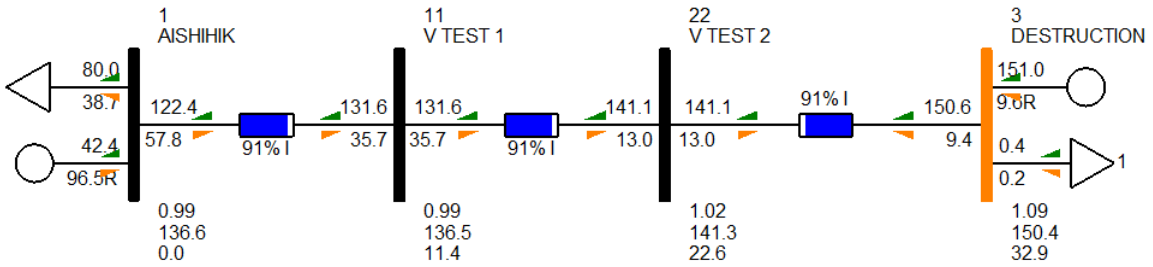

Table A-17: PSS®E Results – Aishihik → Destruction Bay (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Aishihik	-42.4	96.5	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	0.99	11.4
Voltage Test 2	-	-	-	-	1.02	22.6
Destruction Bay	151.0	9.6	0.4	0.2	1.09	32.9

A.5.3 Results

Analysis results are listed in Table A-18.

Table A-18: Analysis Results – Aishihik → Destruction Bay (138 kV)

Parameter	Value
Line Capacity:	122 MW
Limiting Issue:	33° Voltage Angle

A.6 Route 4: Whitehorse → Skagway (230 kV)

A.6.1 Transmission Line Characteristics

Key physical parameters are listed in Table A-19.

Table A-19: Physical Parameters – Whitehorse → Skagway (230 kV)

Parameter	Value
From:	Whitehorse
To:	Skagway
Distance:	170 km
Transmission Voltage:	230 kV
Transmission Conductor:	Hawk 477 MCM
Conductor Thermal Rating:	765 MVA in Winter 575 MVA in Summer

Using a 100 MVA system base and 230 kV line voltage, Table A-20 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-20: Transmission Line Characteristics – Whitehorse → Skagway (230 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	84.8	0.006071923	0.059307501	0.197893825
Voltage Test 1	Skagway	84.8	0.006071923	0.059307501	0.197893825

A.6.2 PSSE Simulation

Table A-21 lists the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-21 and Figure A-5 shows that the Yukon system can receive 443 MW of power through the 230 kV transmission line between Whitehorse and Skagway, when an imaginary generator at Skagway generates its maximum power while maintaining acceptable system conditions.

Figure A-5: PSS®E Single Line Diagram – Whitehorse → Skagway (230 kV)

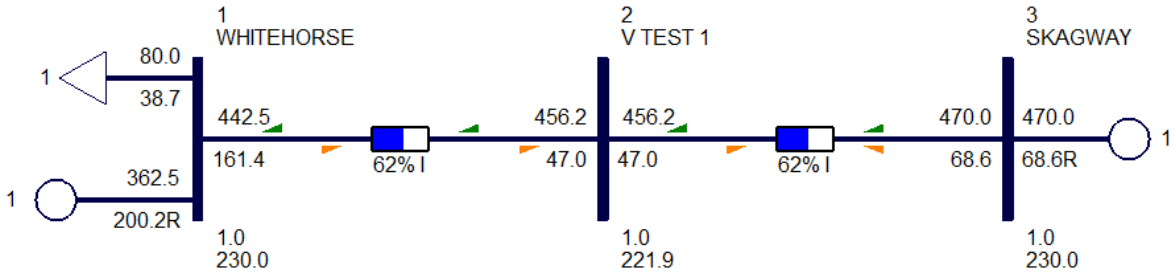

Table A-21: PSS®E Results – Whitehorse → Skagway (230 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-362.5	200.2	80	38.7458	1.000	0.000
Voltage Test 1	-	-	-	-	0.965	16.430
Skagway	470.0	68.6	-	-	1.000	32.930

A.6.3 Results

Analysis results are listed in Table A-22.

Table A-22: Analysis Results – Whitehorse → Skagway (230 kV)

Parameter	Value
Line Capacity:	443 MW
Limiting Issue:	33° Voltage Angle

A.7 Route 4: Whitehorse → Skagway (138 kV)

A.7.1 Transmission Line Characteristics

Key physical parameters are listed in Table A-23.

Table A-23: Physical Parameters – Whitehorse → Skagway (138 kV)

Parameter	Value
From:	Whitehorse
To:	Skagway
Distance:	170 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	152 MVA in Winter 202 MVA in Summer

Using a 100 MVA system base and 138 kV line voltage, Table A-24 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-24: Transmission Line Characteristics – Whitehorse → Skagway (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	56.5	0.053342059	0.146611265	0.035683154
Voltage Test 1	Voltage Test 2	56.5	0.053342059	0.146611265	0.035683154
Voltage Test 2	Skagway	56.5	0.053342059	0.146611265	0.035683154

A.7.2 PSSE Simulation

Table A-25 lists the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-25 and Figure A-6 shows that the Yukon system can receive 114 MW of power through the 138 kV transmission line between Whitehorse and Skagway, when an imaginary generator at Skagway generates its maximum power while maintaining acceptable system conditions.

Figure A-6: PSS®E Single Line Diagram – Whitehorse → Skagway (138 kV)

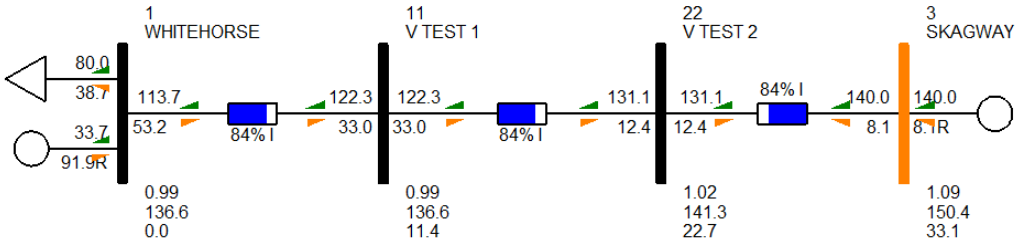

Table A-25: PSS®E Results – Whitehorse → Skagway (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-33.7	91.9	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	0.99	11.4
Voltage Test 2	-	-	-	-	1.02	22.7
Skagway	140.0	8.1	-	-	1.09	33.1

A.7.3 Results

Analysis results are listed in Table A-26.

Table A-26: Analysis Results – Whitehorse → Skagway (138 kV)

Parameter	Value
Line Capacity:	114 MW
Limiting Issue:	33° Voltage Angle

A.8 Route 5: Whitehorse → Atlin (138 kV)

A.8.1 Transmission Line Characteristics

Key physical parameters are listed in Table A-27.

Table A-27: Physical Parameters – Whitehorse → Atlin (138 kV)

Parameter	Value
From:	Whitehorse
To:	Atlin
Distance:	172 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	204 MVA in Winter 153 MVA in Summer

A.8.2 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-28 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-28: Transmission Line Characteristics – Whitehorse → Atlin (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	57.2	0.054668175	0.149062512	0.035935065
Voltage Test 1	Voltage Test 2	57.2	0.054668175	0.149062512	0.035935065
Voltage Test 2	Atlin	57.2	0.054668175	0.149062512	0.035935065

A.8.3 PSSE Simulation

Table A-29 lists the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-29 and Figure A-7 shows that the Yukon system can receive 97 MW of power through the 138 kV transmission line between Whitehorse and Atlin, when an imaginary generator at Atlin generates its maximum power while maintaining acceptable system conditions.

Figure A-7: PSS®E Single Line Diagram – Whitehorse → Atlin (138 kV)

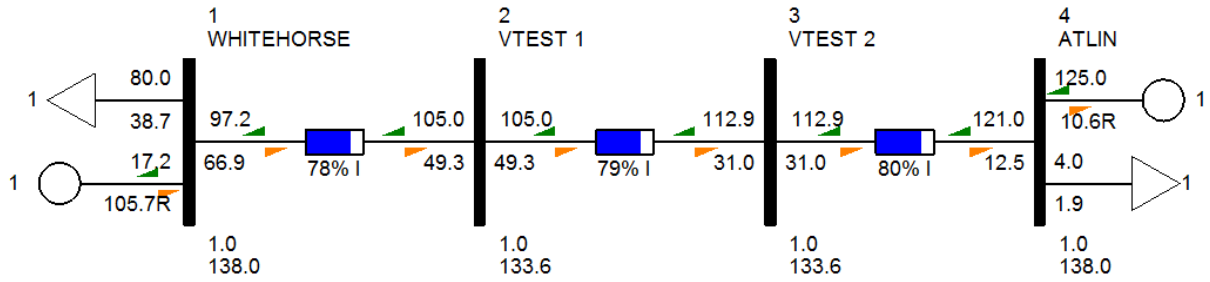

Table A-29: PSS®E Results – Whitehorse → Atlin (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-17.2	105.7	80	38.7458	1.000	0.000
Voltage Test 1	-	-	-	-	0.968	10.870
Voltage Test 2	-	-	-	-	0.968	22.220
Atlin	125.0	-10.6	4	1.9	1.000	33.310

A.8.4 Results

Analysis results are listed in Table A-30.

Table A-30: Analysis Results – Whitehorse → Atlin (138 kV)

Parameter	Value
Line Capacity:	97 MW
Limiting Issue:	33° Voltage Angle

A.9 Route 6: Whitehorse → Teslin (138 kV)

A.9.1 Transmission Line Characteristics

Key physical parameters are listed in Table A-31.

Table A-31: Physical Parameters – Whitehorse → Teslin (138 kV)

Parameter	Value
From:	Whitehorse
To:	Teslin
Distance:	174 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	204 MVA in Winter 153 MVA in Summer

A.9.2 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-32 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-32: Transmission Line Characteristics – Whitehorse → Teslin (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	87.0	0.083094343	0.226875857	0.054782068
Voltage Test 1	Teslin	87.0	0.083094343	0.226875857	0.054782068

A.9.3 PSSE Simulation

Table A-33 lists the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-33and Figure A-8 shows that the Yukon system can receive 95 MW in winter and summer through the 138 kV transmission line between Whitehorse and Teslin, when an imaginary generator at Teslin generates its maximum power while maintaining acceptable system conditions.

Figure A-8: PSS®E Single Line Diagram – Whitehorse → Teslin (138 kV)

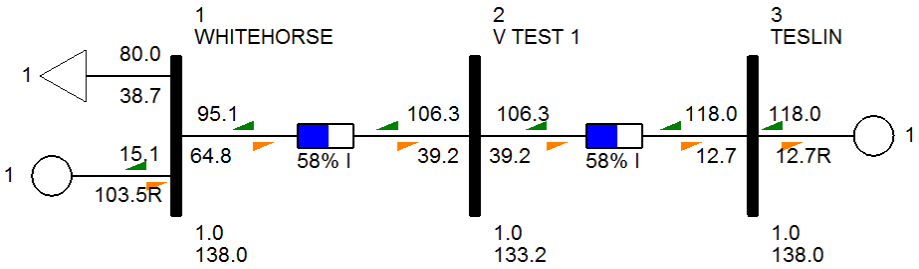

Table A-33: PSS®E Results – Whitehorse → Teslin (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-15.1	103.5	80	38.7458	1.00	0.00
Voltage Test 1	-	-	-	-	0.96	16.36
Teslin	118.0	-12.7	-	-	1.00	32.98

A.9.4 Results

Analysis results are listed in Table A-34.

Table A-34: Analysis Results – Whitehorse → Teslin (138 kV)

Parameter	Value
Line Capacity:	95 MW
Limiting Issue:	33° Voltage Angle

A.10 Route 7: Whitehorse → Squanga-Dalayee PSH (138 kV)

Key physical parameters are listed in Table A-35.

Table A-35: Physical Parameters – Whitehorse → Squanga-Dalayee PSH (138 kV)

Parameter	Value
From:	Whitehorse
To:	Squanga-Dalayee PSH
Distance:	105 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	153 MVA in Winter 203 MVA in Summer

A.10.1 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-36 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-36: Transmission Line Characteristics – Whitehorse → Squanga-Dalayee PSH (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	34.9	0.033020429	0.090247853	0.021817834
Voltage Test 1	Voltage Test 2	34.9	0.033020429	0.090247853	0.021817834
Voltage Test 2	Squanga-Dalayee PSH	34.9	0.033020429	0.090247853	0.021817834

A.10.2 PSSE Simulation

Table A-37 and Table A-38 list the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-37/Table A-38 and Figure A-9/Figure A-10 show that the Yukon system can receive 169 MW in winter and 134 MW in summer through the 138 kV transmission line between Whitehorse and Squanga-Dalayee PSH, when an imaginary generator at Squanga-Dalayee PSH generates its maximum power while maintaining acceptable system conditions.

Figure A-9: PSS®E Winter Single Line Diagram – Whitehorse → Squanga-Dalayee PSH (138 kV)

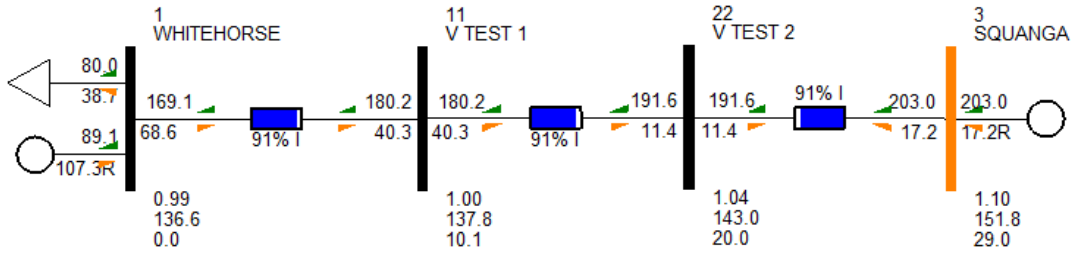

Figure A-10: PSS®E Summer Single Line Diagram – Whitehorse → Squanga-Dalayee PSH (138 kV)

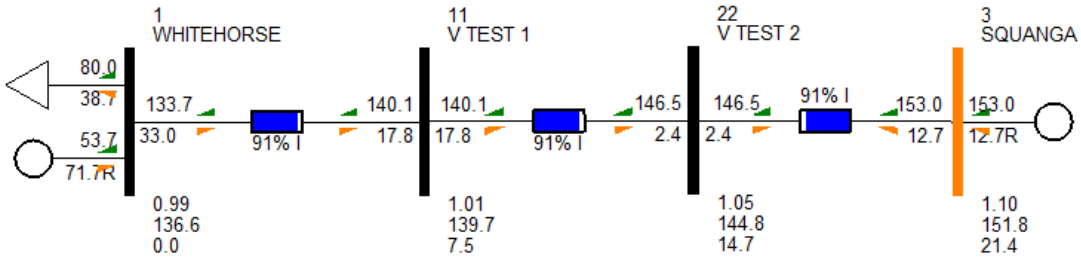

Table A-37: PSS®E Winter Results – Whitehorse → Squanga-Dalayee PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-89.1	107.3	80	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	1.00	10.1
Voltage Test 2	-	-	-	-	1.04	20.0
Squanga-Dalayee PSH	203.0	17.2	-	-	1.10	29.0

Table A-38: PSS®E Summer Results – Whitehorse → Squanga-Dalayee PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-53.7	71.7	80	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	1.01	7.5
Voltage Test 2	-	-	-	-	1.05	14.7
Squanga-Dalayee PSH	153.0	12.7	-	-	1.10	21.4

A.10.3 Results

Analysis results are listed in Table A-39.

Table A-39: Analysis Results – Whitehorse → Squanga-Dalayee PSH (138 kV)

Parameter	Value
Line Capacity:	169 MW in Winter 134 MW in Summer
Limiting Issue:	Thermal Limit

A.11 Route 8: Whitehorse → Atlin-Mt.Black PSH (138 kV)

Key physical parameters are listed in Table A-40.

Table A-40: Physical Parameters – Whitehorse → Atlin-Mt.Black PSH (138 kV)

Parameter	Value
From:	Whitehorse
To:	Atlin-Mt.Black PSH
Distance:	127 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	153 MVA in Winter 204 MVA in Summer

A.11.1 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-41 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-41: Transmission Line Characteristics – Whitehorse → Atlin-Mt.Black PSH (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	42.2	0.039757188	0.108827990	0.026358396
Voltage Test 1	Voltage Test 2	42.2	0.039757188	0.108827990	0.026358396
Voltage Test 2	Atlin-Mt.Black PSH	42.2	0.039757188	0.108827990	0.026358396

A.11.2 PSSE Simulation

Table A-42 and Table A-43 list the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-42/Table A-43 and Figure A-11/Figure A-12 show that the Yukon system can receive 154 MW in the winter and 131 MW in the summer through the 138 kV transmission line between Whitehorse and Atlin-Mt.Black PSH, when an imaginary generator at Atlin-Mt.Black PSH generates its maximum power while maintaining acceptable system conditions.

Figure A-11: PSS®E Winter Single Line Diagram – Whitehorse → Atlin-Mt.Black PSH (138 kV)

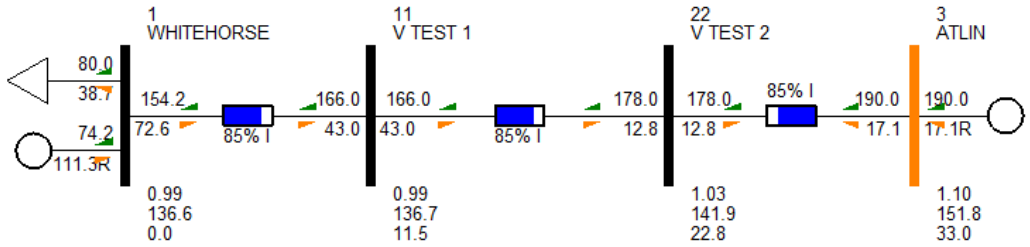

Figure A-12: PSS®E Summer Single Line Diagram – Whitehorse → Atlin-Mt.Black PSH (138 kV)

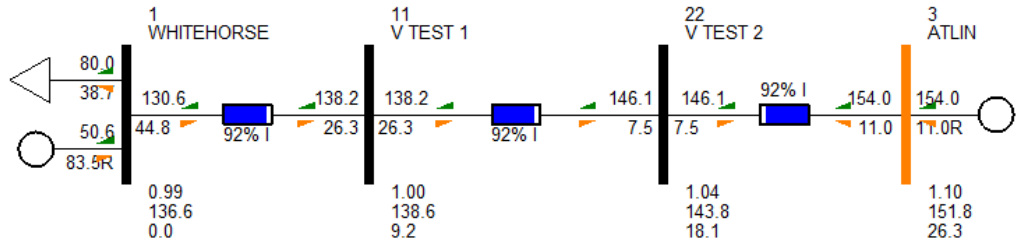

Table A-42: PSS®E Winter Results – Whitehorse → Atlin-Mt.Black PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-74.2	111.3	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	0.99	11.5
Voltage Test 2	-	-	-	-	1.03	22.8
Atlin-Mt.Black PSH	190.0	17.1	-	-	1.10	33.0

Table A-43: PSS®E Summer Results – Whitehorse → Atlin-Mt.Black PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-50.6	83.5	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	1.00	9.2
Voltage Test 2	-	-	-	-	1.04	18.1
Atlin-Mt.Black PSH	154.0	11.0	-	-	1.10	26.3

A.11.3 Results

Analysis results are listed in Table A-44.

Table A-44: Analysis Results – Whitehorse → Atlin-Mt.Black PSH (138 kV)

Parameter	Value
Line Capacity:	190 MW in Winter 154 MW in Summer
Limiting Issue:	33° Voltage Angle (Winter) Thermal Limit (Summer)

A.12 Route 9: Whitehorse → Tutshi Windy Arm (138 kV)

Key physical parameters are listed in Table A-45.

Table A-45: Physical Parameters – Whitehorse → Tutshi Windy Arm (138 kV)

Parameter	Value
From:	Whitehorse
To:	Tutshi Windy Arm
Distance:	96 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	153 MVA in Winter 204 MVA in Summer

A.12.1 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-46 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-46: Transmission Line Characteristics – Whitehorse → Tutshi Windy Arm (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	48.0	0.045673785	0.124767031	0.030144575
Voltage Test 1	Tutshi Windy Arm	48.0	0.045673785	0.124767031	0.030144575

A.12.2 PSSE Simulation

Table A-47 and Table A-48 list the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-47/Table A-48 and Figure A-13/Figure A-14 show that the Yukon system can receive 172 MW in winter and 135 MW in summer through the 138 kV transmission line between Whitehorse and Tutshi Windy Arm, when an imaginary generator at Tutshi Windy Arm generates its maximum power while maintaining acceptable system conditions.

Figure A-13: PSS®E Winter Single Line Diagram – Whitehorse → Tutshi Windy Arm (138 kV)

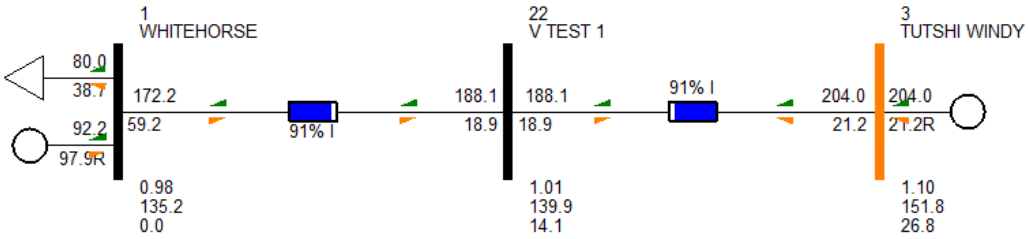

Figure A-14: PSS®E Summer Single Line Diagram – Whitehorse → Tutshi Windy Arm (138 kV)

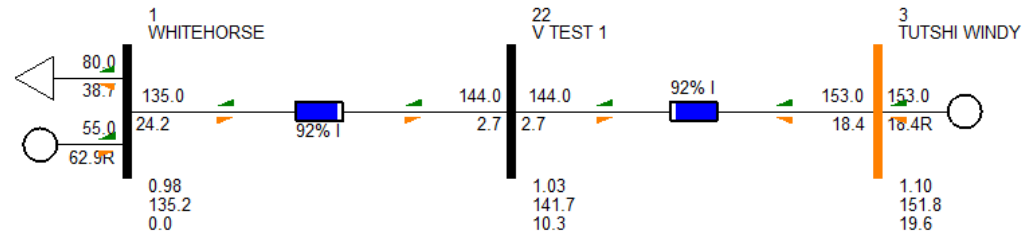

Table A-47: PSS®E Winter Results – Whitehorse → Tutshi Windy Arm (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-92.2	97.9	80.0	38.7	0.98	0.0
Voltage Test 1	-	-	-	-	1.01	14.1
Tutshi Windy Arm	204.0	21.2	-	-	1.10	26.8

Table A-48: PSS®E Summer Results – Whitehorse → Tutshi Windy Arm (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-55.0	62.9	80.0	38.7	0.98	0.0
Voltage Test 1	-	-	-	-	1.03	10.3
Tutshi Windy Arm	153.0	18.4	-	-	1.10	19.6

A.12.3 Results

Analysis results are listed in Table A-49.

Table A-49: Analysis Results – Whitehorse → Tutshi Windy Arm (138 kV)

Parameter	Value
Line Capacity:	172 MW in Winter 135 MW in Summer
Limiting Issue:	Thermal Limit

A.13 Route 10: Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

Key physical parameters are listed in Table A-50.

Table A-50: Physical Parameters – Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

Parameter	Value
From:	Whitehorse
To:	Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH
Distance:	112 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	152 MVA in Winter 202 MVA in Summer

A.13.1 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-51 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

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APPENDIX A: PSSE SIMULATION DETAILS

Table A-51: Transmission Line Characteristics – Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	55.8	0.053423433	0.146092738	0.035342255
Voltage Test 1	Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	55.8	0.053423433	0.146092738	0.035342255

A.13.2 PSSE Simulation

Table A-52 and Table A-53 list the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-52/Table A-53 and Figure A-15/Figure A-16 shows that the Yukon system can receive 166 MW in winter and 132 MW in summer through the 138 kV transmission line between Whitehorse and Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH, when an imaginary generator at the end of the line generates its maximum power while maintaining acceptable system conditions.

Figure A-15: PSS®E Winter Single Line Diagram – Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

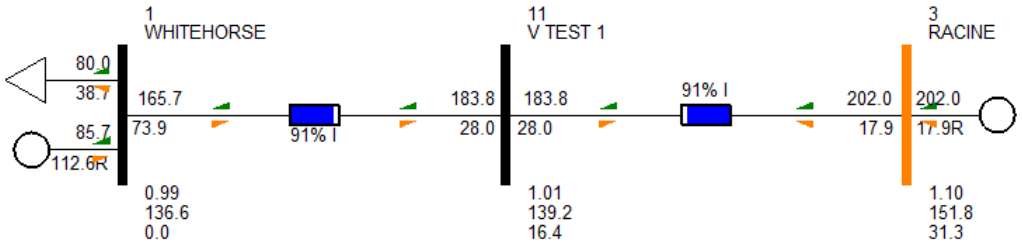

Figure A-16: PSS®E Summer Single Line Diagram – Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

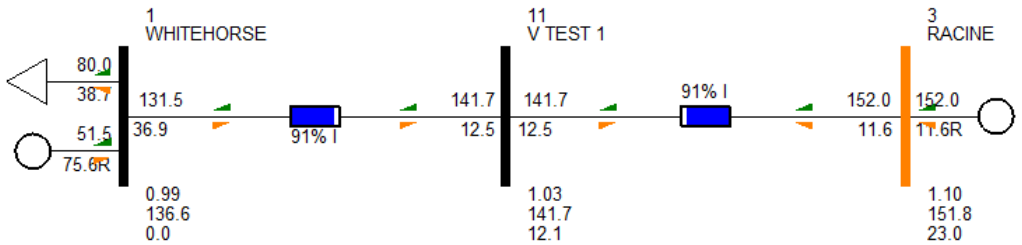

Table A-52: PSS®E Winter Results – Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-85.7	112.6	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	1.01	16.4
Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	202.0	17.9	-	-	1.10	31.3

Table A-53: PSS®E Summer Results – Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-51.5	75.6	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	1.03	12.1
Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH	152.0	11.6	-	-	1.10	23.0

A.13.3 Results

Analysis results are listed in Table A-54.

Table A-54: Analysis Results – Whitehorse → Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH (138 kV)

Parameter	Value
Line Capacity:	166 MW in Winter 132 MW in Summer
Limiting Issue:	Thermal Limit

A.14 Route 11: Whitehorse → Lindeman-Fraser PSH (138 kV)

Key physical parameters are listed in Table A-55.

Table A-55: Physical Parameters – Whitehorse → Lindeman-Fraser PSH (138 kV)

Parameter	Value
From:	Whitehorse
To:	Lindeman-Fraser PSH
Distance:	129 km
Transmission Voltage:	138 kV
Transmission Conductor:	Ibis 397.5 MCM
Conductor Thermal Rating:	152 MVA in Winter 202 MVA in Summer

A.14.1 Transmission Line Characteristics

Using a 100 MVA system base and 138 kV line voltage, Table A-56 was tabulated based on Table A-1 and tower structure assumptions for phase spacing.

Table A-56: Transmission Line Characteristics – Whitehorse → Lindeman-Fraser PSH (138 kV)

From	To	Distance (km)	Resistance R (p.u.)	Reactance X (p.u.)	Charging B (p.u.)
Whitehorse	Voltage Test 1	64.6	0.061776554	0.169164012	0.040989919
Voltage Test 1	Lindeman-Fraser PSH	64.6	0.061776554	0.169164012	0.040989919

A.14.2 PSSE Simulation

Table A-57 and Table A-58 list the generation and load parameters for all buses considered in the power flow simulation. For simplicity, all loads are assumed to have a power factor of 0.9, and each generator is capable of producing at 0.9 power factor lagging or leading.

Table A-57/Table A-58 and Figure A-17/Figure A-18 show that the Yukon system can receive 147 MW in winter and 129 MW in summer through the 138 kV transmission line between Whitehorse and Lindeman-Fraser PSH, when an imaginary generator at Lindeman-Fraser PSH generates its maximum power while maintaining acceptable system conditions.

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APPENDIX A: PSSE SIMULATION DETAILS

Figure A-17: PSS®E Winter Single Line Diagram – Whitehorse → Lindeman-Fraser PSH (138 kV)

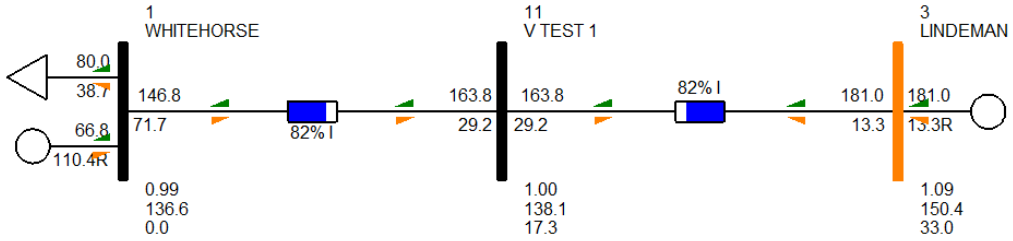

Figure A-18: PSS®E Summer Single Line Diagram – Whitehorse → Lindeman-Fraser PSH (138 kV)

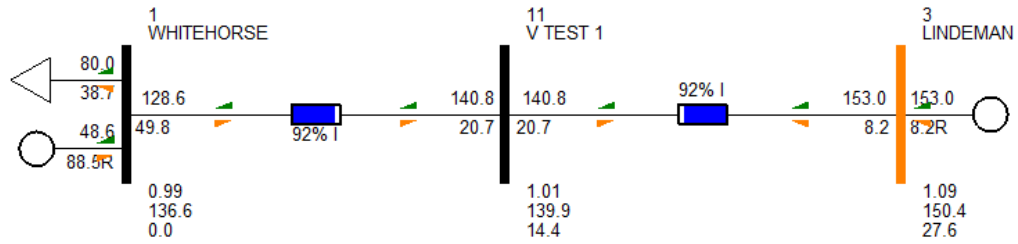

Table A-57: PSS®E Winter Results – Whitehorse → Lindeman-Fraser PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-66.8	110.4	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	1.00	17.3
Lindeman-Fraser PSH	181.0	13.3	-	-	1.09	33.0

Table A-58: PSS®E Summer Results – Whitehorse → Lindeman-Fraser PSH (138 kV)

Location	Pgen (MW)	Qgen (MVAr)	Pload (MW)	Qload (MVAr)	Voltage (p.u.)	Voltage Angle (degrees)
Whitehorse	-48.6	88.5	80.0	38.7	0.99	0.0
Voltage Test 1	-	-	-	-	1.01	14.4
Lindeman-Fraser PSH	153.0	8.2	-	-	1.09	27.6

A.14.3 Results

Analysis results are listed in Table A-59.

Table A-59: Analysis Results – Whitehorse → Lindeman-Fraser PSH (138 kV)

Parameter	Value
Line Capacity:	147 MW in Winter 129 MW in Summer
Limiting Issue:	33° Voltage Angle (Winter) Thermal Limit (Summer)

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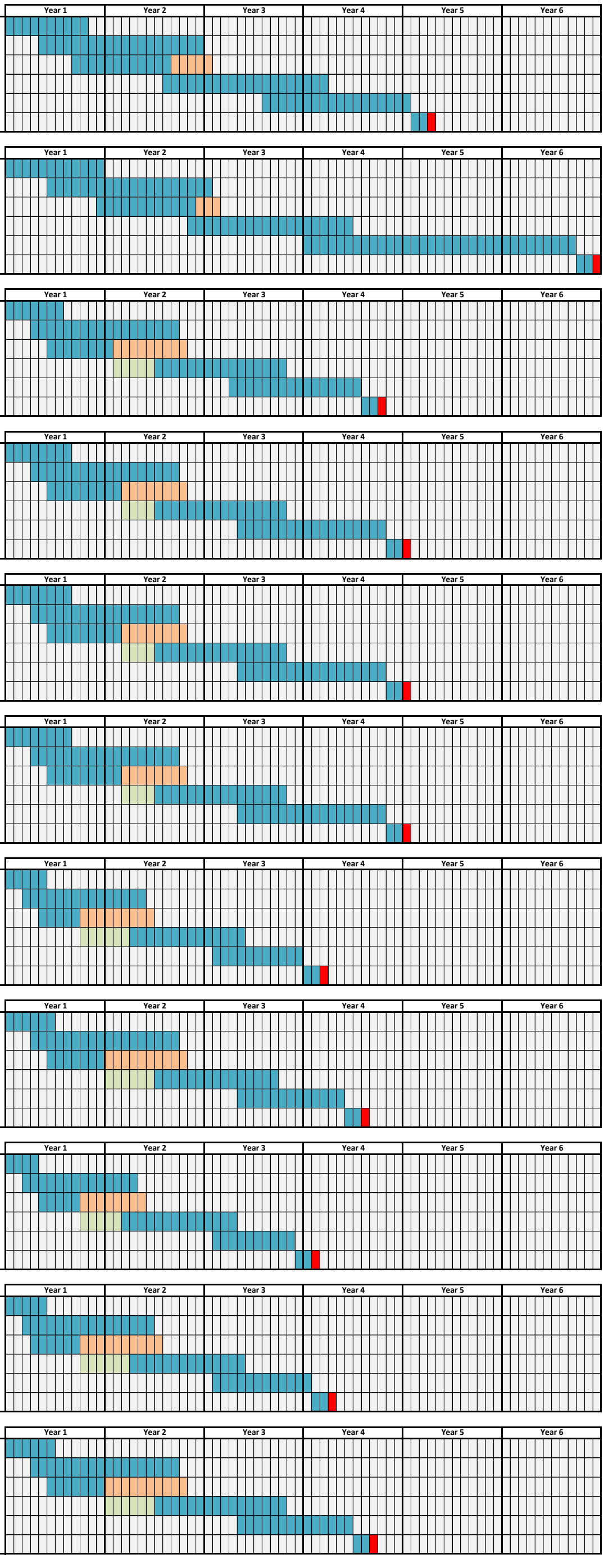
Appendix B:

Transmission Option Schedules

Appendix B: Transmission Option Schedules (Page 1 of 1)

Actual Work Task Period:
Permitting Dependent Design Refinement Period:
At-risk Advanced Procurement Window:
End of Project:

Route Option	Phases	Phase Time	Total (Start to Finish) Time
ROUTE 1 Faro ↓ Finlayson [233 km]	Phase 1: Preliminary Engineering & Cost Estimates	10 Mo.	52 Mo.
	Phase 2: Permitting	20 Mo.	
	Phase 3: Detailed Design Complete	12 Mo.	
	Phase 4: Procurement & Logistics	20 Mo.	
	Phase 5: Tendering & Construction	18 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 2 Faro ↓ Watson Lake [414 km]	Phase 1: Preliminary Engineering & Cost Estimates	12 Mo.	72 Mo.
	Phase 2: Permitting	20 Mo.	
	Phase 3: Detailed Design Complete	12 Mo.	
	Phase 4: Procurement & Logistics	20 Mo.	
	Phase 5: Tendering & Construction	33 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 3 Aishihik ↓ Destruction Bay [157 km]	Phase 1: Preliminary Engineering & Cost Estimates	7 Mo.	46 Mo.
	Phase 2: Permitting	18 Mo.	
	Phase 3: Detailed Design Complete	8 Mo.	
	Phase 4: Procurement & Logistics	16 Mo.	
	Phase 5: Tendering & Construction	16 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 4 Whitehorse ↓ Skagway [170 km]	Phase 1: Preliminary Engineering & Cost Estimates	8 Mo.	49 Mo.
	Phase 2: Permitting	18 Mo.	
	Phase 3: Detailed Design Complete	9 Mo.	
	Phase 4: Procurement & Logistics	16 Mo.	
	Phase 5: Tendering & Construction	18 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 5 Whitehorse ↓ Atlin [172 km]	Phase 1: Preliminary Engineering & Cost Estimates	8 Mo.	49 Mo.
	Phase 2: Permitting	18 Mo.	
	Phase 3: Detailed Design Complete	9 Mo.	
	Phase 4: Procurement & Logistics	16 Mo.	
	Phase 5: Tendering & Construction	18 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 6 Whitehorse ↓ Teslin [174 km]	Phase 1: Preliminary Engineering & Cost Estimates	8 Mo.	49 Mo.
	Phase 2: Permitting	18 Mo.	
	Phase 3: Detailed Design Complete	9 Mo.	
	Phase 4: Procurement & Logistics	16 Mo.	
	Phase 5: Tendering & Construction	18 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 7 Whitehorse ↓ Squanga-Dalayee PSH [104 km]	Phase 1: Preliminary Engineering & Cost Estimates	5 Mo.	39 Mo.
	Phase 2: Permitting	15 Mo.	
	Phase 3: Detailed Design Complete	5 Mo.	
	Phase 4: Procurement & Logistics	14 Mo.	
	Phase 5: Tendering & Construction	11 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 8 Whitehorse ↓ Atlin-Mt.Black PSH [126 km]	Phase 1: Preliminary Engineering & Cost Estimates	6 Mo.	44 Mo.
	Phase 2: Permitting	18 Mo.	
	Phase 3: Detailed Design Complete	7 Mo.	
	Phase 4: Procurement & Logistics	15 Mo.	
	Phase 5: Tendering & Construction	13 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 9 Whitehorse ↓ Tutshi Windy Arm [97 km]	Phase 1: Preliminary Engineering & Cost Estimates	4 Mo.	38 Mo.
	Phase 2: Permitting	14 Mo.	
	Phase 3: Detailed Design Complete	5 Mo.	
	Phase 4: Procurement & Logistics	14 Mo.	
	Phase 5: Tendering & Construction	10 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 10 Whitehorse ↓ Racine-Mt.Brown PSH, Racine-Moon Lake PSH, and Tutshi-Moon Lake PSH [113 km]	Phase 1: Preliminary Engineering & Cost Estimates	5 Mo.	40 Mo.
	Phase 2: Permitting	16 Mo.	
	Phase 3: Detailed Design Complete	6 Mo.	
	Phase 4: Procurement & Logistics	14 Mo.	
	Phase 5: Tendering & Construction	12 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	
ROUTE 11 Whitehorse ↓ Lindeman-Fraser PSH [130 km]	Phase 1: Preliminary Engineering & Cost Estimates	6 Mo.	45 Mo.
	Phase 2: Permitting	18 Mo.	
	Phase 3: Detailed Design Complete	7 Mo.	
	Phase 4: Procurement & Logistics	16 Mo.	
	Phase 5: Tendering & Construction	14 Mo.	
	Phase 6: Commissioning & In Service Date	3 Mo.	



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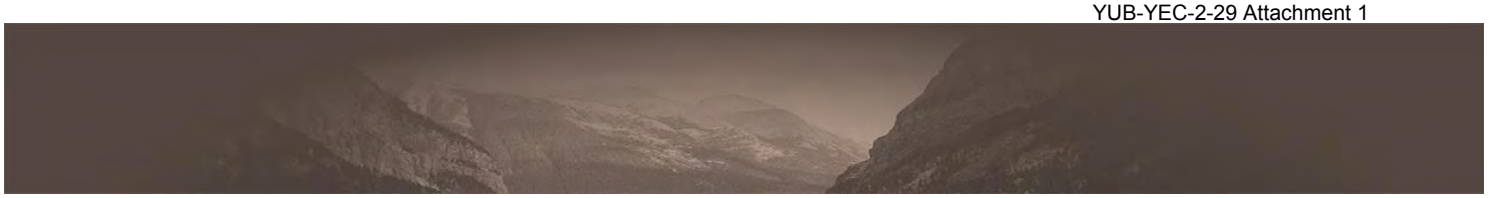
Appendix C:

JDMA Transmission Routing Report



J.D. Mollard and Associates (2010) Limited

Preliminary Transmission Line Corridor Identification Study

FINAL REPORT
November 02, 2016

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Contents

List of Figures 3

List of Tables 3

1 Introduction 4

1.1 Scope of work 4

1.2 Study areas 4

2 Methodology 6

2.1 Data sources 6

2.2 Corridor Identification 9

3 Results 9

3.1 Aishihik to Destruction Bay 11

3.2 Whitehorse to Carcross Cutoff 12

3.3 Carcross Cutoff to Jakes Corner 13

3.4 Jakes Corner to Teslin 13

3.5 Jakes Corner to Atlin (YK, BC) 14

3.6 Carcross Cutoff to Skagway (YK, BC, AK) 14

3.7 Faro to Watson Lake 15

3.8 Two Mile Canyon and Fraser Falls 15

3.9 Granite Canyon 16

3.10 Slate Rapids 17

3.11 False Canyon 17

3.12 Middle Canyon 17

3.13 Hoole Canyon 17

4 Summary 17

5 Deliverables 18

6 Signatures 19

7 APPENDIX A: CORRIDOR MAPS 20

List of Figures

Figure 1: Overview map 5

Figure A1: Ashihik to Destruction Bay map booklet 20
Figure A2: Whitehorse to Carcross Cutoff map 23
Figure A3: Carcross Cutoff to Jakes Corner map booklet 24
Figure A4: Jakes Corner to Teslin map booklet 26
Figure A5: Jakes Corner to Atlin map booklet 29
Figure A6: Carcross Cutoff to Skagway map booklet 32
Figure A7: Faro to Watson Lake map booklet 36
Figure A8: Fraser Falls and Two Mile Canyon map booklet 43
Figure A9: Granite Canyon map 46

List of Tables

Table 1: Transmission Line Corridors Evaluated 4
Table 2: Geospatial data sources used 6
Table 3: New Routes Comparison Table 10
Table 4: Original Routes Comparison Table 11

1 Introduction

1.1 Scope of work

Midgard Consulting Inc. (MC) asked J.D. Mollard and Associates (2010) Limited (JDMA) to conduct a desktop identification and evaluation of transmission line corridors for a number of endpoint locations within the Yukon Territory, BC and Alaska. MC specified that the transmission line corridors be approximately 500 m wide with the flexibility to narrow or widen the corridors locally to accommodate routing constraints. Transmission line corridor routing and characterization was conducted at a high level and ground truthing was not included in the scope of work. MC requested that the width of the transmission line corridors be 500 m.

1.2 Study areas

MC provided six (6) new endpoint pairs for transmission line corridor identification in May 2016 in addition to the previous eight (8) endpoint pairs that MC provided in April 2015. The six new endpoint pairs and original eight endpoint pairs are listed in Table 1. The corridor lengths listed in Table 1 are based on JDMA's analysis of the final corridor lengths as they have been described in this report. The location of the six new endpoint pairs and eight previous endpoint pairs are shown in Figure 1.

Table 1: Transmission Line Corridors Evaluated

Transmission Line Name	Length (km)
Aishihik to Destruction Bay	157
Whitehorse to Carcross Cutoff	17
Carcross Cutoff to Jakes Corner	62
Jakes Corner to Teslin	95
Jakes Corner to Atlin	92
Carcross Cutoff to Skagway	154
Faro to Watson Lake	414
Two Mile Canyon	112
Fraser Falls	48
Granite Canyon	15
Slate Rapids	9
False Canyon	7
Middle Canyon	6
Hoole Canyon	2

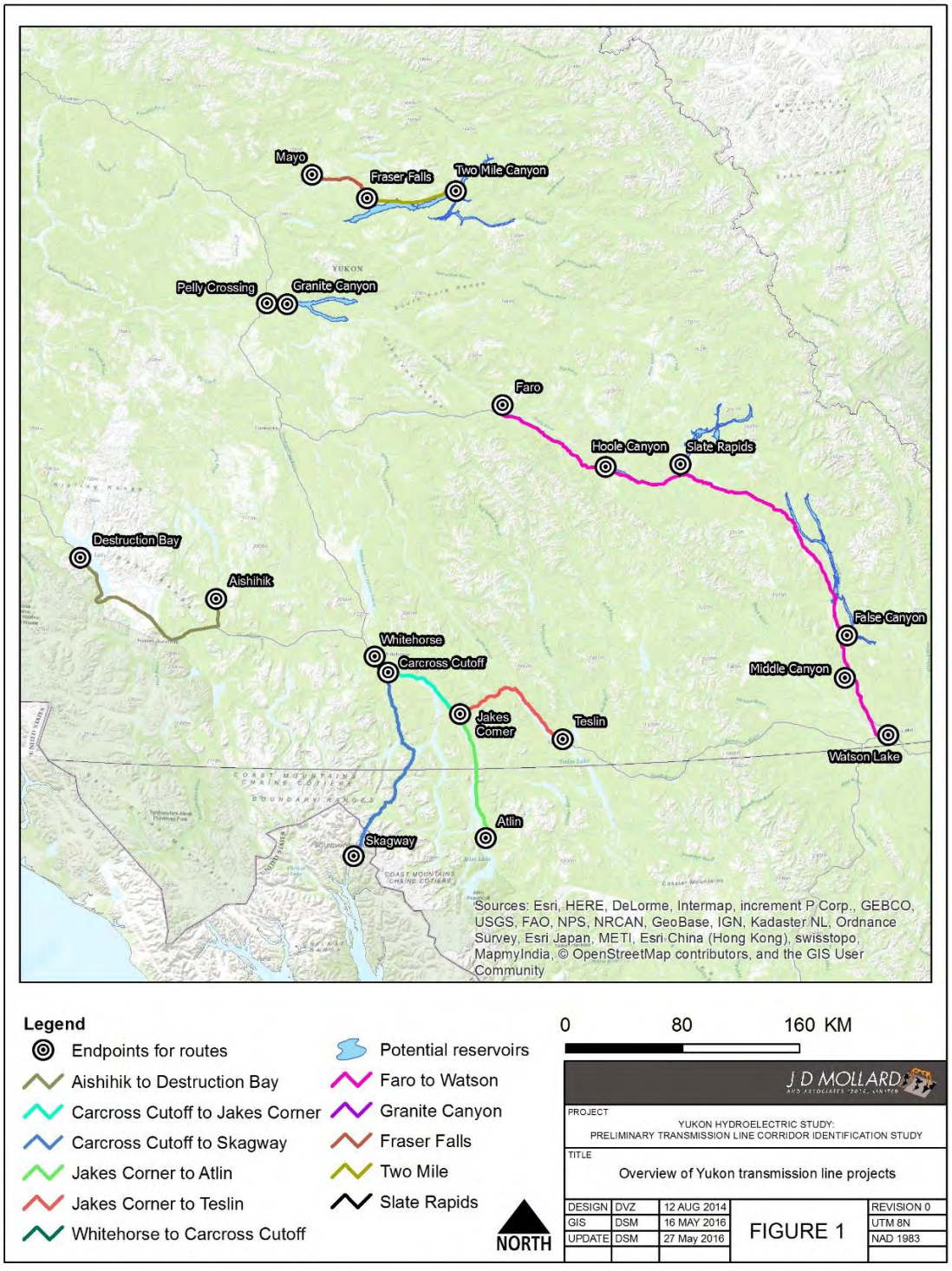


Figure 1: Overview map

2 Methodology

The transmission line corridor identification was done at a high level, and as such no detailed data sources were used in the analyses (e.g., air photographs, high resolution satellite, LiDAR). All evaluation of corridors was completed using ESRI ArcGIS and MicroImages TNT MIPS. Data were obtained from various territorial, provincial and national sources to aid in the evaluation of the routes.

MC provided the following criteria to JDMA for transmission line corridor identification:

- Transmission line span length will be approximately 200-230 m with longer spans possible in special cases,
- Where practical, place the transmission line corridor adjacent to roadways for maintenance and construction access,
- Where practical, narrow the corridor to less than 500 m to avoid major terrain constrictions adjacent to the corridor (e.g. next to a steep slope, river, etc.),
- Avoid crossing privately held land,
- Deflections up to 15° will not require special structures.

In addition to these specific criteria, JDMA also considered surficial geology and surface materials, terrain and slope, total length, as well as stream and wetland crossings to help in identifying feasible corridors.

In the case of the Jakes Corner to Atlin connection, one of the endpoints is located in BC. In the case of Carcross Cutoff to Skagway connection, one endpoint is in Alaska, requiring this corridor to pass through parts of Yukon, BC and Alaska. In these cases, the corridors were segmented for analysis based on territory, province, or state because different datasets exist for Yukon, BC and Alaska. This results in data being presented for nine (9) new corridor segments in Table 3 and the original eight (8) corridors in Table 4. The Faro to Watson Lake corridor in Table 4 was segmented based on the tap locations that extend along it.

2.1 Data sources

JDMA obtained base data for this project from free open-source files found on Government of Yukon, Government of Canada, Government of BC, and United States Geological Survey (USGS) web pages.

The data used in this study include both physical and cultural data. Geospatial data sources used in this study are listed in Table 2.

Table 2: Geospatial data sources used

Data Name	Data Type	Data Source
SPOT 20 m multispectral, 10 m panchromatic imagery	Satellite Imagery	SPOT imagery. © Department of Natural Resources Canada. "Orthoimagery". All rights reserved.
Canadian Digital Elevation Model (CDEM)	Digital elevation dataset (For Canada)	Elevation Data. © Department of Natural Resources Canada. "Canadian Digital Elevation Model". All rights reserved.
Shuttle Radar Topographic Mission	Digital elevation dataset (for Alaska)	Elevation Data. © United States Geological Survey Earth Explorer. "SRTM 1 Arc-Second Global". All rights reserved.

(SRTM)		
Surficial geology of the Yukon	Surficial geology and surficial material data for Yukon	Surficial Geology. © Ministry of Energy, Mines and Resources. "Yukon Digital Surficial Geology Compilation". All rights reserved.
Quaternary Geology of the Atlin Area	Surficial geology and surficial material data for BC	Surficial Geology. © BC Geological Survey Branch. "Quaternary Geology of the Atlin Area" 1:50,000. All rights reserved.
Surficial geology of the Skagway Quadrangle	Surficial geology and surficial material data for BC	Surficial Geology. © United States Geological Survey. "Photointerpretive map of the Skagway B-1 Quadrangle, Alaska" 1:63,360. All rights reserved.
JDMA mapped surficial geology	Surficial geology and surficial material data for BC	Mapped Surficial Geology. © JDMA. All rights reserved
LCC-2000	Land Cover data	Land Cover. © Department of Natural Resources Canada. "Land Cover Circa 2000" 1:250,000. All rights reserved.
NLCD-2001	Land Cover data	Land Cover. © Multi-Resolution Land Characteristics Consortium. "National Land Cover Database 2001" All rights reserved.
Rivers	Hydrographic data	Rivers. © Department of Natural Resources Canada. "CanVec single line watercourse layer" 1:50,000. All rights reserved.
Waterbodies	Hydrographic data	Waterbodies. © Department of Natural Resources Canada. "CanVec waterbodies layer" 1:50,000. All rights reserved.
Permafrost probability map	Permafrost regions of YK, BC, AK	Permafrost. © Department of Natural Resources Canada. "Yukon Permafrost Network". All rights reserved.
Road network - YK	Road network of the Yukon	Road network. © Department of Natural Resources Canada. "NRN YT". All rights reserved.
Road network – BC	Road network of British Columbia	Road network. © Department of Natural Resources Canada. "NRN BC". All rights reserved.
Road network – AK	Road network of Alaska	Road network. © Department of Transportation. "DOT Road System". All rights reserved.
Municipal boundaries	Town and village boundaries	Municipal boundaries. © GeoYukon Yukon. "Municipal boundaries". All rights reserved.
First Nations Settlement lands	First Nation land boundaries	First Nations lands. © GeoYukon Yukon. "First Nations Settlement Lands Surveyed, First Nations Settlement Lands Unsurveyed". All rights reserved.
Surficial land parcels and land use files (various) - YK	Various land uses and registered land parcels in the Yukon	Land parcels. © GeoYukon Yukon. "Active Land Applications, Land Dispositions, Land Notations, Easements, Land Licenses, Surveyed Land Parcels". All rights reserved.
Utilities	Power lines or pipelines	Utilities. © GeoYukon Yukon. "Utilities". All rights reserved.
Surficial land parcels and land use files (various) - BC	Various land uses and registered land parcels in British Columbia	Land parcels. © GeoBC. "Crown Land Licenses and Crown Land Reserves and Tenures". All rights reserved.

The above data were downloaded from the following links:

- SPOT, CDEM, rivers, waterbodies, and road network data were obtained from http://ftp2.cits.rncan.gc.ca/pub/,
- SRTM, NLCD data were obtained from http://earthexplorer.usgs.gov/
- Alaska road network were obtained from http://www.asgdc.state.ak.us/
- Yukon surficial geology data were obtained from http://www.geology.gov.yk.ca/digital_surficial_data.html
- Atlin surficial geology data were obtained from http://www.empr.gov.bc.ca/Pages/default.aspx
- Skagway surficial geology were obtained from http://www.dggs.alaska.gov/pubs/id/93
- Permafrost data were obtained from http://permafrost.gov.yk.ca/data/arcgis/
- Yukon municipal boundaries, First Nations Settlement lands, land parcels, land use, utility data and other base data were obtained from ftp://ftp.geomaticsyukon.ca/GeoYukon/.
- BC land parcels, land use, and other base data were obtained from https://apps.gov.bc.ca/pub/dwds/addProducts.do?orderId=1651722.

The data sources listed above were used as screening tools and to derive the statistics presented in Table 3 and Table 4. It should be noted that these data sources have limitations related to scale and the amount of ground truthing that was done in local areas. Within the study areas JDMA conducted a limited quality control check on these data sources through visual examination of the data in comparison to features discernible in the SPOT satellite imagery. At the locations checked, it was found that the data were generally consistent with features visible in the satellite imagery.

The wetland datasets are derived from the LCC-2000 national landcover data set and NLCD-2001 US landcover dataset. Wetlands are categorized as treed, shrub, or herb. These classes represent the dominant vegetation type for each wetland. In comparing the wetland boundaries to satellite imagery it appears that the wetland file may underrepresent the actual number of wetlands in the study areas. The LCC-2000/NLCD-2001 dataset was primarily interpreted from classified Landsat imagery with little to no ground truthing. Wetlands that may have gone unclassified are likely mostly included in the forest land cover classes where wetlands may be masked by the forest canopy.

The forest classes in the LCC-2000 dataset are classified according to crown closure. This provides information on forest density. The boundaries between dense canopy, open canopy, sparse canopy forests are discernible in the SPOT satellite imagery.

Riparian zones were calculated by taking all stream courses, water bodies, and wetlands identified in the CanVec, LCC-2000, and NLCD-2001 datasets and applying a 15 m buffer around them. Non-vegetated land classes were omitted from this buffer and the remaining area is considered the riparian zone. Therefore, riparian zone defined in this way represents a vegetated buffer around waterbodies and wetlands.

Major stream crossings were identified from the CanVec water body layer. Any stream that had both river banks represented, as opposed to being represented by a single line was considered to be a major stream.

Surficial geology maps were obtained primarily at a scale of 1:100,000 and 1:250,000. These two datasets were merged to provide surficial geology coverage across all of the study areas with the smaller scale dataset being used only where larger scale data are not available. For corridor segments located in BC and Alaska, surficial geology data only exist for small areas near Atlin and Skagway. For those areas in BC and Alaska where mapping does not exist, JDMA provided surficial geology mapping. The primary material unit attribute was used to identify the surficial geology within the corridor. When identifying thin-drift-over-bedrock, the surficial geology dataset was interpreted to identify those areas where bedrock was a secondary unit and the depth of the primary unit was veneer (<1 m thick).

Slopes were calculated from the CDEM and SRTM dataset. Slope calculations were performed in ArcGIS. The slope calculation in Table 3 considers all slopes regardless of aspect.

First Nations lands, settled lands, and land uses were taken from base data available from GeoYukon for Yukon datasets and from GeoBC for BC datasets. These data exist as several data layers and these data

layers were merged to provide a summary of all of the land uses that are crossed by the corridors. Alaska datasets could not be located.

The road layers were taken from the National Road Network – Yukon/BC and US DOT - Alaska. Paved roads were identified from the road surface attribute. Improved gravel roads were identified from the road surface attribute and road type attribute. These are roads that have a gravelled surface and are designated as either collector, or highway class roads. All other roads are included in the trail or resource road category and included various smaller gravelled roads, dirt roads and roads with an unknown surface type.

2.2 Corridor Identification

After all of the geospatial imagery was compiled JDMA began identifying corridors for each of the connections that were identified by MC for this study. The various datasets were overlaid on the imagery in the GIS and routes were identified. Routes were drawn as single lines which would later become the basis for the final 500 m corridors. The imagery and the digital elevation data were incorporated in TNT MIPS which allows the user to view the imagery in 3D. This provided a view of the terrain, land cover (vegetation) and land use and helped to refine the routes in places where these may be limiting factors.

500 m corridors were generated from the centreline routes that were mapped. The corridors were then offset from the centreline in places to take advantage of more than one centreline option within the same corridor, to centre the corridor on a roadway, or to minimize hazardous or other undesirable terrain. In places where the transmission line corridor was wider than adjacent terrain constraints, the corridor was narrowed to only cover those areas where it would be practical to construct and maintain a transmission line. In a few areas the corridor was widened beyond 500 m to allow for consideration of multiple alternatives that are more than 500 m apart.

3 Results

Statistics were collected and compiled for each corridor and are summarized in Table 3 and Table 4. These tables break down the routes according to many factors including corridor length, surficial geology, slopes, environmental concerns, First Nations lands, incidence of land parcels / land uses crossed, and other infrastructure crossings. These categories provide a high level view of the types of terrain and land uses that are to be expected within each corridor. The following subsections describe some of the distinctive characteristics of the transmission line corridors. Base data comparable to that available in the Yukon were not found or provided for corridor segments that extend into BC and Alaska. Because of this, the route comparison table is broken down based upon territory, province, and state. Where data are unavailable the table entry was marked “No Data”.

The corridors **Slate Rapids to False Canyon**, **Jakes Corner to Atlin (BC)**, and **Jakes Corner to Teslin** were broken down into sections with endpoints specified by the client. These sections are split up in the tables below and in the figures in Appendix A.

Corridor maps for each of the endpoint pairs are included in Appendix A.

Table 3: New Routes Comparison Table (May 2016)

ROUTE ALTERNATIVES STATISTICS SUMMARY
PROJECT: Midgard Yukon Hydroelectric Connection
DATE: 05 AUG 2016

	Aishihik to Destruction Bay	Whitehorse to Carcross Cutoff	Carcross Cutoff to Jakes Corner	Jakes Corner to Squanga Lake	Squanga Lake to Teslin	Jakes Corner to Atlin - YK	Jakes Corner to Atlin - BC (North of split)	Jakes Corner to Atlin - BC (South of split)	Carcross Cutoff to Skagway - YK	Carcross Cutoff to Skagway - BC (YK-Split 1)	Carcross Cutoff to Skagway - BC (Split 1 - 2)	Carcross Cutoff to Skagway - BC (Split 2 - 3)	Carcross Cutoff to Skagway - BC (Split 3 - AK)	Carcross Cutoff to Skagway - AK
CONSTRUCTION														
Total centreline length (Km)	157	17	62	26	69	42	5	45	77	3	16	18	20	21
Total corridor area (Ha)	7948	260	3050	1289	3245	1955	233	2179	3612	76	717	774	792	854
Total # of deep valley / canyon crossings	2	0	0	0	9	1	0	3	0	0	0	0	0	0
Total # of major stream crossings	6	1	2	0	1	0	0	0	1	0	0	0	0	1
LAND COVER (Ha)(Selected land classes were were included in the Terms of References.)														
Undifferentiated forest	3400	0	0	0	0	0	0	0	0	0	0	0	0	0
Dense coniferous (>60% crown closure)	179	6	280	82	126	64	70	246	236	0	16	13	9	0
Coniferous - open canopy (26-60% crown closure)	1349	81	1386	735	1459	688	85	887	1465	0	134	268	15	221
Coniferous - sparse (10-25% crown closure)	692	19	202	90	645	408	2	349	285	0	4	86	40	0
Dense broadleaf (>60% crown closure)	35	0	21	9	37	52	0	0	65	17	116	9	31	0
Broadleaf - open canopy (26-60% crown closure)	10	0	0	0	0	0	0	0	0	0	0	0	0	6
Broadleaf - sparse (10-25% crown closure)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mixedwood - open canopy (26-60% crown closure)	0	0	0	0	2	1	0	1	0	0	5	9	0	108
Mixedwood - sparse (10-25% crown closure)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Riparian zones (15 m around wetlands, streams, waterbodies)	120	11	57	34	72	38	15	103	76	5	45	58	75	70
Open water	66	5	39	6	28	8	0	7	36	0	9	12	7	2
Treed wetlands	0	0	3	1	3	10	0	5	49	0	0	0	0	7
Shrub wetlands	36	0	26	11	1	23	0	12	5	0	0	0	0	1
Herb wetlands	0	0	10	0	0	0	0	0	1	0	0	1	0	0
SURFICIAL GEOLOGY AND PERMAFROST (Ha)														
Anthropogenic/urban area	0	113	0	0	0	0	0	0	0	0	0	0	0	0
Aeolian	404	0	65	0	0	0	0	0	322	0	0	0	0	0
Colluvium	339	0	0	282	25	4	0	148	127	64	83	6	0	0
Fluvial	2302	120	1273	404	895	1210	0	198	648	5	0	311	0	75
Lacustrine	1842	5	392	21	0	315	155	520	534	0	1	2	0	0
Moraine	2921	20	809	535	2324	5	0	720	1608	0	0	0	0	10
Organic	30	0	0	0	0	6	0	132	42	0	0	0	0	0
Exposed bedrock	8	0	348	48	0	415	78	182	187	6	365	454	792	769
Thin layer (veneer <1 m thick) with bedrock as second unit	102	3	163	0	2	0	0	279	143	0	268	0	0	0
Sporadic discontinuous permafrost	6784	256	3050	1289	2048	890	4	61	2546	34	25	64	9	20
Extensive discontinuous permafrost	1164	0	0	0	0	0	0	0	0	0	0	0	0	0
SLOPE (Ha)														
Area of corridor on slopes 0 - 15°	7620	260	2912	1226	3219	1855	216	2051	3298	9	523	592	561	308
Area of corridor on slopes 15 - 30°	305	0	136	63	27	100	17	127	256	54	184	128	227	425
Area of corridor on slopes over 30°	23	0	2	0	0	0	0	1	59	13	10	54	5	121
FIRST NATIONS SETTLEMENT LANDS and SETTLED LAND (Ha)														
Category A First Nations land	652	0	596	44	303	0	0	0	700	0	0	0	0	No Data
Category B First Nations land	719	58	242	9	635	143	0	0	800	0	0	0	0	No Data
Uncategorized FN lands	0	0	0	0	17	0	0	0	53	0	0	0	0	No Data
Fee Simple First Nations land	51	0	0	0	0	0	0	0	27	0	0	0	0	No Data
First Nation Hertiage Site	0	0	4	0	0	0	0	0	12	0	0	0	0	No Data
BC First Nations Site of Cultural Importance	0	0	0	0	0	0	49	189	0	0	0	0	85	No Data
BC First Nations Statement of Intent Boundaries	0	0	0	0	0	0	233	2179	0	76	717	774	792	No Data
Interim Protected	4	0	0	0	18	0	0	0	0	0	0	0	0	No Data
Urban land	331	248	0	0	14	0	0	0	0	0	0	0	0	No Data
LAND USES (Ha)														
Development Holds	1558	0	0	0	0	0	0	0	0	0	0	0	0	No Data
Agricultural lands	23	0	11	0	0	3	0	0	0	0	0	0	0	No Data
Airport	0	0	0	0	8	0	0	0	2	0	0	0	0	No Data
Bridgehead	3	0	13	0	21	22	0	0	9	0	0	0	0	No Data
Environment	16	0	32	0	0	0	0	0	0	0	0	0	0	No Data
Forestry	375	0	0	0	0	0	0	0	0	0	0	0	0	No Data
Garbage dump	0	0	2	0	0	0	0	7	6	0	0	0	0	No Data
Gravel Pit	216	0	88	29	160	90	0	43	89	0	20	14	15	No Data
Heritage	0	0	0	0	3	0	0	0	4	0	0	0	0	No Data
Industrial / commercial	96	0	91	12	63	0	0	0	2	0	1	0	1	No Data
Marine	3	0	0	0	0	0	0	0	4	0	0	0	0	No Data
Navigation aid	0	0	0	0	0	0	0	1	0	0	0	0	0	No Data
Parks, Campground, or Recreational	1	0	0	0	1	0	0	247	3	149	717	774	792	No Data
Quarry	112	0	58	0	23	30	0	0	53	0	0	0	0	No Data
Rural residence	0	2	4	0	0	0	0	0	0	0	0	0	0	No Data
Trapping	14	110	0	0	0	6	0	0	197	0	0	0	0	No Data
Utility	73	0	125	0	1	0	0	0	26	0	0	0	0	No Data
ROADS PARALLEL TO AND WITHIN CORRIDOR (Km)														
Paved road	64	14	62	22	65	19	0	40	69	2	16	18	19	18
Improved gravel road	7	0	0	0	0	0	6	6	0	0	0	0	0	0
Trail or resource road	7	0	0	0	1	20	0	0	0	0	0	0	0	0

Table 4: Original Routes Comparison Table (July 2015)

ROUTE ALTERNATIVES STATISTICS SUMMARY
PROJECT: Midgard Yukon Hydroelectric Connection
DATE: 05 AUG 2016

	Faro to Hoole Canyon	Hoole Canyon to Slate Rapids	Slate Rapids to False Canyon (West)	Slate Rapids to False Canyon (East)	False Canyon to Middle Canyon	Middle Canyon to Watson Lake	Hoole Canyon Connection	Slate Rapids Connection	False Canyon Connection	Middle Canyon Connection	Granite Canyon	Fraser Falls to Mayo	Two Mile Canyon to Fraser Falls
CONSTRUCTION													
Total centreline length (Km)	94.6	56.8	81.5	102.7	20.4	58.0	1.8	9.2	7.4	6.2	14.6	48.2	64.5
Total corridor area (Ha)	4733	2840	4062	5133	1027	3072	79	454	162	294	734	2420	3212
Total # of deep valley / canyon crossings	1	2	0	1	0	1	0	1	1	0	0	3	3
Total # of major stream crossings	2	2	0	1	0	1	0	0	0	0	0	1	1
LAND COVER (Ha)(Selected land classes were were included in the Terms of References.)													
Undifferentiated forest	0	0	0	0	0	0	0	0	0	0	0	0	0
Dense coniferous (>60% crown closure)	523	340	316	427	280	731	9	196	40	74	10	53	83
Coniferous - open canopy (26-60% crown closure)	1414	1624	2317	3475	649	1843	56	165	42	210	182	740	811
Coniferous - sparse (10-25% crown closure)	934	605	1114	192	7	40	9	47	0	7	119	552	513
Dense broadleaf (>60% crown closure)	66	0	1	1	0	0	0	0	3	0	0	15	14
Broadleaf - open canopy (26-60% crown closure)	1	0	6	14	0	0	0	0	0	0	0	0	3
Broadleaf - sparse (10-25% crown closure)	0	0	1	6	0	0	0	0	0	0	0	0	0
Mixedwood - open canopy (26-60% crown closure)	12	0	9	108	37	71	0	10	26	2	0	16	36
Mixedwood - sparse (10-25% crown closure)	2	0	0	0	0	0	0	0	0	0	0	0	0
Riparian zones (15 m around wetlands, streams, waterbodies)	99	33	148	148	23	60	1	18	5	7	7	42	90
Open water	85	20	30	22	3	8	1	7	0	0	4	13	64
Treed wetlands	0	0	10	13	7	26	0	0	0	0	1	6	0
Shrub wetlands	0	0	0	23	0	2	0	0	0	0	0	18	7
Herb wetlands	181	19	5	25	13	69	0	0	0	0	28	20	169
SURFICIAL GEOLOGY AND PERMAFROST (Ha)													
Anthropogenic/urban area	0	0	0	0	0	0	0	0	0	0	0	0	0
Aeolian	0	440	0	0	0	0	0	217	0	0	731	0	0
Colluvium	0	0	2	0	0	0	0	0	0	0	0	96	4
Fluvial	951	939	613	1259	578	451	30	141	139	39	3	301	361
Lacustrine	8	0	0	33	96	0	0	0	0	0	0	54	421
Moraine	3238	1014	2303	3854	353	2139	26	93	23	254	0	1573	83
Organic	490	447	1128	0	0	483	23	4	0	0	0	0	0
Exposed bedrock	45	0	11	0	0	0	0	0	0	0	0	0	0
Thin layer (veneer <1 m thick) with bedrock as second unit	0	0	0	0	0	0	0	0	0	0	0	396	2344
Sporadic discontinuous permafrost	0	0	0	1980	1026	3072	0	0	159	0	0	1	1
Extensive discontinuous permafrost	4733	2840	4062	3153	1	0	79	454	3	294	734	2419	3211
SLOPE (Ha)													
Area of corridor on slopes 0 - 15°	4587	2840	3927	5087	1026	3056	77	452	146	286	731	1966	2893
Area of corridor on slopes 15 - 30°	145	0	134	46	1	16	1	2	16	8	3	453	317
Area of corridor on slopes over 30°	1	0	1	0	0	0	0	0	0	0	0	1	2
FIRST NATIONS SETTLEMENT LANDS and SETTLED LAND (Ha)													
Category A First Nations land	0	673	24	1250	0	6	0	281	0	0	0	0	0
Category B First Nations land	662	112	566	253	462	811	0	96	112	7	661	1664	937
Uncategorized FN lands	1	0	0	0	0	41	0	0	0	0	0	0	0
Fee Simple First Nations land	0	0	0	0	0	0	0	0	0	0	0	0	0
First Nation Hertiage Site	0	0	0	0	0	0	0	0	0	0	0	0	0
BC First Nations Site of Cultural Importance	0	0	0	0	0	0	0	0	0	0	0	0	0
BC First Nations Statement of Intent Boundaries	0	0	0	0	0	0	0	0	0	0	0	0	0
Interim Protected	662	785	590	1503	462	817	0	377	112	7	0	0	0
Urban land	942	0	0	0	0	599	0	0	0	0	0	0	0
LAND USES (Ha)													
Development Holds	0	0	0	0	0	0	0	0	0	0	0	0	0
Agricultural lands	0	0	0	0	0	0	0	0	0	0	0	0	0
Airport	0	0	0	0	0	0	0	0	0	0	0	0	0
Bridgehead	10	1	9	0	0	9	0	0	0	0	0	0	0
Environment	0	0	0	0	4	0	0	0	0	0	0	0	0
Forestry	2	0	0	0	4	345	0	0	0	0	0	0	0
Garbage dump	0	0	0	0	0	12	0	0	0	0	0	0	0
Gravel Pit	104	108	130	174	12	112	0	0	5	0	0	0	0
Heritage	1	0	0	0	0	0	0	0	0	0	0	0	0
Industrial / commercial	2	0	0	0	0	0	0	0	0	0	0	0	0
Marine	1	0	0	0	0	0	0	0	0	0	0	0	0
Navigation aid	0	0	0	0	0	0	0	0	0	0	0	0	0
Parks, Campground, or Recreational	1	49	7	1145	0	2	0	0	0	0	0	25	0
Quarry	0	0	4	0	0	6	0	0	0	0	0	0	0
Rural residence	0	0	0	0	0	0	0	0	0	0	0	0	0
Trapping	0	0	0	0	0	0	0	0	0	0	0	0	0
Utility	296	0	0	0	0	0	0	0	0	0	118	0	5
ROADS PARALLEL TO AND WITHIN CORRIDOR (Km)													
Paved road	15	0	0	4	0	38	0	0	0	0	1	1	0
Improved gravel road	72	42	80	88	20	12	0	0	0	0	0	0	0
Trail or resource road	3	0	0	0	0	3	0	0	0	0	0	2	0

3.1 Aishihik to Destruction Bay

The Aishihik to Destruction Bay corridor is 157 km long. The corridor follows the Alaska Highway (Highway #1) between Destruction Bay and Canyon where it deflects north to the Aishihik Generating Station. In its western portion, the corridor is located adjacent to Kluane Lake between Destruction Bay and Silver City, except for a 15 km segment where it follows the Slims River Valley upstream to a

suggested crossing of the Slims River. On the west side of Kluane Lake the corridor parallels an old pipeline right-of-way that appears to be abandoned.

The dominant terrain unit within the Aishihik to Destruction Bay corridor is classified as morainal. The next dominant unit is classified as fluvial terrain and mainly occurs where the corridor crosses creeks and alluvial fans on the west and east sides of Kluane Lake. There are also minor amounts of organic terrain located within this corridor. In total the corridor crosses 30 hectares of organic terrain. Organic terrain is considered poor for routing a transmission line due to the likelihood of a high water table and compressive soils. Slopes along this route are generally quite gentle. Extensive areas of lacustrine terrain occur locally south of Kloo Lake, near Haines Junction and adjacent to the Aishihik and Desadeash rivers in the eastern portion of the corridor. There are only a few instances of slopes being steeper than 15°. These areas primarily occur near the mouth of the Slims River, where the low flat fluvial landscape narrows and bedrock slopes form a pinch point. In this area there is very little exposed bedrock as the lower bedrock slopes are covered by colluvium. This corridor crosses 1,164 hectares of extensive discontinuous permafrost.

The crossing of the Slims River is one of the most significant constraints along this corridor. The Slims River is a large river that discharges into Kluane Lake. Locating the transmission line adjacent to the Alaska Highway across the floodplain is not considered a good option because of susceptibility to flooding and scour, poor foundations and aesthetic impacts along the scenic Alaska Highway. As a result, the corridor has been located farther up the valley where two side-valley alluvial fans will provide the crossing with the shortest span. These fans are well treed and appear to be relatively stable. This crossing span may be up to 500 m depending on final structure locations. Other major constraints on this route may be the land uses located adjacent to and offset from the Alaska Highway on the west side of Kluane Lake. Steep slopes and evidence of debris flows and rock avalanches in this area also require further evaluation. Several gravel pits, campgrounds, and other land uses were identified along the corridor as well, in addition to two (2) airstrips. The corridor has been routed so that it should be possible to maintain adequate clearance from the runways.

3.2 Whitehorse to Carcross Cutoff

The Whitehorse to Carcross Cutoff corridor is 17 km long and mainly located in the City of Whitehorse. The corridor width was reduced to 150 m in the urban area due to the constricted nature of development in this area. The Whitehorse corridor originates at the Whitehorse Dam and the primary corridor option follows the Alaska/Klondike highways (Highway #1/2) south of the city to the junction of the Alaska and Klondike highways.

The main surficial material within this corridor is fluvial sediment, followed by anthropogenic features because much of this route goes through urban areas. The slopes on this route are all below 15° owing to dominance the gently sloping fluvial terrain.

There are many rural residences listed along this route that would have to be considered in selection of a final route centreline. These residences are primarily located immediately adjacent to roadways.

Transmission line development could be located either directly next to the road or farther from the road behind these residences.

An alternative corridor that might be considered to avoid the built up urban area is a 500 m corridor that crosses the Alaska/Klondike Highway 4.7 km south of the Whitehorse Dam and passes south of the developed areas. This corridor could terminate either south or east of Carcross Crossing depending on where it extends to. The terrain along this corridor is quite flat and appears to be free of development.

3.3 Carcross Cutoff to Jakes Corner

The Carcross Cutoff to Jakes Corner corridor is 62 km long and originates in Carcross Cutoff. It follows the Alaska Highway eastwards towards Jakes Corner. The corridor crosses the Yukon River at a location that would require an approximately 250 m span. It then parallels Marsh Lake before turning towards Jakes Corner.

The dominant terrain unit within the Carcross Cutoff to Jakes Corner corridor is fluvial terrain. The next most dominant terrain type is moraine followed by bedrock. The corridor follows the base of several mountains. These locations are characterized by more frequent bedrock exposures and steeper slopes. Throughout most of the corridor the slopes are below 15° but in some isolated areas the slopes exceed 15°.

There are many developments and land uses along the Alaska Highway including gravel pits, industrial developments, and utilities.

3.4 Jakes Corner to Teslin

The Jakes Corner to Teslin corridor is 95 km in length. It begins at Jakes Corner and follows the Alaska Highway northeast to Johnsons Crossing where it turns southeast to Teslin. The corridor crosses the Teslin River at a location that will require a span of approximately 400 m. The corridor passes through the communities of Johnsons Crossing, Brooks Brook, and Teslin Lake in addition to the communities that are located at its two end points.

The terrain along this corridor is relatively flat with most of the slopes below 15°. The dominant terrain unit is morainal and the next most common unit is fluvial terrain. There are several land uses in the corridor with the most prevalent being gravel pits located along the highways. There are two airstrips along the corridor. The corridor has been routed to allow for a centreline selection that provides adequate clearance from the runways. Even so, the separation distance at the Teslin airstrip will need to be confirmed given the location of the transmission line termination point and the orientation of the airstrip.

As an alternative to crossing the Teslin River at Johnsons Landing, JDMA has identified a second corridor option that is slightly shorter in length and has a shorter span across the river. The terrain and material types appear to be similar to the Johnsons Landing crossing location but the route alignment does require the corridor to depart from the highway adjacent location for a distance of approximately 1.5 km.

3.5 Jakes Corner to Atlin (YK, BC)

The Jakes Corner to Atlin corridor is 92 km long and connects Jakes Corner to Atlin, BC. Jakes Corner is north of Atlin and the corridor is mainly oriented north-south. The corridor follows Highway #7 and is adjacent to Little Atlin Lake and Atlin Lake. Approximately 42 km of the corridor is located in the Yukon with the remaining 50 km located in BC.

The main terrain unit in the corridor is fluvial terrain followed by lacustrine terrain. The lacustrine units primarily occur adjacent to Atlin Lake where the road and corridor are located next to the lake. In this area, several mountain slopes constrain the corridor to a zone between Atlin Lake and the steep mountain slopes. In addition to fluvial and lacustrine terrain some exposed bedrock and organic terrain are mapped within the corridor.

No major land uses are affected by this corridor; however, there are several gravel pits within the corridor. The British Columbia portion of the corridor lacks the same amount/type of land use data that are available for the Yukon. As a result, there is no land use land data available for the BC segment of the corridor.

3.6 Carcross Cutoff to Skagway (YK, BC, AK)

The Carcross Cutoff to Skagway corridor is 154 km long and extends across parts of Yukon, British Columbia, and Alaska. The Yukon section is 77 km, the British Columbia section is 56 km, and Alaska section is 21 km. The corridor runs mostly north-south from Carcross Crossing in the Yukon to Skagway on the Taiya Inlet, in Alaska. The corridor passes by several communities as it parallels the Klondike Highway all the way to Skagway. The corridor passes by and follows adjacent to Nares Lake, Tutshi Lake, Shallow Lake, Bernard Lake, and Summit Lake.

The main terrain unit in the corridor is bedrock. The second most common unit is moraine. This corridor has the steepest slopes of any of the corridors. Lacustrine terrain occurs locally south of Cowley Lake and in several short segments north of Carcross. There are many stretches of corridor where the slopes are greater than 15° reaching greater than 30° in some locations. Many of these steep slopes are bedrock terrain with varying thicknesses of colluvium depending on slope steepness and the proximity of the corridor to the base of the slope. In these areas the corridor was narrowed to only include the lower parts of the slopes. In many parts of this corridor the transmission line will need to be placed on the mountain side of the road because there is inadequate space on the lakeward side. In some locations the road is cut into the side of the mountain with a near vertical blasted or cut face adjacent to the road. In these cases it will be necessary to locate the transmission line higher on the slope, above the steep blasted or cut face. This situation will make construction and maintenance more challenging and costly.

Land uses within this corridor include many rural residences, gravel pits, parks and campgrounds. The British Columbia and Alaska portions of the corridor lack the same amount/type of land use data that are available for the Yukon. As a result, there is no land use land data available for the BC and Alaska segments of the corridor.

3.7 Faro to Watson Lake

The Faro to Watson Lake corridor is 414.1 km long, following the Robert Campbell Highway (Highway #4) corridor between the communities of Faro and Watson Lake. At the north end this corridor parallels the Pelly River for a distance of approximately 56 km between the communities of Faro and Ross River. In many places, the Faro to Ross River transmission line is also located within or near the corridor proposed for the Faro-Watson Lake transmission line. At the southern end the proposed corridor crosses several larger rivers including the Frances and Liard rivers.

The dominant terrain unit along the Faro to Watson lake corridor is classified as moraine (12,901 Ha). The next dominant unit is classified as fluvial (4,791 Ha). The fluvial unit is encountered where the corridor is located near several river channels located in the Faro-Watson Lake study area. Morainal and fluvial terrains are generally favourable for transmission line construction. Less favourable is organic terrain which covers approximately 2,547 Ha of the corridor. Organic terrain is generally less favourable for transmission line construction and maintenance due to higher water table, compressive soils, and a greater likelihood of permafrost-affected soils. Slopes along this route are generally quite low with only a few scattered instances of slopes being steeper than 15°.

Other possible constraints within the corridor are the land uses adjacent to and offset from the Robert Campbell Highway. These include a large number of gravel pits, some campgrounds, and other land uses that appear in available GIS datasets. In addition, there are two stream crossings that are approximately 250 m wide. There are also at least five, and possibly six, airports near the corridor. Even so, the corridor has been routed so that adequate clearance has been maintained from these airports.

Apart from a few short exceptions, the Robert Campbell Highway is located within the Faro to Watson Lake transmission line corridor making it possible to locate the transmission line near the highway in most locations. Near Faro, the corridor also encompasses an existing distribution line that links the communities of Faro and Ross River. The corridor is situated so that potential centrelines can take advantage of either being adjacent to the highway or parallel to the existing distribution line. It appears as though there is a wide right-of-way for the distribution line and existing access trails from the Robert Campbell Highway to the transmission line right-of-way. Near Watson Lake, the corridor goes south around Watson Lake before terminating at its end location within the community of Watson Lake. Going north around the lake decreases the overall length of the route but would result in the transmission line being in close proximity to the Watson Lake airport and passing through an area with more existing infrastructure.

3.8 Two Mile Canyon and Fraser Falls

The Two Mile Canyon and Fraser Falls corridors both originate at the Mayo substation near the community of Mayo. From the substation a common corridor extends east to the Fraser Falls site. From there the remainder of the Two Mile Canyon corridor continues for an additional 65 km to the Two Mile Canyon site. Both corridors are located mainly north of the Stewart River. Two possible alternative sections have been identified south of the river; one is located from the Mayo substation to the Fraser Falls site. A second southern alternative section approaches the Two Mile Canyon site from a river crossing about 25 km to the west.

The termination point suggested by MC for the Fraser Falls site is located on the west side of Stewart River at the proposed Fraser Falls hydroelectric site. However, the proposed transmission line corridor approaches the site from the east side of the river. With this layout the transmission line would have to cross the river at this site. This would not be a problem because the proposed hydroelectric station is located at a narrowing of the river and the proposed corridor represents a preferred location to cross the Stewart River. Cross the Stewart River at other locations would involve span lengths of >300 m from bank to bank plus crossing a wide floodplain that is subject to flooding and possible permafrost conditions.

Farther east, the Two Mile Canyon corridor crosses the river near the Two Mile Canyon site where the river channel is approximately 225 m wide. In the event that the Fraser Falls hydroelectric project is built, a span of approximately 725 m would be required to cross the reservoir at this location.

The main terrain type crossed by the Fraser Falls and Two Mile Canyon corridors is moraine on the lower valley slopes and upland adjacent to the Stewart River floodplain. In some upland areas the morainal sediment (till) may form a relatively thin and discontinuous cover over the underlying bedrock. Toward the east end of the Two Mile Canyon corridor the corridor crosses fluvial and lacustrine terrain on lower-lying terraces adjacent to the Stewart River floodplain. Although these terrain types may be more susceptible to a higher water table and permafrost-affected conditions, they cannot be avoided when crossing the Stewart River to reach the Two-Mile Canyon site. For this reason, a possible alternative crossing has been identified approximately 25 km west where the terrain is more favourable. However, this alternative would also require a span of approximately 725 m across the Fraser Falls reservoir with access from a narrow peninsula that may be subject to bank erosion. (Assuming both the Fraser Falls and Two-Mile Canyon projects are built.)

Except for the area immediately around Mayo, there is no infrastructure development in the Two Mile Canyon / Fraser Falls area. As such the major constraints on these routes are terrain related. There are a high number of steep slopes in this area (i.e., > 15°) and there are areas prone to ground ice in permafrost making construction, operation and maintenance challenging.

3.9 Granite Canyon

The Granite Canyon corridor is 14.6 km in length. Its west endpoint appears to be a tap from an existing transmission line that parallels the Klondike Highway (Highway #2). The east endpoint is a potential hydroelectric site on the Pelly River.

The terrain along this corridor is a low relief aeolian plain. The only other terrain unit identified in the area is a small area classified as fluvial terrain located adjacent to the Pelly River. Almost the entire length of this corridor is located on Category B (surface rights) First Nations Settlement land belonging to the Selkirk First Nations. The other designated land in the study area is a Land Disposition classified as *utility* at the eastern end of the corridor. This designation may be related to the hydroelectric potential at this site. Should a transmission line be built here it will require crossing over the Klondike Highway in order to tap the transmission line which is located on the west side of the highway.

3.10 Slate Rapids

The Slate Rapids corridor is 9.2 km long and extends from the Slate Rapids site on the Ross River to the proposed Faro to Watson Lake corridor. The Slate Rapids corridor deflects around a large low-lying area classified as organic terrain and follows a low ridge adjacent to the Ross River. Big Campbell Creek enters the Ross River near the south end of the corridor where an alluvial fan has formed. Therefore, the tap location has been located east of the fan.

The majority of the corridor is located on First Nations Category A and Category B land belonging to the Ross River Dena Council. There are no other designated land uses within the Slate Rapids study area.

3.11 False Canyon

The False Canyon corridor is 7.4 km long and extends from the Faro to Watson Lake corridor to the False Canyon site on the Frances River. Almost the entire length of this corridor is 200 m wide being confined to the lower slope between the Frances River to the east and the adjacent steeper slope and more rugged upland to the west. The corridor widens to 500 m near the tap location in the Faro to Watson Lake corridor.

A gravel pit is located near the tap location. However, most of the gravel pit is outside the corridor leaving sufficient room within the corridor to avoid crossing the gravel pit.

The tap point in the Faro to Watson Lake corridor is located on First Nations Category B land belonging to the Liard First Nation.

3.12 Middle Canyon

The Middle Canyon corridor is 6.2 km long from a potential hydroelectric site on the Frances River to the tap location in the Faro to Watson Lake corridor. The dominant terrain in the corridor is moraine and the slopes within corridor are gentle. The corridor is 500 m-wide over its entire length and there are no designated land uses in this area including no First Nations Settlement lands.

3.13 Hoole Canyon

The Hoole Canyon corridor is 1.7km long and connects the potential hydroelectric site on the Ross River to the tap location in the Faro to Watson Lake corridor. The primary terrain within the corridor is moraine, but also includes small amounts of fluvial and organic terrain. The majority of this corridor is on slopes that are less than 5°. There are no land uses or First Nations Settlement lands within the corridor.

4 Summary

JDMA has identified transmission line corridors for fourteen (14) potential routes identified by Midgard Consultants. A high level desktop study was carried out using readily available satellite imagery and GIS data sources. No detailed analysis was done using air photos and no ground-truthing or other field work has been carried out. While attempts have been made to identify major routing constraints, the possibility remains that site specific land use or terrain issues may exist that are not detectable with the

data resolution used in this study. Therefore, JDMA recommends more detailed analysis should be completed for each of these corridors including detailed air photo analysis, acquisition of high resolution satellite imagery and LiDAR data and field reconnaissance should further development of these corridors be considered.

Having said that, the corridors identified here are believed to represent viable routing options and the data presented provides a reasonable basis for a high level evaluation of the feasibility of constructing and maintaining a transmission line to each of the potential hydroelectric sites that have been included in this study.

5 Deliverables

The following products accompany this final report:

1) Route comparison spreadsheet in Excel format
2) Fourteen (14) corridor shapefiles – 1 for each corridor

These GIS products were created in ESRI ArcMap V.10.4

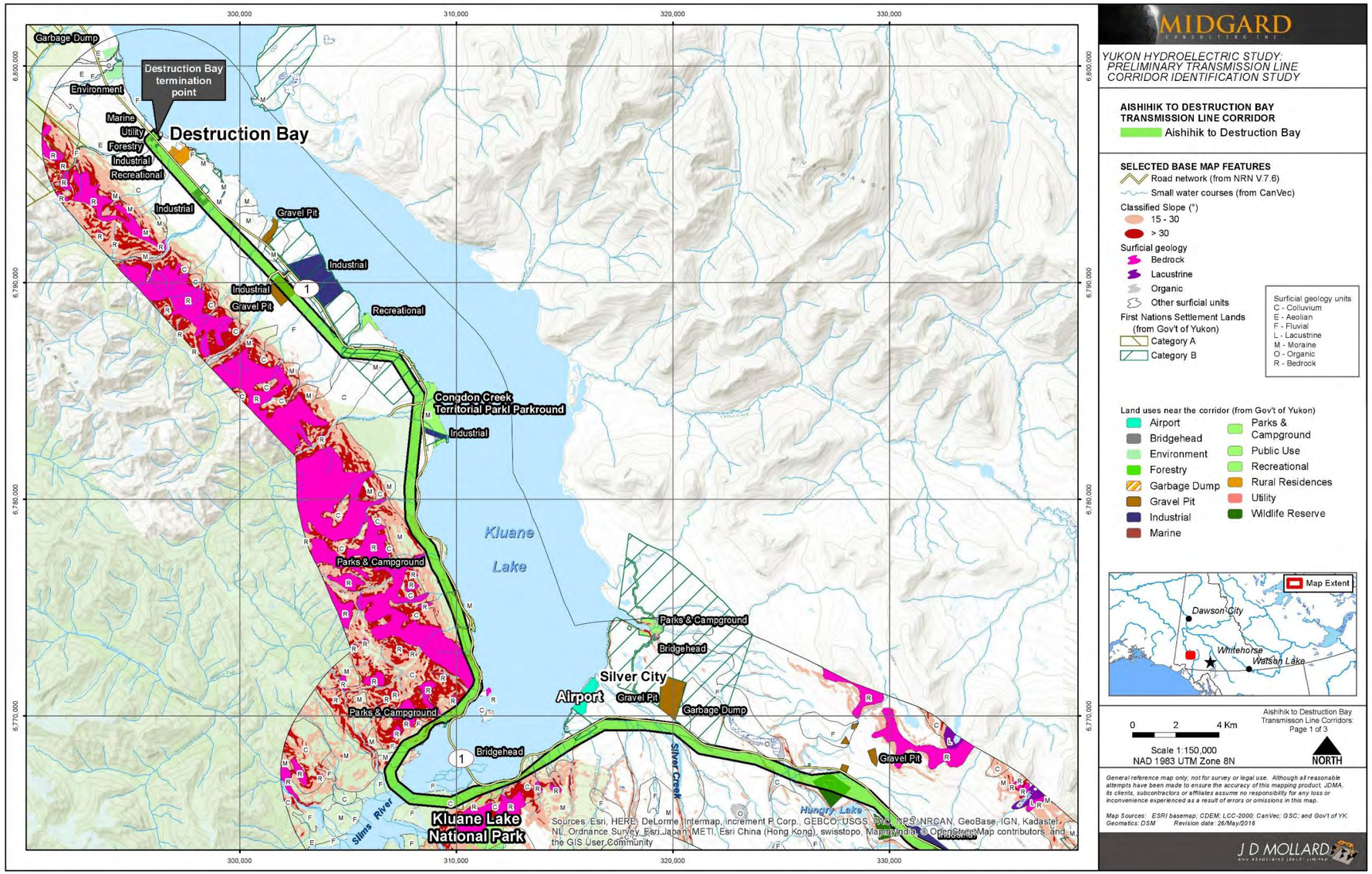
6 Signatures

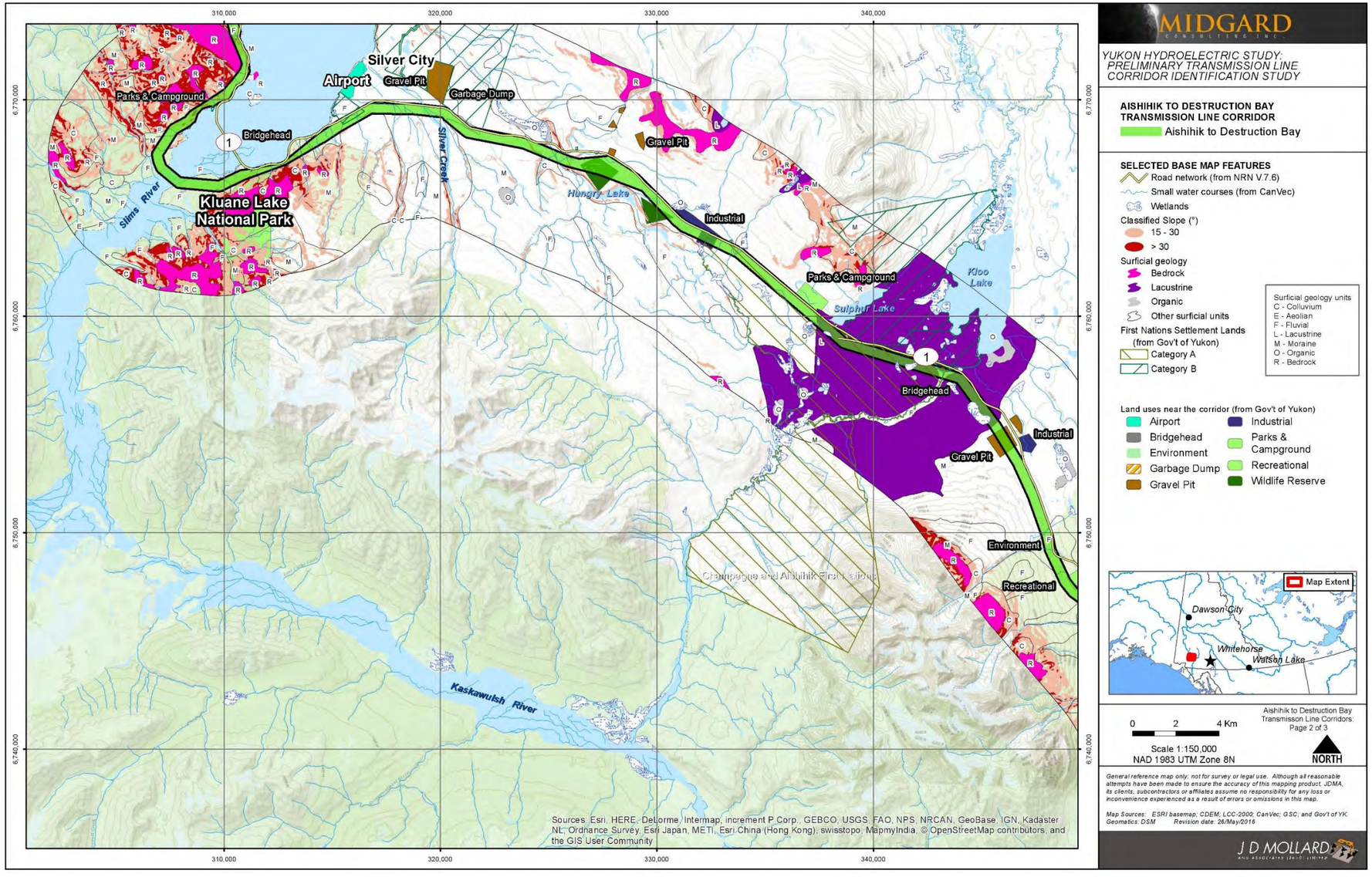
Shayne MacDonald, B.Sc.

Lynden Penner, M.Sc., P.Eng., P.Geo.

7 APPENDIX A: CORRIDOR MAPS

Figure A1: Ashihik to Destruction Bay map booklet

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320,000
330,000
340,000
6,770,000
6,760,000
6,750,000
6,740,000
Silver City
Airport
Gravel Pit
Garbage Dump
Parks & Campground
Bridgehead
1
Silver Creek
Slims River
Kluane Lake
National Park
Hungry Lake
Industrial
Kloo Lake
Sulphur Lake
Champagne and Aishihik First Nations
Kaskawulsh River
Environment
Recreational
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
AISHIHIK TO DESTRUCTION BAY
TRANSMISSION LINE CORRIDOR
Aishihik to Destruction Bay
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Organic
Other surficial units
First Nations Settlement Lands
(from Gov't of Yukon)
Category A
Category B
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Airport
Bridgehead
Environment
Garbage Dump
Gravel Pit
Industrial
Parks & Campground
Recreational
Wildlife Reserve
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
Aishihik to Destruction Bay
Transmisson Line Corridors:
Page 2 of 3
NORTH
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Geomatics: DSM Revision date: 26/May/2016
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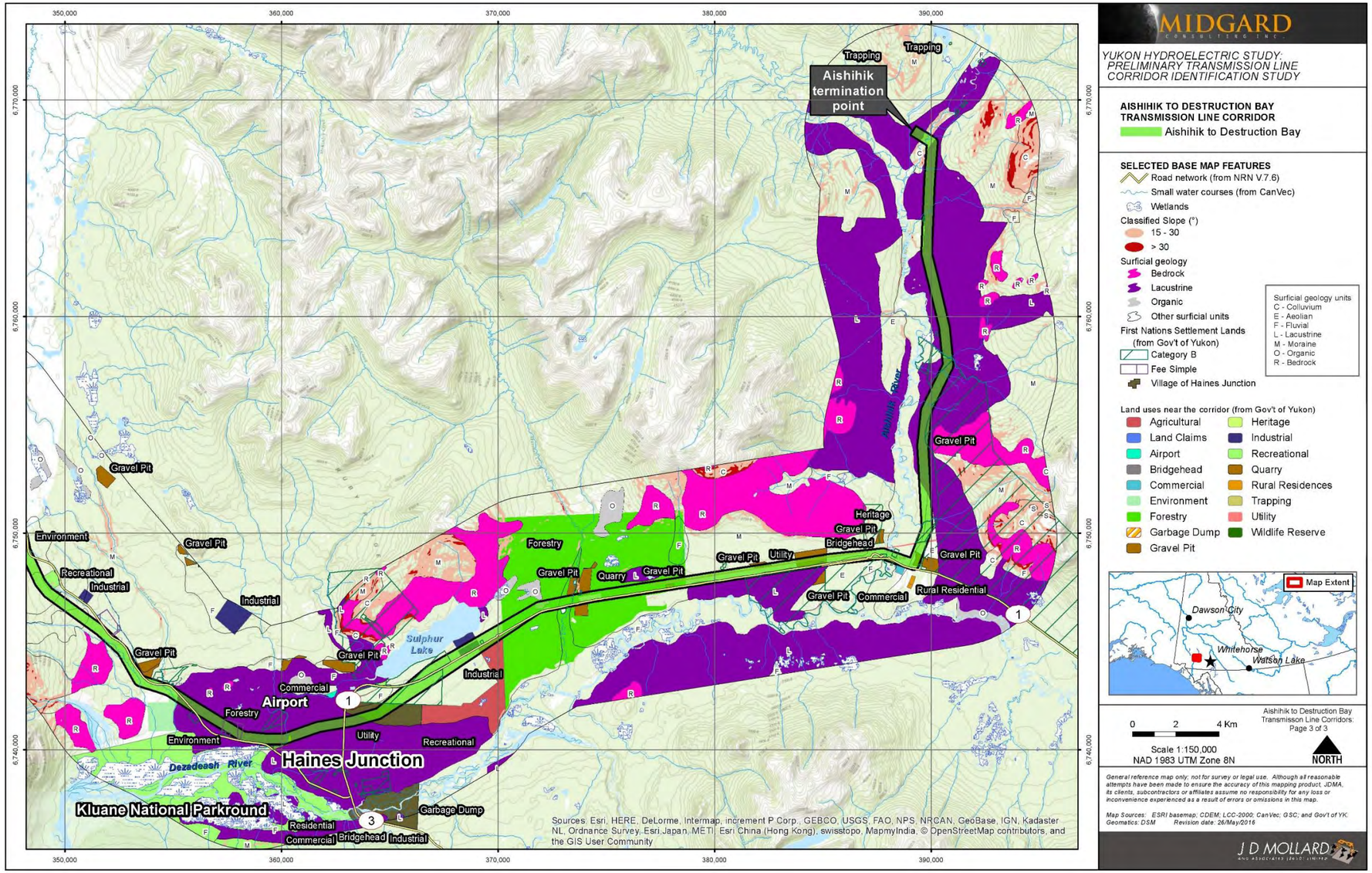
350,000
360,000
370,000
380,000
390,000
6,770,000
6,760,000
6,750,000
6,740,000
Aishihik termination point
Trapping
Trapping
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Gravel Pit
Aishihik River
Heritage
Bridgehead
Utility
Forestry
Quarry
Commercial
Rural Residential
Environment
Recreational
Industrial
Industrial
Industrial
Sulphur Lake
Commercial
Airport
Forestry
Environment
Utility
Recreational
Dezadeash River
Haines Junction
Kluane National Parkround
Residential
Commercial
Bridgehead
Industrial
Garbage Dump
1
1
3
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE CORRIDOR IDENTIFICATION STUDY
AISHIHIK TO DESTRUCTION BAY TRANSMISSION LINE CORRIDOR
Aishihik to Destruction Bay
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Organic
Other surficial units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
First Nations Settlement Lands (from Gov't of Yukon)
Category B
Fee Simple
Village of Haines Junction
Land uses near the corridor (from Gov't of Yukon)
Agricultural
Land Claims
Airport
Bridgehead
Commercial
Environment
Forestry
Garbage Dump
Gravel Pit
Heritage
Industrial
Recreational
Quarry
Rural Residences
Trapping
Utility
Wildlife Reserve
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
Aishihik to Destruction Bay Transmisson Line Corridors: Page 3 of 3
NORTH
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Geomatics: DSM Revision date: 26/May/2016
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Figure A2: Whitehorse to Carcross Cutoff map

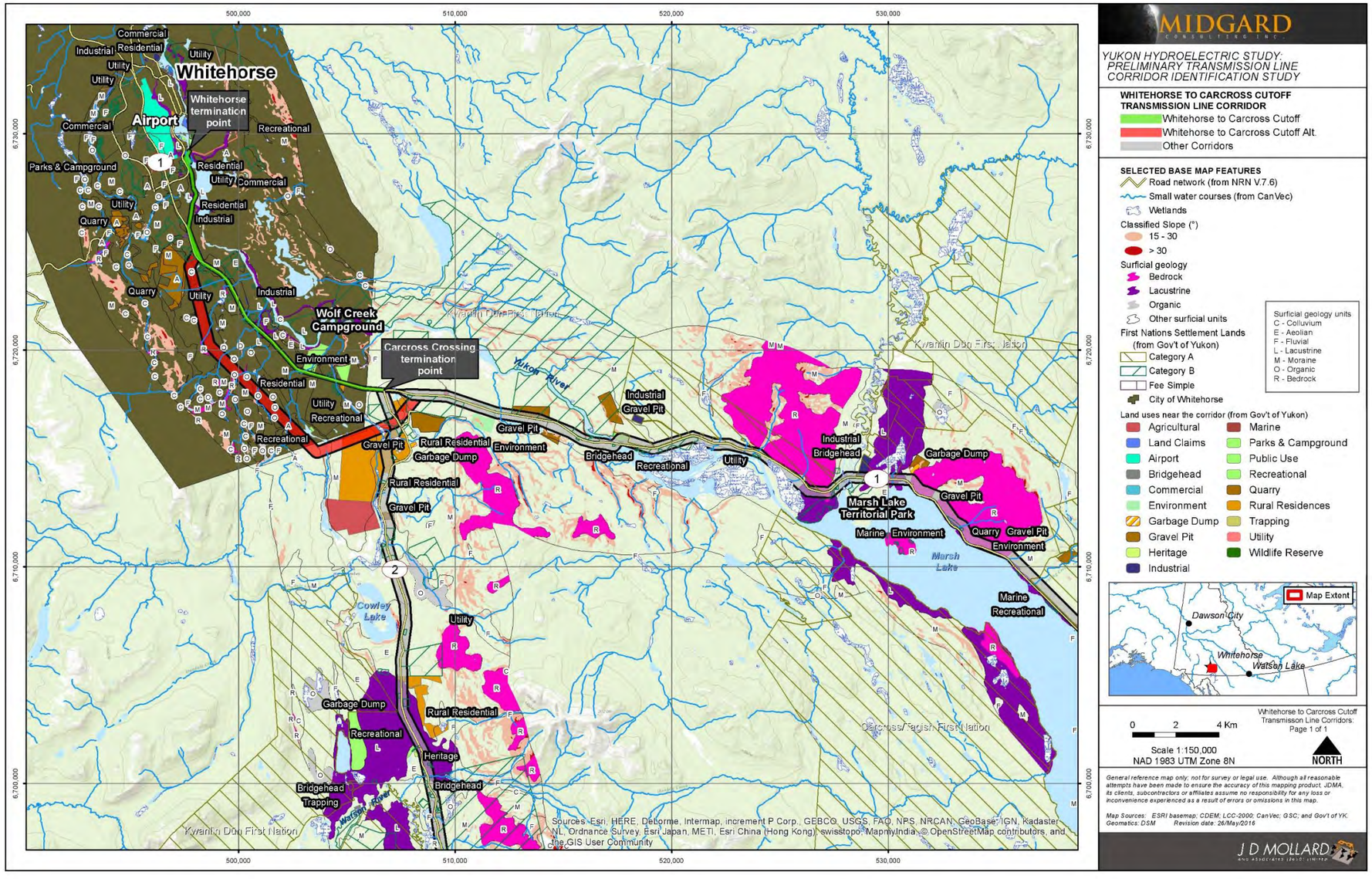
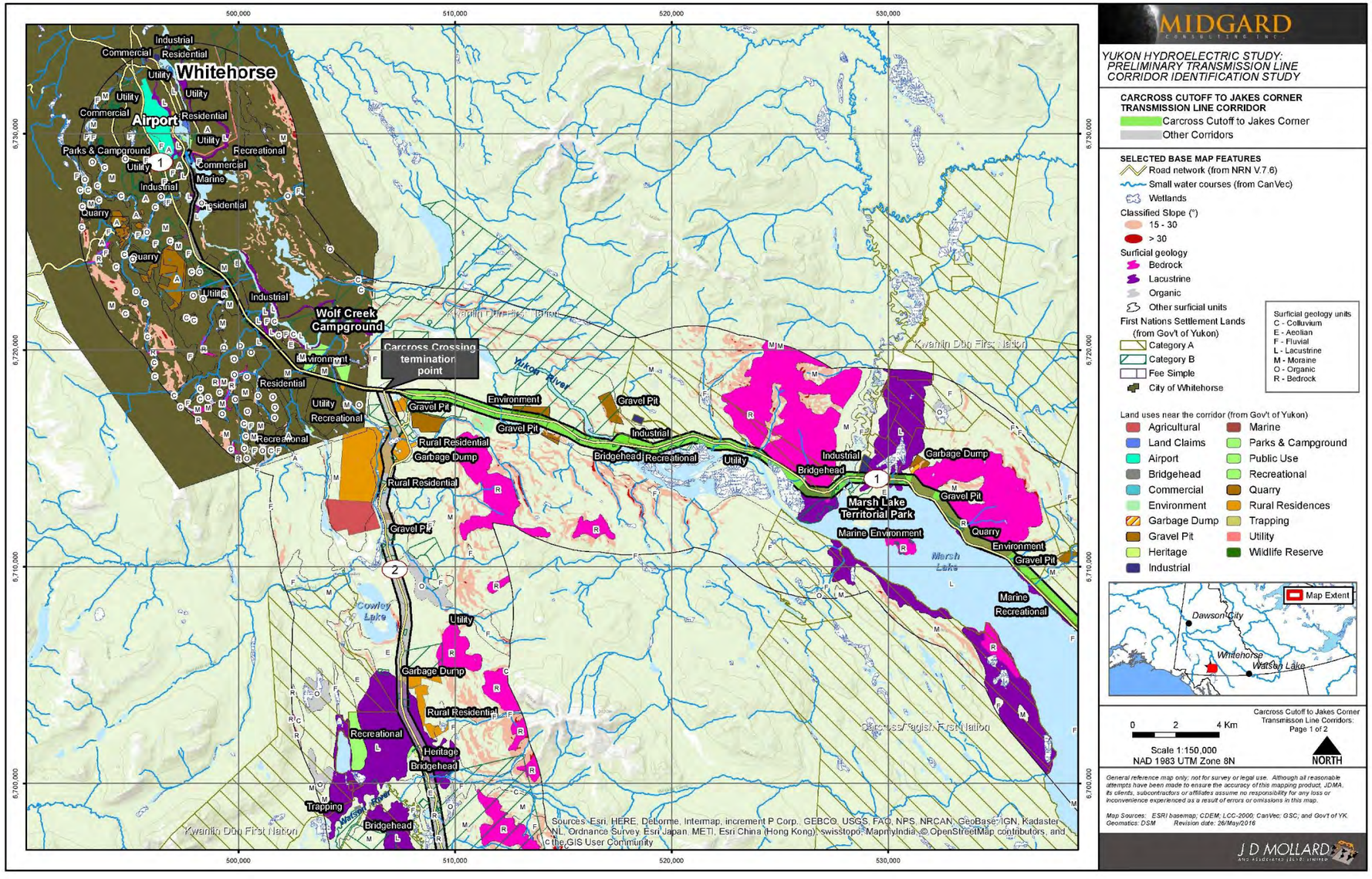
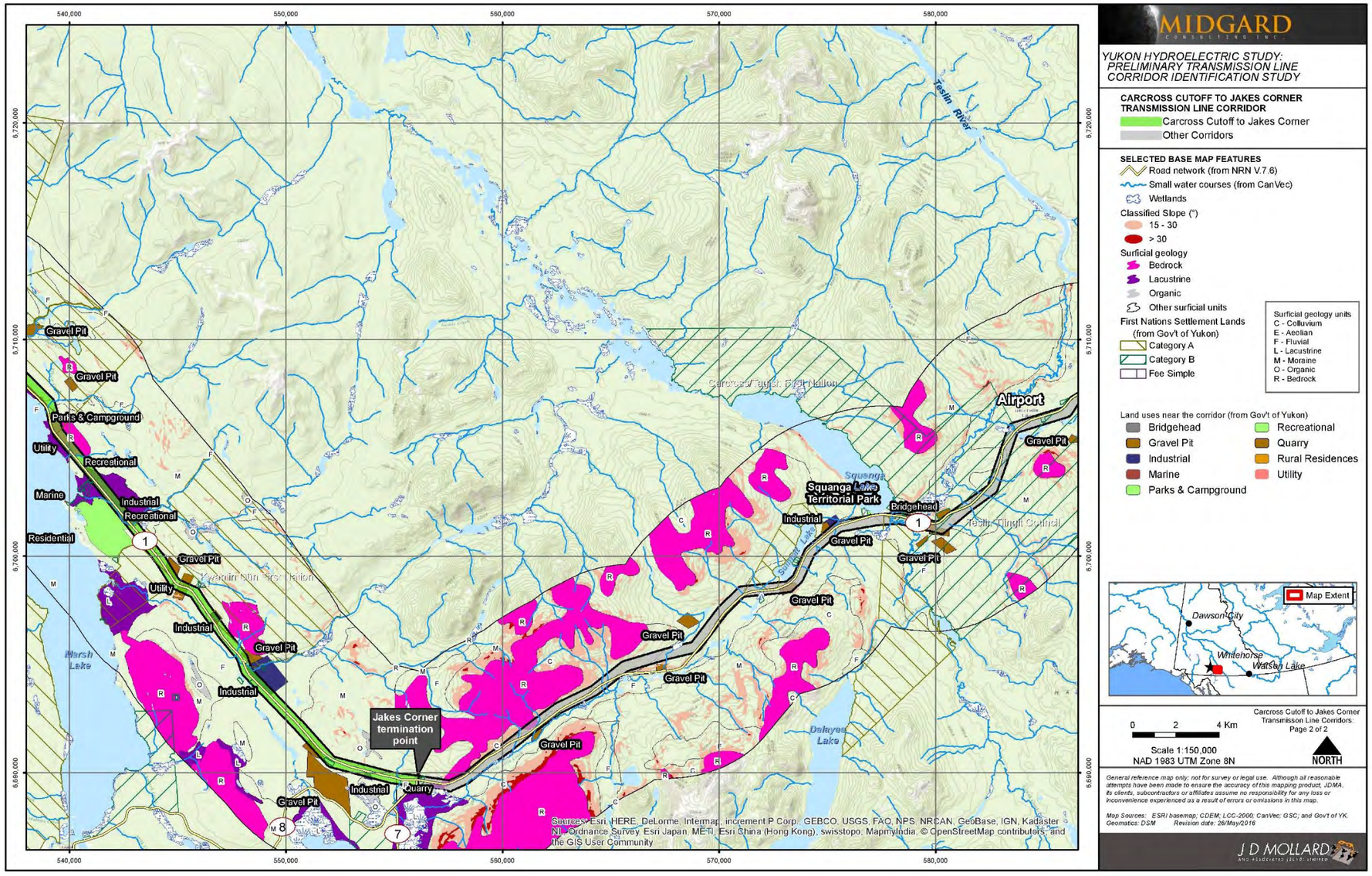


Figure A3: Carcross Cutoff to Jakes Corner map booklet

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560,000
570,000
580,000
6,720,000
6,710,000
6,700,000
6,690,000
Teslin River
Carcross/Tagish First Nation
Kwanlin Dün First Nation
Tesl. Tlingit Council
Gravel Pit
Parks & Campground
Utility
Recreational
Marine
Industrial
Residential
Airport
Squanga Lake
Squanga Lake Territorial Park
Bridgehead
Marsh Lake
Jakes Corner termination point
Quarry
Dalayes Lake
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
CARCROSS CUTOFF TO JAKES CORNER TRANSMISSION LINE CORRIDOR
Carcross Cutoff to Jakes Corner
Other Corridors
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Organic
Other surficial units
First Nations Settlement Lands (from Gov't of Yukon)
Category A
Category B
Fee Simple
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Bridgehead
Gravel Pit
Industrial
Marine
Parks & Campground
Recreational
Quarry
Rural Residences
Utility
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
Carcross Cutoff to Jakes Corner Transmisson Line Corridors: Page 2 of 2
NORTH
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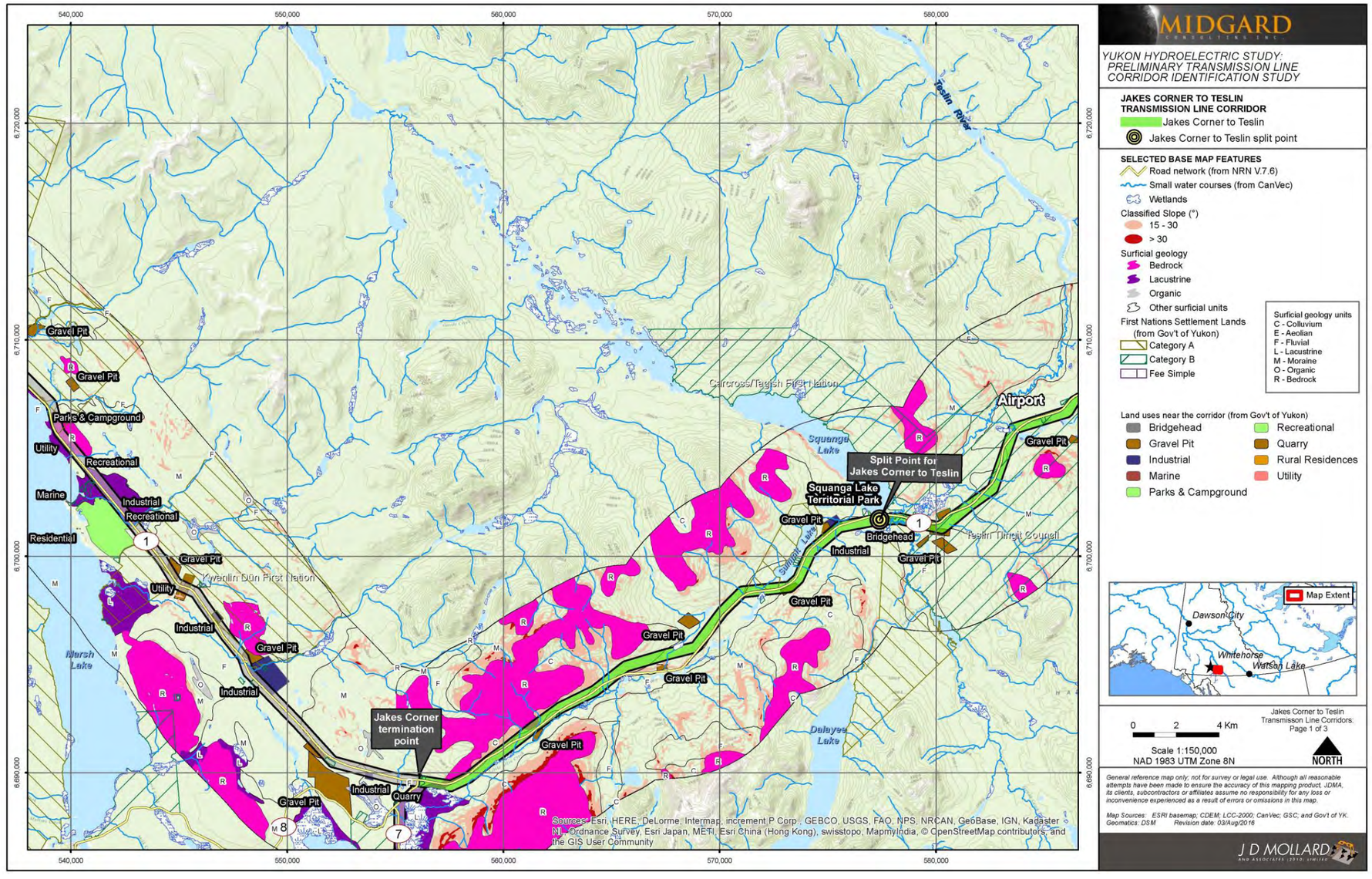
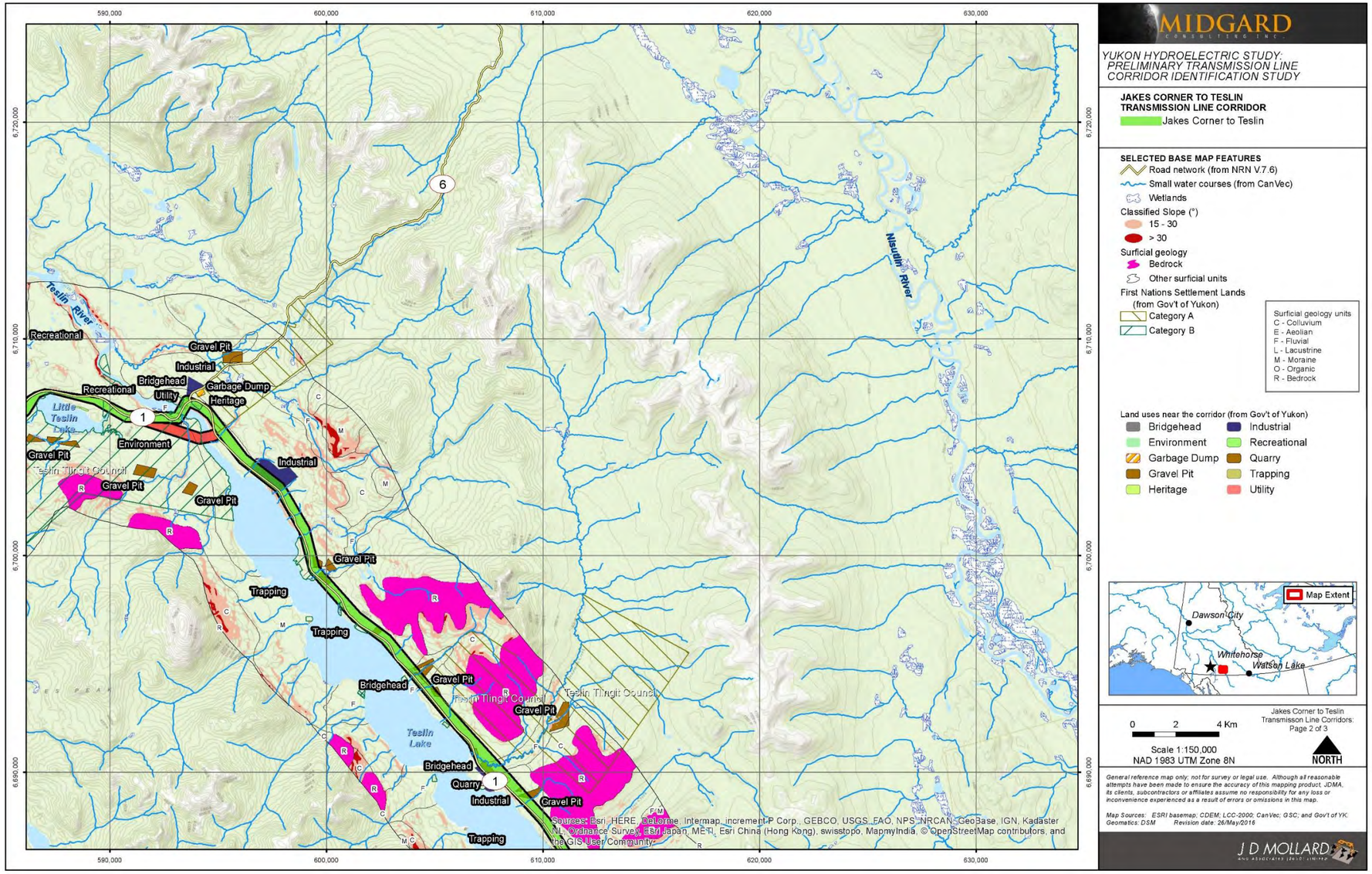
Figure A4: Jakes Corner to Teslin map booklet





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YUKON HYDROELECTRIC STUDY: PRELIMINARY TRANSMISSION LINE CORRIDOR IDENTIFICATION STUDY

JAKES CORNER TO TESLIN TRANSMISSION LINE CORRIDOR
Jakes Corner to Teslin

SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Other surficial units
First Nations Settlement Lands (from Gov't of Yukon)
Category A
Category B

Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock

Land uses near the corridor (from Gov't of Yukon)
Bridgehead
Environment
Garbage Dump
Gravel Pit
Heritage
Industrial
Recreational
Quarry
Trapping
Utility

0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N

Jakes Corner to Teslin Transmisson Line Corridors: Page 2 of 3

NORTH

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Geomatics: DSM Revision date: 26/May/2016

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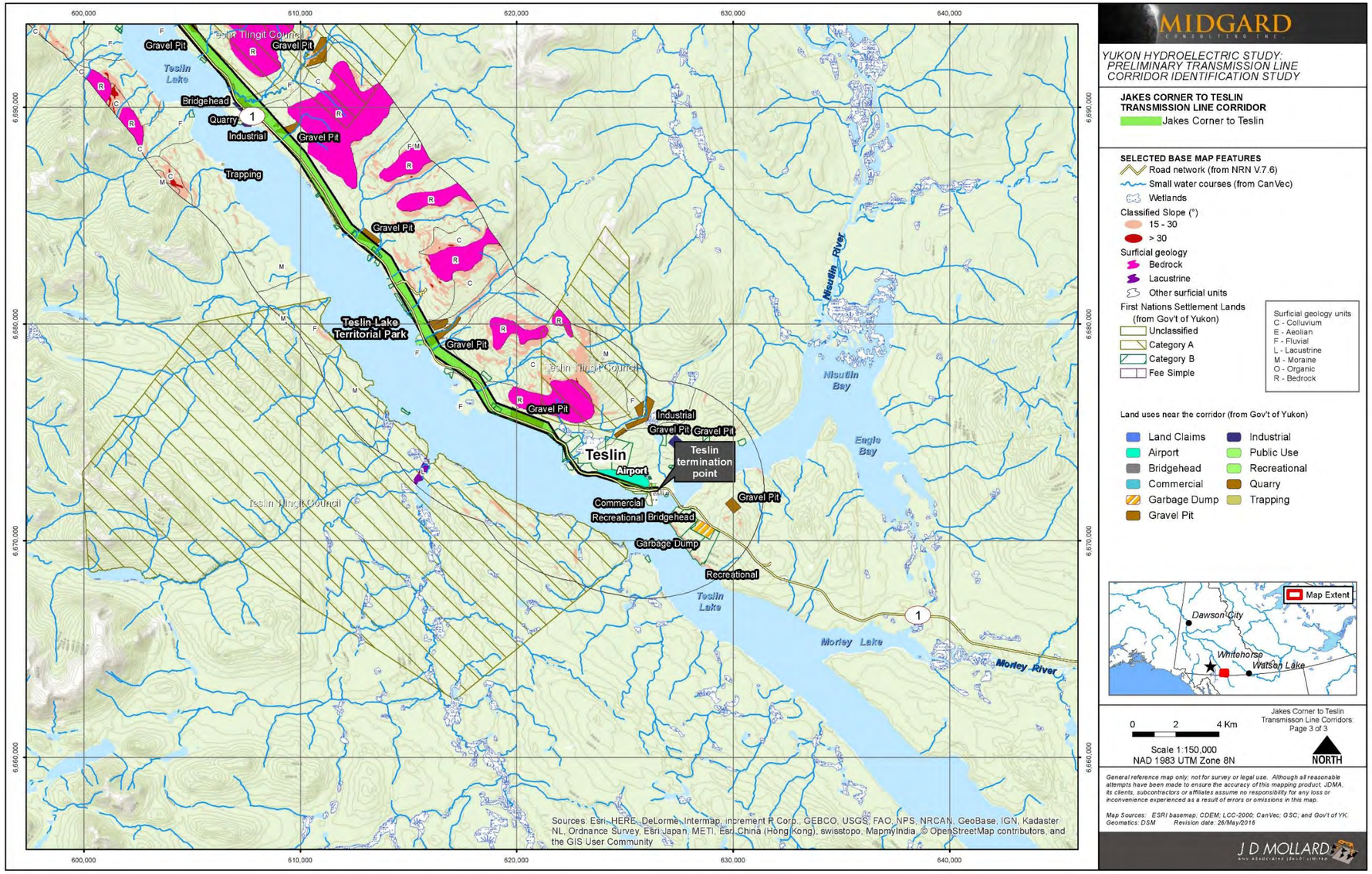
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Teslin Tlingit Council
Gravel Pit
Teslin Lake
Bridgehead
Quarry
Industrial
Trapping
Teslin Lake Territorial Park
Teslin
Airport
Teslin termination point
Commercial
Recreational
Bridgehead
Garbage Dump
Nisutlin Bay
Eagle Bay
Nisutlin River
Morley Lake
Morley River
1
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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PRELIMINARY TRANSMISSION LINE CORRIDOR IDENTIFICATION STUDY
JAKES CORNER TO TESLIN TRANSMISSION LINE CORRIDOR
Jakes Corner to Teslin
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Other surficial units
First Nations Settlement Lands (from Gov't of Yukon)
Unclassified
Category A
Category B
Fee Simple
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Land Claims
Airport
Bridgehead
Commercial
Garbage Dump
Gravel Pit
Industrial
Public Use
Recreational
Quarry
Trapping
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
Jakes Corner to Teslin Transmisson Line Corridors: Page 3 of 3
NORTH
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Geomatics: DSM Revision date: 26/May/2016
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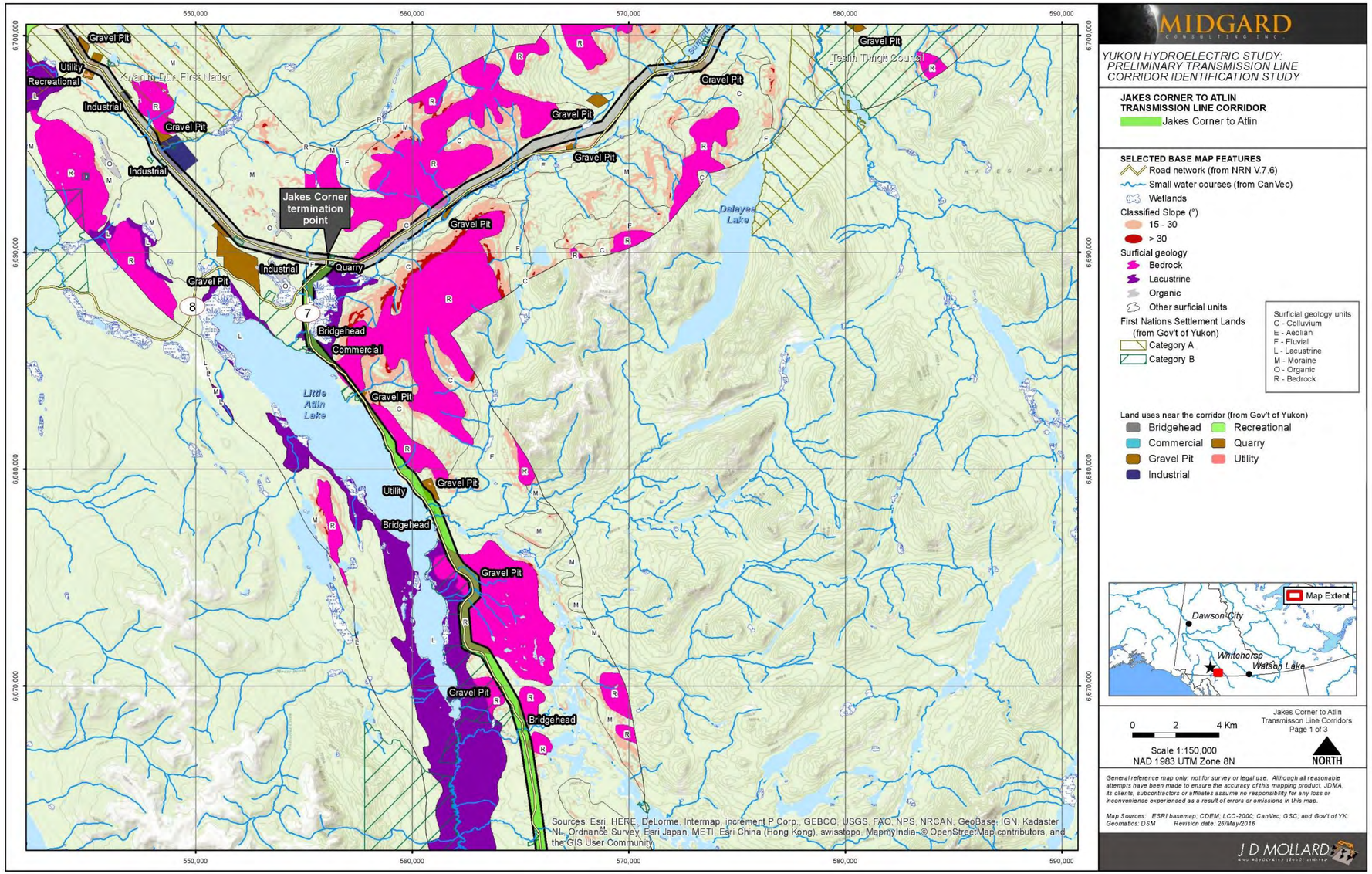
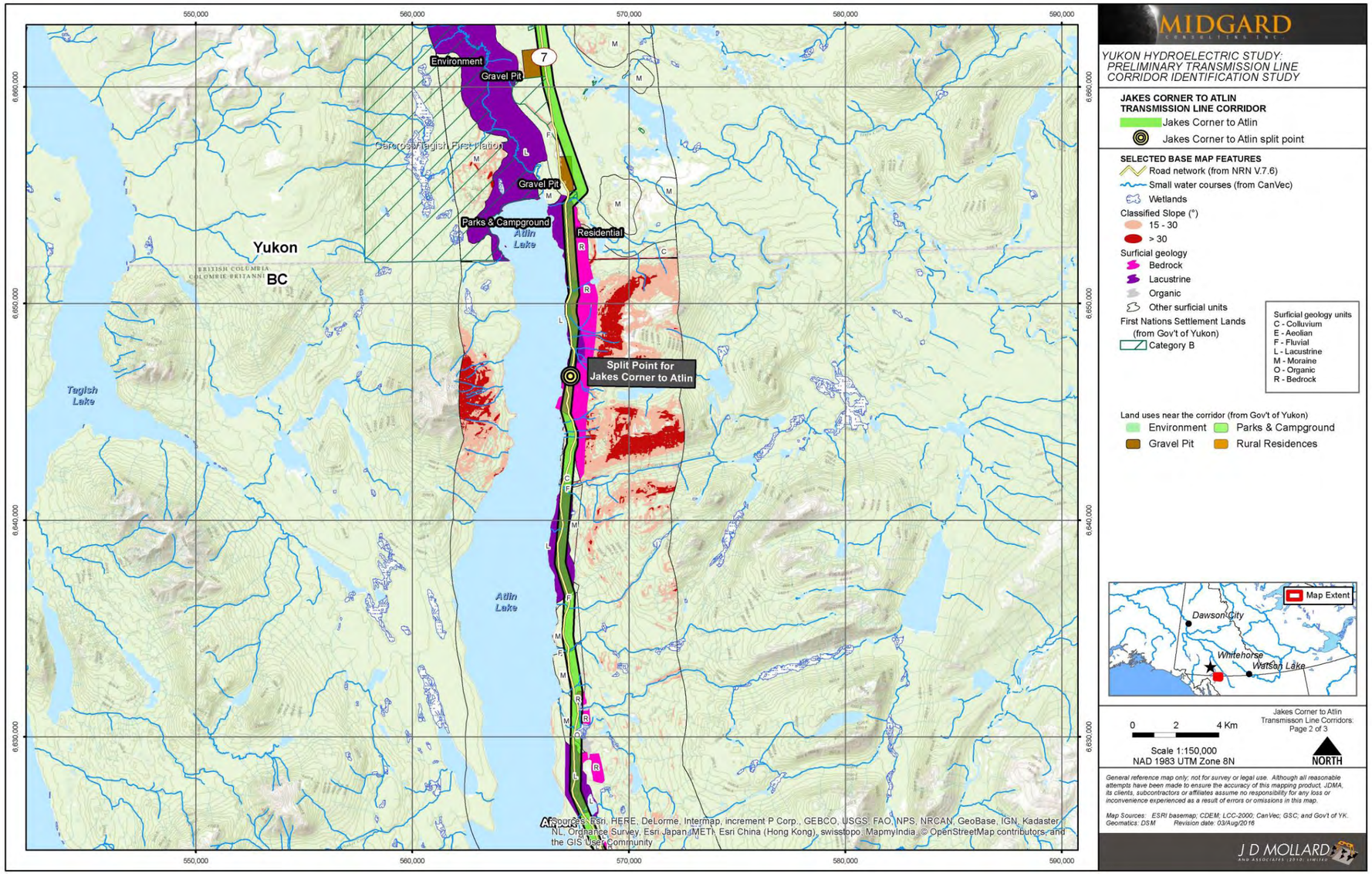
Figure A5: Jakes Corner to Atlin map booklet




550,000
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590,000
6,660,000
6,650,000
6,640,000
6,630,000
Environment
Gravel Pit
Carcross/Tagish First Nation
Gravel Pit
Parks & Campground
Residential
Atlin Lake
Yukon
BRITISH COLUMBIA
COLOMBIE BRITANNIQUE
BC
Split Point for
Jakes Corner to Atlin
Tagish Lake
Atlin Lake
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
JAKES CORNER TO ATLIN
TRANSMISSION LINE CORRIDOR
Jakes Corner to Atlin
Jakes Corner to Atlin split point
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Organic
Other surficial units
First Nations Settlement Lands
(from Gov't of Yukon)
Category B
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Environment
Parks & Campground
Gravel Pit
Rural Residences
Map Extent
Dawson City
Whitehorse
Watson Lake
0
2
4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
Jakes Corner to Atlin
Transmisson Line Corridors:
Page 2 of 3
NORTH
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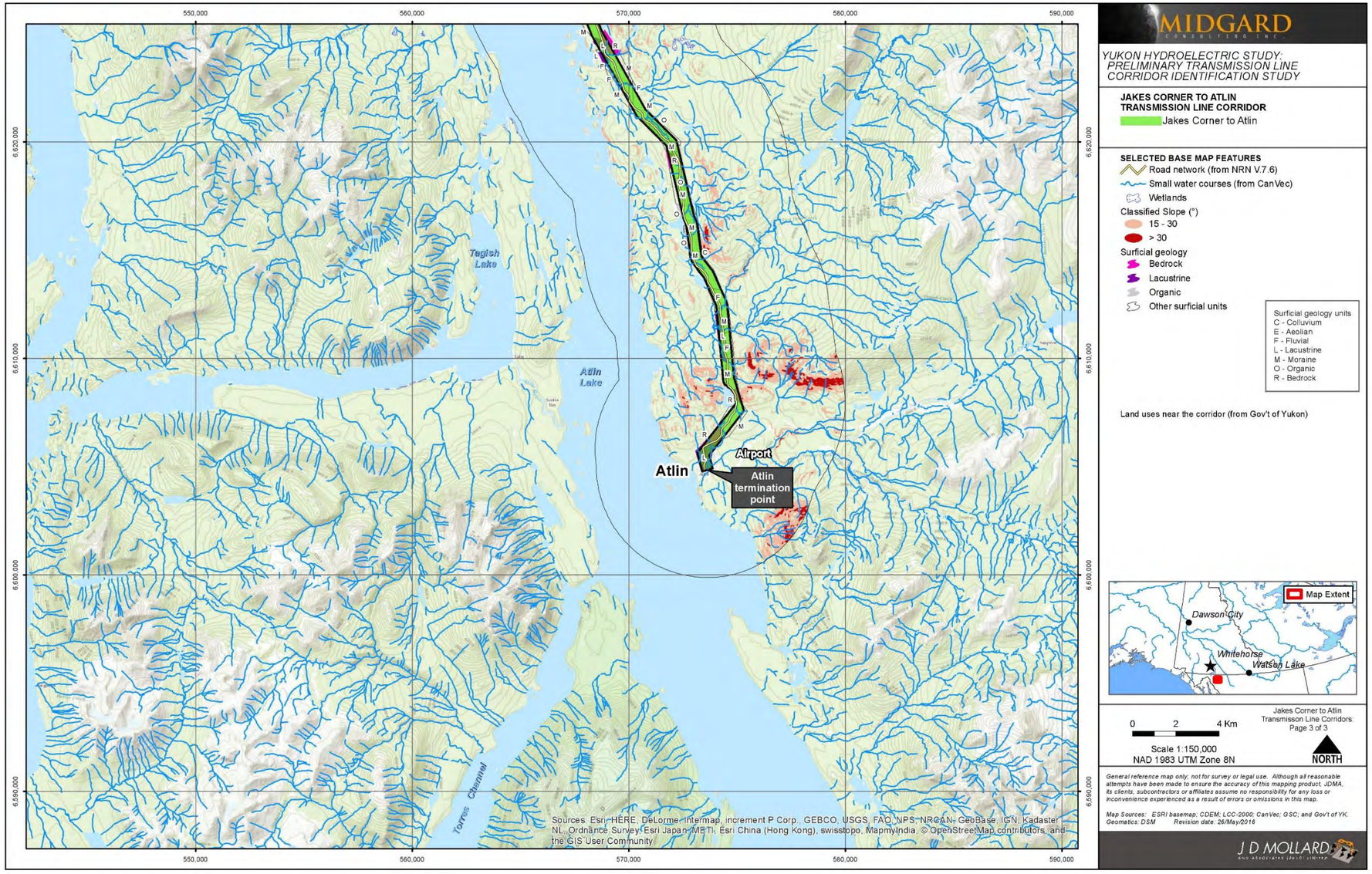
Map Sources: ESRI basemap; CDEM; LCC-2000; CanVec; GSC; and Gov't of YK.
Geomatics: DSM Revision date: 03/Aug/2016
J D MOLLARD


550,000
560,000
570,000
580,000
590,000
6,620,000
6,610,000
6,600,000
6,590,000
Tagish Lake
Atlin Lake
Atlin
Airport
Atlin termination point
Torres Channel
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
MIDGARD CONSULTING INC.
YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
JAKES CORNER TO ATLIN
TRANSMISSION LINE CORRIDOR
Jakes Corner to Atlin
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Organic
Other surficial units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
Jakes Corner to Atlin
Transmisson Line Corridors:
Page 3 of 3
NORTH
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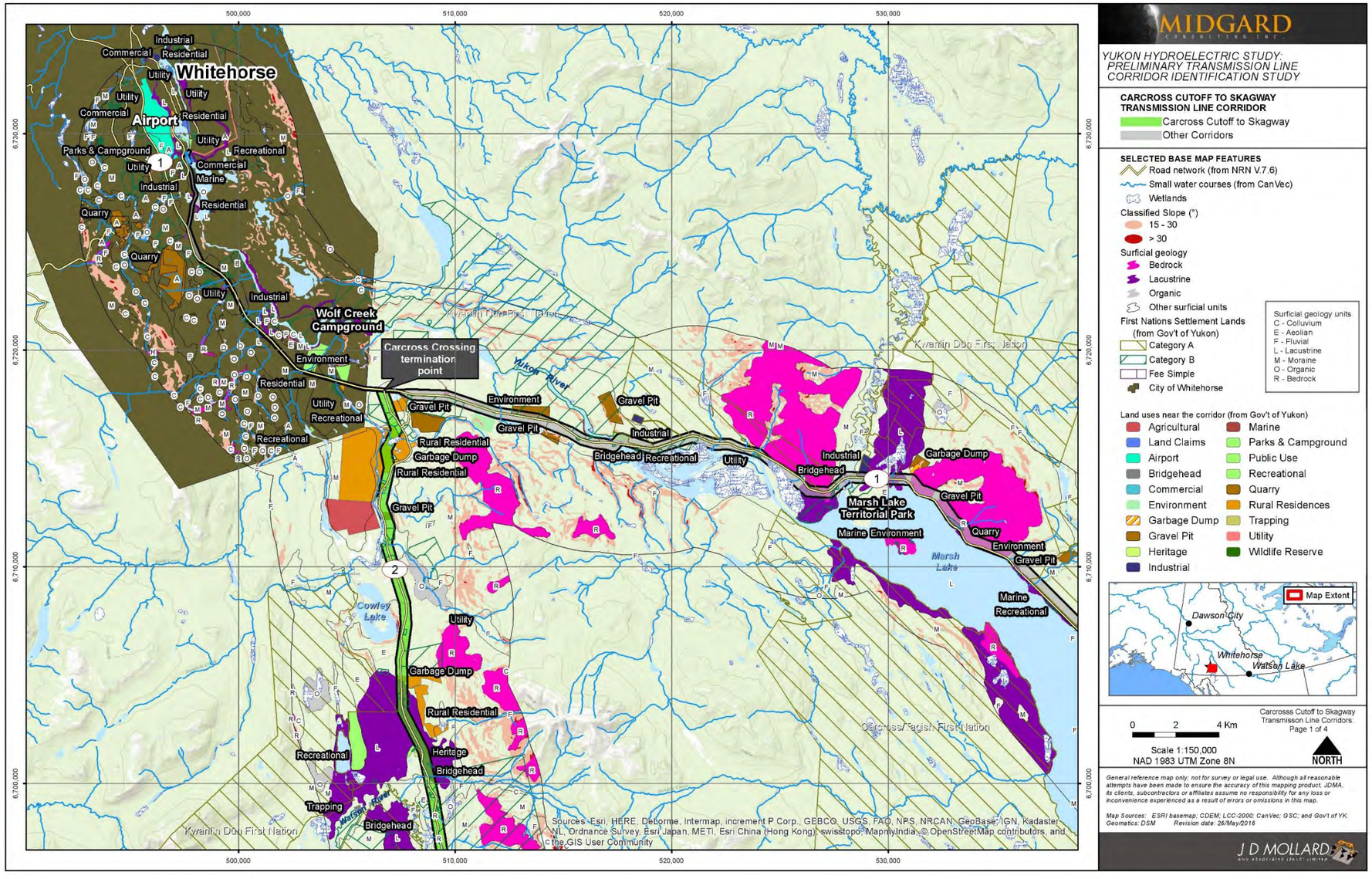
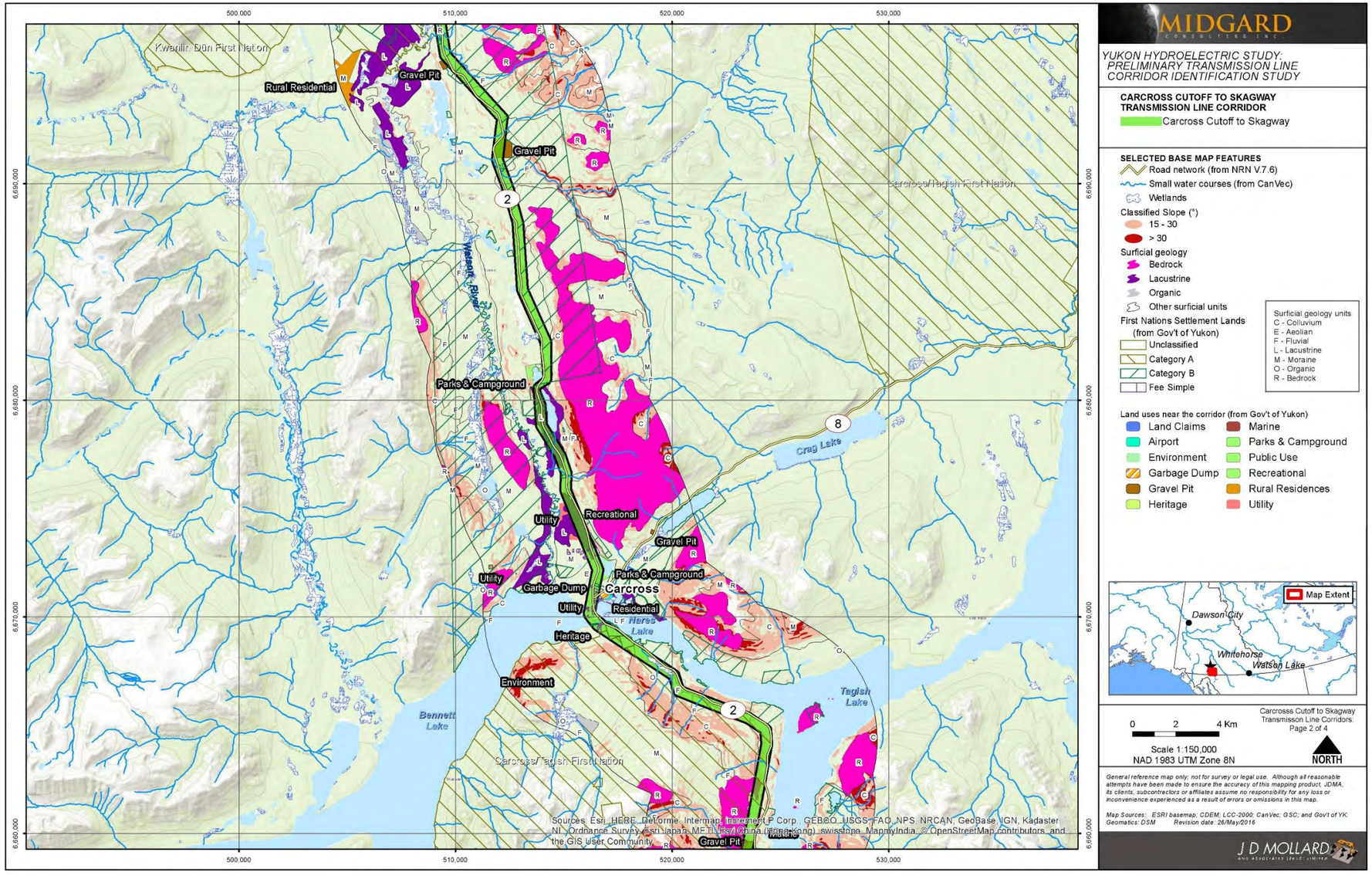
Map Sources: ESRI basemap; CDEM; LCC-2000; CanVec; GSC; and Gov't of YK
Geomatics: DSM Revision date: 26/May/2016
J.D. MOLLARD AND ASSOCIATES (2010) LIMITED

Figure A6: Carcross Cutoff to Skagway map booklet





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YUKON HYDROELECTRIC STUDY: PRELIMINARY TRANSMISSION LINE CORRIDOR IDENTIFICATION STUDY

CARCROSS CUTOFF TO SKAGWAY TRANSMISSION LINE CORRIDOR

Carcross Cutoff to Skagway

SELECTED BASE MAP FEATURES

- Road network (from NRN V.7.6)
- Small water courses (from CanVec)
- Wetlands

Classified Slope (°)

- 15 - 30
- > 30

Surficial geology

- Bedrock
- Lacustrine
- Organic
- Other surficial units

Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock

First Nations Settlement Lands (from Gov't of Yukon)

- Unclassified
- Category A
- Category B
- Fee Simple

Land uses near the corridor (from Gov't of Yukon)

- Land Claims
- Airport
- Environment
- Garbage Dump
- Gravel Pit
- Heritage
- Marine
- Parks & Campground
- Public Use
- Recreational
- Rural Residences
- Utility

Carcrosss Cutoff to Skagway Transmisson Line Corridors: Page 2 of 4

0 2 4 Km

Scale 1:150,000
NAD 1983 UTM Zone 8N

NORTH

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Map Sources: ESRI basemap; CDEM; LCC-2000; CanVec; GSC; and Gov't of YK
Geomatics: DSM Revision date: 26/May/2016

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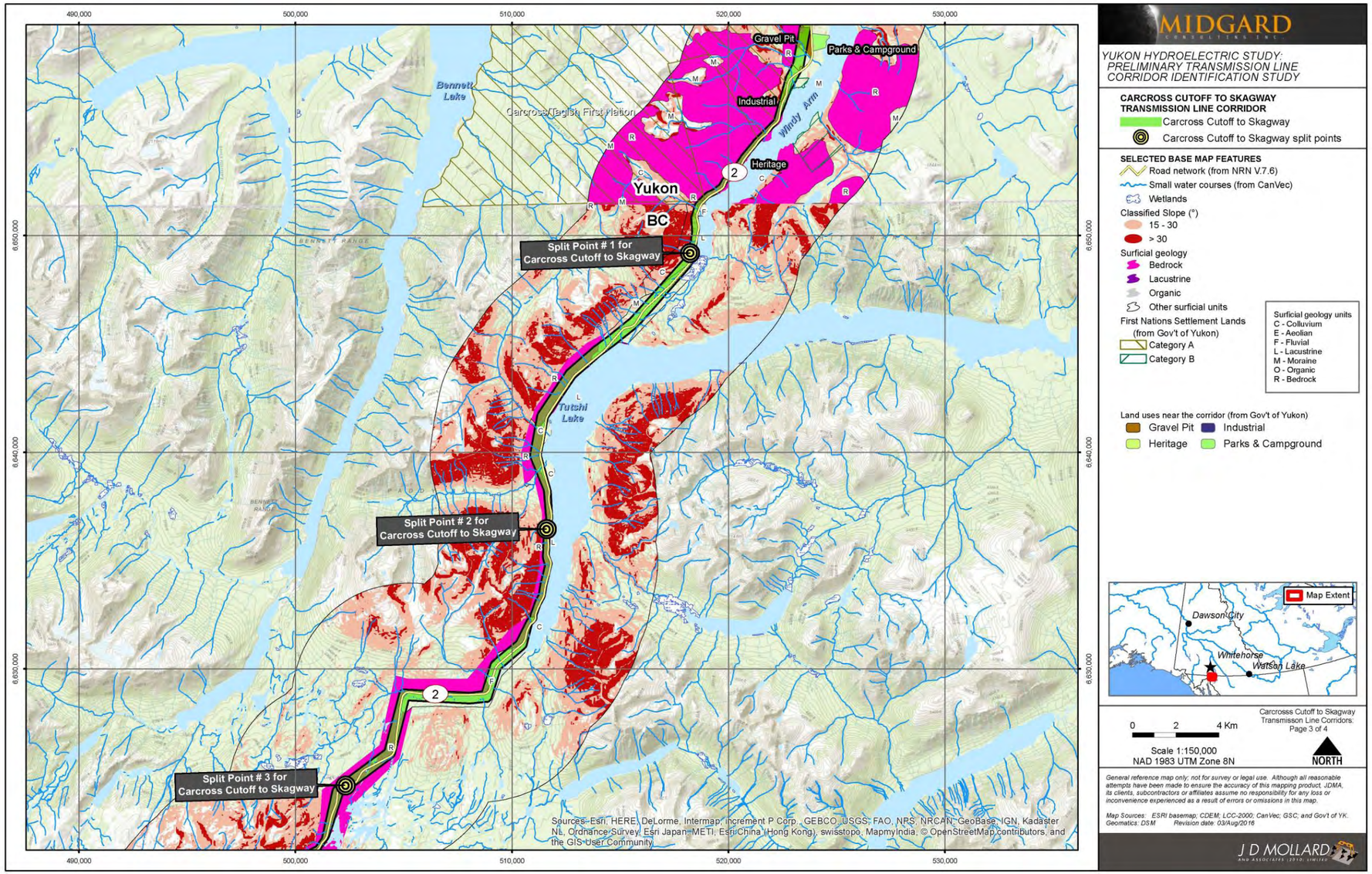
490,000
500,000
510,000
520,000
530,000
6,650,000
6,640,000
6,630,000
Gravel Pit
Parks & Campground
Industrial
Heritage
Bennett Lake
Carcross/Tagish First Nation
Windy Arm
Yukon
BC
2
Split Point # 1 for
Carcross Cutoff to Skagway
Tutshi Lake
Split Point # 2 for
Carcross Cutoff to Skagway
Split Point # 3 for
Carcross Cutoff to Skagway
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
CARCROSS CUTOFF TO SKAGWAY
TRANSMISSION LINE CORRIDOR
Carcross Cutoff to Skagway
Carcross Cutoff to Skagway split points
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Organic
Other surficial units
First Nations Settlement Lands
(from Gov't of Yukon)
Category A
Category B
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Gravel Pit
Industrial
Heritage
Parks & Campground
Map Extent
Dawson City
Whitehorse
Watson Lake
Carcross Cutoff to Skagway
Transmisson Line Corridors:
Page 3 of 4
0
2
4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
NORTH
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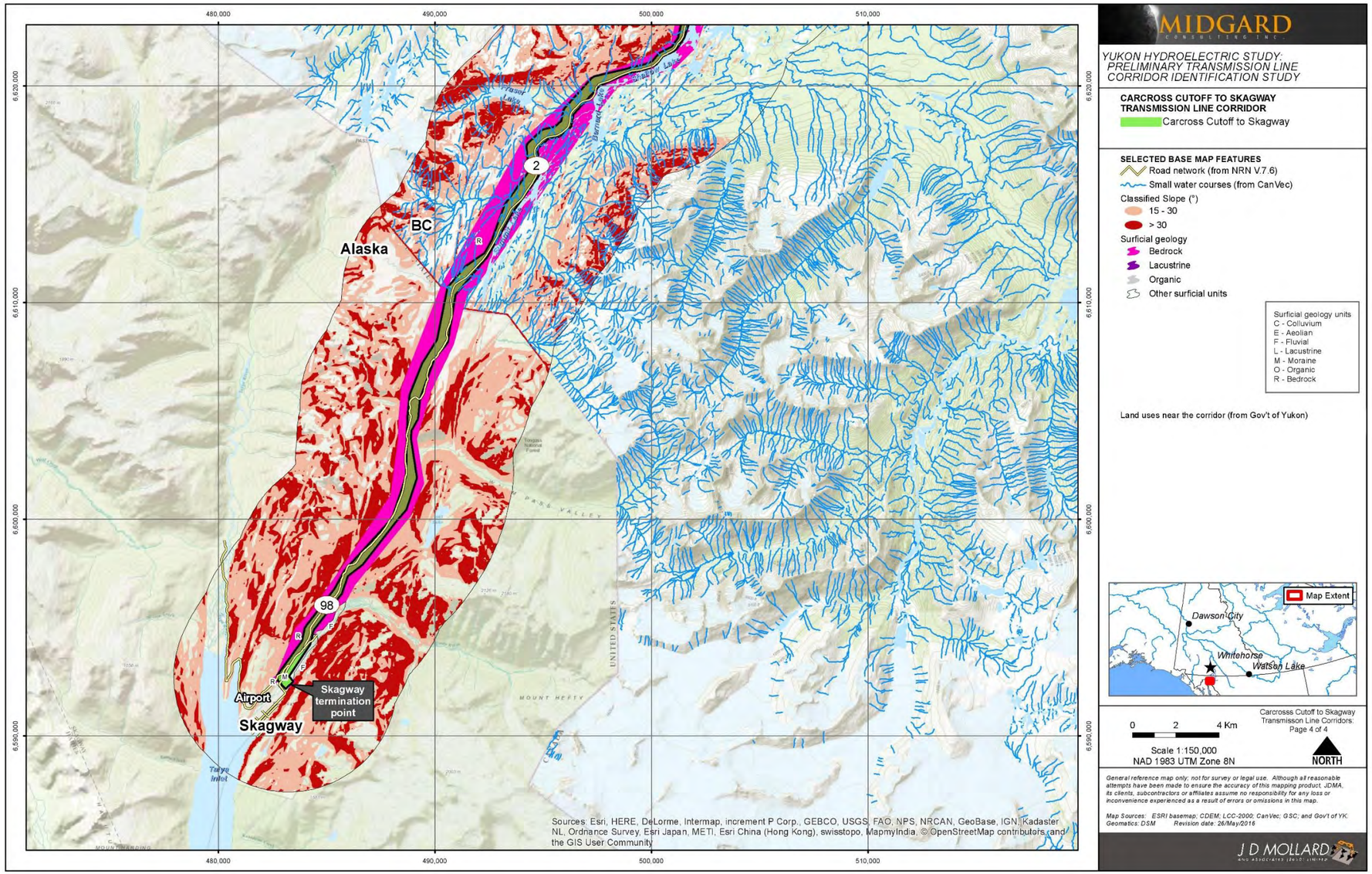
Map Sources: ESRI basemap; CDEM; LCC-2000; CanVec; GSC; and Gov't of YK.
Geomatics: DSM Revision date: 03/Aug/2016
J D MOLLARD AND ASSOCIATES (2010) LIMITED


480,000
490,000
500,000
510,000
6,620,000
6,610,000
6,600,000
6,590,000
BC
Alaska
2
98
Airport
Skagway
Skagway termination point
Tarya Inlet
UNITED STATES
MOUNT HEFTY
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
CARCROSS CUTOFF TO SKAGWAY
TRANSMISSION LINE CORRIDOR
Carcross Cutoff to Skagway
SELECTED BASE MAP FEATURES
Road network (from NRN V.7.6)
Small water courses (from CanVec)
Classified Slope (°)
15 - 30
> 30
Surficial geology
Bedrock
Lacustrine
Organic
Other surficial units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
Carcrosss Cutoff to Skagway
Transmisson Line Corridors:
Page 4 of 4
NORTH
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Map Sources: ESRI basemap; CDEM; LCC-2000; CanVec; GSC; and GovT of YK
Geomatics: DSM Revision date: 26/May/2016
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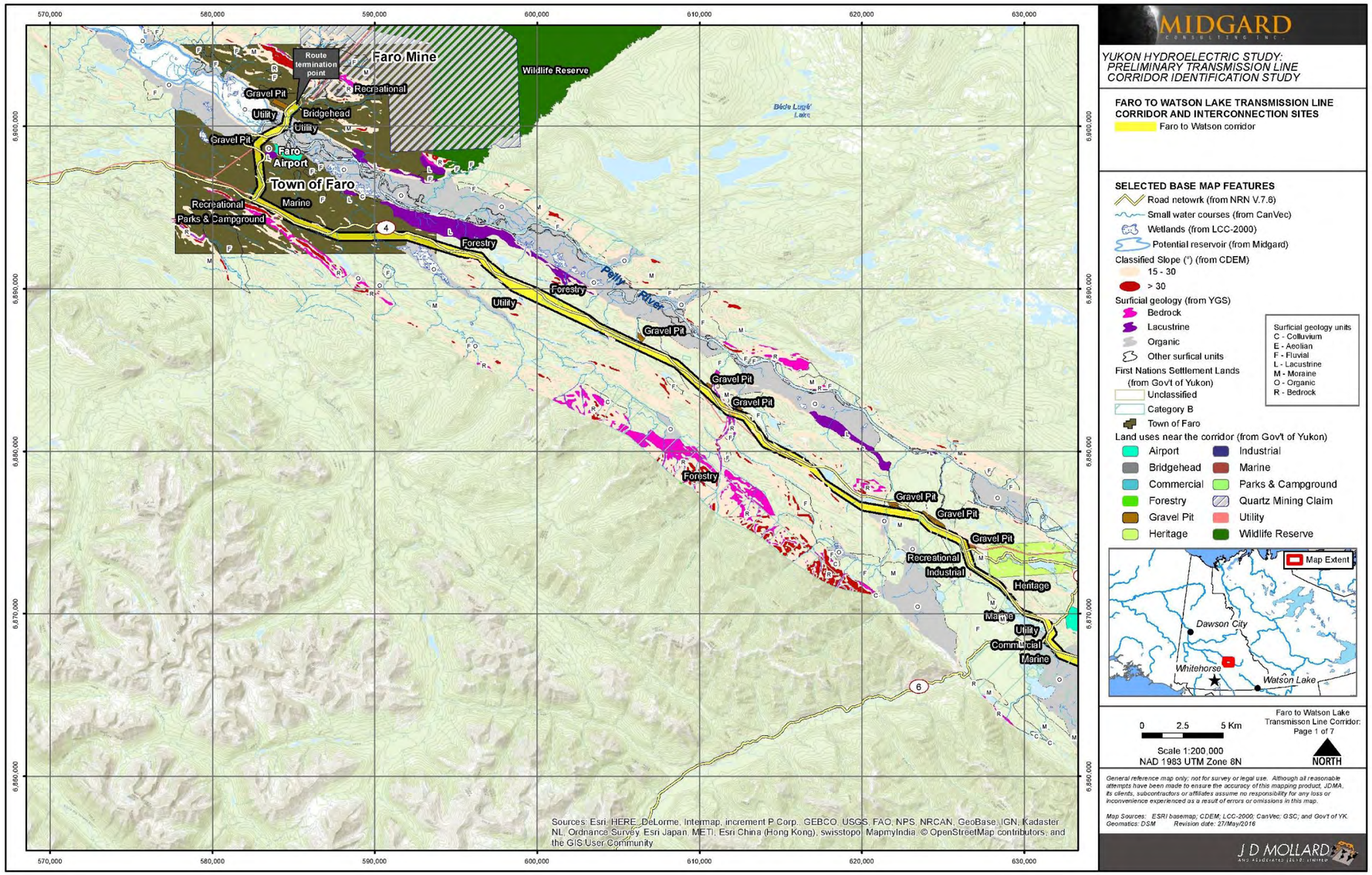
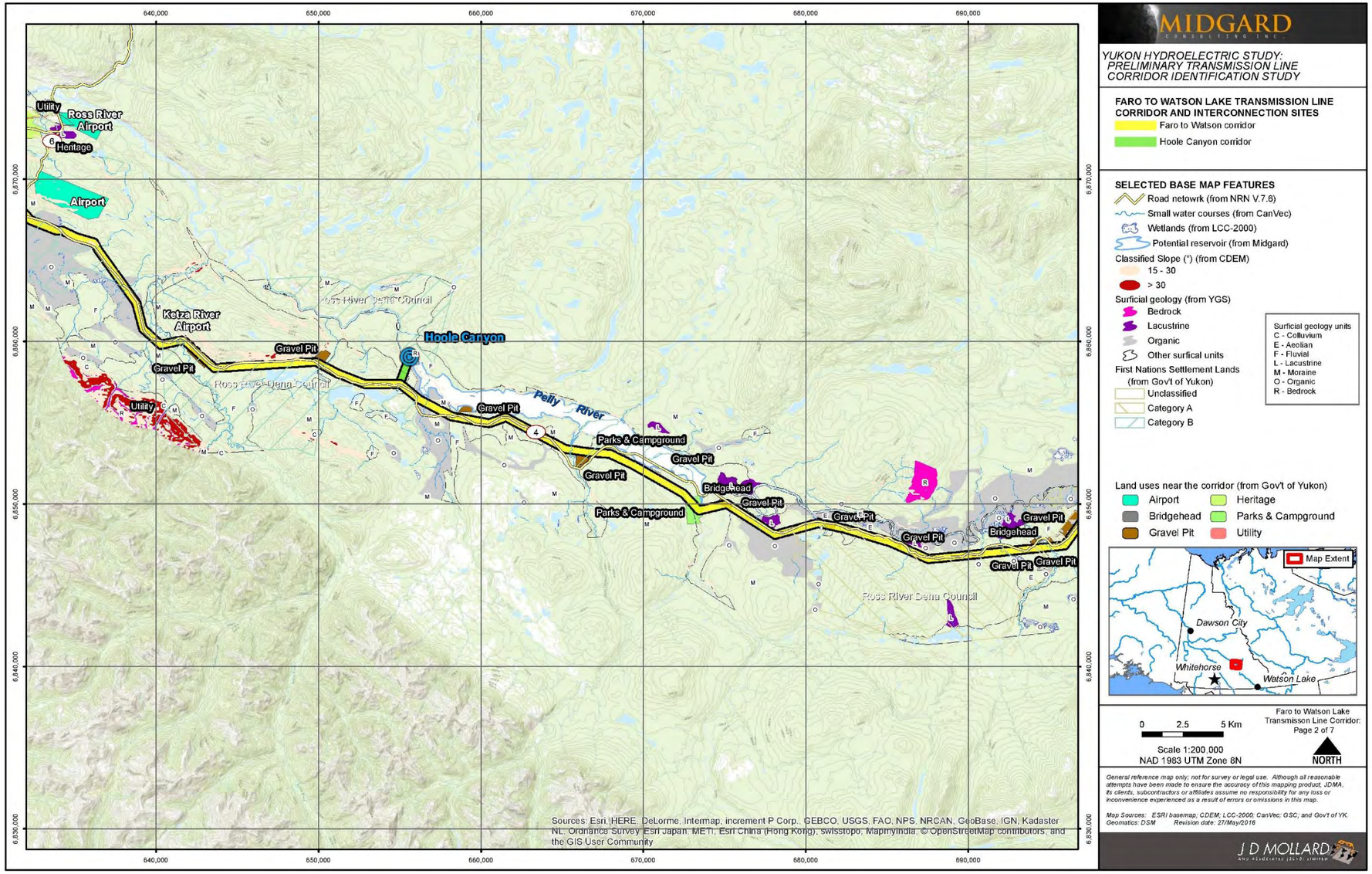
Figure A7: Faro to Watson Lake map booklet

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650,000
660,000
670,000
680,000
690,000
6,870,000
6,860,000
6,850,000
6,840,000
6,830,000
Utility
Ross River Airport
Heritage
Airport
Kelza River Airport
Gravel Pit
Hoole Canyon
Ross River Dena Council
Pelly River
Parks & Campground
Bridgehead
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
FARO TO WATSON LAKE TRANSMISSION LINE CORRIDOR AND INTERCONNECTION SITES
Faro to Watson corridor
Hoole Canyon corridor
SELECTED BASE MAP FEATURES
Road netowrk (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands (from LCC-2000)
Potential reservoir (from Midgard)
Classified Slope (°) (from CDEM)
15 - 30
> 30
Surficial geology (from YGS)
Bedrock
Lacustrine
Organic
Other surfical units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
First Nations Settlement Lands (from Gov't of Yukon)
Unclassified
Category A
Category B
Land uses near the corridor (from Gov't of Yukon)
Airport
Heritage
Bridgehead
Parks & Campground
Gravel Pit
Utility
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2.5 5 Km
Scale 1:200,000
NAD 1983 UTM Zone 8N
Faro to Watson Lake Transmisson Line Corridor: Page 2 of 7
NORTH
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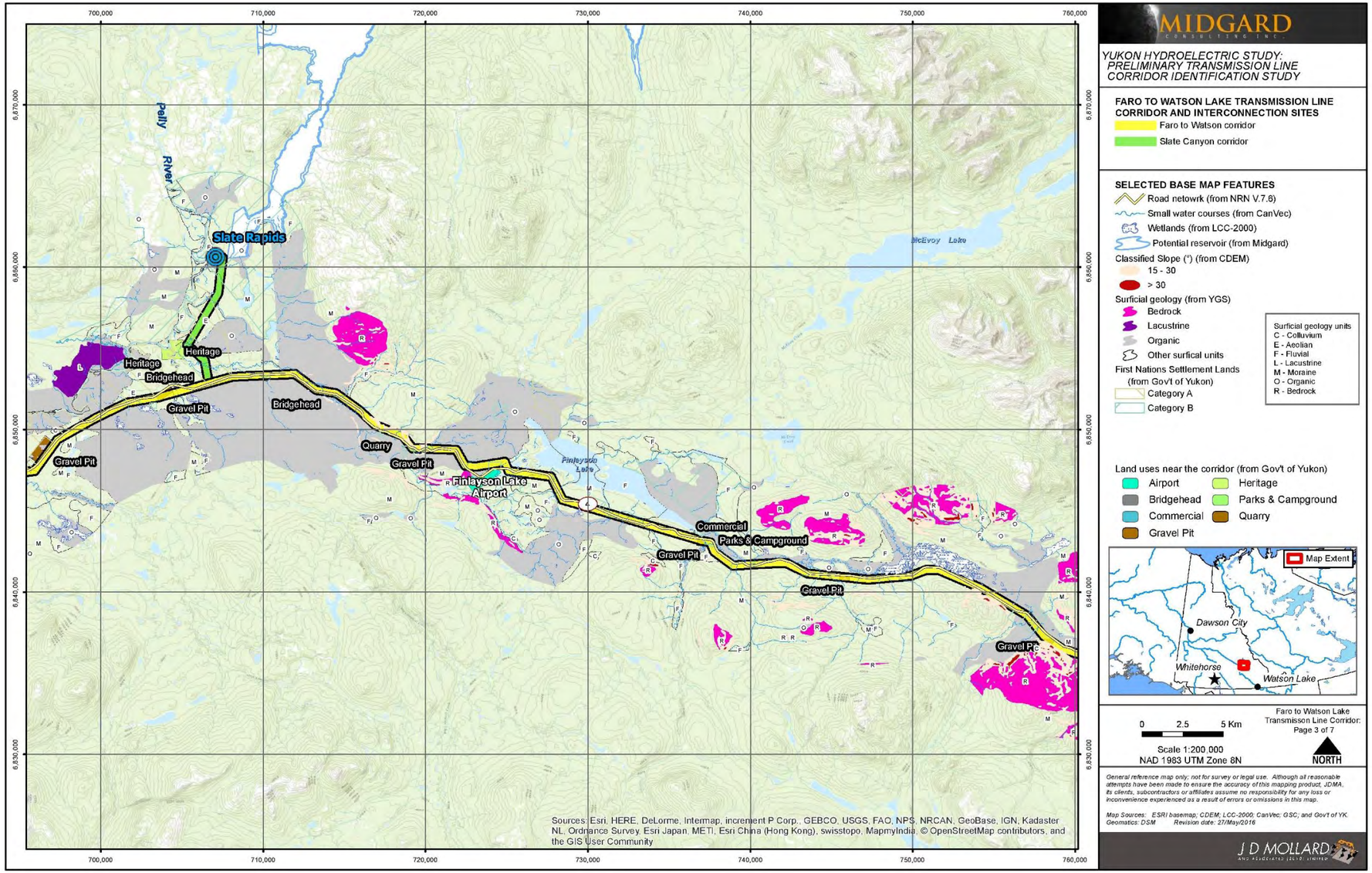
Map Sources: ESRI basemap; CDEM, LCC-2000; CanVec; GSC; and Gov't of YK.
Geomatics: DSM Revision date: 27/May/2016
J.D. MOLLARD AND ASSOCIATES (2010) LIMITED


700,000
710,000
720,000
730,000
740,000
750,000
760,000
6,870,000
6,860,000
6,850,000
6,840,000
6,830,000
Petly River
Slate Rapids
McEvoy Lake
Heritage
Heritage
Bridgehead
Gravel Pit
Bridgehead
Quarry
Gravel Pit
Gravel Pit
Finlayson Lake
Airport
Pinkyada Lake
Commercial
Parks & Campground
Gravel Pit
Gravel Pit
Gravel Pit
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
FARO TO WATSON LAKE TRANSMISSION LINE CORRIDOR AND INTERCONNECTION SITES
Faro to Watson corridor
Slate Canyon corridor
SELECTED BASE MAP FEATURES
Road netowrk (from NRN V.7.8)
Small water courses (from CanVec)
Wetlands (from LCC-2000)
Potential reservoir (from Midgard)
Classified Slope (°) (from CDEM)
15 - 30
> 30
Surficial geology (from YGS)
Bedrock
Lacustrine
Organic
Other surfical units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
First Nations Settlement Lands
(from Gov't of Yukon)
Category A
Category B
Land uses near the corridor (from Gov't of Yukon)
Airport
Bridgehead
Commercial
Gravel Pit
Heritage
Parks & Campground
Quarry
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2.5 5 Km
Scale 1:200,000
NAD 1983 UTM Zone 8N
Faro to Watson Lake
Transmisson Line Corridor:
Page 3 of 7
NORTH
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Geomatics: DSM Revision date: 27/May/2016
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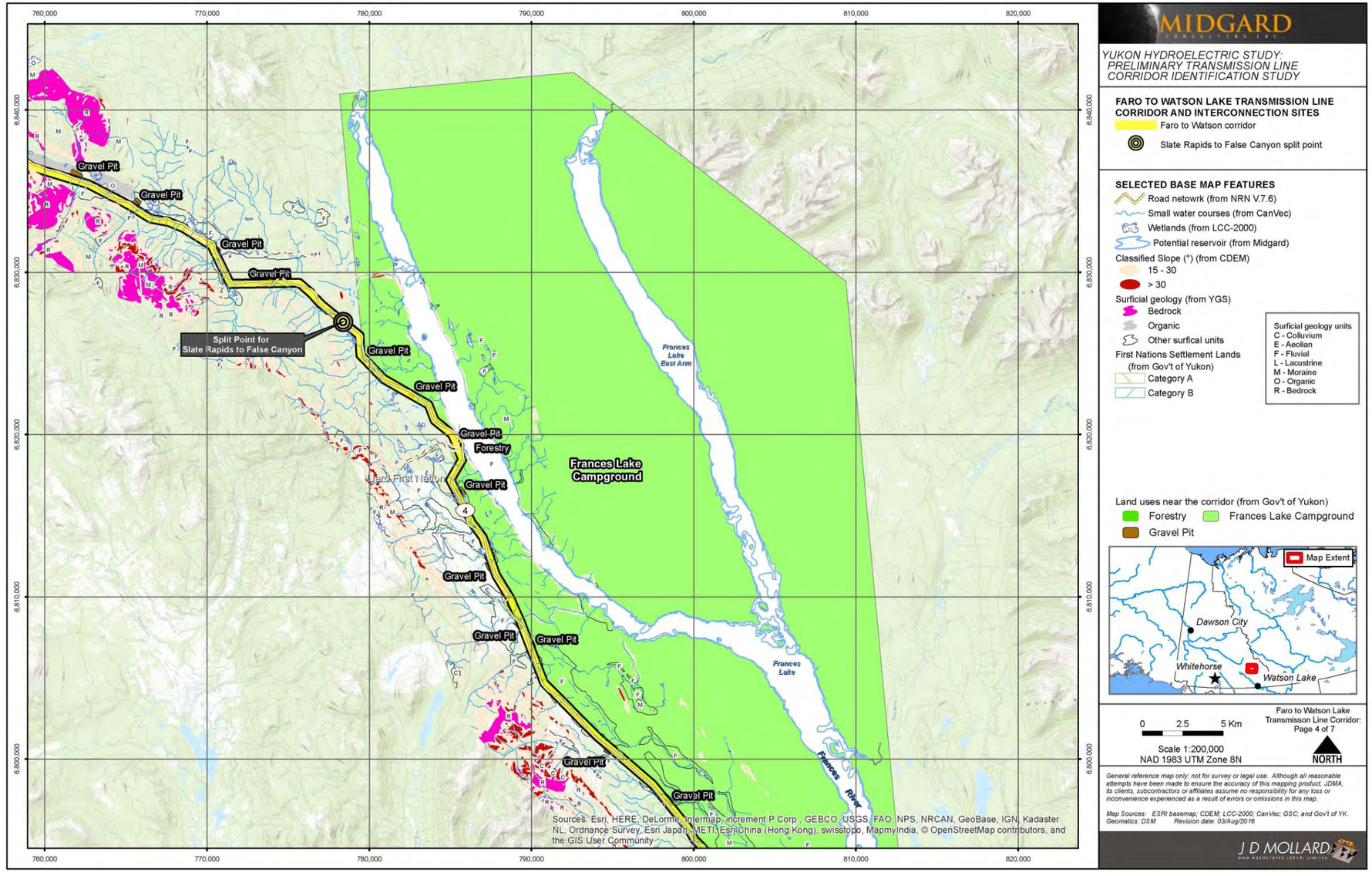
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770,000
780,000
790,000
800,000
810,000
820,000
6,840,000
6,830,000
6,820,000
6,810,000
6,800,000
Gravel Pit
Split Point for Slate Rapids to False Canyon
Frances Lake East Arm
Frances Lake Campground
Forestry
Liard First Nation
Frances Lake
Frances River
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE CORRIDOR IDENTIFICATION STUDY
FARO TO WATSON LAKE TRANSMISSION LINE CORRIDOR AND INTERCONNECTION SITES
Faro to Watson corridor
Slate Rapids to False Canyon split point
SELECTED BASE MAP FEATURES
Road netowrk (from NRN V.7.6)
Small water courses (from CanVec)
Wetlands (from LCC-2000)
Potential reservoir (from Midgard)
Classified Slope (°) (from CDEM)
15 - 30
> 30
Surficial geology (from YGS)
Bedrock
Organic
Other surfical units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
First Nations Settlement Lands (from Gov't of Yukon)
Category A
Category B
Land uses near the corridor (from Gov't of Yukon)
Forestry
Frances Lake Campground
Gravel Pit
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2.5 5 Km
Scale 1:200,000
NAD 1983 UTM Zone 8N
Faro to Watson Lake Transmisson Line Corridor: Page 4 of 7
NORTH
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Geomatics: DSM Revision date: 03/Aug/2016
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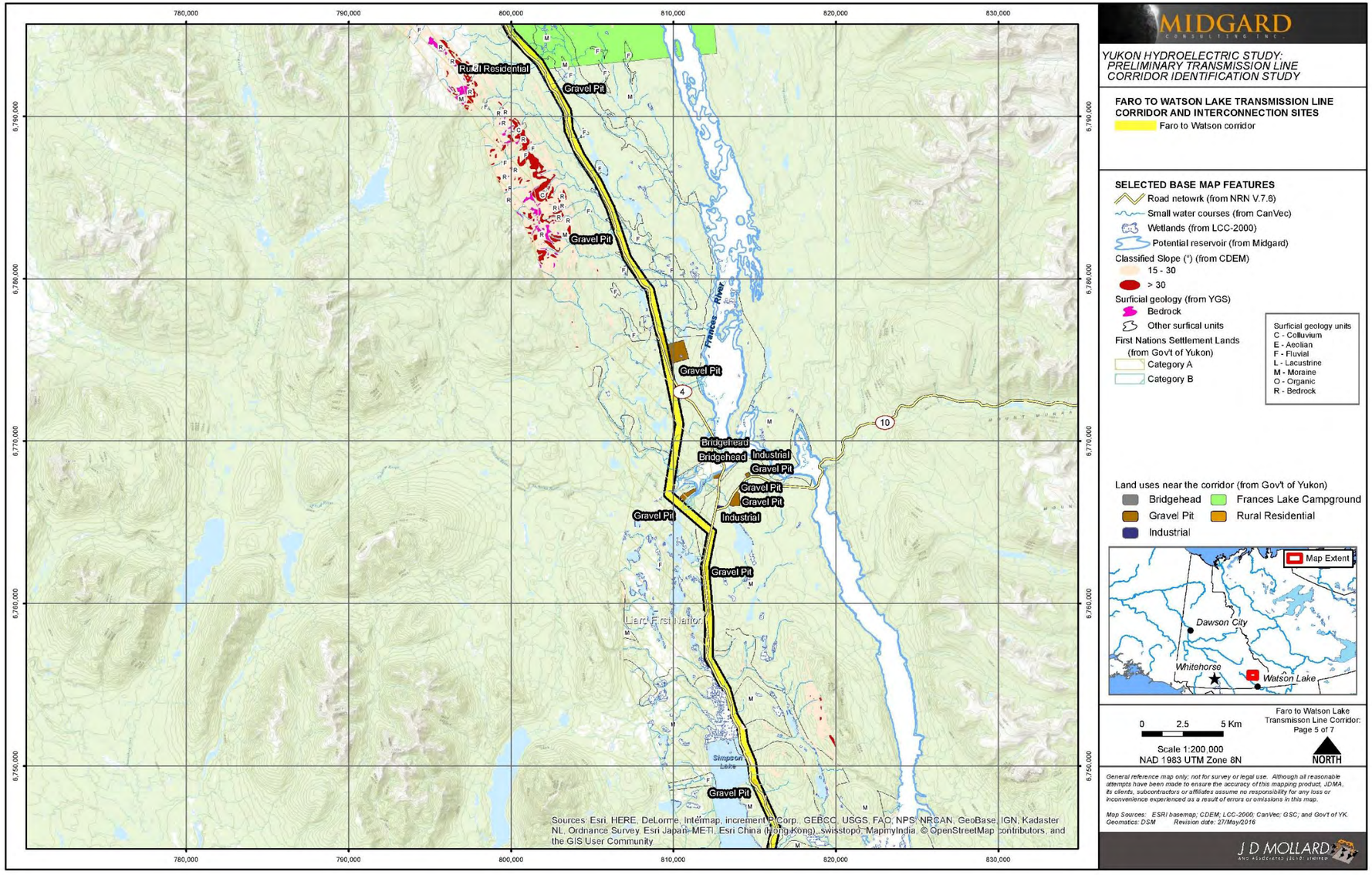
780,000
790,000
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810,000
820,000
830,000
6,780,000
6,770,000
6,760,000
6,750,000
Rural Residential
Gravel Pit
Frances River
4
10
Bridgehead
Industrial
Liard First Nation
Simpson Lake
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
FARO TO WATSON LAKE TRANSMISSION LINE CORRIDOR AND INTERCONNECTION SITES
Faro to Watson corridor
SELECTED BASE MAP FEATURES
Road netowrk (from NRN V.7.8)
Small water courses (from CanVec)
Wetlands (from LCC-2000)
Potential reservoir (from Midgard)
Classified Slope (°) (from CDEM)
15 - 30
> 30
Surficial geology (from YGS)
Bedrock
Other surfical units
First Nations Settlement Lands (from Gov't of Yukon)
Category A
Category B
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Bridgehead
Gravel Pit
Industrial
Frances Lake Campground
Rural Residential
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2.5 5 Km
Scale 1:200,000
NAD 1983 UTM Zone 8N
Faro to Watson Lake Transmisson Line Corridor: Page 5 of 7
NORTH
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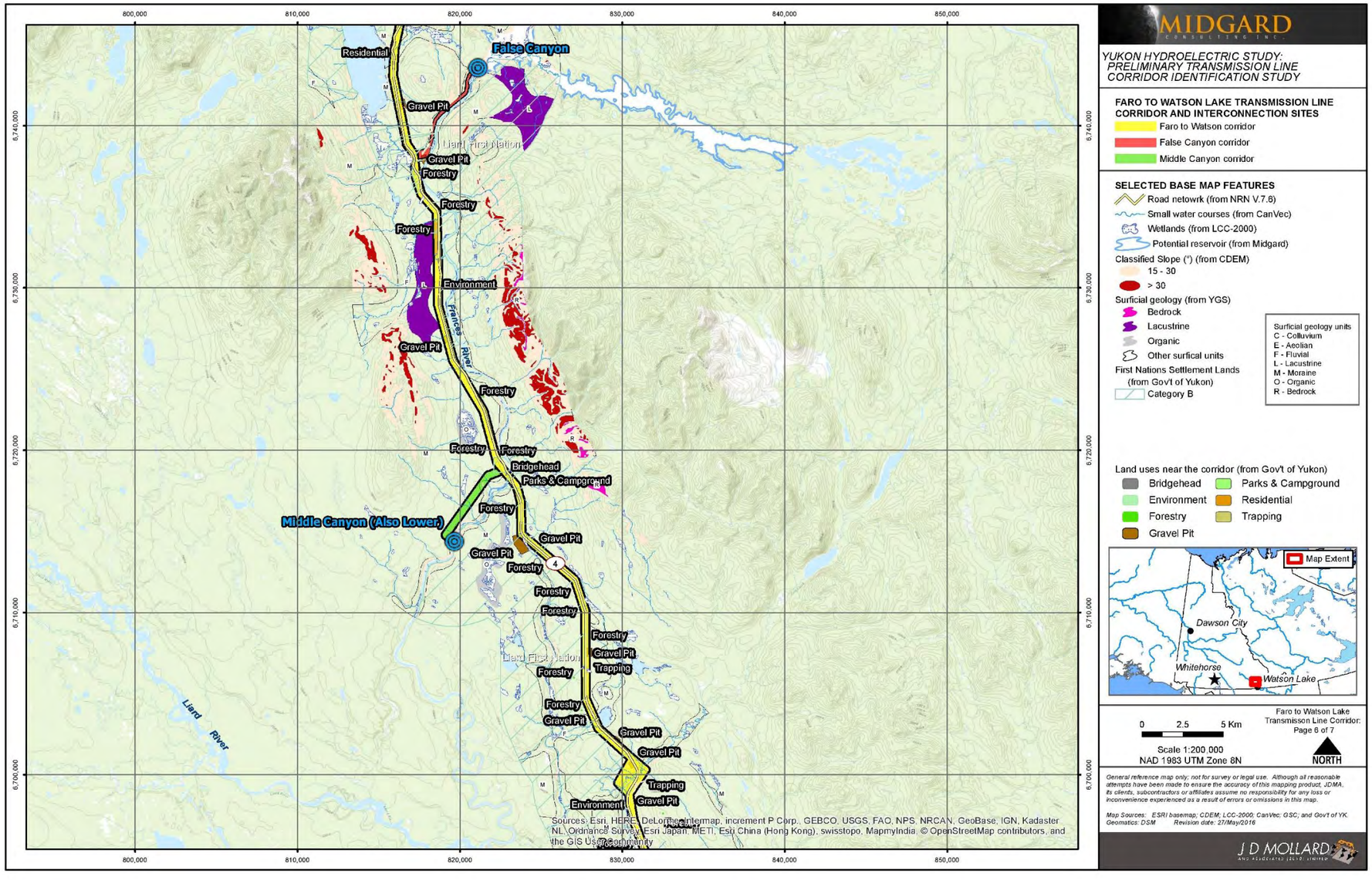
Geomatics: DSM Revision date: 27/May/2016
J.D. MOLLARD AND ASSOCIATES (2010) LIMITED


800,000
810,000
820,000
830,000
840,000
850,000
6,740,000
6,730,000
6,720,000
6,710,000
6,700,000
Residential
False Canyon
Gravel Pit
Liard First Nation
Forestry
Environment
Frances River
Bridgehead
Parks & Campground
Middle Canyon (Also Lower)
Trapping
Liard River
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
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PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
FARO TO WATSON LAKE TRANSMISSION LINE CORRIDOR AND INTERCONNECTION SITES
Faro to Watson corridor
False Canyon corridor
Middle Canyon corridor
SELECTED BASE MAP FEATURES
Road netowrk (from NRN V.7.8)
Small water courses (from CanVec)
Wetlands (from LCC-2000)
Potential reservoir (from Midgard)
Classified Slope (°) (from CDEM)
15 - 30
> 30
Surficial geology (from YGS)
Bedrock
Lacustrine
Organic
Other surfical units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
First Nations Settlement Lands
(from Gov't of Yukon)
Category B
Land uses near the corridor (from Gov't of Yukon)
Bridgehead
Environment
Forestry
Gravel Pit
Parks & Campground
Residential
Trapping
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2.5 5 Km
Scale 1:200,000
NAD 1983 UTM Zone 8N
Faro to Watson Lake
Transmisson Line Corridor:
Page 6 of 7
NORTH
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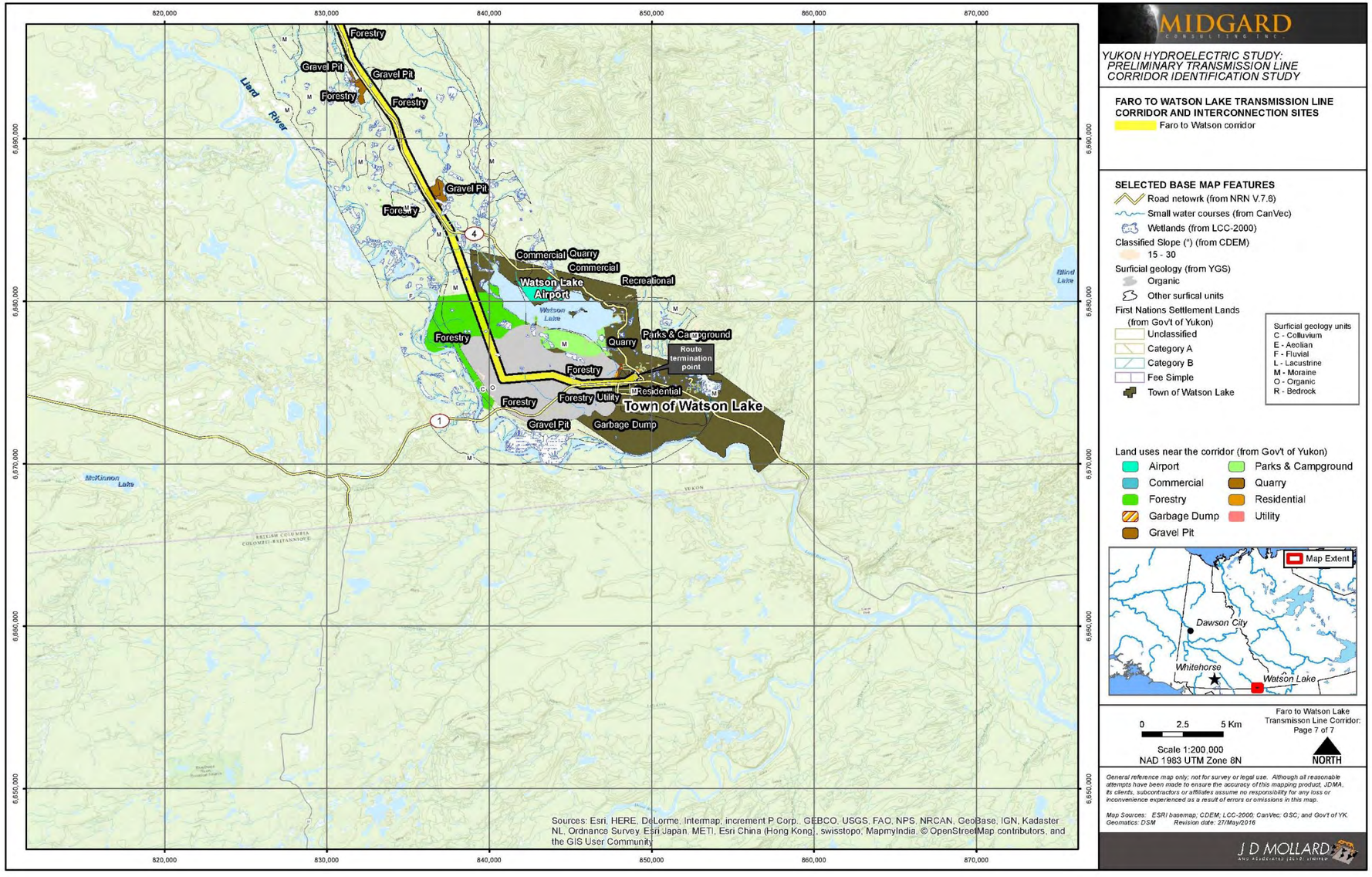
Map Sources: ESRI basemap; CDEM; LCC-2000; CanVec; GSC; and Gov't of YK
Geomatics: DSM Revision date: 27/May/2016
J.D. MOLLARD AND ASSOCIATES (2010) LIMITED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830,000
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850,000
860,000
870,000
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6,680,000
6,670,000
6,660,000
6,650,000
Forestry
Gravel Pit
Gravel Pit
Forestry
Forestry
Land River
Gravel Pit
Forestry
4
Commercial Quarry
Commercial
Watson Lake Airport
Recreational
Watson Lake
Forestry
Quarry
Parks & Campground
Route termination point
Forestry
Forestry
Forestry Utility
Residential
Town of Watson Lake
1
Gravel Pit
Garbage Dump
McKinnon Lake
BRITISH COLUMBIA
COLOMBIE-BRITANNIQUE
YUKON
Blind Lake
Sources: Esri, HERE, DeLorme, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community
MIDGARD CONSULTING INC.
YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE
CORRIDOR IDENTIFICATION STUDY
FARO TO WATSON LAKE TRANSMISSION LINE CORRIDOR AND INTERCONNECTION SITES
Faro to Watson corridor
SELECTED BASE MAP FEATURES
Road netowrk (from NRN V.7.8)
Small water courses (from CanVec)
Wetlands (from LCC-2000)
Classified Slope (°) (from CDEM)
15 - 30
Surficial geology (from YGS)
Organic
Other surfical units
First Nations Settlement Lands
(from Gov't of Yukon)
Unclassified
Category A
Category B
Fee Simple
Town of Watson Lake
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
Land uses near the corridor (from Gov't of Yukon)
Airport
Commercial
Forestry
Garbage Dump
Gravel Pit
Parks & Campground
Quarry
Residential
Utility
Map Extent
Dawson City
Whitehorse
Watson Lake
0 2.5 5 Km
Scale 1:200,000
NAD 1983 UTM Zone 8N
Faro to Watson Lake
Transmisson Line Corridor:
Page 7 of 7
NORTH
General reference map only; not for survey or legal use. Although all reasonable attempts have been made to ensure the accuracy of this mapping product, JDMA, its clients, subcontractors or affiliates assume no responsibility for any loss or inconvenience experienced as a result of errors or omissions in this map.
Map Sources: ESRI basemap; CDEM; LCC-2000; CanVec; GSC; and Gov't of YK.
Geomatics: DSM Revision date: 27/May/2016
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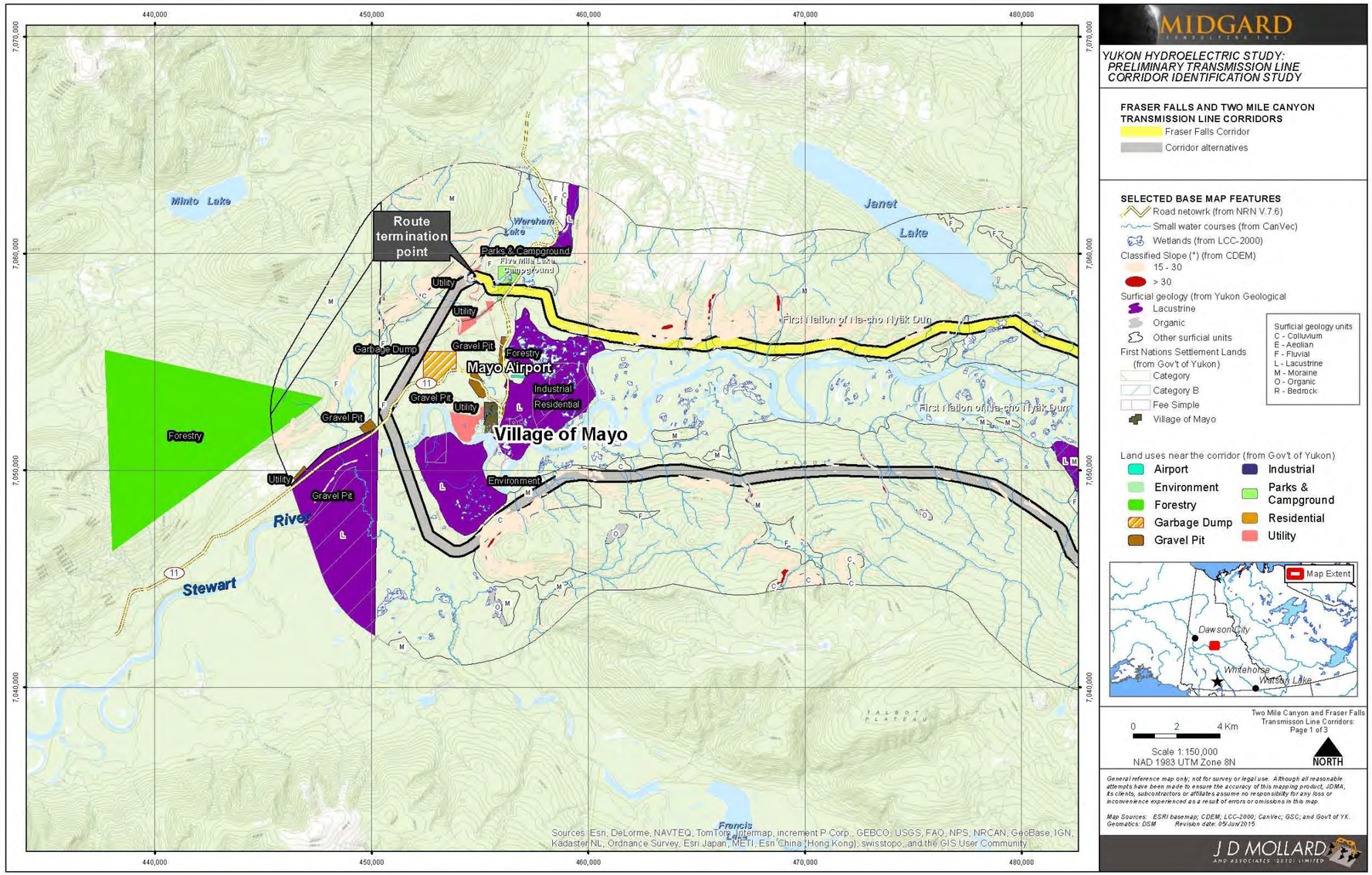
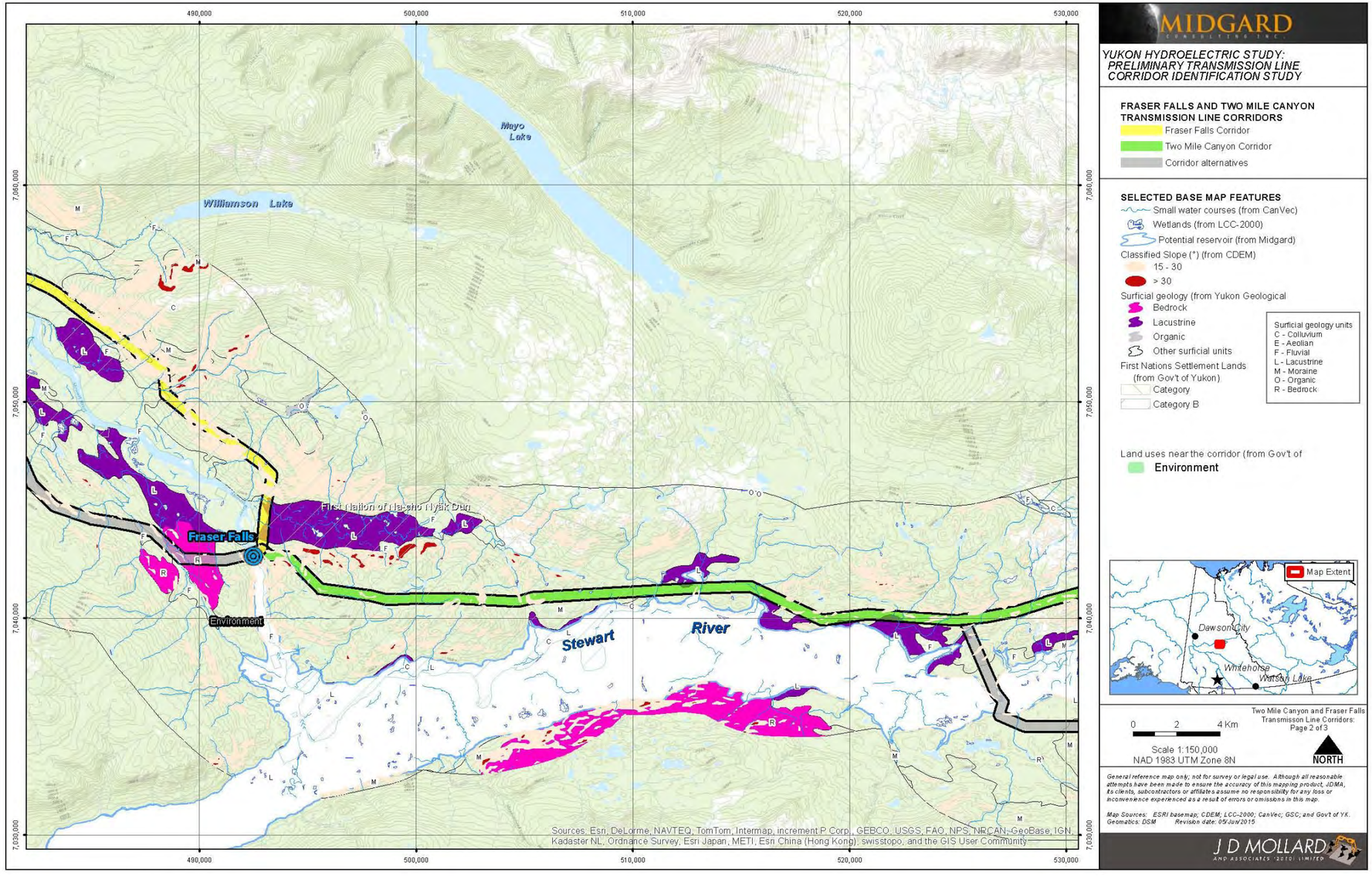
Figure A8: Fraser Falls and Two Mile Canyon map booklet




490,000
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Mayo Lake
Williamson Lake
First Nation of Na-cho Nyak Dun
Fraser Falls
Environment
Stewart River
Sources: Esri, DeLorme, NAVTEQ, TomTom, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, and the GIS User Community
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YUKON HYDROELECTRIC STUDY:
PRELIMINARY TRANSMISSION LINE CORRIDOR IDENTIFICATION STUDY
FRASER FALLS AND TWO MILE CANYON TRANSMISSION LINE CORRIDORS
Fraser Falls Corridor
Two Mile Canyon Corridor
Corridor alternatives
SELECTED BASE MAP FEATURES
Small water courses (from CanVec)
Wetlands (from LCC-2000)
Potential reservoir (from Midgard)
Classified Slope (°) (from CDEM)
15 - 30
> 30
Surficial geology (from Yukon Geological
Bedrock
Lacustrine
Organic
Other surficial units
Surficial geology units
C - Colluvium
E - Aeolian
F - Fluvial
L - Lacustrine
M - Moraine
O - Organic
R - Bedrock
First Nations Settlement Lands (from Gov't of Yukon)
Category
Category B
Land uses near the corridor (from Gov't of
Environment
Map Extent
Dawson City
Whitehorse
Watson Lake
Two Mile Canyon and Fraser Falls Transmisson Line Corridors: Page 2 of 3
0 2 4 Km
Scale 1:150,000
NAD 1983 UTM Zone 8N
NORTH
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Geomatics: DSM Revision date: 05/Jun/2015
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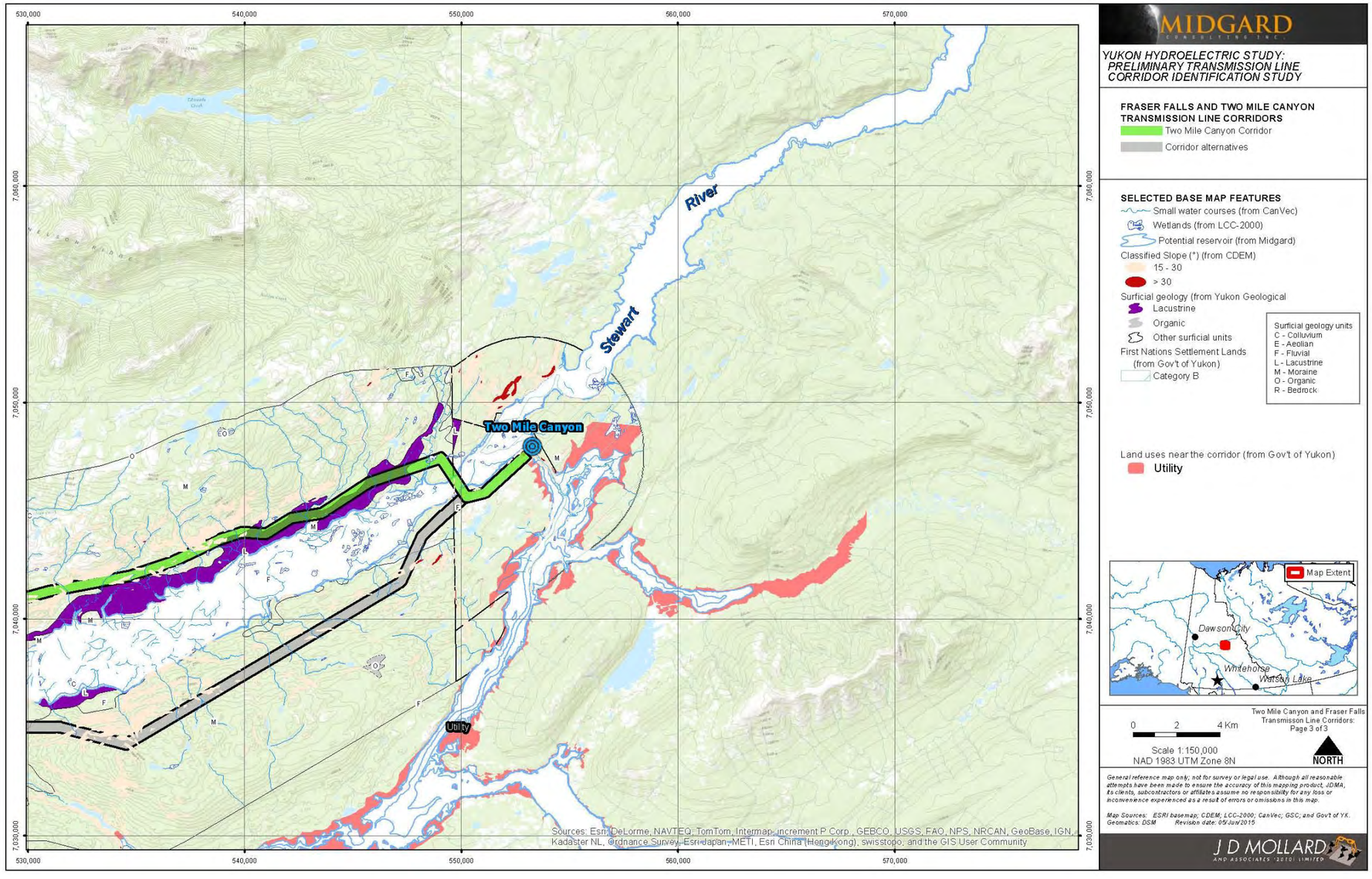
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Stewart River
Two Mile Canyon
Utility
Sources: Esri, DeLorme, NAVTEQ, TomTom, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, and the GIS User Community
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Land uses near the corridor (from Gov't of Yukon)
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Map Extent
Dawson City
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Geomatics: DSM Revision date: 05/Jun/2015
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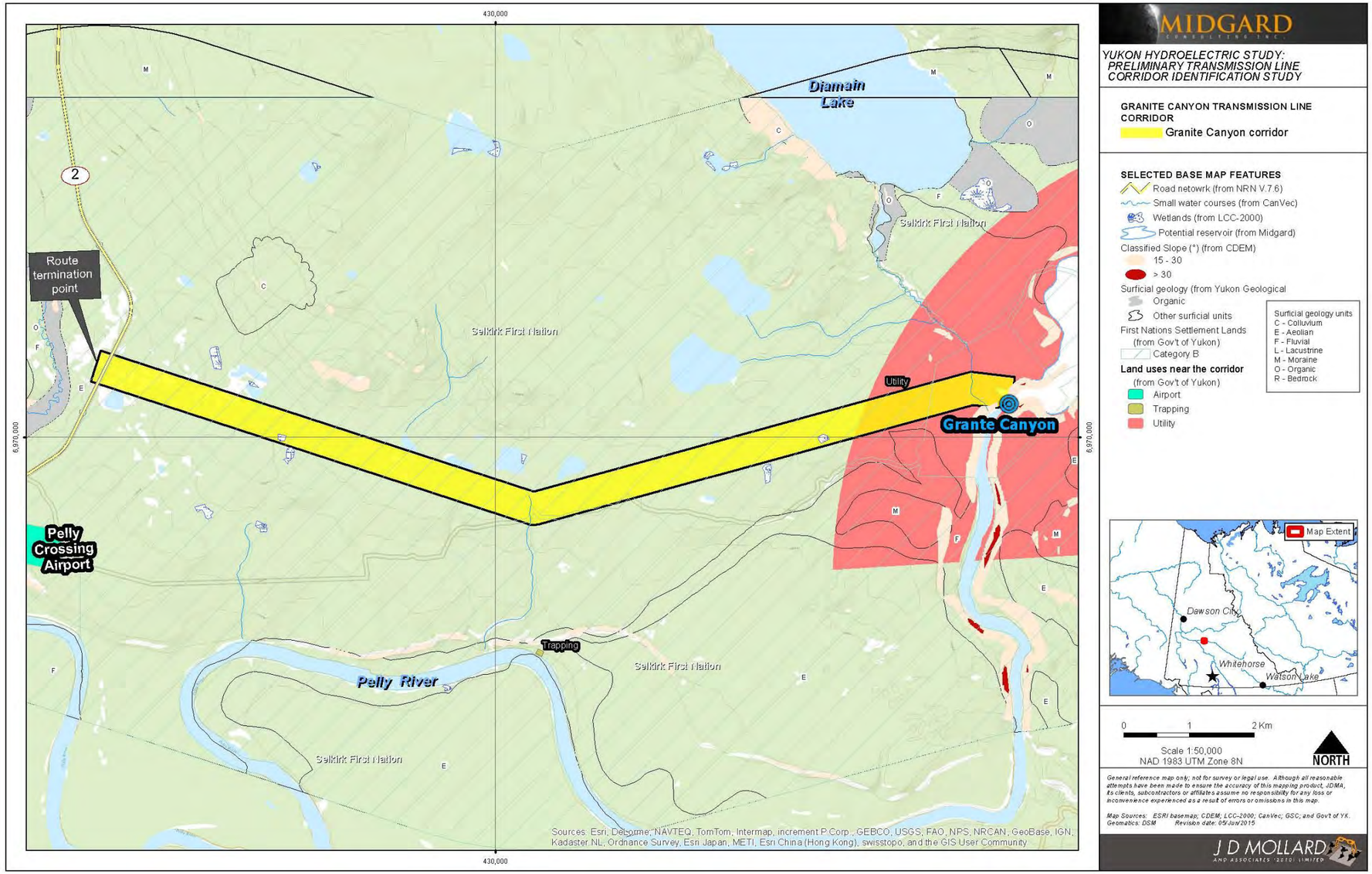
Figure A9: Granite Canyon map



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Appendix D:

69 kV Alternative Routing Analysis

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MEMORANDUM

To: Marc-Andre Lavigne, Yukon Energy Corporation

From: Sunil Bhatti, P.Eng.

Date: 1 November 2016

Subject: Transmission Options Evaluation – 69 kV Transmission Line Options Addendum

---

- Midgard Consulting Incorporated ("Midgard") was commissioned to calculate the capital cost and average losses incurred to serve a load of 8 MW for two 69 kV transmission lines:
  - Atlin → Jake's Corner
  - Whitehorse → Atlin
- The results of this exercise are summarized in Table 1 below

Table 1: 69 kV Transmission Line Option Evaluation Summary

Transmission Route	Voltage Class	Line Length	Reliable Transfer Capacity	Line Losses (at 8 MW Load)	Capital Cost	Operating Cost	Earliest Possible ISD
Atlin → Jake's Corner	69 kV	93 km	38 MW	0.4 MW	$54.2 M	$129 k / Year	Jan 2020
Whitehorse → Atlin	69 kV	172 km	21 MW	0.6 MW	$104 M	$236 k / Year	Oct 2020

Note: Whitehorse → Atlin line losses were achieved using a 2 MVAr shunt capacitor on the load bus.

Cost Assumptions

Capital Cost

- Midgard was unable to find cost data for recently-constructed 69 kV transmission lines in western Canada, and therefore was unable to use the costing methodology applied in the Transmission Options Evaluation report
- The 69 kV voltage class is no longer a common voltage class for new transmission lines; at transmission levels, utilities seem to opt for 138 kV instead
- 69 kV line cost estimate was derived by marking down the cost components of 138 kV lines:
  - Materials & Shipping cost for 69 kV were 50% of that of 138 kV
  - Engineering, Construction & Salvage for 69 kV were 75% of 138 kV
  - Land & Access for 69 kV were 66% of 138 kV

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Operating Cost & Schedule

- Operating cost & schedule calculated in accordance with methodology used in Transmission Options Evaluation

PSSE Simulation Details & Criteria

Table 2: Conductor Characteristics

Voltage Class	Conductor Type	Geometric Mean Radius	External Diameter	Conductors per Bundle	Phase Spacing	Conductor Temperature
69 kV	Partridge 266.8	0.0217 ft	0.642 in	1	1.35 m	100 °C

Table 3: Reliable Transfer Capacity Limit Modelling Criteria

Voltage Angle Limit:	Not to exceed 33 degrees
Thermal Limit:	Not studied
VAR Limits:	Not applied
Reliable Transfer Limit Calculation:	Real power injected into load bus

Table 4: Average Losses Modelling Criteria

Load Size:	8.89 MVA (8 MW at 0.9 power factor)
Bus Voltage Limits:	0.95 to 1.05 per unit
Average Loss Type:	Considered real power losses only
Average Loss Calculation:	Real power injected into generator bus less real power injected into load bus
Generator Power Factor:	Power factor >= 1.0
Shunt Compensation:	Minimized requirement for shunt compensation (to reduce capital cost)

PSSE Modelling Diagrams

Figure 1: Atlin → Jake's Corner Reliable Transfer Capacity PSSE Model

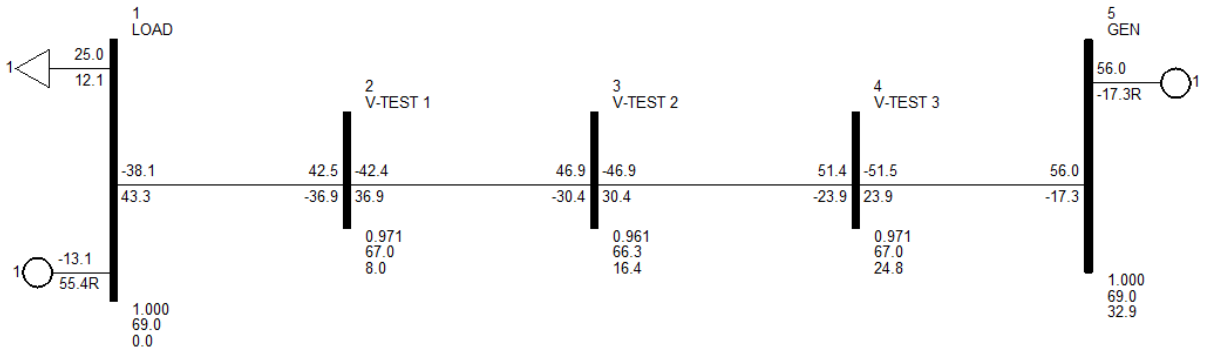

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Figure 2: Whitehorse → Atlin Reliable Transfer Capacity PSSE Model

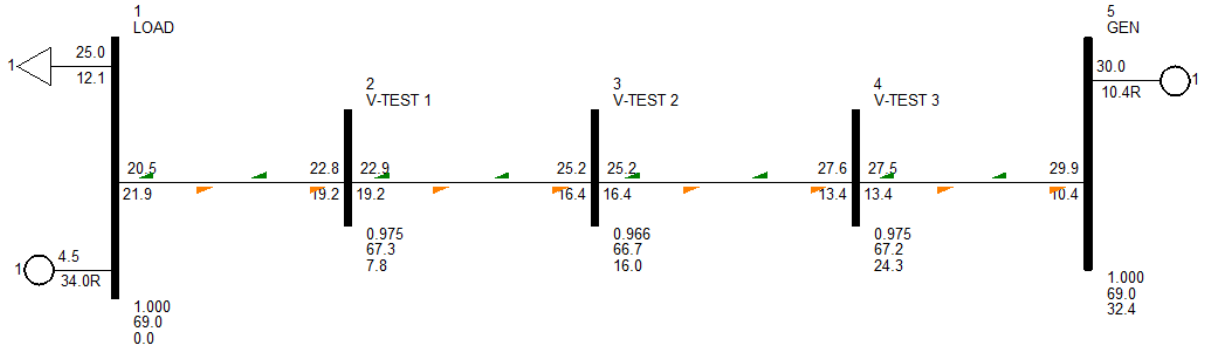


Figure 3: Atlin → Jake's Corner Average Losses PSSE Model

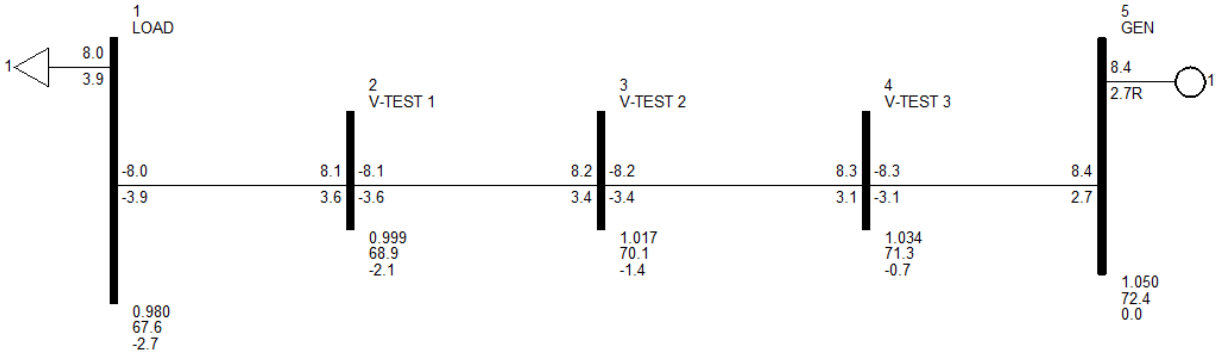
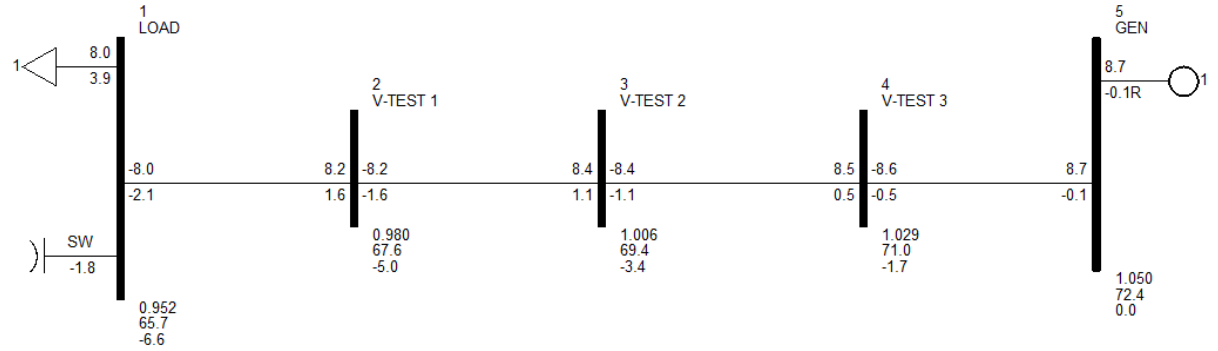


Figure 4: Whitehorse → Atlin Average Losses PSSE Model



Appendix 6.1
Liquefied Natural Gas: Potential Supply Options

Introduction

In May, 2016, as inputs to the pending 2016 Resource Plan, YEC undertook a 20 year forecast of future Liquefied Natural Gas (LNG) prices. This forecast included conservative assumptions with respect to the non-commodity components of delivered LNG. That is, the forecast assumed that the source of, and transportation routes of its LNG feedstock would remain relatively unchanged.

To augment the May work, YEC has now reviewed other possible LNG delivery options, which may achieve costs savings relative to the current forecast assumptions.

The approximate current $22/GJ cost of LNG delivered to YEC (Whitehorse) can be broken down as follows[1]:

LNG Cost Component

Transportation and Tanker Charge:	62%
Commodity Charge:	16%
Gas Charge:	22%
Total:	100%

These cost categories are detailed as follows:

- Transportation: this covers the cost of LNG delivery, from liquefaction plant to YEC, including the Tanker Charge, which is the rental fee for the LNG shipping vessel.
- Commodity Charge: This is the charge to convert natural gas to LNG using a refrigeration/liquefaction process; and
- Gas Charge: is the cost of the natural gas that is the LNG feedstock.

In estimating a possible future change in the above costs, YEC has reviewed potential options in each of the cost categories above.

Transportation Charge

The Transportation Charge should be highly correlated to the distance travelled, as it is composed of cost of labour (driver), the rental time for the vehicle, and the cost of the vehicle fuel (diesel). Larger loads and shorter distances should result in savings. Distances, driving time and status can be seen below in Table 1.

[1] This breakdown was obtained from delivered LNG invoices (2015- early 2016); the source data is commercially sensitive.

Table 1. Existing and Potential Sources of LNG

Location	Distance	Driving time	Status
Dawson Creek, BC (AltaGas)	1,460 km	16 hours	Existing
Delta, BC (Tilbury Island)	2,390 km	25 hours	Existing
Fort Nelson, BC (KT Energy)	988 km	11 hours	Potential

YEC's current source of LNG is Delta British Columbia (Tilbury Island). Dawson Creek is the location of the existing AltaGas LNG facility, which has announced plans to expand by over 30% to over 100 m^3/d. Dawson Creek is located in the heart of the Montney gas field, one of the largest, most prolific and most cost-competitive gas plays in North America. There is currently no LNG Facility in Fort Nelson, but in early 2016 KT Energy announced the potential for smaller-scale modular facilities in the region. Fort Nelson is situated in the Horn River gas supply basin, a major current and potential source of natural gas supply.

As transportation costs are highly correlated with the distance travelled, a more northerly LNG supply source should result in significant savings. Larger shipments than the current 60m^3 volume should result in cost savings. A number of different delivery options was reviewed, up to 90m^3 per load, a 50% increase in delivered LNG per shipment.

Commodity Charge

The two largest cost components for LNG production are capital cost recovery for the liquefaction plant, and the fuel cost for undertaking the chilling/liquefaction process. Natural gas is almost always used as the energy source for the LNG process, with approximately 7% of the input gas being consumed in the process. This is in large, efficient plants, with a higher percentage of gas consumed as fuel in smaller facilities. A very limited number of liquefaction plants use electricity to run the refrigeration process, but electricity is generally a more expensive source of energy than natural gas. The commodity charge is highly related to the efficiency of the liquefaction plant, with the cost of gas to LNG conversion being equivalent to $4/GJ and above. YEC has no information to indicate that with respect to this charge category, the Dawson Creek or a Fort Nelson LNG facility would be more efficient and more cost effective than its current supplier. Generally, the larger and older (depreciated) the LNG facility, the lower the liquefaction cost.

Gas Charge

Typically, the closer to the wellhead the natural gas supply, the less expensive, due to lower pipeline tolls. This makes North Eastern British Columbia sourced natural gas inherently less expensive that gas sourced further south. An analysis of natural gas prices at the Station 2 and Sumas market hubs indicates an approximate $0.50/GJ difference, with the northern hub having a lower average price. This differential is consistent with the transportation cost between the markets (pipeline tolls). Logistically and economically it would make more sense to produce LNG in the north, as opposed to shipping the gas to the south and then trucking LNG north, thereby incurring transportation charges in both directions. The "Optimized Supply" LNG price scenario described following assumes that natural gas is sourced at Station 2, taking advantage of the lower cost of gas closer to the supply in northeast BC.

Summary

The transportation charge represents the significant potential source of future cost savings, due to the potential for economies of scale (larger delivery vessels), and shorter delivery distances between Whitehorse and the source of the natural gas feedstock. YEC is conservative with respect to estimating cost savings due to larger vessels, as it has not fully reviewed the challenges in single larger LNG shipments. Before deliveries from larger containers should be counted on, shipping constraints (physical due to bridges and axle loadings, and local bylaws) should be thoroughly researched.

Based on currently available information, YEC estimates an $8/GJ overall LNG cost reduction due to sourcing LNG from Dawson Creek. This saving assumption is mostly due to reduced shipping distances, but also due to larger ($80m^3$) shipping vessels.

YEC recommends that it initiate negotiations with alternative suppliers of LNG, in order to firm-up these price estimates, and potentially realize these savings.

Figure 1 following shows a breakdown of forecast LNG costs in the key scenarios studied, for the first year of delivery. Fuel cost refers to the cost of the natural gas feedstock at the LNG liquefaction plant. Table 2 shows the content of Figure 1 as numerical values.

Figure 2 following shows the cost of LNG under the "Status Quo" assumptions, specifically current $60m^3$ LNG shipments, sourced from Tilbury Island - for each of the three underlying natural gas scenarios: Base, Low and High. The "Optimized Supply" scenarios are based on larger $80m^3$ shipments and LNG sourced from Dawson Creek - for each of the same 3 underlying natural gas price forecasts. Table 3 shows the content of Figure 2 as numerical values.

Figure 3 is a simplification of Figure 2, in that only the three LNG price scenarios that are used in further analysis are shown: the Base, High and Optimized scenarios. The Base scenario assumes Status Quo shipment volumes and the current Tilbury Island LNG source. The High scenario includes the same Status Quo assumptions as the Base scenario, but with the high gas price forecast. The Optimized Supply scenario selected assumes the Base gas price forecast but with $80m^3$ shipments and LNG sourced from Dawson Creek. These 3 selected forecasts were used as LNG fuel input costs in YEC's portfolio analysis, as discussed in Chapter 8. Table 4 shows the content of Figure 3 as numerical values.

Figure 1: Delivered LNG Price for Different Trailer Size and Fuel Source (2016 $CA/GJ)

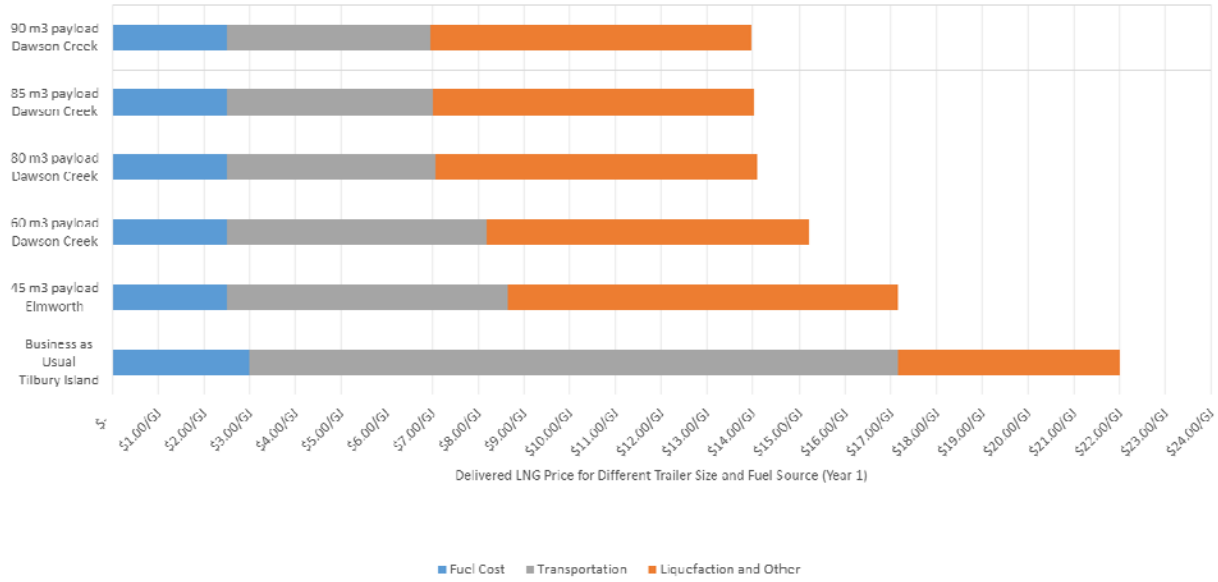


Table 2: Delivered LNG Price for different Trailer Size and Fuel Source (2016 $CA/GJ)

Scenario	Transportation	Liquefaction and Other	Fuel Cost
Business as Usual Tilbury Island	$14.15/GJ	$4.85/GJ	$3.00/GJ
45 m^3 payload Elmworth	$6.15/GJ	$8.50/GJ	$2.50/GJ
60 m^3 payload Dawson Creek	$5.68/GJ	$7.03/GJ	$2.50/GJ
80 m^3 payload Dawson Creek	$4.57/GJ	$7.03/GJ	$2.50/GJ
85 m^3 payload Dawson Creek	$4.50/GJ	$7.03/GJ	$2.50/GJ
90 m^3 payload Dawson Creek	$4.45/GJ	$7.03/GJ	$2.50/GJ

Figure 2: LNG Price Forecast with Alternative Supply and Shipping Options (Real $CA/GJ)

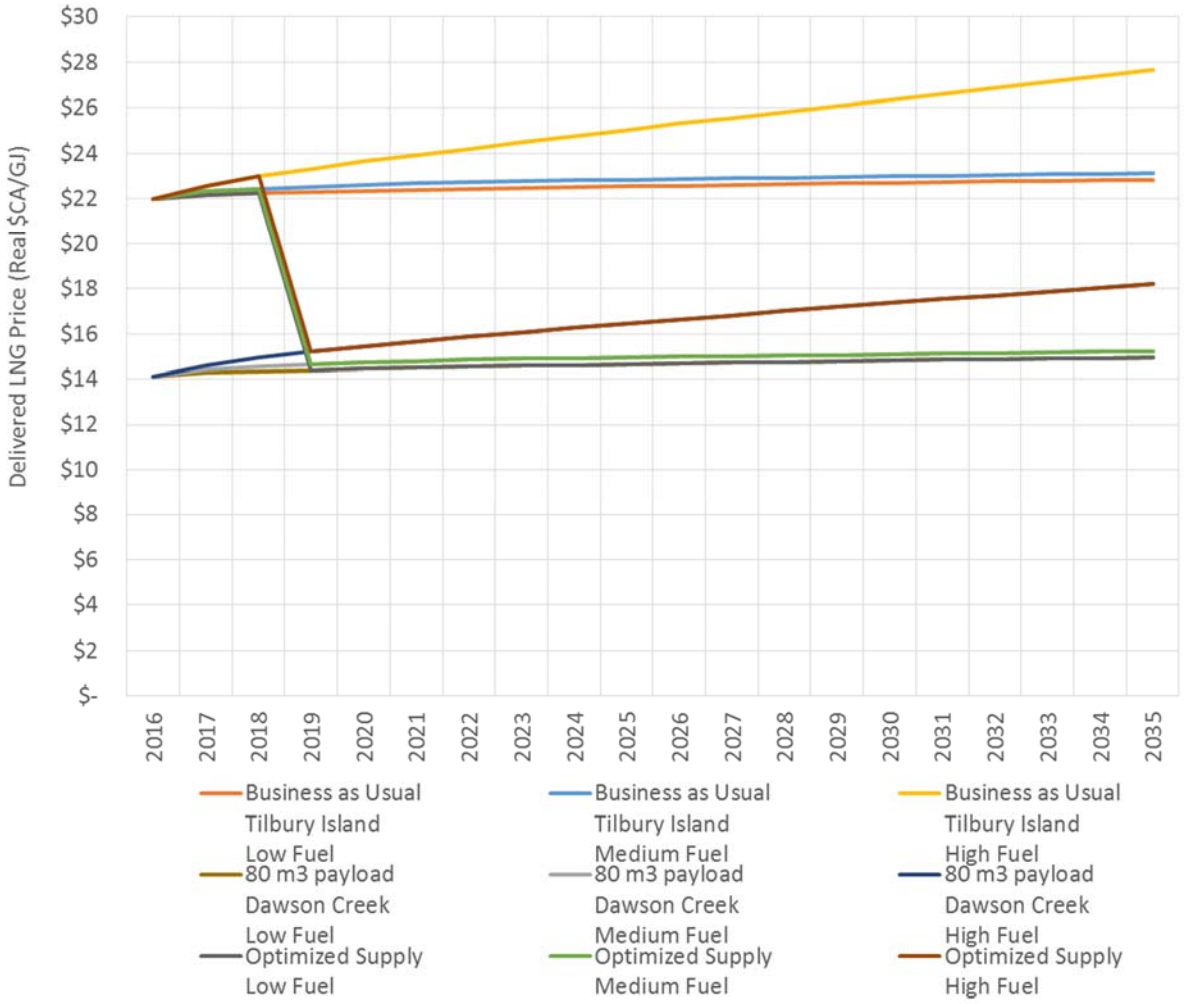


Table 3: LNG Price Forecast with Alternative Supply and Shipping Options (Real $CA/GJ)

Year	Delivered Cost (Real $CA/GJ)								
	Business as Usual Low Fuel	Business as Usual Medium Fuel	Business as Usual High Fuel	Dawson Creek Low Fuel	Dawson Creek Medium Fuel	Dawson Creek High Fuel	Optimized Supply Low Fuel	Optimized Supply Medium Fuel	Optimized Supply High Fuel
2016	$22.00	$22.00	$22.00	$14.10	$14.10	$14.10	$22.00	$22.00	$22.00
2017	$22.18	$22.33	$22.56	$14.29	$14.43	$14.59	$22.18	$22.33	$22.56
2018	$22.24	$22.44	$23.01	$14.34	$14.54	$14.97	$22.24	$22.44	$23.01
2019	$22.29	$22.53	$23.32	$14.40	$14.64	$15.20	$14.40	$14.64	$15.20
2020	$22.35	$22.61	$23.64	$14.45	$14.71	$15.44	$14.45	$14.71	$15.44
2021	$22.40	$22.68	$23.92	$14.51	$14.79	$15.65	$14.51	$14.79	$15.65
2022	$22.45	$22.74	$24.21	$14.55	$14.84	$15.86	$14.55	$14.84	$15.86
2023	$22.48	$22.79	$24.49	$14.59	$14.89	$16.06	$14.59	$14.89	$16.06
2024	$22.51	$22.82	$24.77	$14.62	$14.92	$16.26	$14.62	$14.92	$16.26
2025	$22.55	$22.84	$25.04	$14.65	$14.95	$16.45	$14.65	$14.95	$16.45
2026	$22.58	$22.87	$25.31	$14.68	$14.98	$16.64	$14.68	$14.98	$16.64
2027	$22.61	$22.90	$25.57	$14.72	$15.00	$16.82	$14.72	$15.00	$16.82
2028	$22.65	$22.93	$25.83	$14.75	$15.03	$17.00	$14.75	$15.03	$17.00
2029	$22.68	$22.96	$26.10	$14.78	$15.06	$17.18	$14.78	$15.06	$17.18
2030	$22.71	$22.98	$26.36	$14.82	$15.09	$17.36	$14.82	$15.09	$17.36
2031	$22.74	$23.01	$26.61	$14.85	$15.12	$17.52	$14.85	$15.12	$17.52
2032	$22.78	$23.04	$26.87	$14.88	$15.14	$17.69	$14.88	$15.14	$17.69
2033	$22.80	$23.07	$27.12	$14.90	$15.17	$17.86	$14.90	$15.17	$17.86
2034	$22.82	$23.10	$27.39	$14.93	$15.20	$18.04	$14.93	$15.20	$18.04
2035	$22.83	$23.13	$27.66	$14.94	$15.23	$18.23	$14.94	$15.23	$18.23
2036	$22.84	$23.15	$27.93	$14.95	$15.26	$18.41	$14.95	$15.26	$18.41
20 year Comp. growth	0.19%	0.26%	1.20%	0.29%	0.39%	1.34%	-1.91%	-1.81%	-0.89%

Figure 3: Delivered LNG price to Whitehorse (Real $CA/GJ)

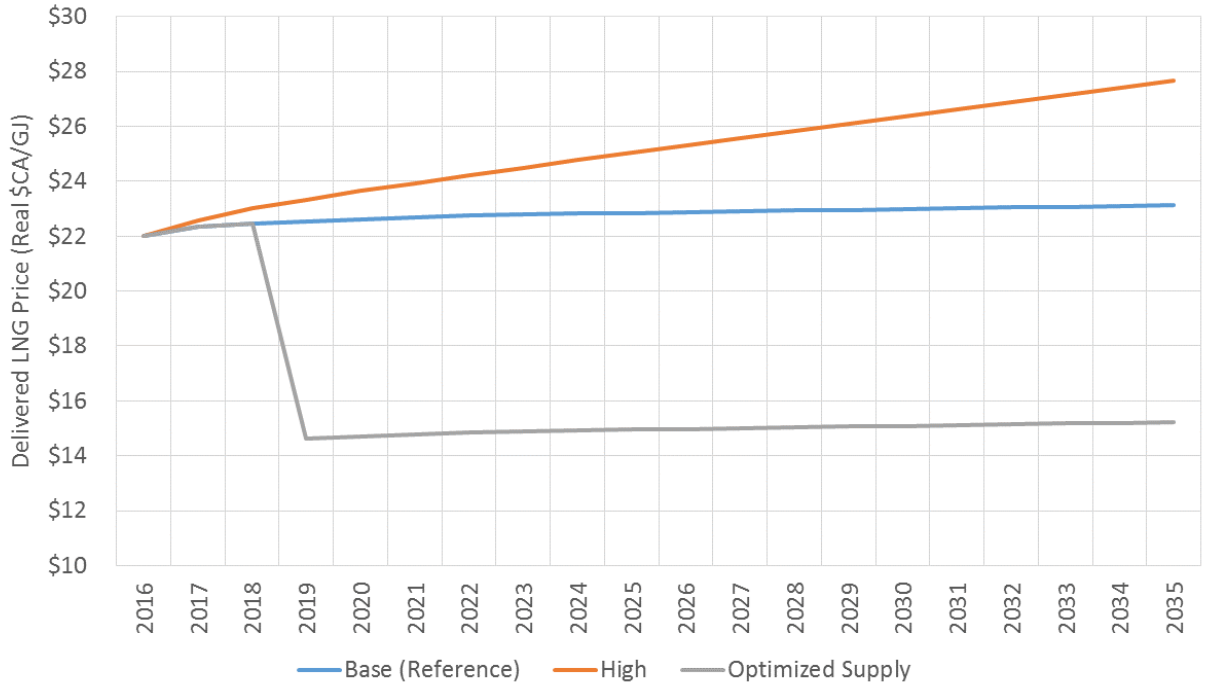


Table 4: Delivered LNG price to Whitehorse (Real $CA/GJ)

Year	Base (Reference) $CA/GJ	High $CA/GJ	Optimized Supply $CA/GJ
2016	22.00	22.00	22.00
2017	22.33	22.56	22.33
2018	22.44	23.01	22.44
2019	22.53	23.32	14.64
2020	22.61	23.64	14.71
2021	22.68	23.92	14.79
2022	22.74	24.21	14.84
2023	22.79	24.49	14.89
2024	22.82	24.77	14.92
2025	22.84	25.04	14.95
2026	22.87	25.31	14.98
2027	22.90	25.57	15.00
2028	22.93	25.83	15.03
2029	22.96	26.10	15.06
2030	22.98	26.36	15.09
2031	23.01	26.61	15.12
2032	23.04	26.87	15.14
2033	23.07	27.12	15.17
2034	23.10	27.39	15.20
2035	23.13	27.66	15.23
2036	23.15	27.93	15.26

Appendix 6.2
Social Cost of Carbon

Final Report

A Social Cost of Carbon for Informing Energy-Climate Policy in the Yukon

February 7, 2016

Prepared for:
Yukon Energy

Prepared by:
Mark Jaccard

Contact:
Mark Jaccard
jaccard@sfu.ca

MKJA
MK Jaccard and Associates

Summary

The social cost of carbon (SCC) is a monetary value that indicates the net harm of human CO2 emissions from burning coal, oil and natural gas (fossil fuels). The SCC is usually measured in dollars per tonne of CO2 ($/tCO2). The Yukon Energy Corporation seeks a value for the SCC that it might use to guide energy investments and other planning and policy decisions.

While there are many reasons why estimates of the SCC can diverge significantly, two stand out. The first is that the SCC must include harm to what are sometimes called the earth's unmanaged systems, for which we cannot readily attribute monetary values. Reduced output from agriculture, forestry and fisheries will result in monetary losses that can be tabulated. In contrast, the extinction of a non-commercial species, such as the polar bear, or the destruction of a major ecosystem, like the Amazon rainforest, is not directly linked to lost market products. The efforts of researchers to address this uncertainty has led to a steady rise in the SCC value used by, for example, the US Environmental Protection Agency, and to its conclusion that its SCC estimates are likely still biased downward. The second major reason for diversity is that some SCC estimates place little value on low probability catastrophic outcomes, such as runaway methane release in the Arctic, collapse of the West Antarctic Ice Sheet, and reversal of the Gulf Stream. More recent SCC estimates attempt to somehow incorporate these potential costs, but there is great uncertainty about what values to use.

The US EPA uses a wide range of values for the SCC when assessing its proposed regulations, such as vehicle or coal plant emissions standards. Because it does not apply a single SCC value, some regulations may be pursued even if not justified according to the lowest values.

In Canada, governments have not used the SCC in such a transparent manner. Instead, four provincial governments are enacting explicit carbon pricing (via a carbon tax, or the price of tradable permits in a cap-and-trade system) covering over 30 million Canadians. These carbon prices are $15 to $30 /tCO2, with provisions in three cases to rise at 5% plus inflation.

At the same time, Canadian provincial governments have enacted other policies that direct crown corporations and in some cases private corporations to shift toward lower emission technologies, especially in electricity generation. It is possible to compute the 'implicit' carbon price for these policies, which is the level of carbon tax that would have been needed to get the same outcome. These implicit carbon prices are in the range of $100 /tCO2 or higher.

Background

The social cost of carbon (SCC) is a monetary value that indicates the net harm of human CO2 emissions from burning coal, oil and natural gas (fossil fuels). The SCC is usually measured in dollars per tonne of CO2 ($/tCO2), but sometimes dollars per tonne of carbon ($/tC).

The harms human CO2 emissions cause to people, the economy and the environment are called 'externality costs' if they are not included ('internalized') in the prices of goods and services that cause these emissions. These harms result from rising CO2 concentrations in the atmosphere and oceans. In the atmosphere, the CO2 raises global temperatures resulting in desertification in some regions, more extreme weather events (floods, droughts, heat waves, hurricanes), rising sea levels (from accelerated melting of glaciers and ice sheets), accelerated species extinction (from rapid ecosystem change), and reduced net global economic output (though some regions may initially experience net benefits from modest levels of warming). In the oceans, the rising CO2 concentration causes acidification, which reduces biological productivity and economic output.

Yukon Energy Corporation seeks to adopt one value, or a range of values, for the SCC that it might use to guide energy investments and other planning and policy decisions. This briefing document explains the SCC concept and how experts estimate its value. It then provide various estimated SCC values, and comments on their significance and potential applicability to Yukon Energy, notably by providing examples of how other governments, corporations and agencies use the SCC and related concepts.

The Challenge of Estimating the Social Cost of Carbon

For over two decades, William Nordhaus of Yale University has played a leading role in the estimation of the SCC.[1] Because the initial stages of global warming may increase agricultural productivity in colder regions of North America and Eurasia, he notes that the SCC should be computed as a 'net' value, in which the benefits of global warming are subtracted from the costs.

When estimating these costs, Nordhaus divides the earth into managed and unmanaged systems.[2] Managed systems are resources that humans use to produce market products. Examples are ocean fish stocks, agricultural land, and commercial forests. If carbon emissions affect the productivity of these systems, one can estimate the cost as the lost market output. Likewise, one can estimate the cost of defensive expenditures caused by CO2 emissions, such as higher dykes, storm protection and more air conditioning.

The bigger challenge is to estimate a monetary value for damage to the mostly unmanaged systems of the earth. An example would be a loss of arctic ice leading to extinction of a non-commercial species, such as the polar bear, or the destruction of a major ecosystem, like the Amazon rainforest. Because these values are not directly linked to market products, estimating

[1] Nordhaus, W., "An optimal transition path for controlling greenhouse gases," Science, Vol.258, Nov. 1992.
[2] Nordhaus, W., The Climate Casino: Risk, Uncertainty and Economics for a Warming World, Yale, 2013.

the monetary loss to humanity is fraught with uncertainty. Some uncertain values are simply omitted, which biases downwards the SCC estimate. For this reason, the US Environmental Protection Agency (EPA) qualifies its own SCC estimate with, "However, given current modelling and data limitations, it does not include all important damages."[3] And this leads Nordhaus to conclude, "So, if anything, the uncertainties point to a more rather than less forceful policy – and one starting sooner rather than later – to slow climate change."[4]

Another big challenge for the SCC is to estimate a monetary value for low probability, catastrophic outcomes whose probability increases as temperatures rise, examples being runaway methane release in the Arctic, collapse of the West Antarctic Ice Sheet, and reversal of the Gulf Stream. Marty Weitzman of Harvard has argued for a decade that SCC estimates need to somehow incorporate these potential harms ('known unknowns'), as well as somehow considering as-yet unimaginable outcomes ('unknown unknowns').[5] As noted below, some researchers have tried to incorporate into the SCC at least some values for known potential damages from the low probability, catastrophic outcomes which seriously concern scientists.

Estimates of the social cost of carbon

Some jurisdictions monitor the SCC estimates of the US EPA, which are updated on a regular basis to incorporate research advances – with the caveat noted above that the estimates are nonetheless biased downwards. The following table shows the range of SCC estimates (in real 2007 $US) for a 3% discount rate for the next 20 years. Note that in all cases, researchers show the SCC to rise over time. This presents an 'optimal path' that minimizes the costs and maximizes the benefits of reducing CO2 emissions. The diversity in estimates is due to a range of values for key assumptions: notabley the forecasts of CO2 concentrations in the absence of efforts to reduce emissions, the impacts of those concentrations on the global atmosphere-land-ocean system, and the costs of reducing emissions. The range gets even wider if one uses a 5% discount rate, which leads to very low SCC estimates in the present and future.

US EPA (2007 $US)	2015	2035
Lowest estimate	$36	$55
Highest estimate	$105	$168

Source: US EPA, 2016, http://www3.epa.gov/climatechange/EPAactivities/economics/scc.html

[3] US EPA, Social Cost of Carbon, 2016. http://www3.epa.gov/climatechange/EPAactivities/economics/scc.html
[4] Nordhaus, W., "Why the global warming skeptics are wrong." New York Review of Books, 2012
[5] Weitzman, M., "Fat-tailed uncertainty in the economics of catastrophic climate change," Review of Environmental Economics and Policy, 2011.

When assessing its proposed regulations, such as vehicle or coal plant standards, the US EPA uses a wide range of values for the SCC. It does not select a single value from which to make decisions. Rather it simply records how each level of regulation performs under the different SCC values, including values that it notes are likely to be strongly biased downwards as in the case of a 5% discount rate.

Aside from the EPA, some researchers have responded to the challenge of unincorporated effects by estimating, by some means, the potential costs and probabilities of catastrophic outcomes. The next table shows the latest estimates provided by Simon Dietz and Nicholas Stern of the London School of Economics, using the same model as Nordhaus, but with some inclusion of low probability, catastrophic outcomes.[6] (Note that these values are in 2015 $US, while the EPA estimates in the previous table are in 2007 $US.)

Dietz & Stern (2015 $US)	2015	2035
Lowest estimate	$32	$82
Highest estimate	$103	$260

Source: Dietz and Stern, 2015.

As both tables show, the SCC estimates in each year cover a wide range. This presents a dilemma for policy-makers who seek to internalize the SCC into private and public decision-making in their jurisdiction. Even if they recognize the great uncertainty, they need to pick one or a few values if they intend to 'internalize' the externality of CO2 emissions.

Carbon pricing and the social cost of carbon

Economists argue that the prices of fossil fuels should be increased by the SCC value according to the CO2 emissions from fossil fuels – 'carbon pricing'. To reflect their different carbon intensities, the price of coal per unit of energy would increase by more than that of oil, which would increase by more than that of natural gas.

Carbon pricing via carbon taxes

The simplest and most transparent method of carbon pricing is by levying a carbon tax on coal, oil and natural gas. Experts widely agree that British Columbia's carbon tax, implemented in 2008, is a model example because of its consistency and comprehensiveness.[7] It is applied to

[6] Dietz, S. and N. Stern, "Endogenous growth, convexity of damage, and climate risk: How Nordhaus' framework supports deep cuts in carbon emissions," The Economic Journal, 2015.
[7] Murray, B. and N. Rivers, "British Columbia's revenue-neutral carbon tax: a review of the latest 'grand experiment' in environmental policy." Energy Policy, 2015.

fossil fuel combustion in virtually all sectors of the economy. At $30, the tax increases the price of gasoline by 7 cents per litre, with comparable effects on the price of coal and natural gas.

While there are other jurisdictions around the world with carbon taxes, the tax level tends to vary within each jurisdiction in order to prevent significant cost increases for carbon-intensive, trade-exposed sectors. Thus, Alberta's intended carbon tax, to be applied in 2017, will be the same as BC's for gasoline used in vehicles, natural gas used in buildings, and natural gas and coal used in electricity generation, but will be lower on average for these fuels when used in oil sands production facilities, refineries and petrochemical plants.

In keeping with the economists' argument that the carbon price should rise over time, Alberta's tax is slated to grow 5% annually over the rate of inflation. BC's tax increased $5 annually from 2008 to 2012, but is currently frozen at $30.

Carbon pricing via tradable permit prices in cap-and-trade systems

A second method for carbon pricing is to establish a jurisdiction-wide cap on CO2 emissions, and then allocate tradable permits that each year sum to the level of the cap – called 'cap-and-trade.' The market price of the tradable permits has the same effect as a carbon tax. If gasoline retailers must purchase permits at $30 / tCO2 for the carbon content in their gasoline, they will pass on this extra cost to consumers at a rate of 7 cents per litre.

In the case of cap-and-trade, however, the carbon price is uncertain because it depends on the cost of CO2 emission reductions in all sectors of the economy, which are not precisely known by government when it sets the cap. To remove some of this uncertainty, many jurisdictions with cap-and-trade systems now set a minimum price for the permits. In the joint cap-and-trade system of Quebec and California, for example, the minimum price for permits purchased and sold in Quebec was $10 (Cdn) in 2013, and set to increase 5% annually plus inflation. As of 2015, the permit trading price in Quebec has never been more than a few dollars above the minimum price.

Ontario is slated to soon join the Quebec-California system.[8] If this occurs by 2018, explicit emissions pricing will be the norm in Canada. Of a current national population of 36 million, 22 million (Quebec and Ontario) will have a minimum carbon price of almost $15 /tCO2 (depending on the cap-and-trade permit market at that time) and 8.5 million (BC and Alberta) will have a carbon tax of $30 /tCO2.

Implicit carbon prices

Emissions pricing is but one policy option for reducing CO2 emissions. Governments can also regulate private industry or give explicit directions to state-owned corporations and various public agencies. This approach has led to far more CO2 emission reductions in Canada and most other jurisdictions concerned about GHG emissions.

The most significant climate policy in Canada thus far was Ontario's closure of its coal-fired power plants, which it achieved between 2004 and 2014. This one policy reduced annual CO2 emissions by 25 megatonnes (MT). In 2007, BC passed a 'clean electricity' requirement that

[8] Manitoba's government has also expressed its intent to join Quebec and Ontario, although it has not yet progressed down this path to a significant extent.

forced BC Hydro to cancel contracts for two private coal-fired power plants and its own plans for a large natural gas plant, reducing expected annual CO2 emissions in 2020 by 11-17 MT. In comparison, BC's carbon tax is estimated to reduce 2020 annual emissions by 3-5 MT.

From regulations and investment directives like these it is possible to calculate an 'implicit carbon price.' This is the carbon price that would be required to cause the same amount of emissions reduction in the sector in question. For example, it has been calculated that BC's electricity regulation had an implicit carbon price of $90 to $210 /tCO2, depending on assumptions of the cost of energy storage (for wind and run-of-river power) and natural gas in the future.[9] Crude estimates of Ontario's coal phase-out policy suggest that its implicit carbon cost was $100 to $150 /tCO2. Also, the Saskatchewan government subsidized the installation of carbon capture and storage technology at its Boundary Dam coal-fired power plant, and the cost has been estimated at more than $100 /tCO2 reduced, which may be acceptable since there may be future benefits from the development of this new technology. Finally, in announcing its new climate policy, Alberta noted that in addition to implementing a $30 carbon tax it would require an accelerated reduction in coal-fired power, which would include payments for wind power up to an implicit carbon price of $90 /tCO2.[10]

Social cost of carbon as a guide to regulations and investments

The following table summarizes the evidence on explicit and implicit carbon pricing in Canada. It shows, firstly, that real-world explicit carbon prices are either below estimated SCC values, or at least not slated to rise at the rate that would track them into the future. Secondly, it shows that seemingly high, real-world implicit carbon prices, resulting from regulations and public investment decisions, are much closer to the estimated SCC values into the future, given that these decisions about electricity generation investment are multi-decade commitments.

2018 carbon price ($ / tCO2)	Explicit carbon price	Implicit carbon price
Quebec	**≈$15**	**?**
Ontario	**≈$15**	**$100-$150 (coal plant phase-out)**
BC	**$30**	**$90-$210 (clean electricity requirement)**
Alberta	**$30**	**$90 (coal plants to wind)**

[9] Rhodes, K. and M. Jaccard, "A tale of two climate policies: political economy of British Columbia's carbon tax and clean electricity standard." Canadian Public Policy, 2013.
[10] Government of Alberta, "Climate Leadership Plan," 2015.

It is uncertain if estimates of the SCC guided any of the explicit or implicit pricing policies recently applied by Canadian provinces. Some research suggests that political acceptability is the most important factor in determining the type and stringency of climate policy.[11] This may explain why Canadian implicit prices exceed explicit prices. The cost of the carbon tax in BC is obvious to everyone who buys gasoline, since it is indicated on the pumps, whereas only an energy analyst would know the much higher cost of the clean electricity requirement. Thus, politicians who sincerely want to reduce CO2 emissions seem willing to use both the explicit and the implicit carbon pricing methods, but the latter has been applied at higher levels that might be more consistent with current estimates of the SCC trajectory over the next couple of decades.

The use of the SCC to guide policies in the US, at least at the federal level, is more direct and transparent. The EPA must show that any of its regulations pass a cost-benefit test, which includes monetized values for all externalities. Thus, the EPA value for the SCC was used in the latest EPA revisions to US vehicle efficiency and emissions regulations. Likewise, the EPA's new proposed coal plant emission regulation – currently in the comment and review phase – is justified in a cost-benefit analysis that uses the SCC estimate.

Thus, the SCC can provide a 'shadow price' for determining the stringency of government regulations. It can also be used by industry. Many corporations claim that they use an internal 'shadow price' for CO2 emissions in determining the level of energy efficiency and fuel choice in large and small investments.

Informing energy-climate policy in the Yukon

Over the next few years, as part of Canada's federal-provincial climate policy collaboration, the Yukon government might choose to implement a carbon tax, as in BC and soon Alberta, or a cap-and-trade system, as in Quebec and soon Ontario. But, regardless of this decision, the Yukon Energy Corporation has the immediate opportunity to apply a shadow carbon price to guide its investment and operation decisions, decisions that may have carbon emission implications for years and even decades to come.

The challenge is to decide which price to use as its shadow carbon price. Yukon Energy could test any decision against the range of EPA estimates for the SCC. But this range is so wide that it is not that helpful. Yukon Energy could take a precautionary approach, using the EPA's highest SCC values. Or it could be guided by the carbon prices that are explicit or implicit in decisions and policies in other Canadian jurisdictions.

If Yukon Energy were to use the explicit carbon price in other parts of Canada as a guide, the carbon prices in Quebec, Ontario, Alberta and BC will range from $15 to $30 in 2018, rising thereafter. These explicit prices are at the low end of EPA and more recent estimates of the SCC. But the benefit is that they will be applied to almost all CO2 emissions in these provinces, not just the emissions and investment decisions of public corporations and agencies. And all of these

[11] Rhodes, K., Axsen, J. and M. Jaccard, "Does effective climate policy require well-informed citizen support?" Global Environmental Change, 2014.

jurisdictions, with the exception of BC, have scheduled their carbon prices to rise annually.

If Yukon Energy were to use the implicit carbon prices in other parts of Canada as a guide, crown corporations and provincial governments in Ontario, BC, Saskatchewan and soon Alberta are accepting much higher prices to guide energy-related investment and planning, and in setting regulations that affect private investment decisions in renewable electricity generation. Thus, it would be consistent with these other jurisdictions for Yukon Energy to use a value in the neighbourhood of $100 /tCO2. This price reflects government decisions as diverse as Saskatchewan Power's investment in carbon capture and storage, Ontario Power's closure of its coal plants and replacement with low- and zero-emission alternatives, the BC government's clean electricity regulation favouring renewable electricity, and Alberta's recent policy announcement for wind to play a significant role in the accelerated closure of its coal plants.

Appendix 8.1
Portfolio Analysis Data

Portfolio Analysis Input Variables for Industrial Activity Scenarios

The following data inputs were used in the portfolio analysis of the industrial activity scenarios and adjusted as specified in the sensitivity scenarios.

Input Variable	Reference
Energy and peak demand	20-Year Energy and Peak Demand Forecast 2016-2035
Social cost of carbon (SCC)	Appendix 6.2 Social Cost of Carbon
Fuel price forecast	Appendix 6.1 Fuel Price Forecast
Global Warming Potential (GWP)	Appendix 5.1 Greenhouse Gas Emission Life Cycle Assessment of Resource Options (ArcticCan Energy Services 2016)
Transmission Cost	Appendix 5.21 Transmission Options Evaluation (Midgard 2016)
Renewable Cap	Chapter 8 Portfolio Analysis (Section 8.2)

Very Low Industrial Activity

Figure 1: Very Low Industrial Activity Portfolio, Energy

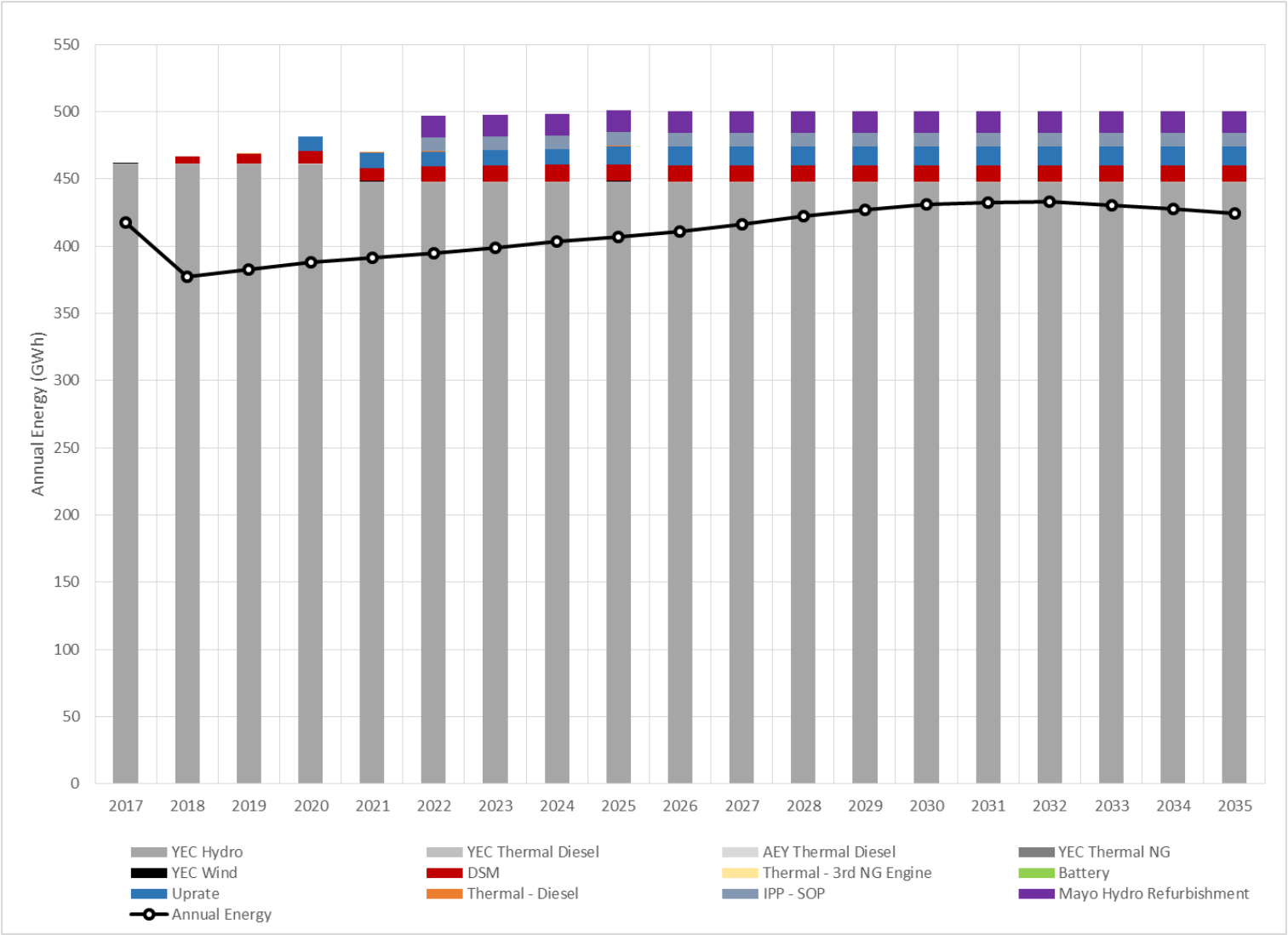


Table 1:Very Low Industrial Activity Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	9.9	10.8	11.7	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Thermal - 3rd NG Engine	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	11.1	11.1	11.1	11.1	11.1	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 2: Very Low Industrial Activity Portfolio, Capacity

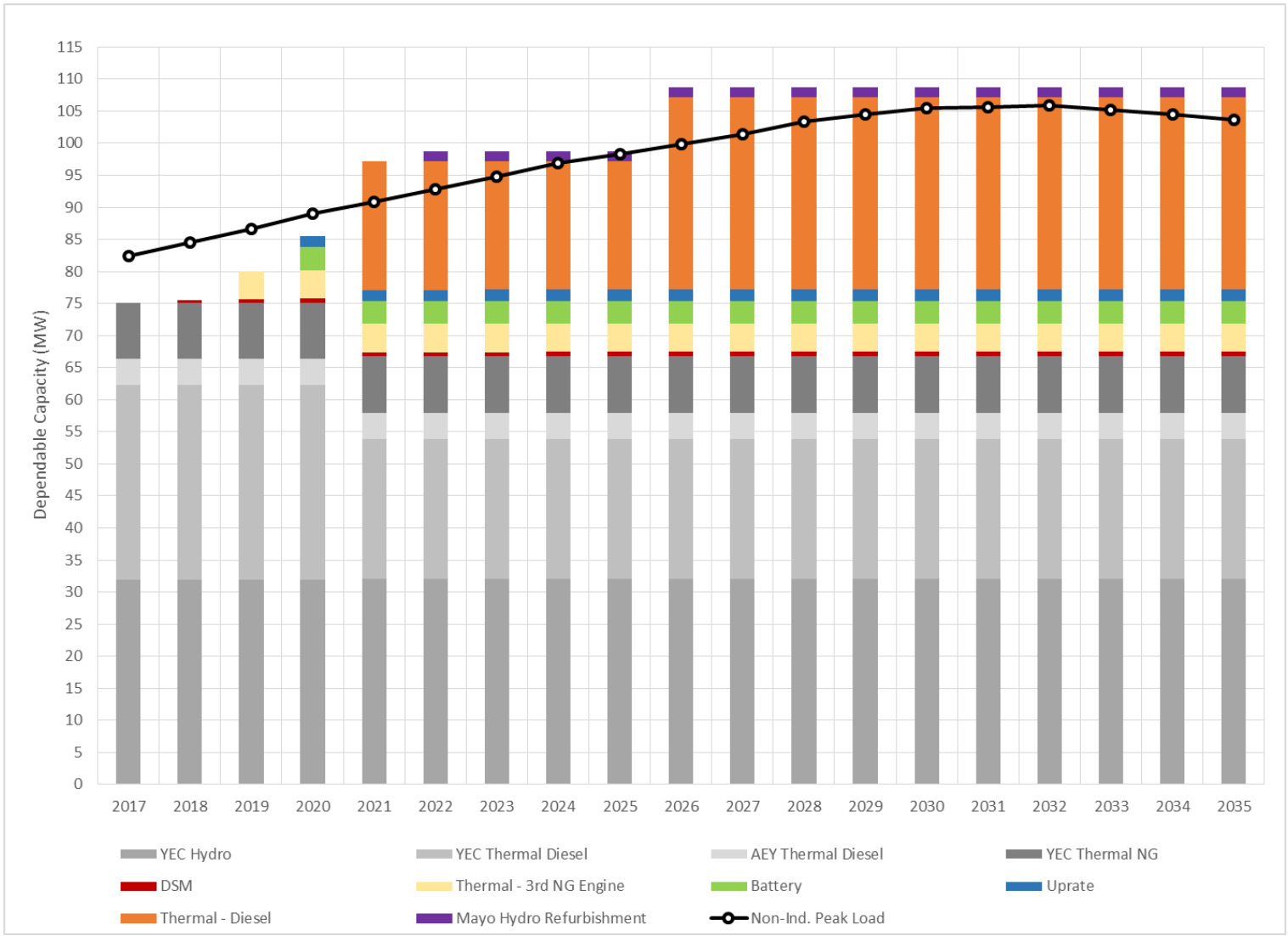


Table 2:Very Low Industrial Activity Portfolio, Energy

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 3: Very Low Industrial Activity Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.3
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Whitehorse Uprate	1.7
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
2025	
Aishihik Uprate	1.3
2026	
Thermal Diesel - Takhini Substation	10.0
Grand Total	45.0

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost:	$ 207.4	
Present Value:		
Fixed Costs	$ 97.6	[A]
Variable Costs	$ 37.0	[B]
Total Costs	$ 134.5	[C] = [A] + [B]

This portfolio generates an average of 99.8% renewable energy over the 20 year planning period, under average water assumptions.

Low Industrial Activity

Figure 3: Low Industrial Activity Portfolio, Energy

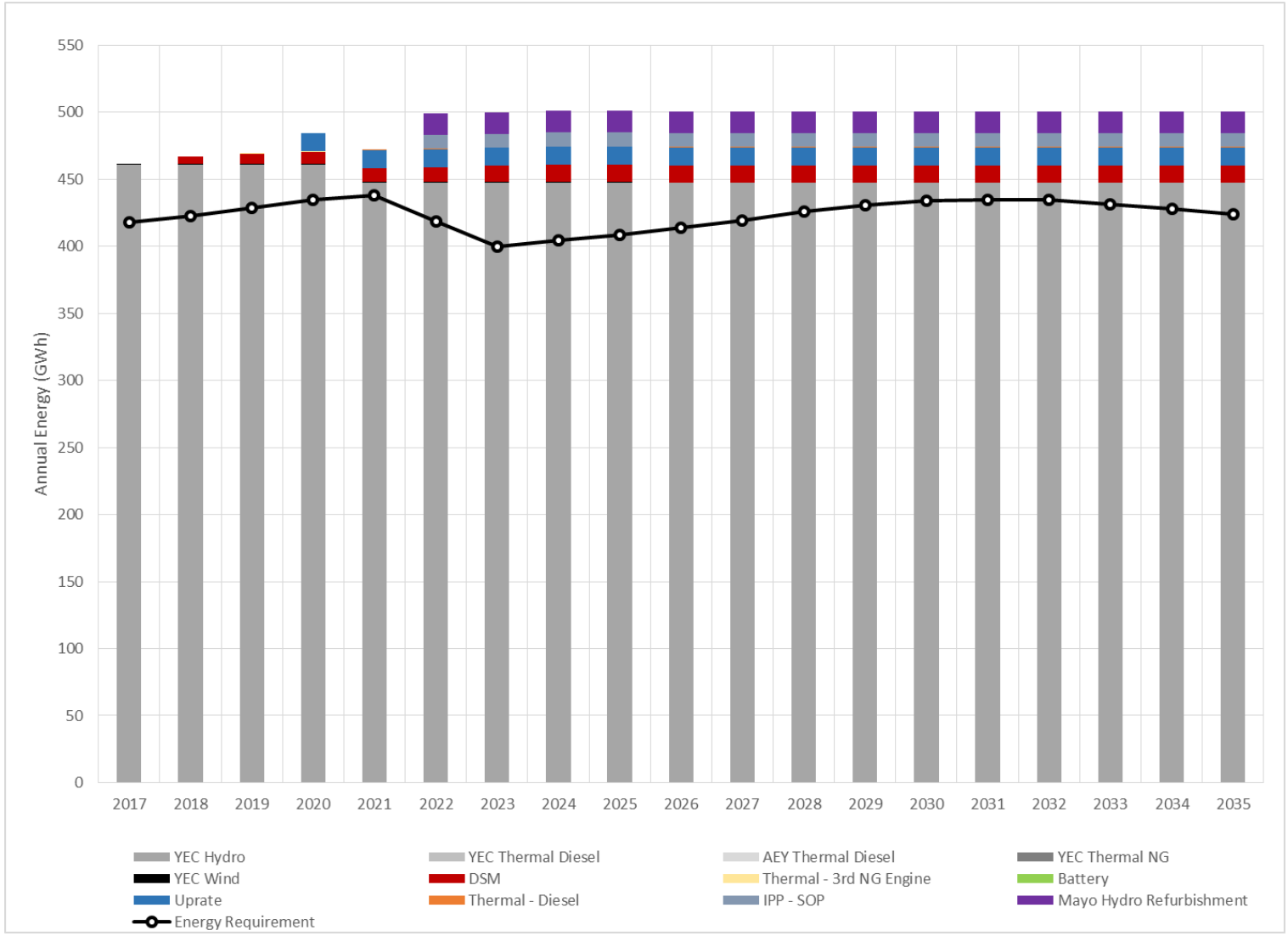


Table 4: Low Industrial Activity Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	9.9	10.8	11.7	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Thermal - 3rd NG Engine	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 4: Low Industrial Activity Portfolio, Capacity

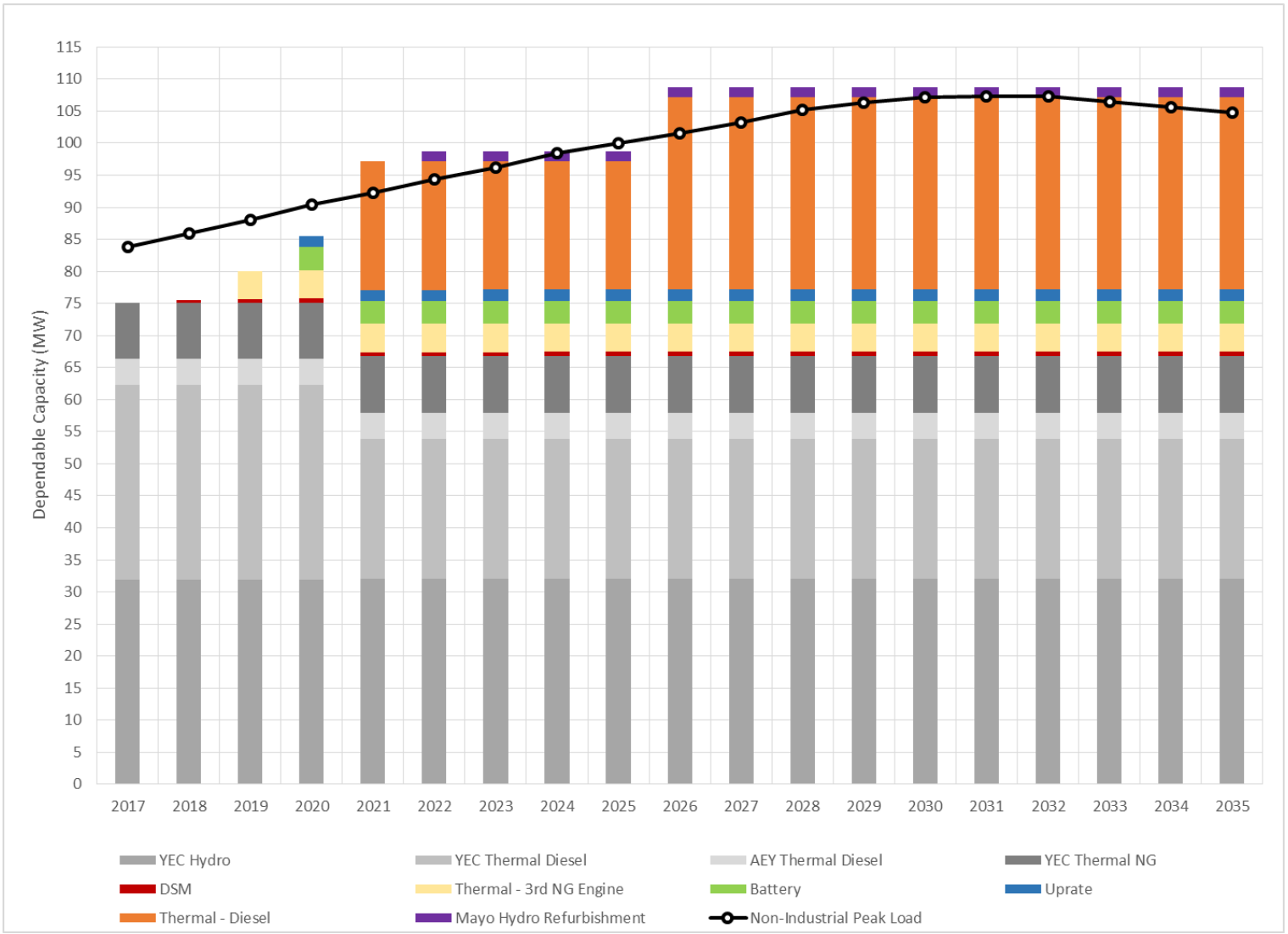


Table 5: Low Industrial Activity Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 6: Low Industrial Activity Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.3
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
2026	
Thermal Diesel - Takhini Substation	10.0
Grand Total	45.0

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 207.4	
Present Value		
Fixed Costs	$ 97.6	[A]
Variable Costs	$ 37.8	[B]
Total Costs	$ 135.4	[C] = [A] + [B]

This portfolio generates an average of 99.8% renewable energy over the 20 year planning period, under average water assumptions.

Low Industrial Activity with Minto Mine Closing Early and Eagle Gold Project

Figure 5: Low Industrial Activity with Minto Closing Early and Eagle Gold Project Portfolio, Energy

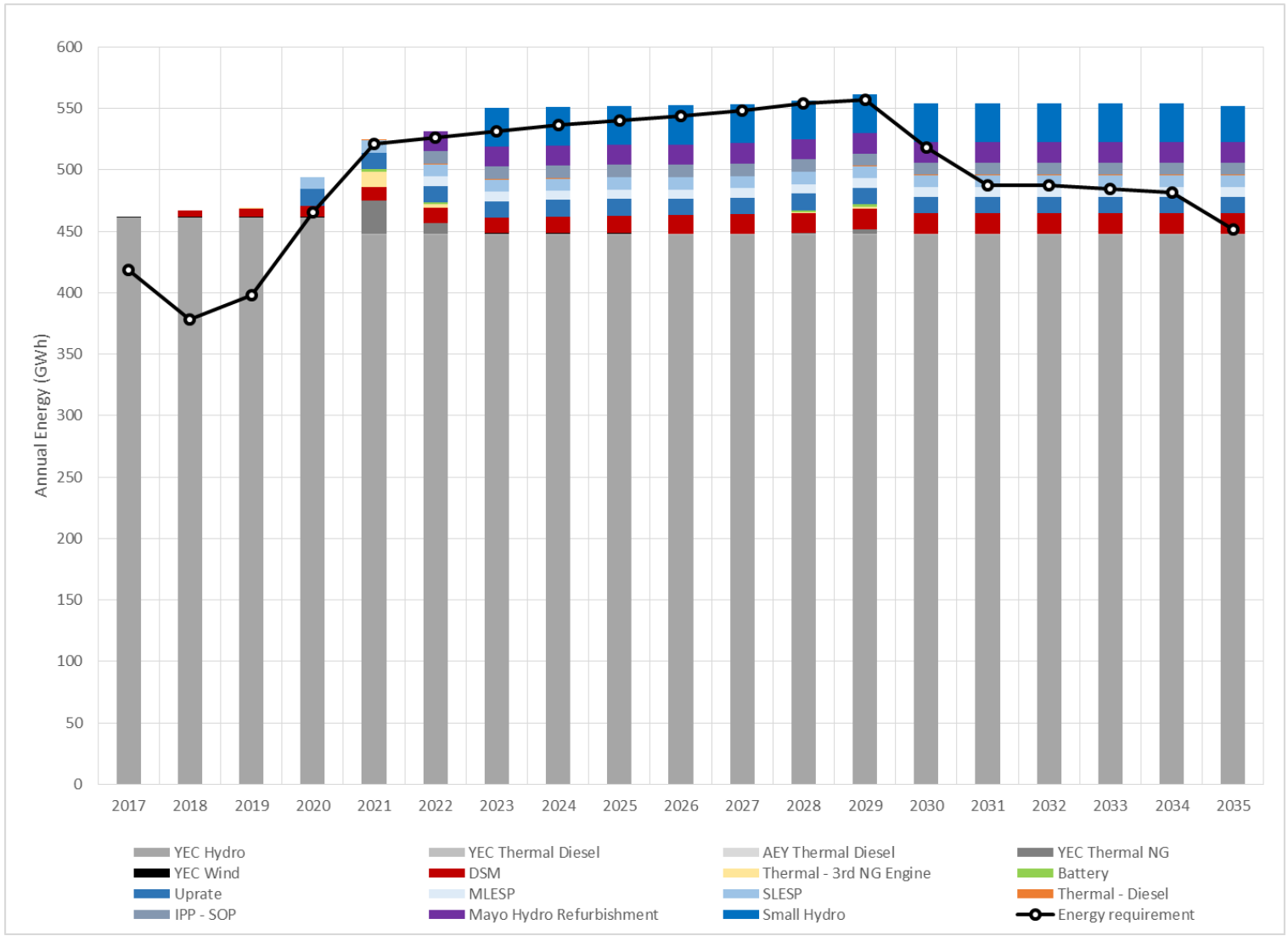


Table 7: Low Industrial Activity with Minto Closing Early and Eagle Gold Project Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Battery	0.0	0.0	0.0	0.0	1.8	1.6	0.0	0.0	0.0	0.0	0.0	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
YEC Thermal NG	0.0	0.0	0.0	0.0	26.9	8.7	0.0	0.0	0.0	0.0	0.0	0.5	3.8	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	11.9	12.8	13.6	14.4	15.2	16.0	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - 3rd NG Engine	0.0	0.0	0.1	0.1	12.5	3.1	0.1	0.1	0.1	0.1	0.1	0.1	1.7	0.1	0.1	0.1	0.1	0.1	0.1
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 6: Low Industrial Activity with Minto Closing Early and Eagle Gold Project Portfolio, Capacity

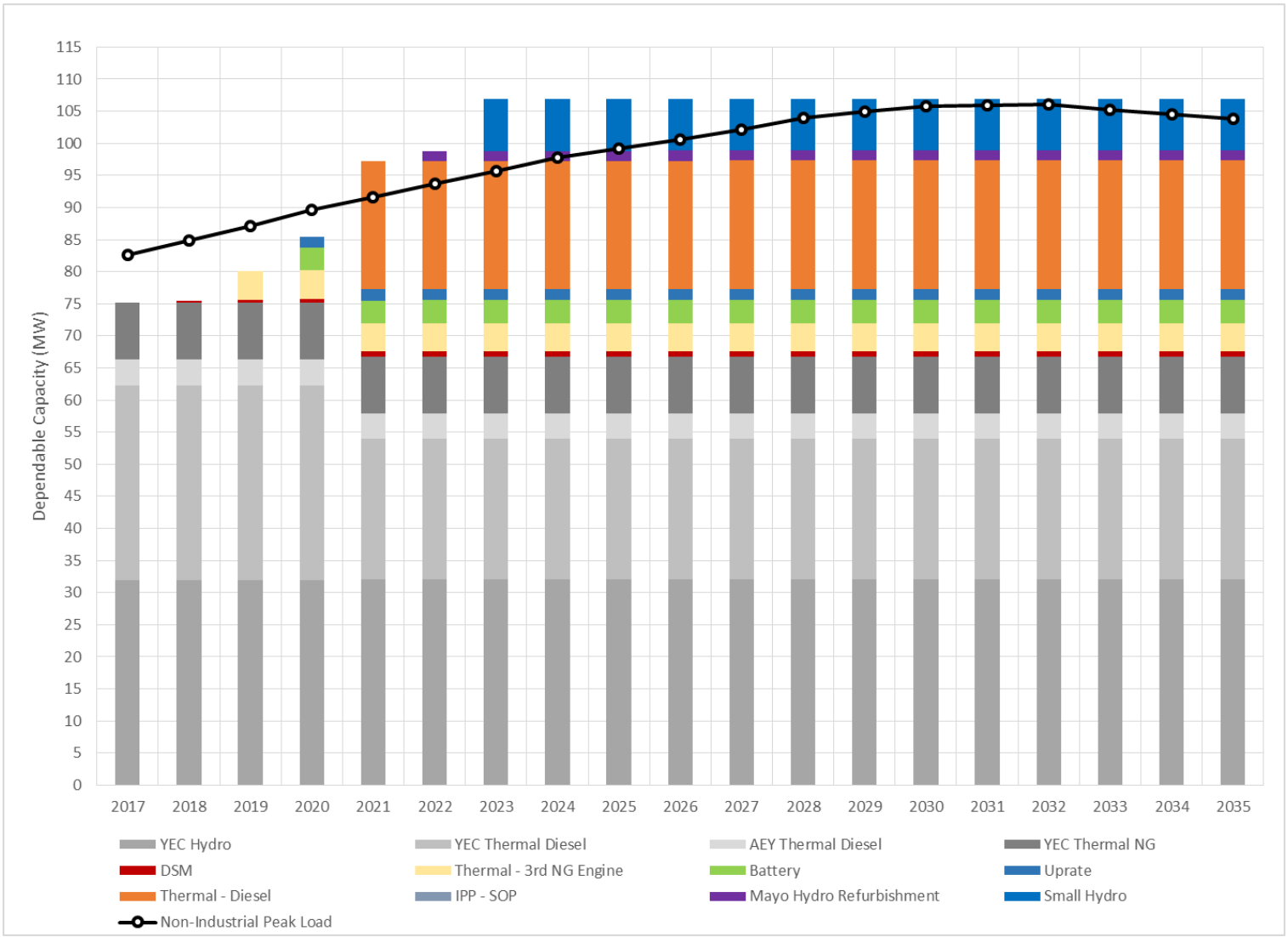


Table 8: Low Industrial Activity with Minto Closing Early and Eagle Gold Project Portfolio, Capacity

Resource Option	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 9: Low Industrial Activity with Minto Closing Early and Eagle Gold Project Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.5
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2023	
Drury Creek Small Hydro	8.1
Grand Total	43.3

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Optimization Results (Present Value)		
Fixed Costs	$ 130.2	[A]
Variable Costs	$ 49.1	[B]
Total Costs	$ 179.4	[C] = [A] + [B]

This portfolio generates an average of 99.3% renewable energy over the 20 year planning period, under average water assumptions.

Medium Industrial Activity

Figure 7: Medium Industrial Activity Portfolio, Energy

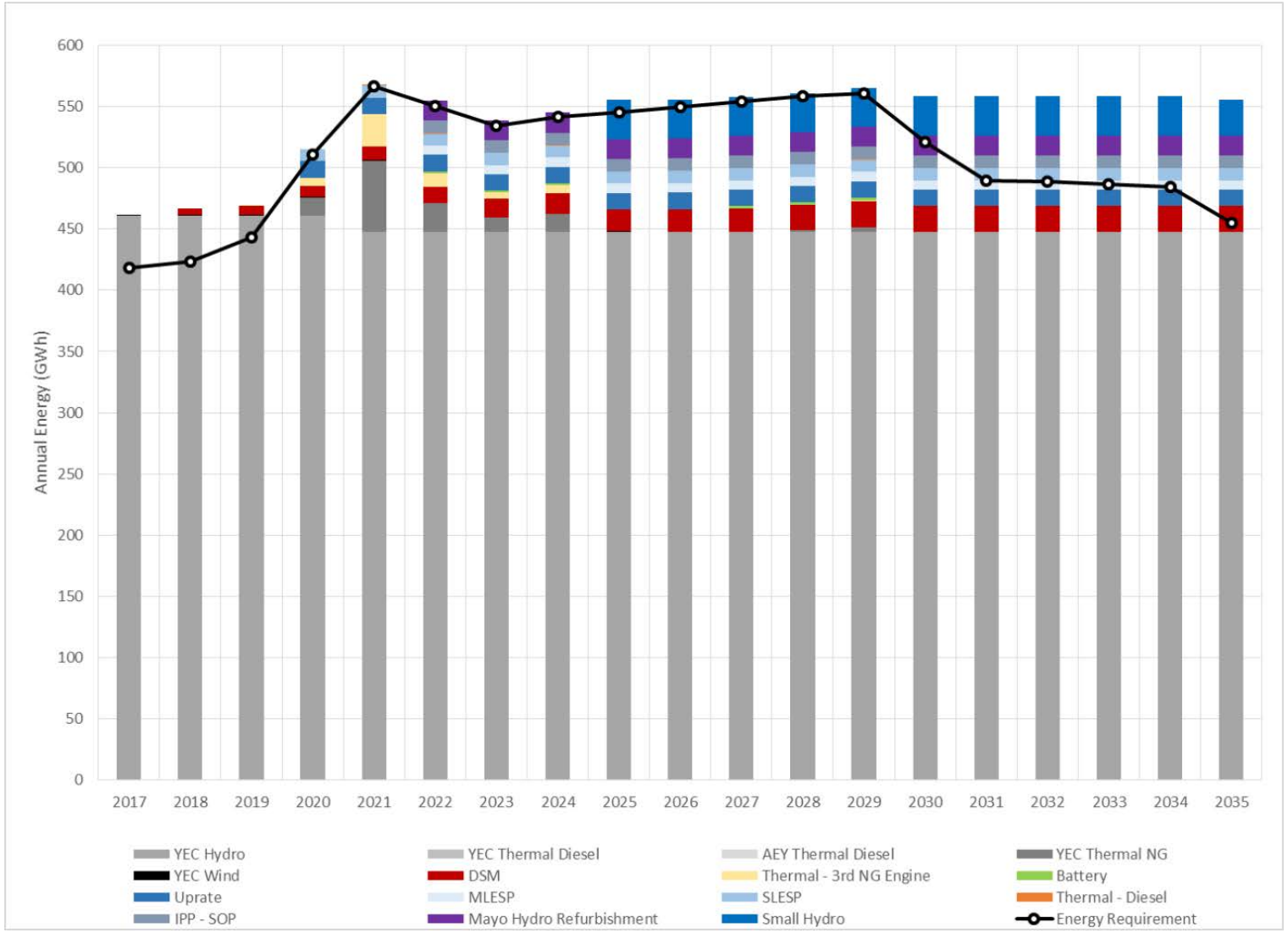


Table 10: Medium Industrial Activity Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Battery	0.0	0.0	0.0	0.0	0.0	1.9	1.5	1.8	0.0	0.0	1.6	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
YEC Thermal NG	0.0	0.0	0.0	14.3	57.8	23.1	11.3	14.3	0.0	0.0	0.0	0.9	3.6	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	17.5	18.3	19.1	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - 3rd NG Engine	0.0	0.0	0.1	6.8	26.5	10.7	5.1	6.2	0.1	0.1	0.1	0.1	1.4	0.1	0.1	0.1	0.1	0.1	0.1
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 8: Medium Industrial Activity Portfolio, Capacity

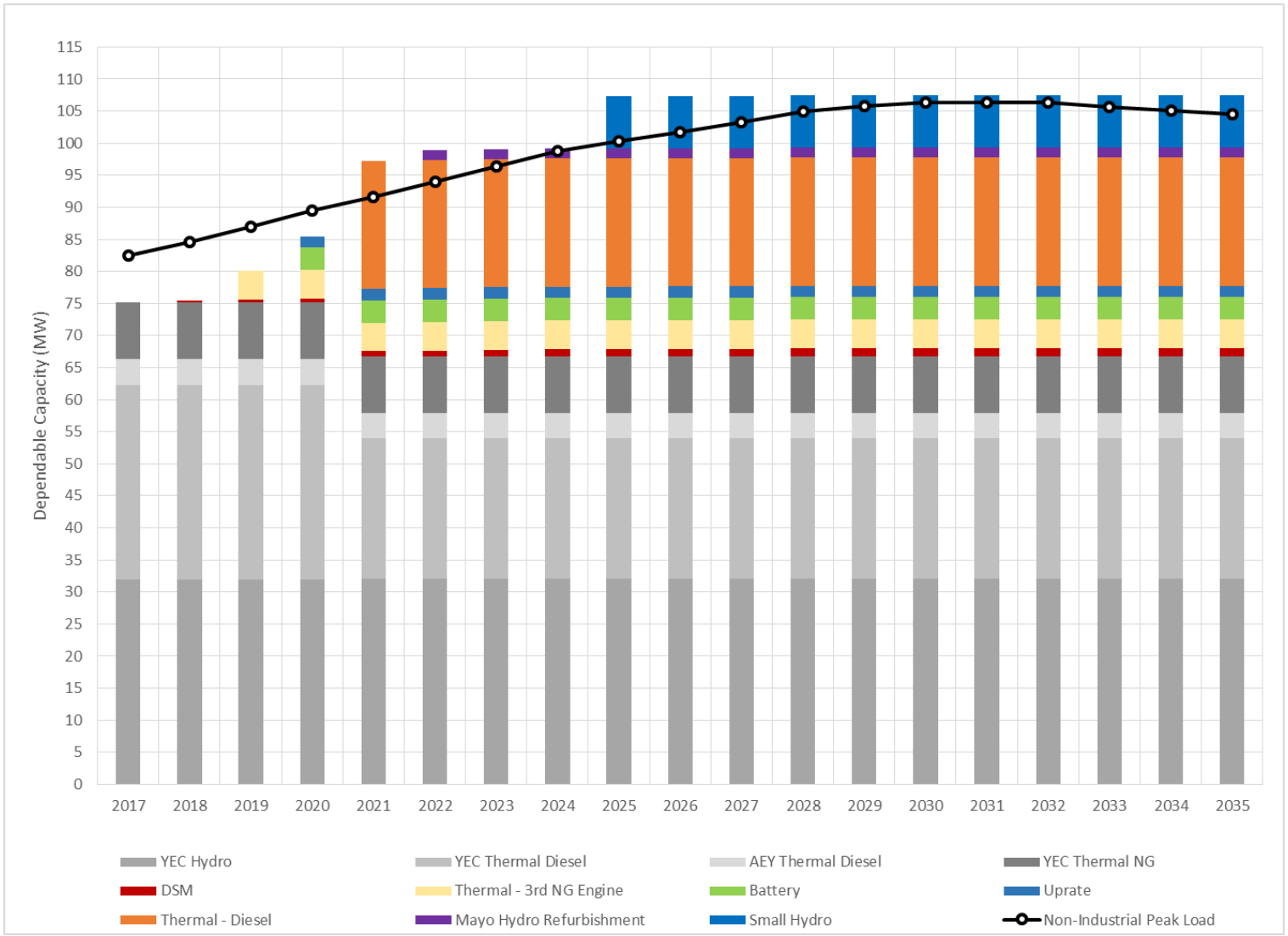


Table 11: Medium Industrial Activity Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 12: Medium Industrial Activity Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.9
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2025	
Drury Creek Small Hydro	8.1
Grand Total	43.7

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Present Value		
Fixed Costs	$ 122.7	[A]
Variable Costs	$ 74.4	[B]
Total Costs	$ 197.1	[C] = [A] + [B]

This portfolio generates an average of 98.1% renewable energy over the 20 year planning period, under average water assumptions.

High Industrial Activity Scenario

Figure 9: High Industrial Activity with Capped Intermittent and Committed Resources Portfolio, Energy

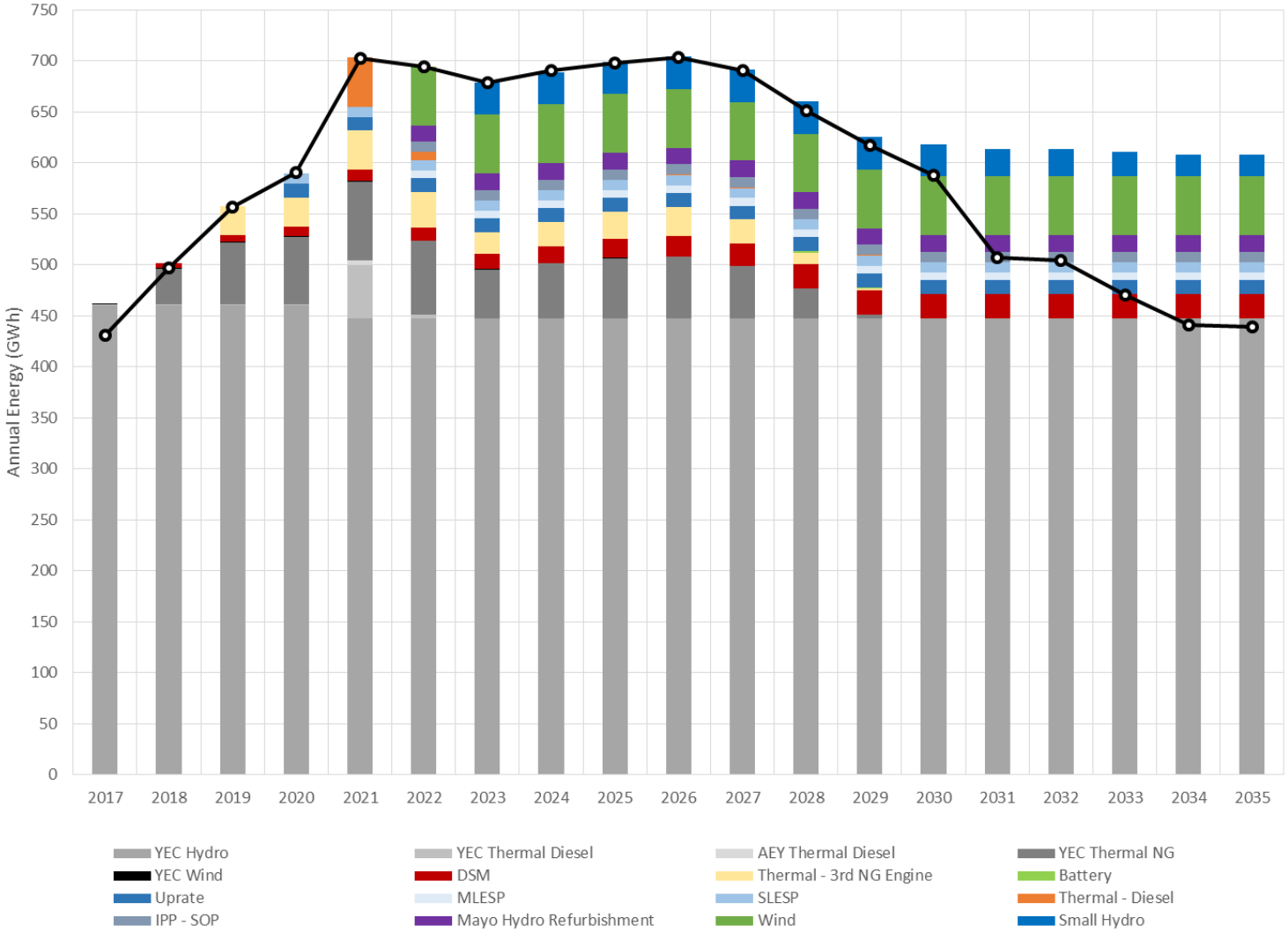


Table 13: High Industrial Activity with Capped Intermittent and Committed Resources Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	52.3	3.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	4.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	35.4	60.8	66.5	77.1	72.4	47.7	53.5	58.6	60.7	51.4	29.1	3.8	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	18.4	20.2	21.9	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7
Thermal - 3rd NG Engine	0.0	0.0	28.2	28.8	38.5	34.7	21.2	23.9	27.0	28.4	23.3	11.2	1.5	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	1.4	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	48.4	7.8	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	27.3	27.1	23.8	21.8	21.7
Wind	0.0	0.0	0.0	0.0	0.0	57.5	57.5	57.5	57.5	57.5	57.5	57.5	57.5	57.3	57.3	57.3	57.3	57.3	57.3
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 10: High Industrial Activity with Capped Intermittent and Committed Resources Portfolio, Capacity

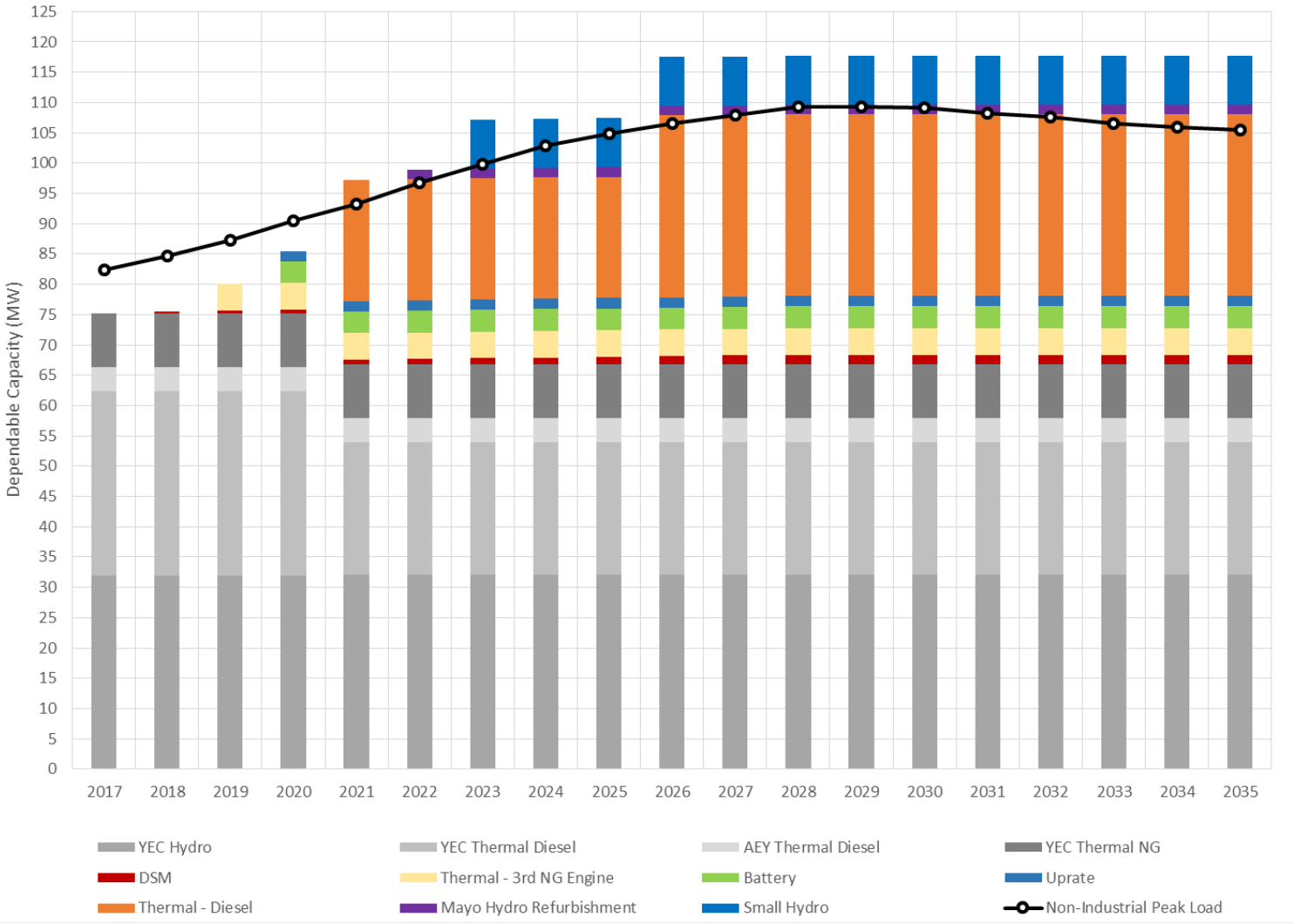


Table 14: High Industrial Activity with Capped Intermittent and Committed Resources Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.3	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 15: High Industrial Activity with Capped Intermittent and Committed Resources Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	2.2
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
Wind - Miller's Ridge	20.0
2023	
Small Hydro - Drury Creek	8.1
2026	
Thermal Diesel - Takhini Substation	10.0
Grand Total	74.0

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 414.0	
Optimization Results (Present Value)		
Fixed Costs	$ 150.9	[A]
Variable Costs	$ 294.8	[B]
Total Costs	$ 445.7	[C] = [A] + [B]

This portfolio generates an average of 91.9% renewable energy over the 20 year planning period, under average water assumptions.

Table 8.6. Resources selected for the five major industrial scenario

Scenario ->	Very Low	Low	Early Minto Closure	Medium	High
2018	DSM	DSM	DSM	DSM	DSM
2019	3rd NG Engine	3rd NG Engine	3rd NG Engine	3rd NG Engine	3rd NG Engine
2020	Battery (Takhini)	Battery (Takhini)	Battery (Takhini)	Battery (Takhini)	Battery (Takhini)
2020		Aishihik uprate	Aishihik uprate	Aishihik uprate	Aishihik uprate
2020	Whitehorse uprate	Whitehorse uprate	Whitehorse uprate	Whitehorse uprate	Whitehorse uprate
2020			SLESP	SLESP	SLESP
2021	Diesel 20 MW (Takhini)	Diesel 20 MW (Takhini)	Diesel 20 MW (Takhini)	Diesel 20 MW (Takhini)	Diesel 20 MW (Takhini)
2021					
2022	Mayo Refurbishment	Mayo Refurbishment	Mayo Refurbishment	Mayo Refurbishment	Mayo Refurbishment
2022	Standing Offer Program	Standing Offer Program	Standing Offer Program	Standing Offer Program	Standing Offer Program
2022			MLESP	MLESP	MLESP
2022					Wind 20 MW (Thulsoo Mt.)
2023			Small Hydro (Drury Lake)		Small Hydro (Drury Lake)
2025	Aishihik re-runnering			Small Hydro (Drury Lake)	
2026	Diesel 10 MW (Takhini)	Diesel 10 MW (Takhini)			Diesel 10 MW (Takhini)
Renewble Energy (%)	99.8	99.8	99.3	98.1	91.9
Total Cost $M	$ 134.5	$ 135.4	$ 179.4	$ 197.1	$ 445.7
Fixed Cost $M	$ 97.6	$ 97.6	$ 130.2	$ 122.7	$ 150.9
Variable Cost $M	$ 37.0	$ 37.8	$ 49.1	$ 74.4	$ 294.8
Portfolio Capital Cost $M	$ 207.4	$ 207.4	$ 298.6	$ 298.6	$ 414.0

Low Industrial Activity without Social Cost of Carbon

Figure 11: Low Industrial Activity with No Price on Carbon Portfolio, Energy

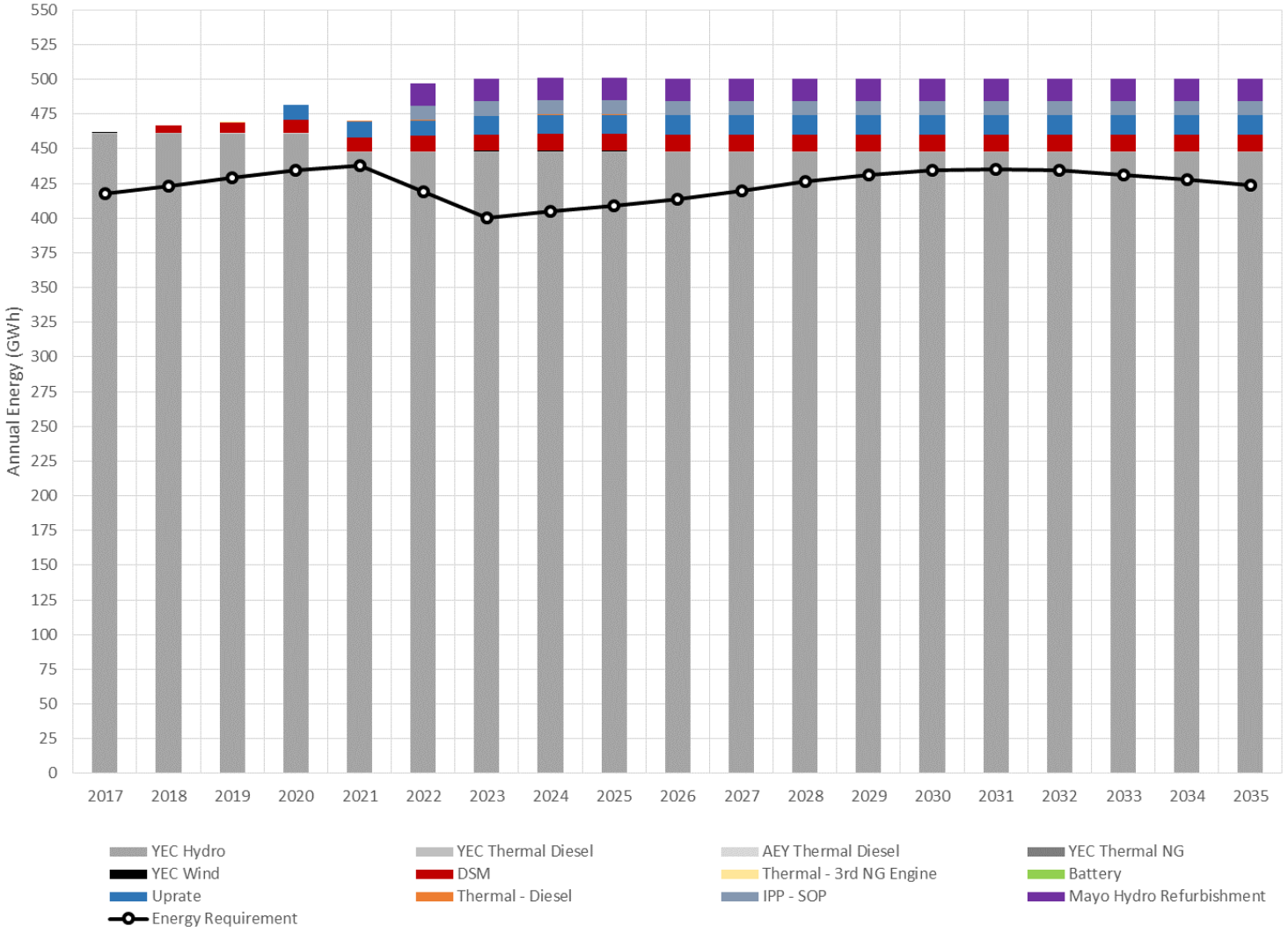


Table 16: Low Industrial Activity with No Price on Carbon Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	9.9	10.8	11.7	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Thermal - 3rd NG Engine	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	11.1	11.1	11.1	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 12: Low Industrial Activity with No Price on Carbon Portfolio, Capacity

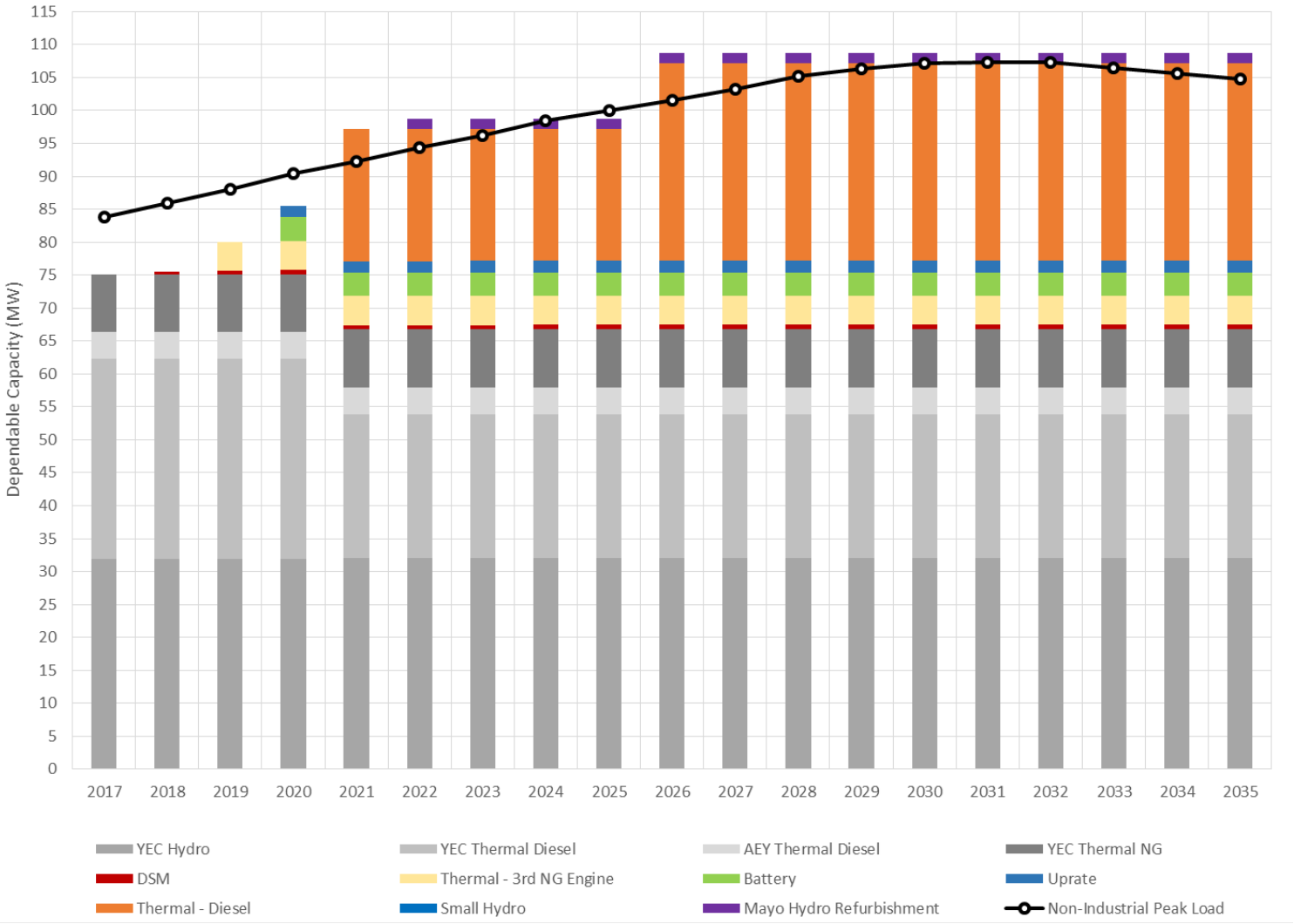


Table 17: Low Industrial Activity with No Price on Carbon Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 18: Low Industrial Activity with No Price on Carbon Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.3
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Whitehorse Uprate	1.7
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
2023	
Aishihik Uprate	1.3
2026	
Thermal Diesel - Takhini Substation	10.0
Grand Total	45.0

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 207.4	
Present Value		
Fixed Costs	$ 97.6	[A]
Variable Costs	$ 36.7	[B]
Total Costs	$ 134.2	[C] = [A] + [B]

This portfolio generates 99.8% energy under average water assumptions.

Medium Industrial Activity without Social Cost of Carbon

Figure 13: Medium Industrial Activity with No Price on Carbon Portfolio, Energy

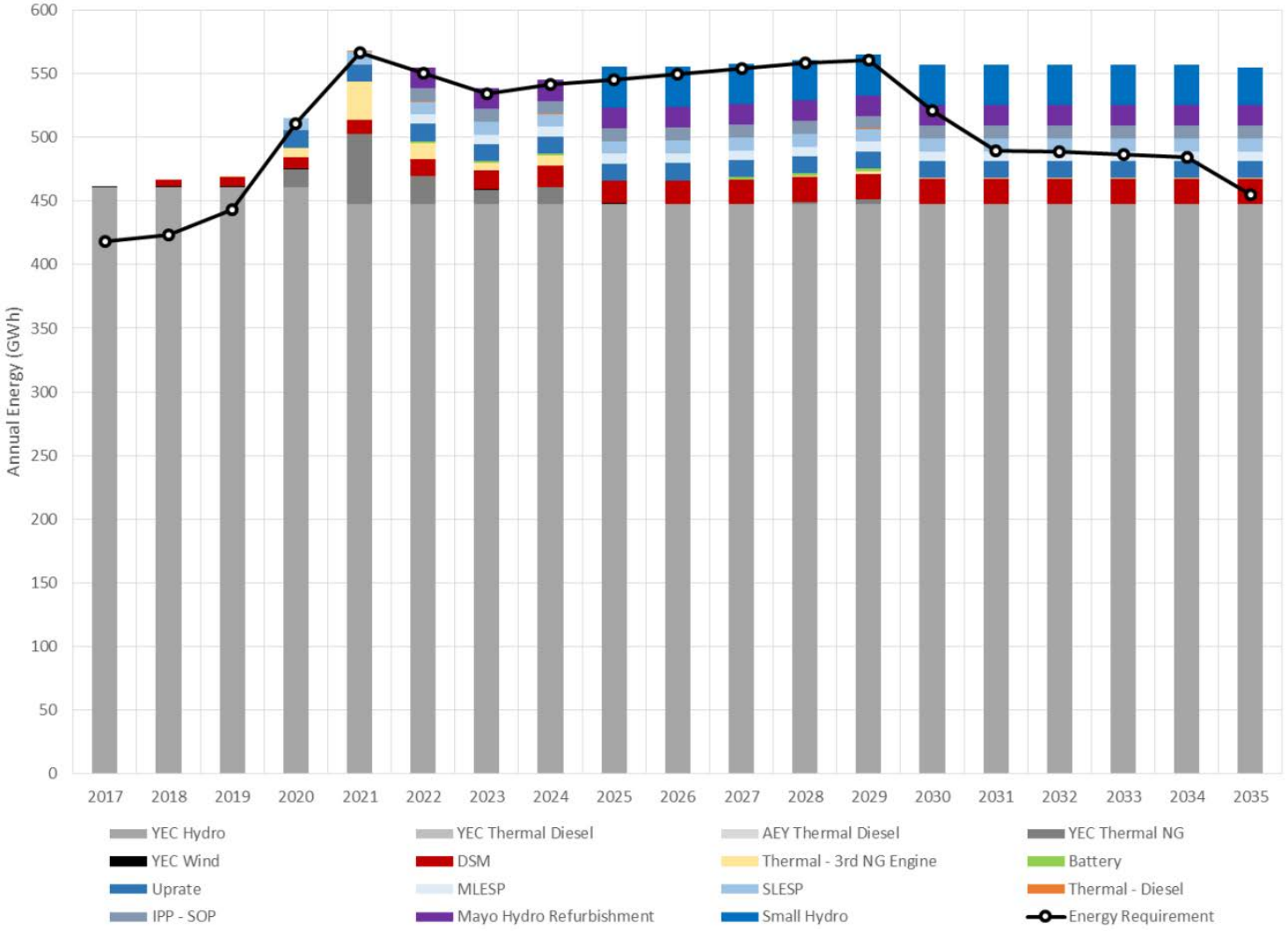


Table 19: Medium Industrial Activity with No Price on Carbon Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	13.5	54.7	21.4	10.7	12.9	0.0	0.0	0.0	1.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	17.5	18.3	19.1	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Thermal - 3rd NG Engine	0.0	0.0	0.1	7.6	29.6	12.3	5.8	7.6	0.1	0.1	0.1	0.9	2.3	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	1.9	1.5	1.8	0.0	0.0	1.6	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 14: Medium Industrial Activity with No Price on Carbon Portfolio, Capacity

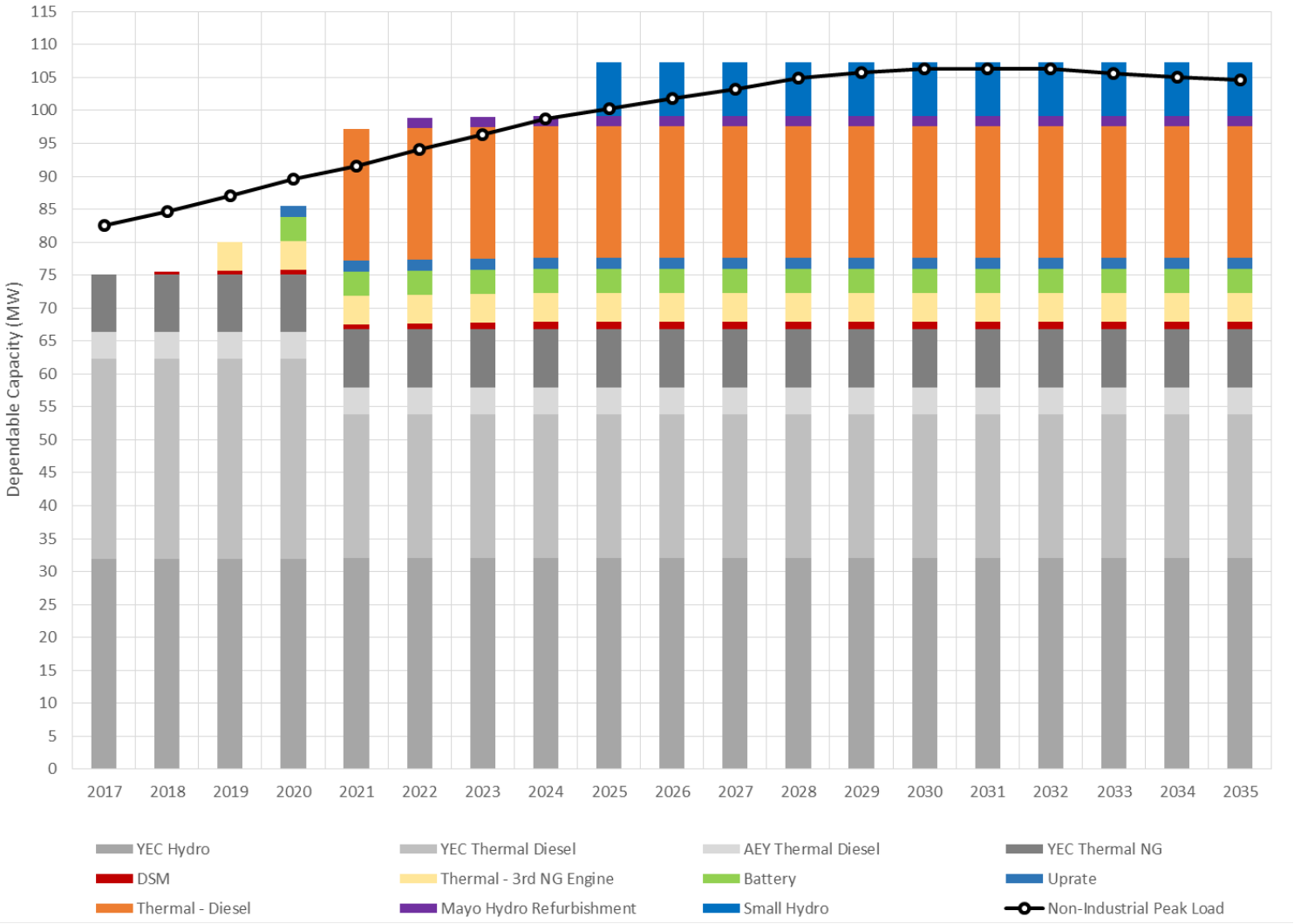


Table 20: Medium Industrial Activity with No Price on Carbon Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 21: Medium Industrial Activity with No Price on Carbon Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.8
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2025	
Drury Creek Small Hydro	8.1
Grand Total	43.6

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Present Value		
Fixed Costs	$ 122.5	[A]
Variable Costs	$ 66.4	[B]
Total Costs	$ 188.9	[C] = [A] + [B]

This portfolio generates 98.1% energy under average water assumptions.

Medium Industrial Activity with 20-Year GWP

Figure 15: Medium Industrial Activity with 20-Year GWP Portfolio, Energy

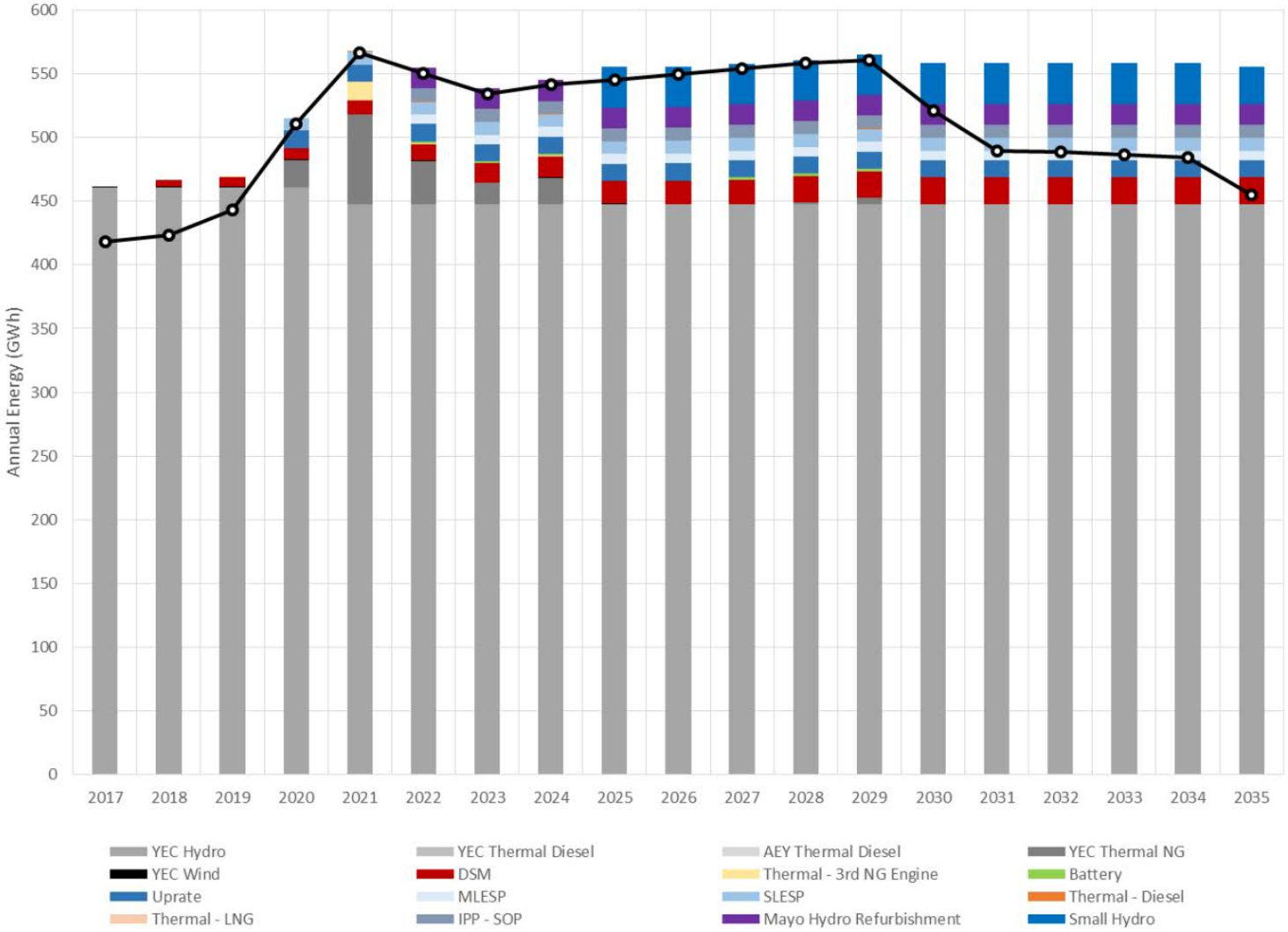


Table 22: Medium Industrial Activity with 20-Year GWP Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	21.0	70.1	33.6	16.3	20.3	0.0	0.0	0.0	0.9	4.9	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	17.5	18.3	19.1	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Thermal - 3rd NG Engine	0.0	0.0	0.1	0.1	14.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	1.9	1.5	1.8	0.0	0.0	1.6	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 16: Medium Industrial Activity with 20-Year GWP Portfolio, Capacity

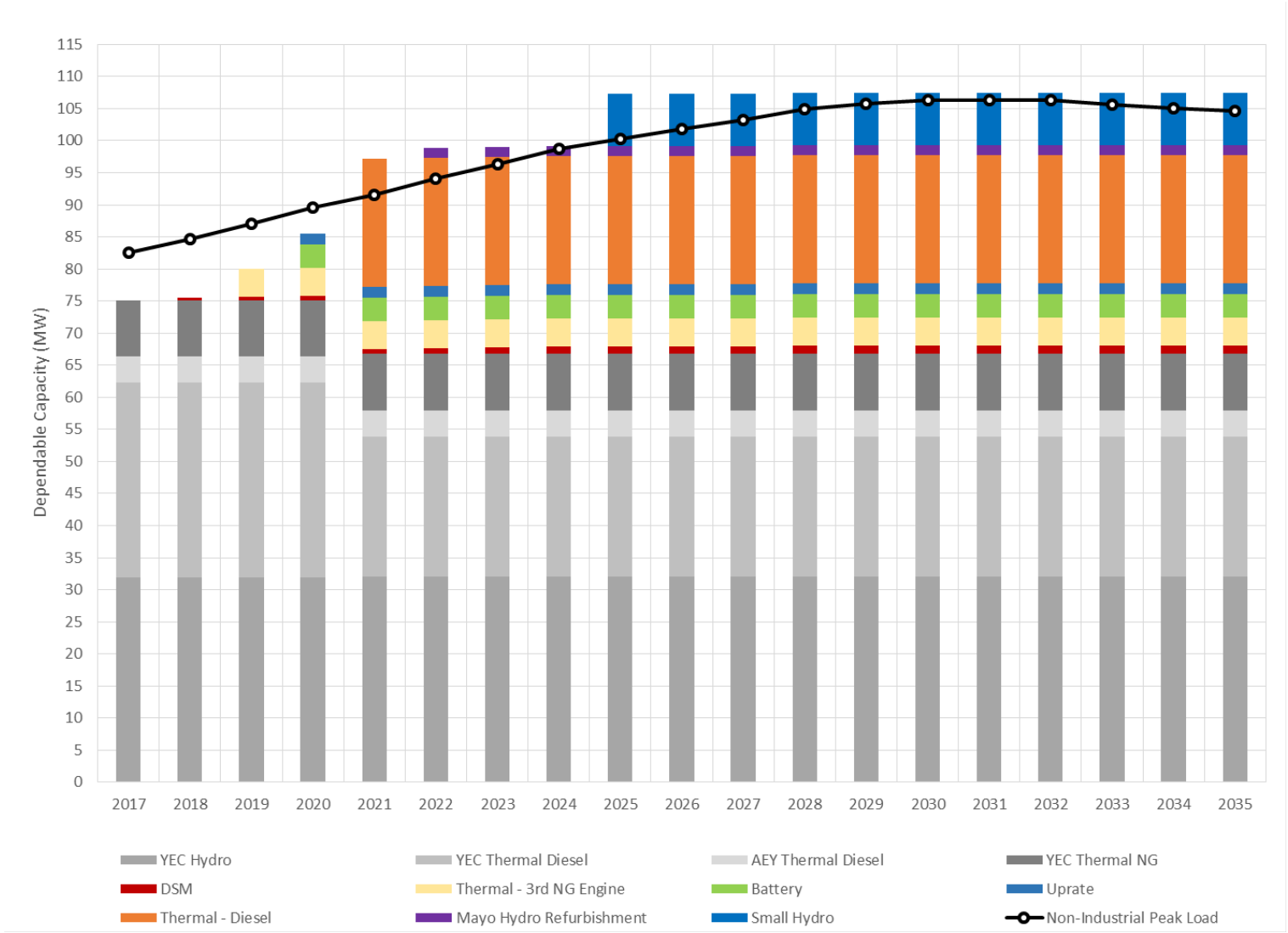


Table 23: Medium Industrial Activity with 20-Year GWP Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 24: Medium Industrial Activity with 20-Year GWP Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.9
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2025	
Drury Creek Small Hydro	8.1
Grand Total	43.7

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Present Value		
Fixed Costs	$ 122.7	[A]
Variable Costs	$ 74.6	[B]
Total Costs	$ 197.3	[C] = [A] + [B]

This portfolio generates 98.1% energy under average water assumptions.

Low Industrial Activity with High Diesel and High LNG Price

Figure 17: Low Industrial Activity with High Diesel and High LNG Price Portfolio, Energy

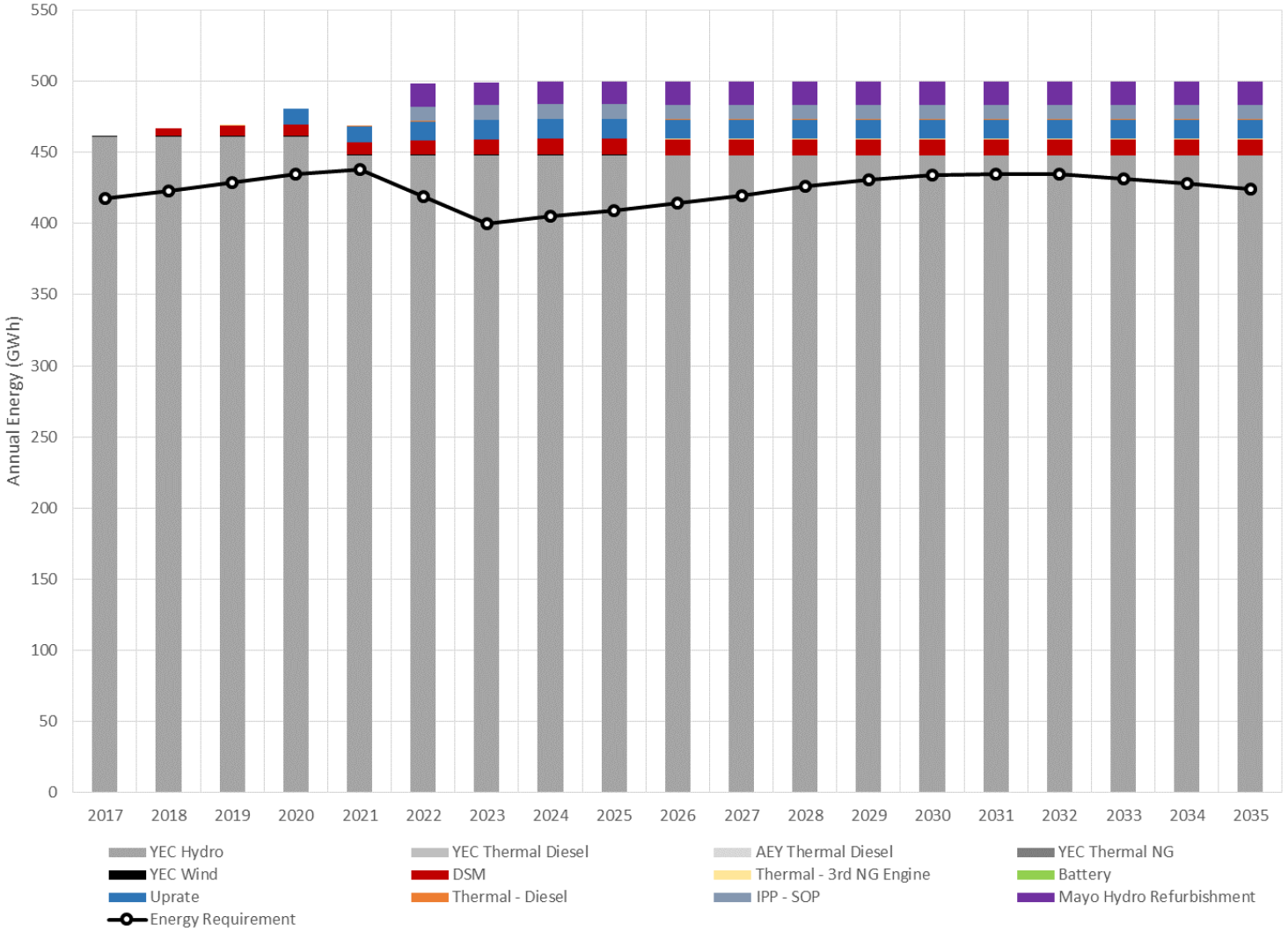


Table 25: Low Industrial Activity with High Diesel and High LNG Price Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	7.9	8.8	9.7	10.6	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Thermal - 3rd NG Engine	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	11.1	11.1	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 18: Low Industrial Activity with High Diesel and High LNG Price Portfolio, Capacity

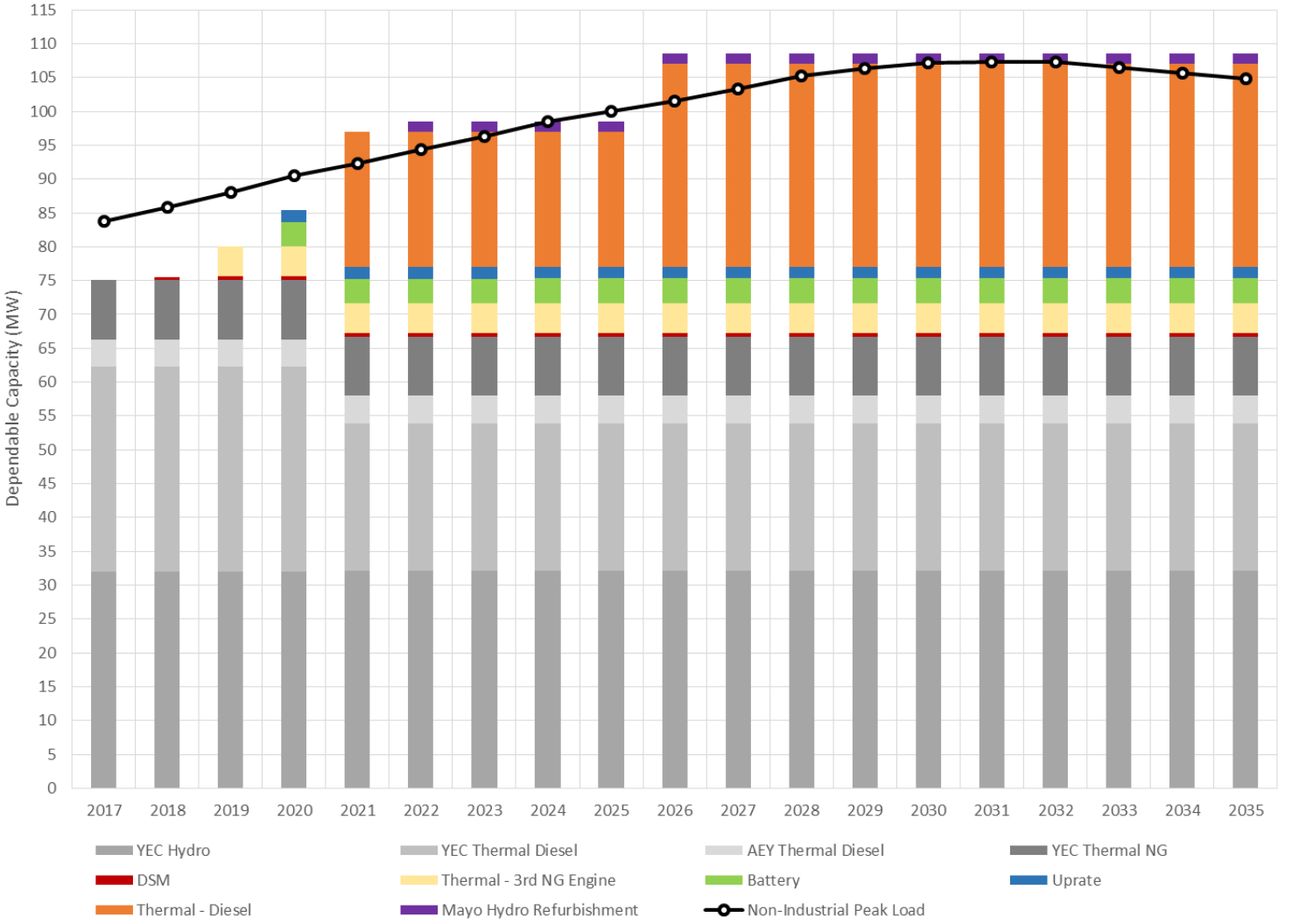


Table 26: Low Industrial Activity with High Diesel and High LNG Price Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 27: Low Industrial Activity with High Diesel and LNG Price Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.2
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Whitehorse Uprate	1.7
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Aishihik Uprate	1.3
Mayo Hydro Refurbishment	2.3
2026	
Thermal Diesel - Takhini Substation	10.0
Grand Total	44.9

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 207.4	
Present Value		
Fixed Costs	$ 96.9	[A]
Variable Costs	$ 37.7	[B]
Total Costs	$ 134.6	[C] = [A] + [B]

This portfolio generates 99.8% energy under average water assumptions.

Medium Industrial Activity with High Diesel and High LNG Price

Figure 19: Medium Industrial Activity with High Diesel and LNG Price Portfolio, Energy

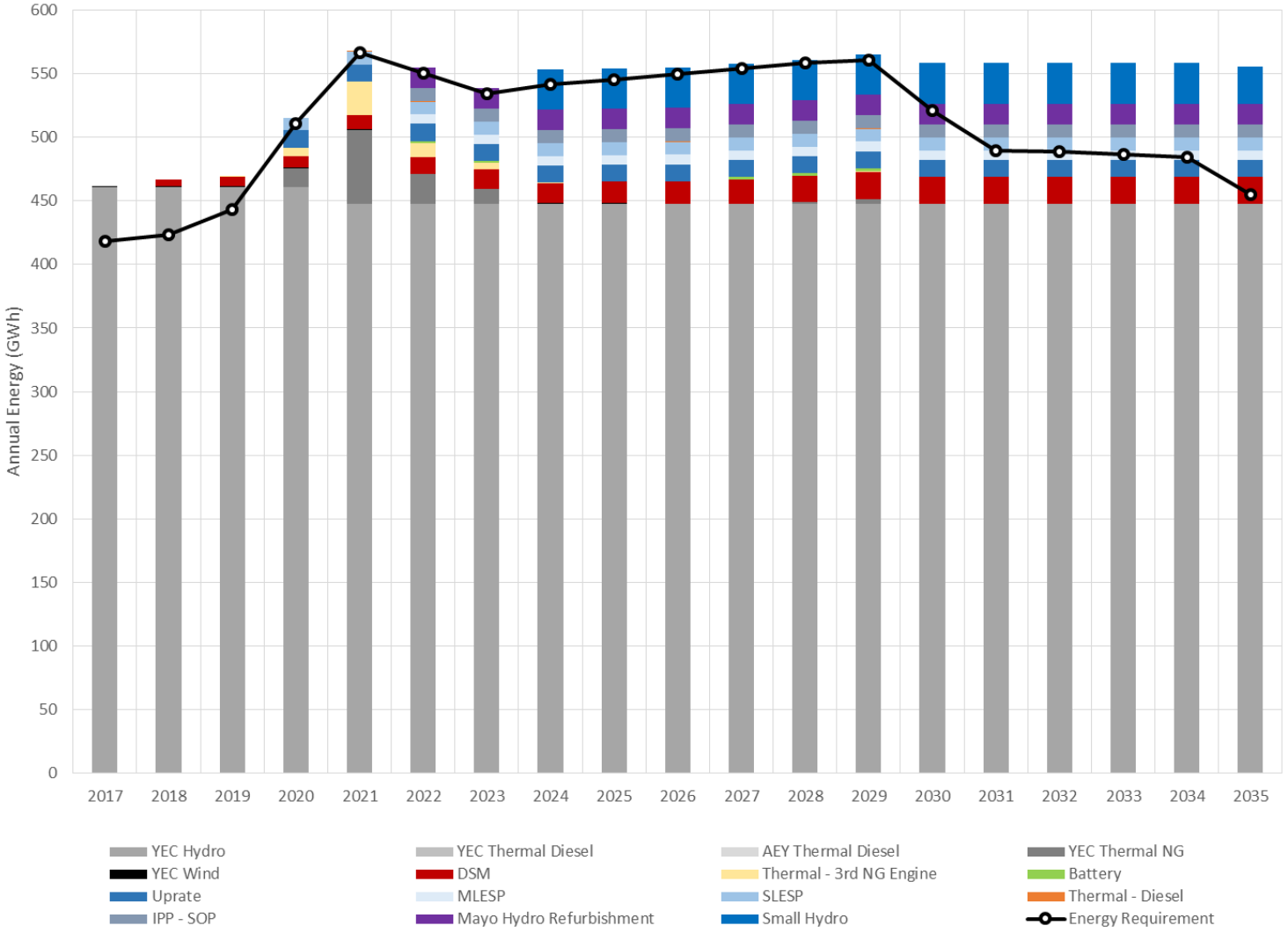


Table 28: Medium Industrial Activity with High Diesel and LNG Price Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	14.3	57.8	23.1	11.3	0.0	0.0	0.0	0.0	0.9	3.6	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	15.7	16.5	17.3	19.1	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Thermal - 3rd NG Engine	0.0	0.0	0.1	6.8	26.5	10.7	5.1	0.1	0.1	0.1	0.1	0.1	1.4	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	1.9	1.5	0.0	0.0	0.0	1.6	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 20: Medium Industrial Activity with High Diesel and High LNG High Price Portfolio, Capacity

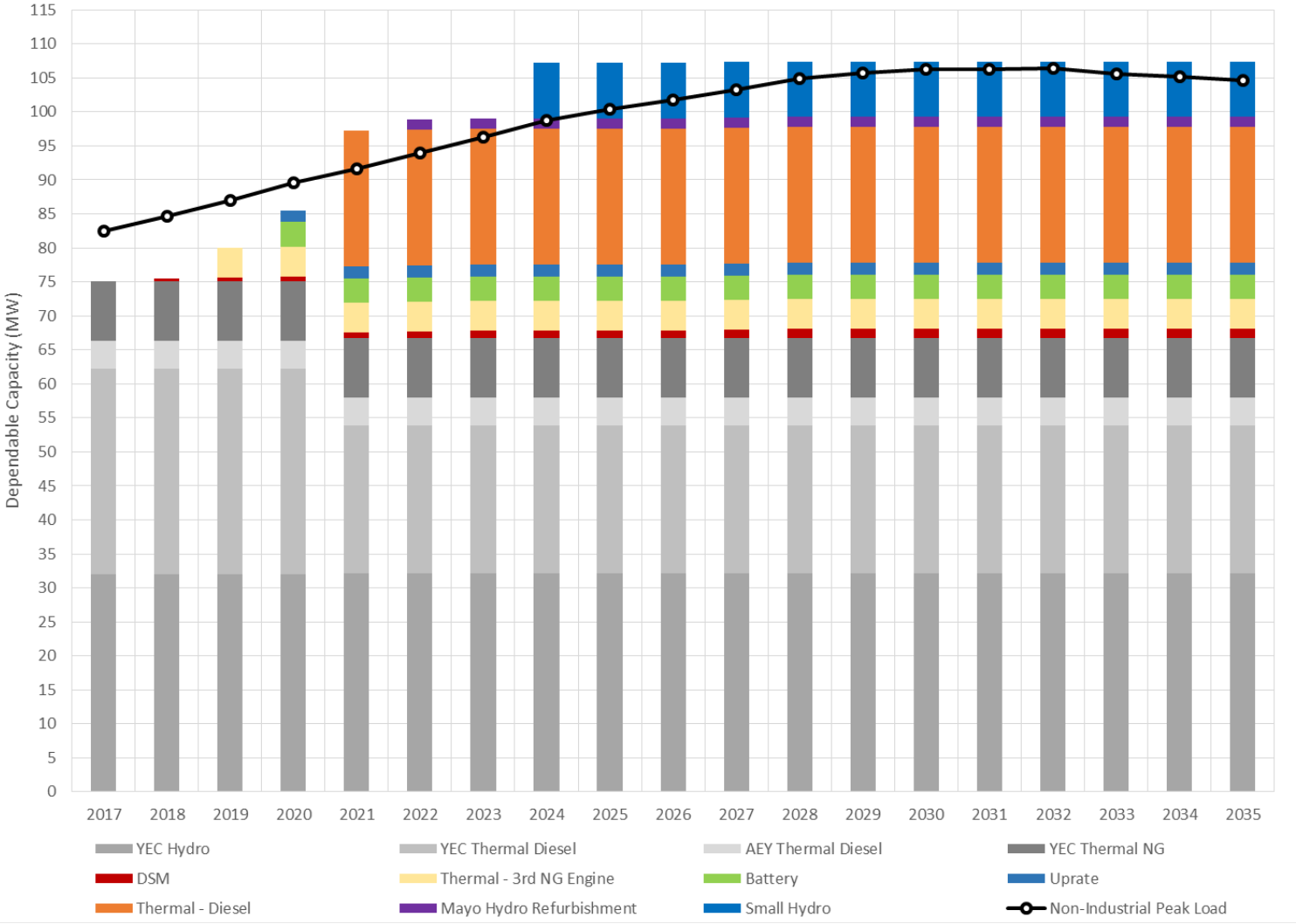


Table 29: Medium Industrial Activity with High Diesel and High LNG High Price Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.0	1.1	1.1	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 30: Medium Industrial Activity with High Diesel and High LNG Price Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.9
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2024	
Drury Creek Small Hydro	8.1
Grand Total	43.7

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Present Value		
Fixed Costs	$ 127.1	[A]
Variable Costs	$ 72.3	[B]
Total Cost	$ 199.4	[C] = [A] + [B]

This portfolio generates 98.3% energy under average water assumptions.

Low Industrial Activity with Medium Diesel and Low LNG Price

Figure 21: Low Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Energy

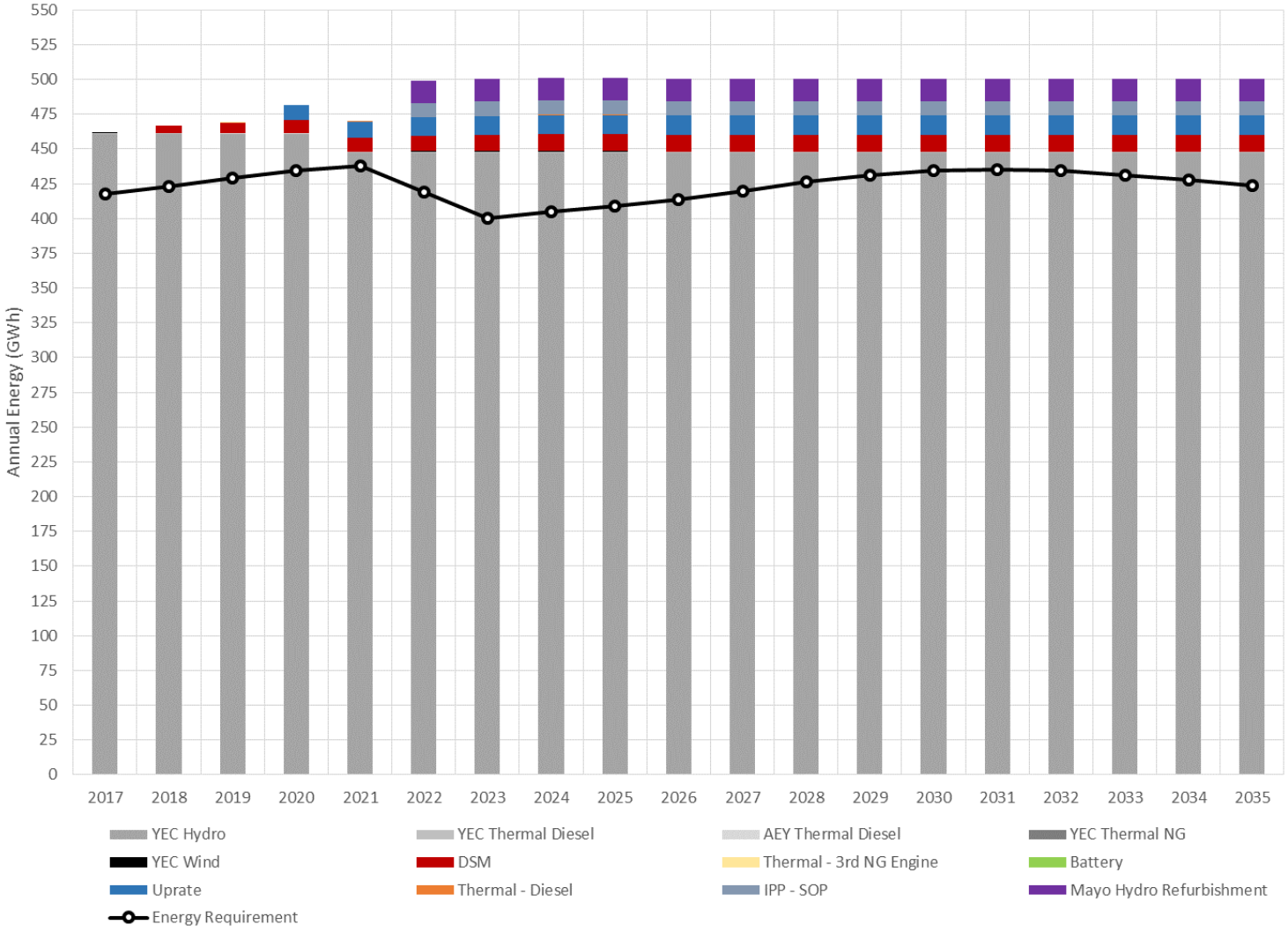


Table 31: Low Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	9.9	10.8	11.7	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Thermal - 3rd NG Engine	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	11.1	11.1	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 22: Low Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Capacity

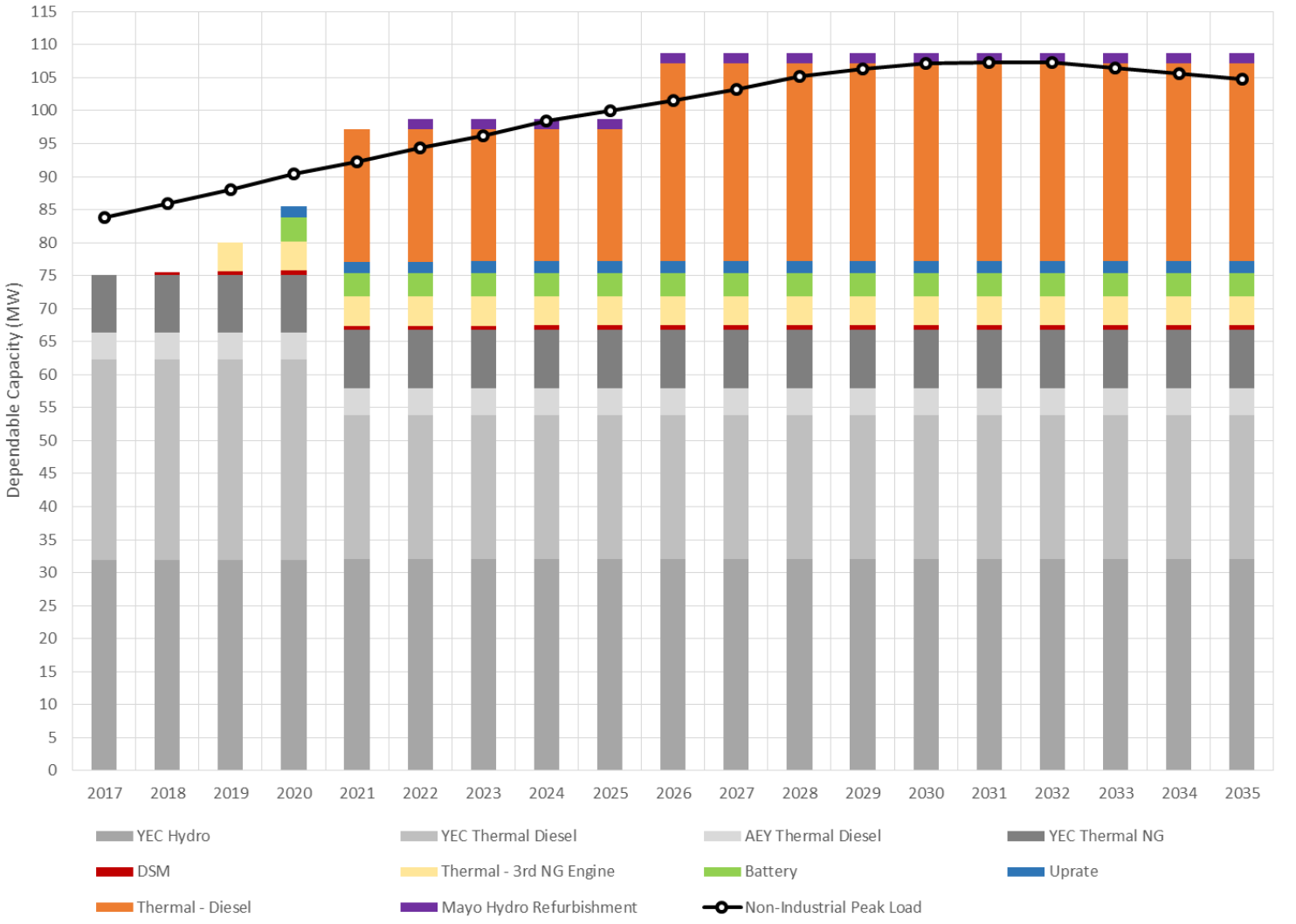


Table 32: Low Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 33: Low Industrial Activity with Medium Diesel and Low LNG Price Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.3
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Whitehorse Uprate	1.7
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Aishihik Uprate	1.3
Mayo Hydro Refurbishment	2.3
2026	
Thermal Diesel - Takhini Substation	10.0
Grand Total	45.0

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 207.4	
Present Value		
Fixed Costs	$ 97.6	[A]
Variable Costs	$ 37.4	[B]
Total Costs	$ 135.0	[C] = [A] + [B]

This portfolio generates 99.8% energy under average water assumptions.

Medium Industrial Activity with Medium Diesel and Low LNG Price

Figure 23: Medium Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Energy

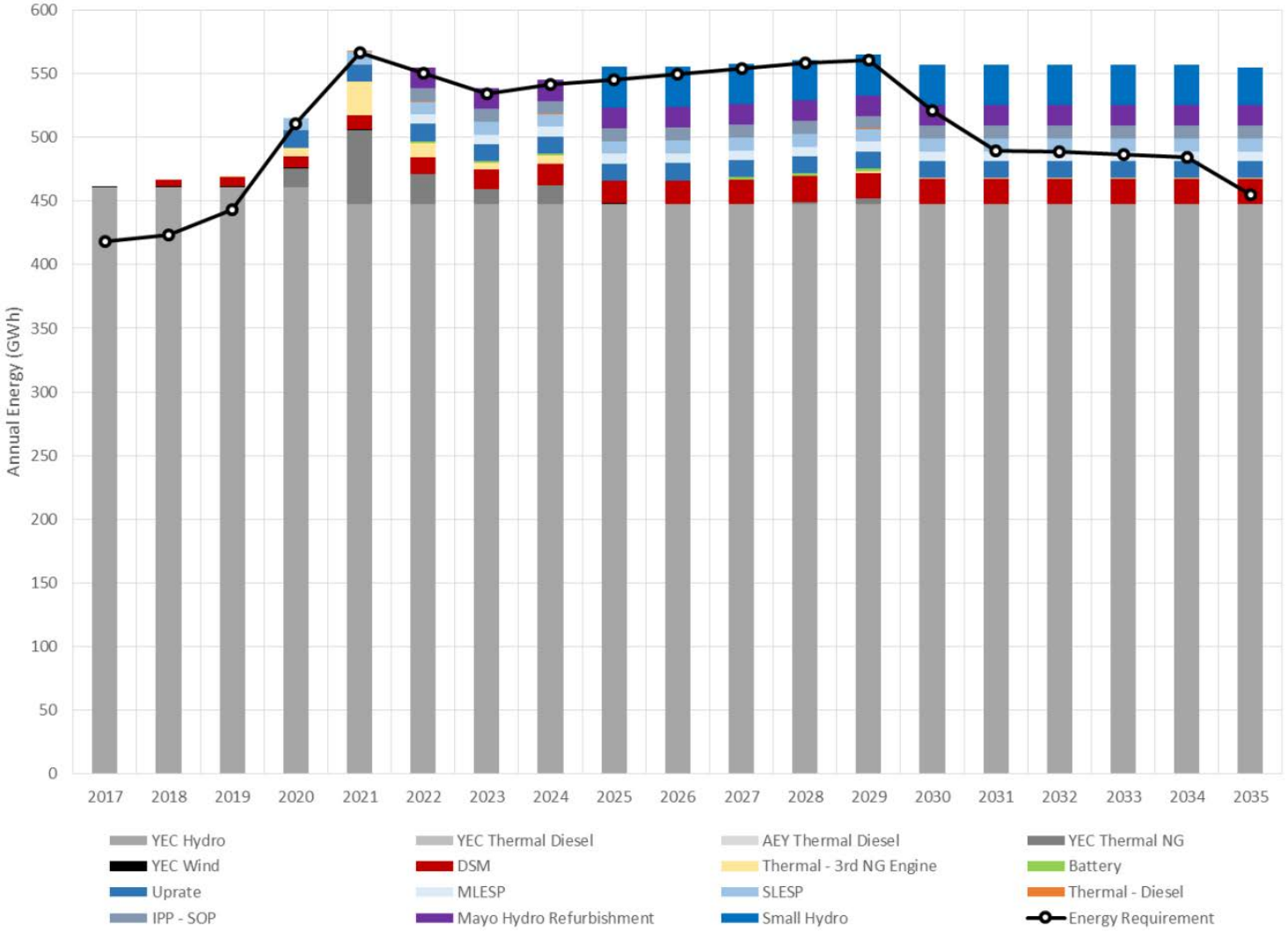


Table 34: Medium Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	14.3	57.8	23.1	11.3	14.3	0.0	0.0	0.0	1.6	4.1	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	17.5	18.3	19.1	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Thermal - 3rd NG Engine	0.0	0.0	0.1	6.8	26.5	10.7	5.1	6.2	0.1	0.1	0.1	0.3	1.7	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	1.9	1.5	1.8	0.0	0.0	1.6	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 24: Medium Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Capacity

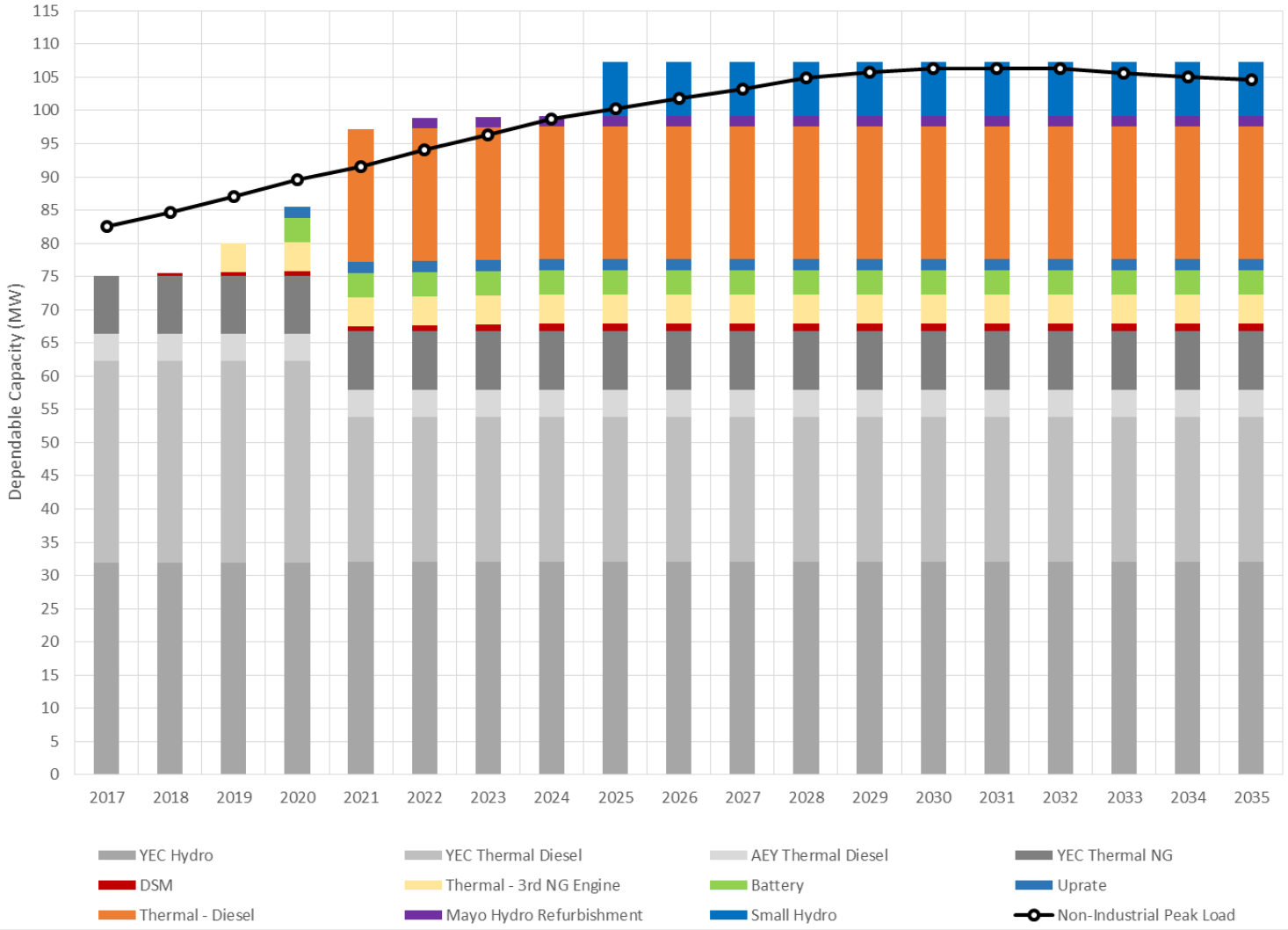


Table 35: Medium Industrial Activity with Medium Diesel and Low LNG Price Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 36: Medium Industrial Activity with Medium Diesel and Low LNG Price Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.8
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2025	
Drury Creek Small Hydro	8.1
Grand Total	43.6

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Present Value		
Fixed Costs	$ 122.5	[A]
Variable Costs	$ 64.3	[B]
Total Costs	$ 186.8	[C] = [A] + [B]

This portfolio generates 98.1% energy under average water assumptions.

Medium Industrial Activity – Renewable Portfolio

Figure 25: Medium Industrial Activity – Renewable Portfolio, Energy

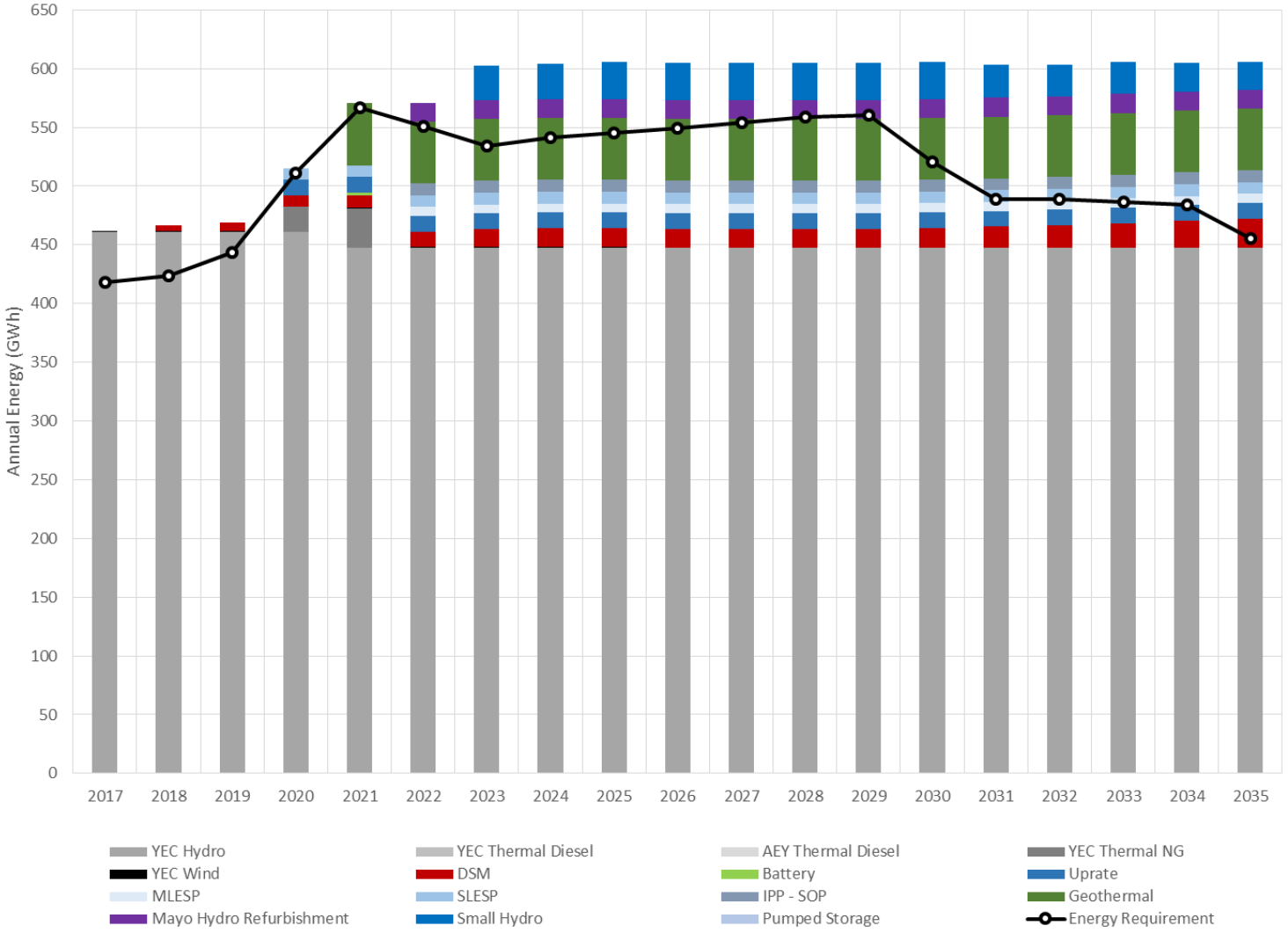


Table 37: Medium Industrial Activity – Renewable Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	21.1	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	15.7	15.7	15.7	15.7	15.7	15.7	16.7	17.6	18.8	20.7	22.7	24.6
Thermal - 3rd NG Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Battery	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	29.4	30.4	31.7	31.7	31.7	31.7	31.7	31.7	28.3	27.1	27.1	25.0	23.2
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	52.8	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 26: Medium Industrial Activity – Renewable Portfolio, Capacity

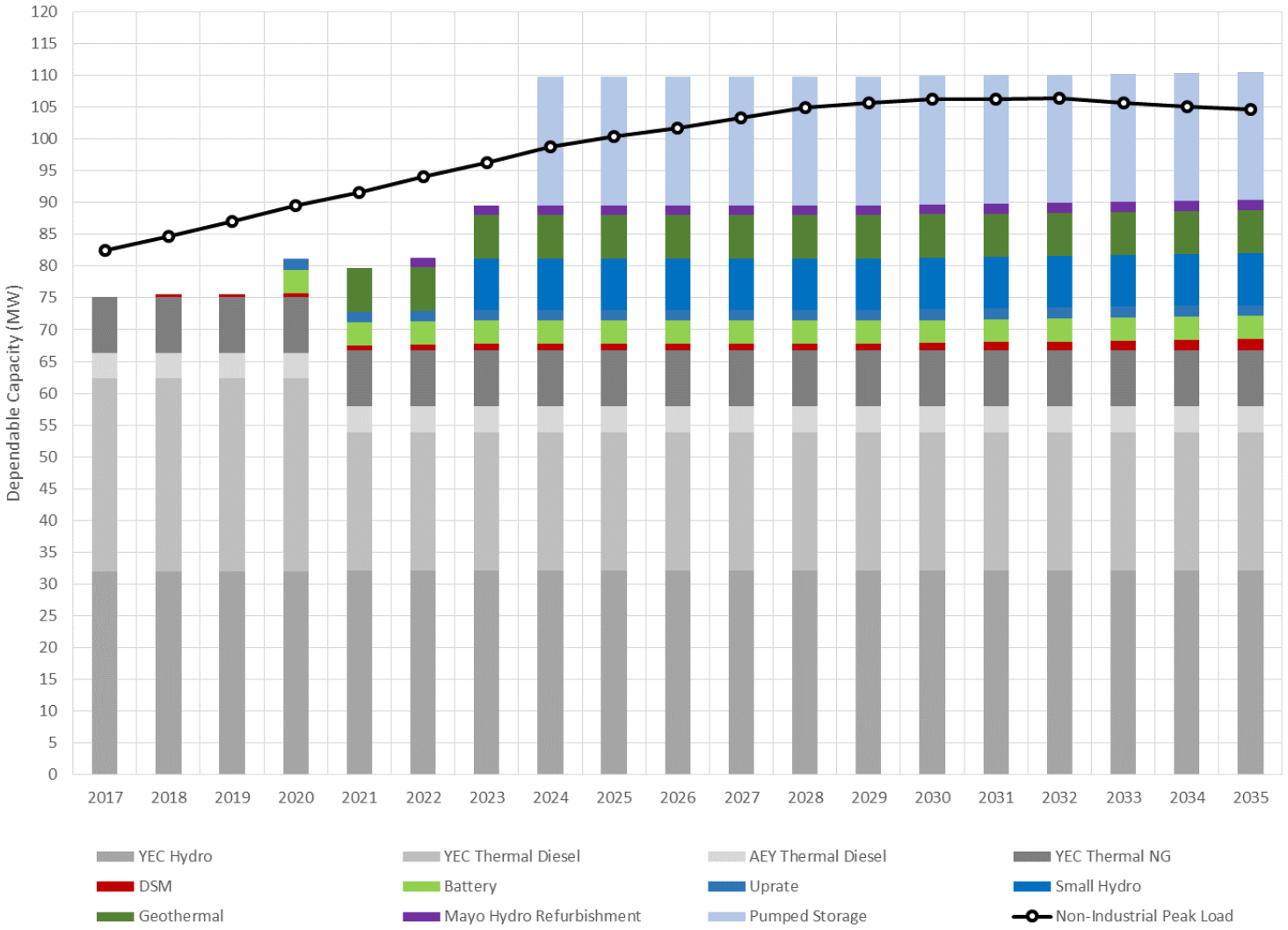


Table 38: Medium Industrial Activity – Renewable Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.2	1.3	1.4	1.5	1.7	1.8
Thermal - 3rd NG Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 39: Medium Industrial Activity – Renewable Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	2.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Geothermal - MacArthur	7.7
Geothermal - Vista Mountain	3.6
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2023	
Drury Creek Small Hydro	8.1
2024	
Pumped Storage - Moon Lake	20.2
2035	
Biomass (ORC) - Haines Junction	0.6
Waste-to-Energy - Whitehorse	1.6
Grand Total	53.6

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 784.6	
Present Value		
Fixed Costs	$ 155.8	[A]
Variable Costs	$ 163.8	[B]
Total Costs	$ 319.6	[C] = [A] + [B]

This portfolio generates an average of 99.4 % renewable energy over the 20 year planning period, under average water assumptions.

High Industrial Activity – Renewable Portfolio

Figure 27: High Industrial Activity – Renewable Portfolio, Energy

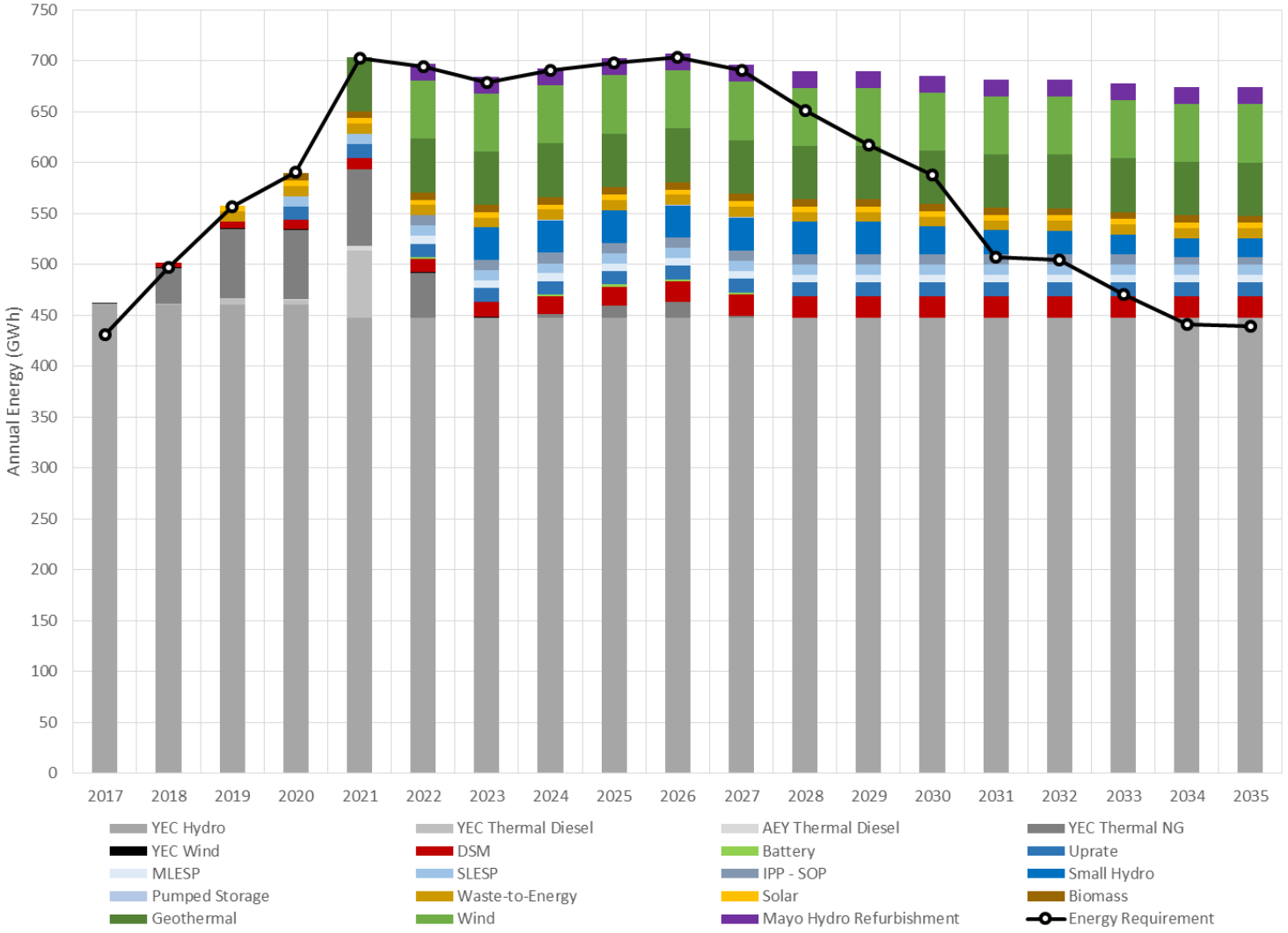


Table 40: High Industrial Activity – Renewable Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	5.9	4.4	66.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.4	0.8	4.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	35.4	67.7	68.2	75.0	43.9	0.0	3.2	11.4	15.1	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	18.4	20.2	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Thermal - 3rd NG Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Battery	0.0	0.0	0.0	0.0	0.0	1.8	0.0	2.0	2.0	2.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	9.8	7.5	7.4
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	27.1	23.4	23.1	19.8	18.5	18.3
Wind	0.0	0.0	0.0	0.0	0.0	57.5	57.3	57.5	57.5	57.5	57.5	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3
Geothermal	0.0	0.0	0.0	0.0	52.8	52.8	52.5	52.8	52.8	52.8	52.8	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.4	0.4	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Solar	0.0	0.0	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 28: High Industrial Activity – Renewable Portfolio, Capacity

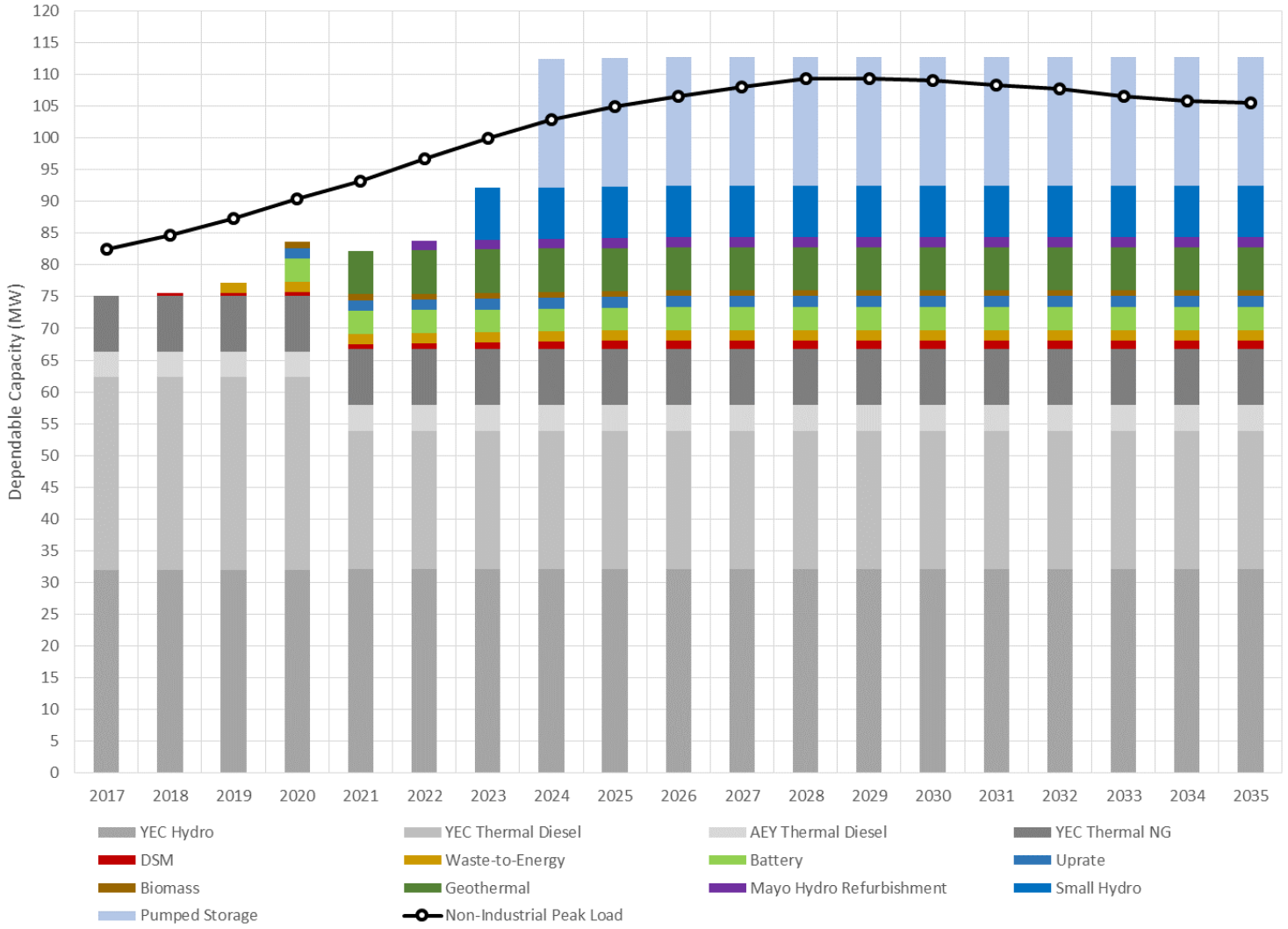


Table 41: High Industrial Activity – Renewable Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Thermal - 3rd NG Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Waste-to-Energy	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 42: High Industrial Activity – Renewable Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	2.0
2019	
Solar - Whitehorse	5.0
Waste-to-Energy - Whitehorse	1.6
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
Biomass (Gasification) - Haines Junction	0.5
Biomass (ORC) - Haines Junction	0.6
2021	
Geothermal - MacArthur	7.7
Geothermal - Vista Mountain	3.6
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0
Wind - Miller's Ridge	20
2023	
Drury Creek Small Hydro	8.1
2024	
Pumped Storage - Moon Lake	20.2
Grand Total	78.673

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 909.6	
Present Value		
Fixed Costs	$ 156.3	[A]
Variable Costs	$ 382.2	[B]
Total Costs	$ 538.5	[C] = [A] + [B]

This portfolio generates an average of 96.6 % renewable energy over the 20 year planning period, under average water assumptions.

Medium Industrial Activity with No Transmission Cost to Moon Lake

Figure 29: Medium Industrial Activity with No Transmission Cost to Moon Lake Portfolio, Energy

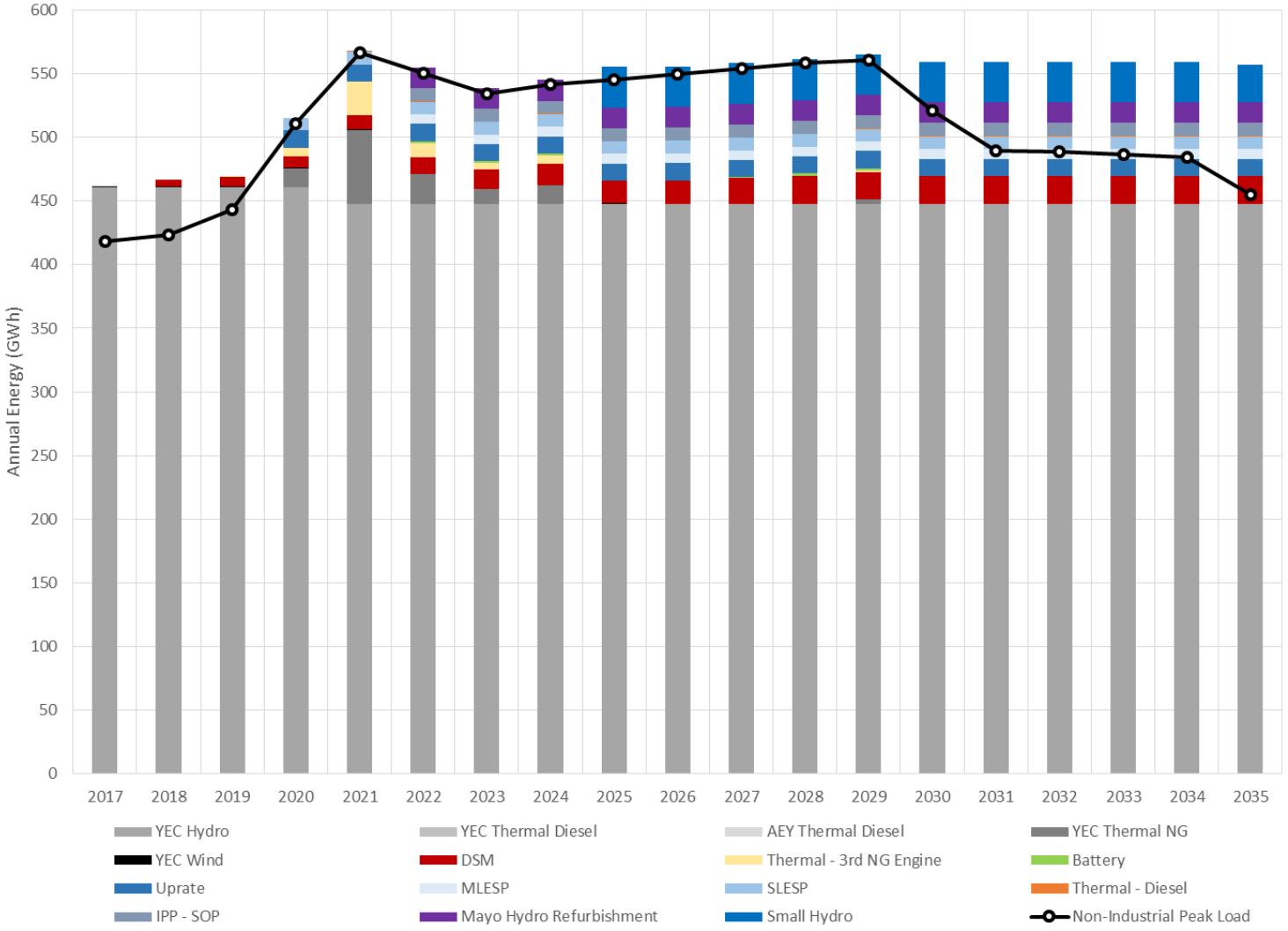


Table 43: Medium Industrial Activity with No Transmission Cost to Moon Lake Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	14.3	57.8	23.1	11.3	14.3	0.0	0.0	0.0	0.1	3.1	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	17.5	18.3	20.0	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Thermal - 3rd NG Engine	0.0	0.0	0.1	6.8	26.5	10.7	5.1	6.2	0.1	0.1	0.1	0.1	1.0	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	1.9	1.5	1.8	0.0	0.0	0.8	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 30: Medium Industrial Activity with No Transmission Cost to Moon Lake Portfolio, Capacity

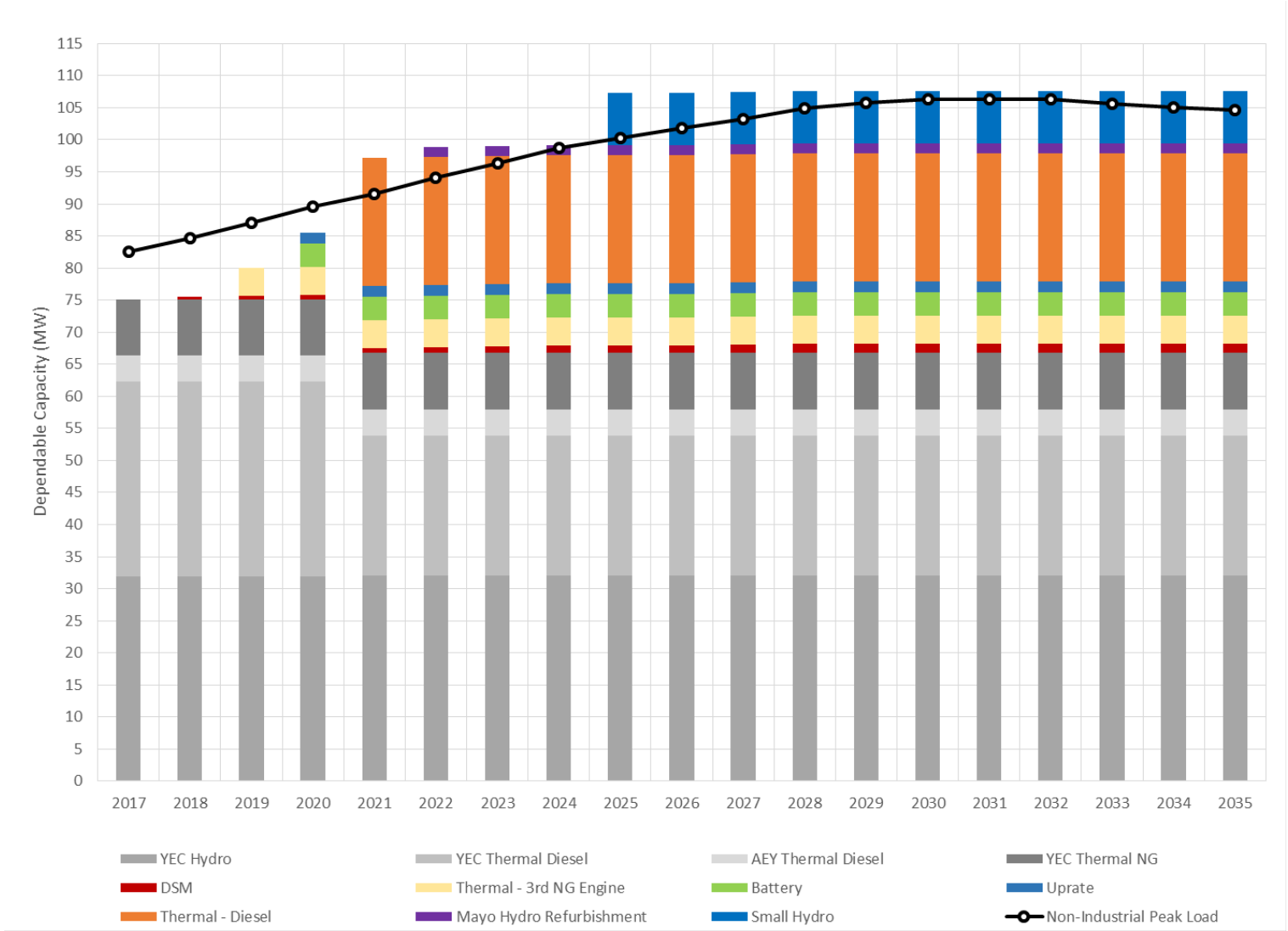


Table 44: Medium Industrial Activity with No Transmission Cost to Moon Lake Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.2	1.2	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 45: Medium Industrial Activity with No Transmission Cost to Moon Lake Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	2.0
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2025	
Drury Creek Small Hydro	8.1
Grand Total	43.8

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Present Value		
Fixed Costs	$ 123.0	[A]
Variable Costs	$ 74.1	[B]
Total Costs	$ 197.1	[C] = [A] + [B]

This portfolio generates an average of 98.1% renewable energy over the 20 year planning period, under average water assumptions.

Medium Industrial Activity with No Transmission Cost to Atlin

Figure 31: Medium Industrial Activity with No Transmission Cost to Atlin Portfolio, Energy

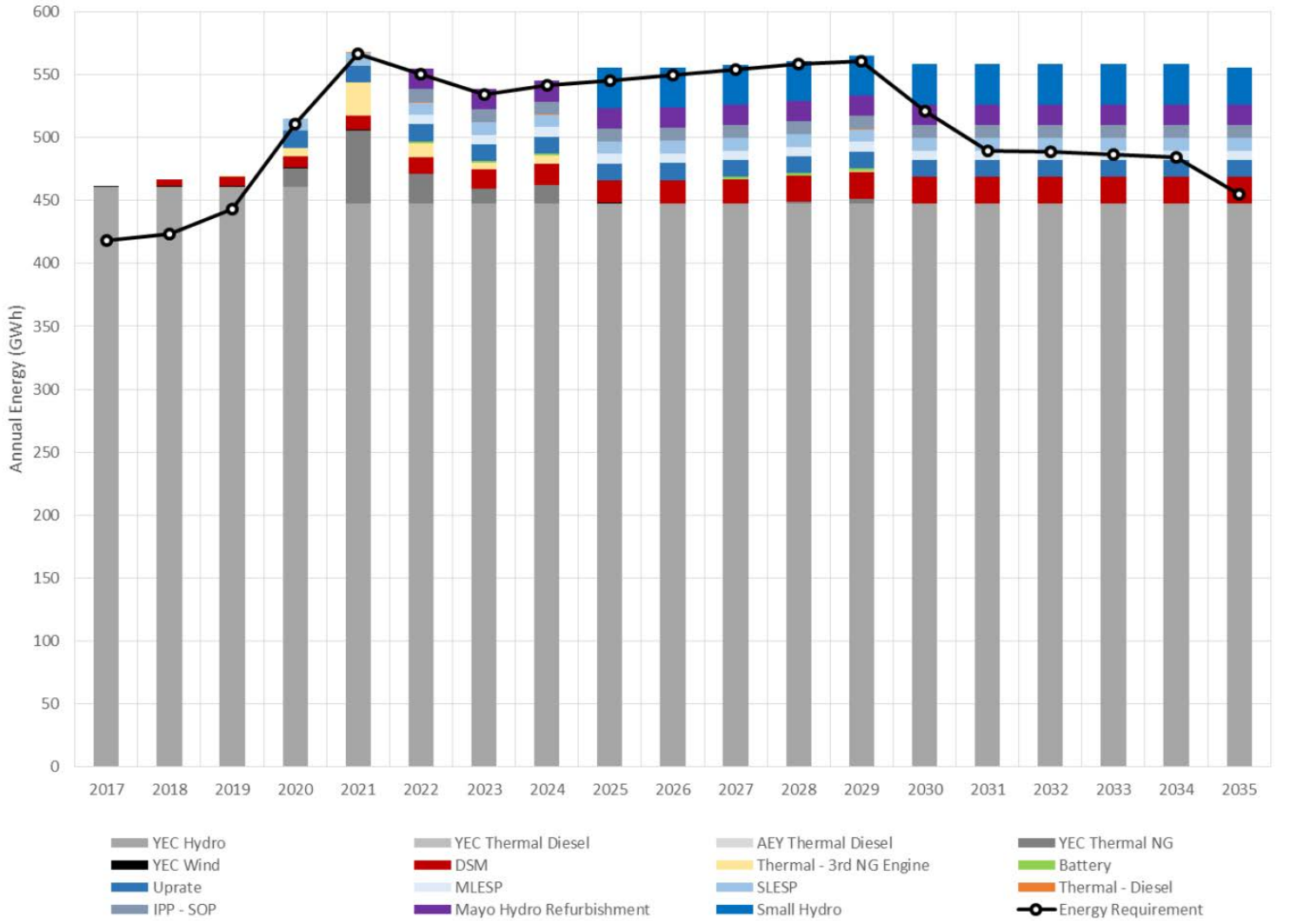


Table 46: Medium Industrial Activity with No Transmission Cost to Atlin Portfolio, Energy

Resource Option	Annual Energy (GWh)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	460.7	460.7	460.7	460.7	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5	447.5
YEC Thermal Diesel	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
AEY Thermal Diesel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YEC Thermal NG	0.0	0.0	0.0	14.3	57.8	23.1	11.3	14.3	0.0	0.0	0.0	0.9	3.6	0.0	0.0	0.0	0.0	0.0	0.0
YEC Wind	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	5.1	7.1	9.0	11.0	13.0	14.9	16.7	17.5	18.3	19.1	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Thermal - 3rd NG Engine	0.0	0.0	0.1	6.8	26.5	10.7	5.1	6.2	0.1	0.1	0.1	0.1	1.4	0.1	0.1	0.1	0.1	0.1	0.1
Battery	0.0	0.0	0.0	0.0	0.0	1.9	1.5	1.8	0.0	0.0	1.6	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
Uprate	0.0	0.0	0.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
MLESP	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SLESP	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Thermal - Diesel	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.7	29.4
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Figure 32: Medium Industrial Activity with No Transmission Cost to Atlin Portfolio, Capacity

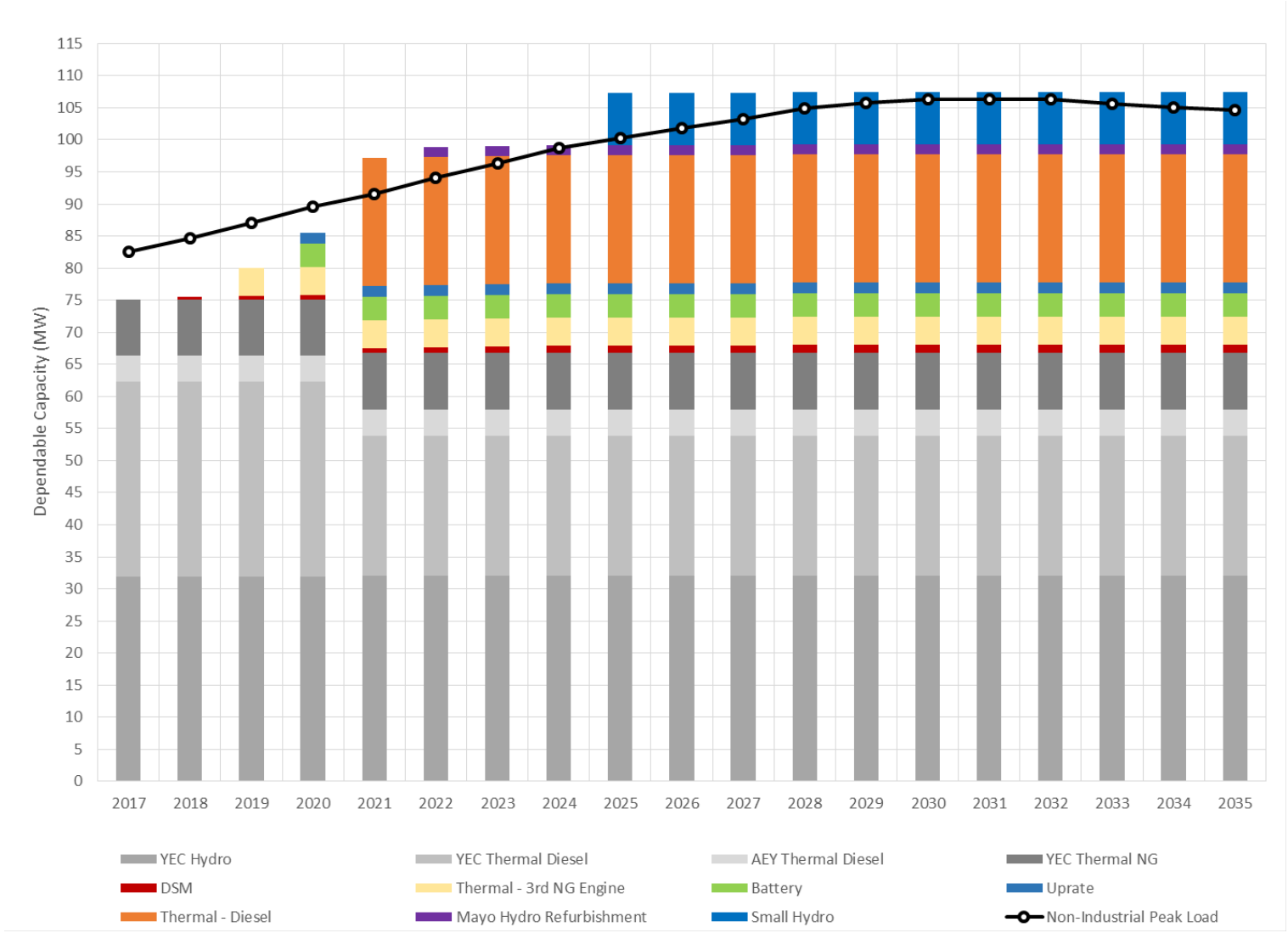


Table 47: Medium Industrial Activity with No Transmission Cost to Atlin Portfolio, Capacity

Resource Option	Dependable Capacity (MW)																		
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
YEC Hydro	32.0	32.0	32.0	32.0	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
YEC Thermal Diesel	30.3	30.3	30.3	30.3	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
AEY Thermal Diesel	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
YEC Thermal NG	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
YEC Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM	0.0	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Thermal - 3rd NG Engine	0.0	0.0	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Battery	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Uprate	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
MLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLESP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal - Diesel	0.0	0.0	0.0	0.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Thermal - LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP - SOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waste-to-Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biogas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mayo Hydro Refurbishment	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 48: Medium Industrial Activity with No Transmission Cost to Atlin Portfolio Summary

Resource Option	Installed Capacity [MW]
2018	
Demand Side Management	1.9
2019	
Thermal - 3rd NG Engine at Whitehorse	4.4
2020	
4 MW Battery - Takhini Substation	4.0
Aishihik Uprate	1.3
Whitehorse Uprate	1.7
Southern Lake Enhancement Storage Project	0.0
2021	
Thermal Diesel - Takhini Substation	20.0
2022	
Mayo Hydro Refurbishment	2.3
Mayo Lake Enhancement Storage Project	0.0
2025	
Drury Creek Small Hydro	8.1
Grand Total	43.7

Cost Components	Cost [2016 $Millions]	Comment
Portfolio Capital Cost	$ 298.6	
Present Value		
Fixed Costs	$ 122.7	[A]

Variable Costs	$ 74.4	[B]
Total Costs	$ 197.1	[C] = [A] + [B]

This portfolio generates an average of 98.1% renewable energy over the 20 year planning period, under average water assumptions.