

ATTACHMENT 1

PRESENTATIONS FROM THE

LIQUEFIED NATURAL GAS WORKSHOP

JANUARY 2012

(Response to UCG-YEC-1-12 (d - f))



LNG Fundamentals

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Braemar Wavespec USA
Houston, Texas**



**Yukon Energy Corporation
LNG Workshop
January 18, 2012**



What is Liquefied Natural Gas (LNG)?

- ❑ Liquefied Natural Gas (LNG) is a clear, colorless, odorless, non-toxic liquid
- ❑ LNG is natural gas that is refrigerated and turns to a liquid at -162 degrees Celsius.
- ❑ LNG is less than ½ the weight of water.



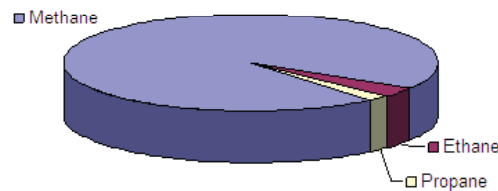
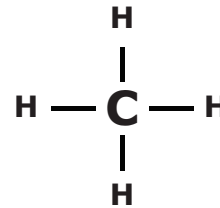
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LNG Properties & First Principles

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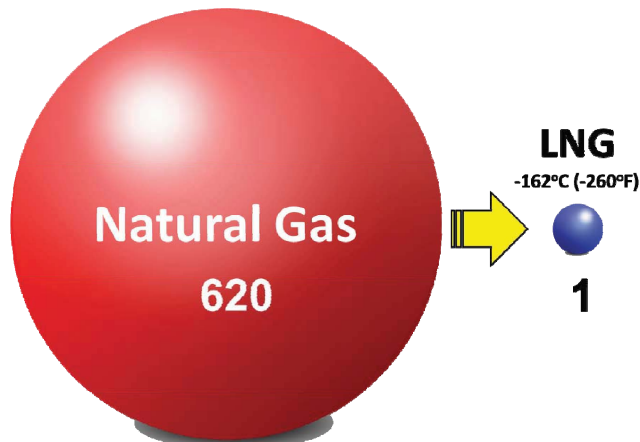
Natural gas and LNG are primarily:

- ☐ Methane CH_4
- ☐ Ethane C_2H_6
- ☐ Propane C_3H_8



3

Why LNG?



- Natural Gas is liquefied to reduce the volume. At atmospheric pressure, the ratio of volumes of gas to the liquid state is about 620:1
- Natural Gas is liquefied in order to transport it from locations with gas supply to locations with no gas pipeline supply.
- Allows for large storage capacity

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LNG Handling

- Produce LNG from pipeline natural gas by automated refrigeration process.
- Transport LNG at low pressure in double wall vacuum jacket transport trailers.
- LNG used as truck fuel.
- Store LNG at -162°C , at 1+ atmosphere pressure
- Vaporize LNG to natural gas as needed for power generation or gas distribution.



5



LNG Safety Record History

- Not new- not unfamiliar
 - 1959- First LNG ship built
 - 1965- First peakshaving plant (there are now over 80 facilities in North America)
 - 1966 – First LNG vehicle
 - 1968- First imports into North America
 - 1969- First exports from North America
 - 1971- First import terminal in North America, Boston (now 9 facilities)
- No release from a storage tank
- No release from a cargo tank



6

LNG Safety Fundamentals

- As a liquid, LNG is not flammable.
- Ignition and burning requires vaporization and mixture with oxygen (air).
- LNG vapor is flammable. The temperature necessary to ignite natural gas is about 1000°F. Gasoline requires only 450°F.
- Burning is not sustainable outside the flammability limits (5% to 15% air, above 15% there is not enough air. Below 5% there is not enough fuel.)
- LNG produces a “lazy flame” which burns more like a candle and not like gasoline.
- An LNG vapor cloud in the atmosphere will not explode, unlike propane.
- LNG is not shipped or stored under high pressure.
- LNG is stored at -162 °C at low pressure.

Safety Regulations

**LNG is regulated by Canadian Standard
CSA Z276 for Liquefied Natural Gas
(LNG) Production, Storage and
Handling**

Environmental Benefits of LNG

Air Emissions for LNG Compared to Diesel*

- ☐ 100% Reduction in Sulfur Dioxide (SO₂)
- ☐ Up to 97 % Reduction in Nitrogen Oxides (NO_x)
- ☐ 50% Reduction in Carbon Dioxide (CO₂)
- ☐ 91% Reduction of Carbon Monoxide (CO)
- ☐ 89% Reduction in Particulate Matter (PM)
- ☐ 50% Reduction In Volatile Organic Hydrocarbon (VOC)

* US Department of Energy



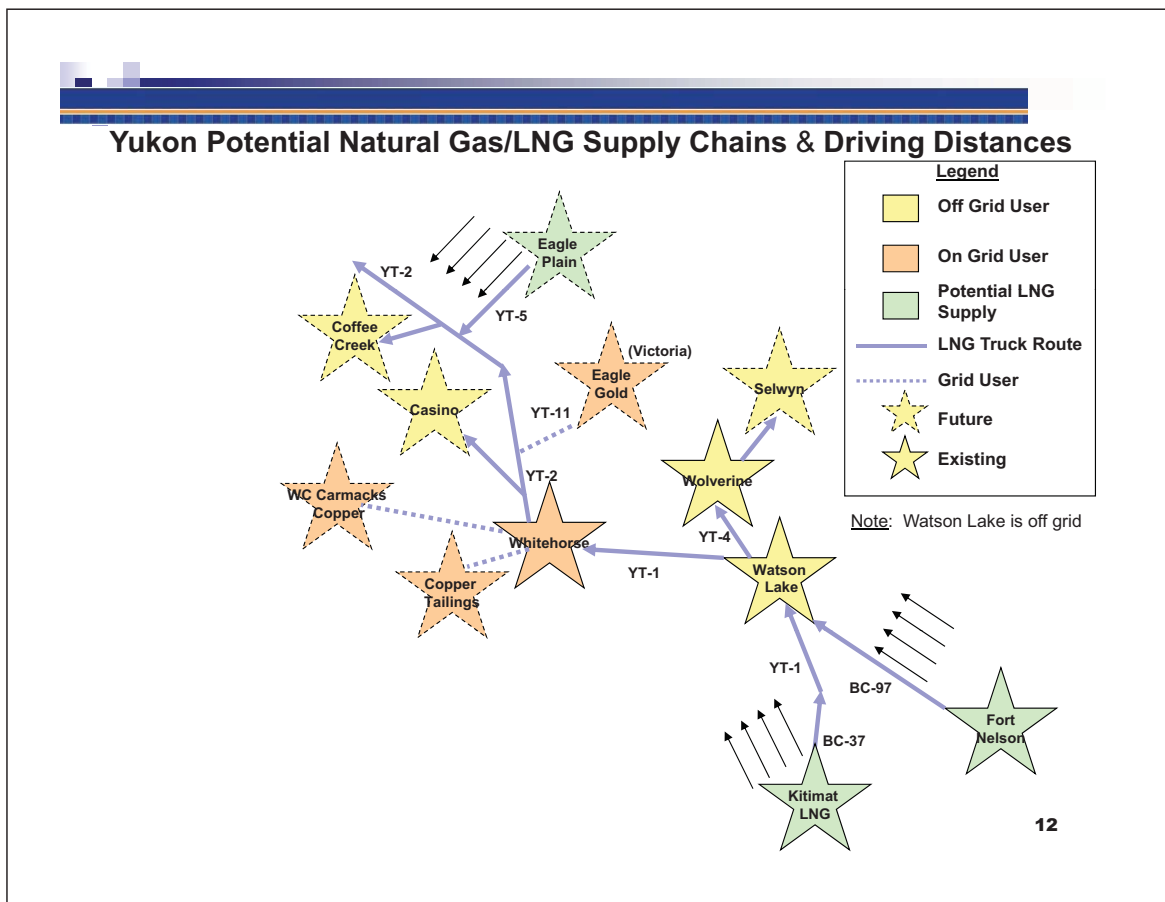
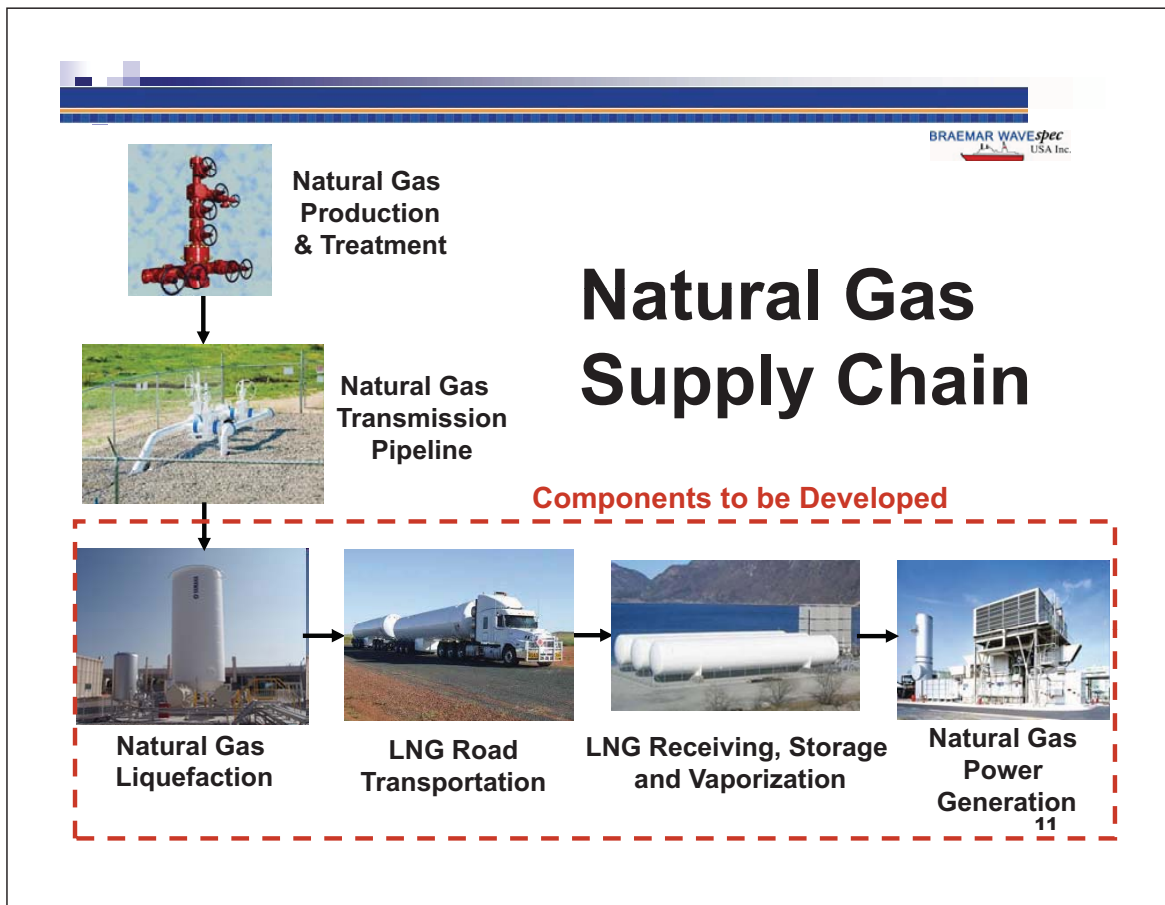
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LNG Uses: Overview

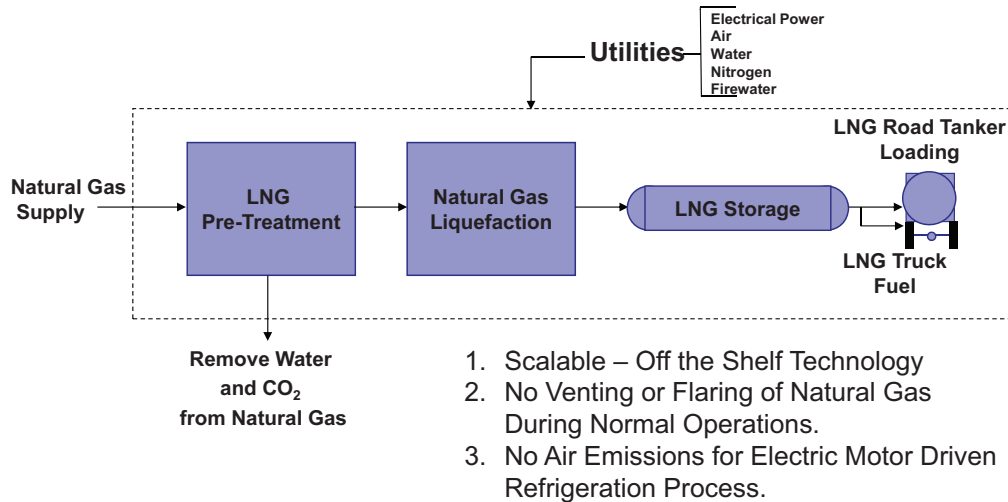
- Storage
 - ☐ Inventory for transportation logistics
 - ☐ Inventory for short term demand variation
 - ☐ Inventory for seasonal loads
 - ☐ Allows for rapid withdrawal
- Transportation
 - ☐ Ship
 - ☐ Truck
 - ☐ Rail
 - ☐ Barge/small ship
- Displace Traditional Gasoline, Diesel and Propane
 - ☐ Power Generation
 - ☐ Natural Gas Distribution
 - ☐ Vehicle Fuel



10



Small Packaged LNG Liquefaction



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China Case Study

4,100 Kilometer LNG Supply Chain One- Way Driving Distance



From Potential Supply Locations		Driving Distances To Potential LNG Receiving Locations					
		Watson Lake	Wolverine	Whitehorse	Coffee Creek	WC Casino	Selwyn
Driving Distance (km)	Fort Nelson	513	695	950	1333	1308	1193
	Kitimat LNG	894	1138	1288	1675	1650	1536
	Eagle Plains	1298	1080	862	744	715	1230

14

LNG Receiving

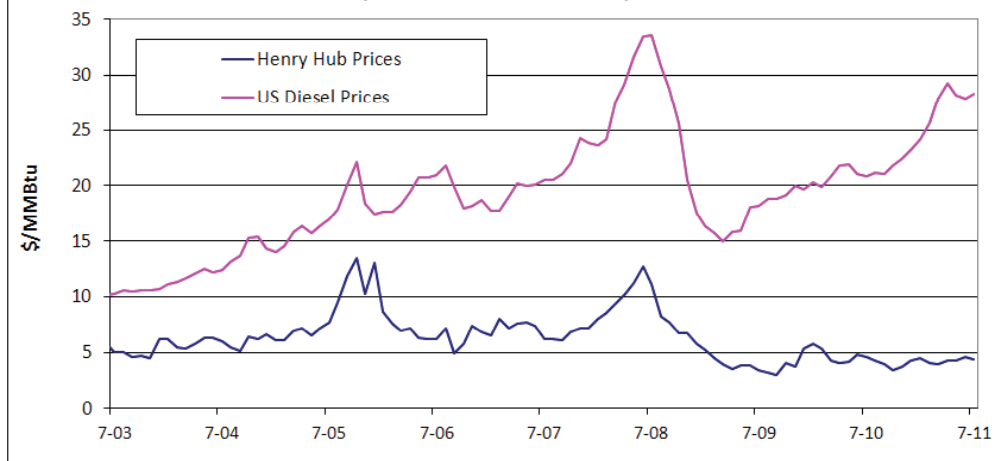
- LNG Truck Unloading
- LNG Storage
- Regasification (Vaporize LNG to Natural Gas)



- Simple, Compact, Scalable
- Low Energy Use
- Heat Recovery from Power Generation

15

Historical Comparison of US Diesel to Henry Hub



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
US Diesel (\$/MMBTU)	7.96	7.93	8.82	8.57	7.46	8.00	10.67	10.03	9.40	10.78	12.91	17.14	19.33	20.59	27.20	17.60	21.36	27.35
Henry Hub (\$/MMBTU)	1.77	1.73	2.75	2.48	2.09	2.27	4.31	3.96	3.36	5.50	5.91	8.81	6.74	6.98	8.86	3.95	4.39	4.18
Margin (\$/MMBTU)	6.19	6.20	6.07	6.09	5.37	5.73	6.36	6.07	6.04	5.28	7.01	8.32	12.58	13.60	18.34	13.65	16.97	23.17

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16
16

Fuel Volume Comparison on a BTU Basis

Diesel	7.72	gallon =	# 2 Diesel	
Biodiesel (B20)	7.86	gallon =	Biodiesel B20	
Biodiesel (B100)	8.45	gallon =	Biodiesel B100	
Gasoline (Regular)	8.76	gallon =	Gasoline	= 1,000,000 BTU
Propane	11.86	gallon =	Propane	
Ethanol (E85)	12.22	gallon =	Ethanol	
LNG	12.23	gallon =	LNG	
CNG	35.58	gallon =	CNG (3000 psig)	

Questions?



**Yukon Energy Corporation
LNG Workshop
January 18, 2012**

LNG - Transition Fuel Option for Yukon

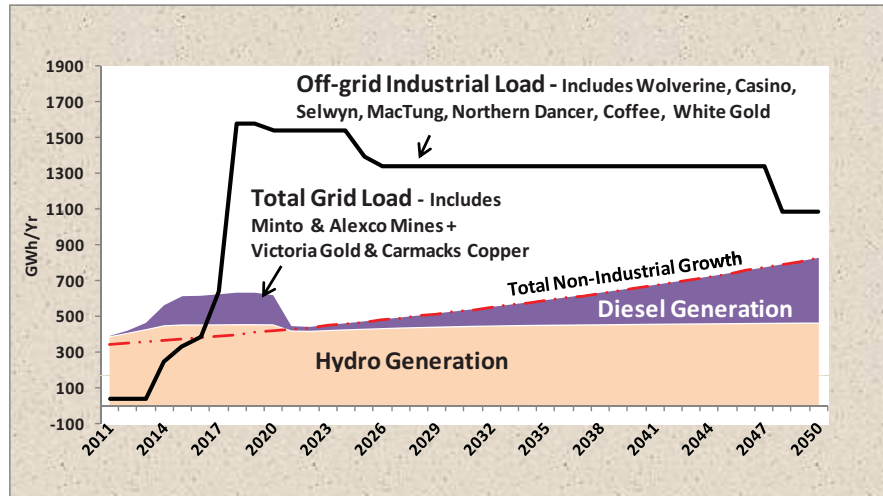
Cam Osler, InterGroup Consultants Ltd.
Yukon Energy LNG Workshop

January 18, 2012

Outline of Presentation

- Forecast Yukon Power Requirements
- LNG Transition Option:
 - Near-term – LNG trucked to Yukon from northern BC by late 2014
 - Longer-term – Potential Transition to other resources within next 10-20 years
- Concluding Comment

Forecast Yukon Power Requirements



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3

LNG Transition Option – Near term

- Near-term – LNG trucked to Yukon from northern BC by late 2014
 - Wavespec Supply Chain feasibility assessments
 - Supply potential far exceeds Yukon requirements
 - Options for Near Term LNG Supply
 - Kitimat or Fort Nelson
 - Trucked to Whitehorse for YEC grid generation
 - Trucked to off-grid sites for power generation
 - Existing & New Mines
 - YECL at Watson Lake

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LNG - YEC Planning Principles

- LNG features similar to Diesel
 - Reliability
 - Flexibility
 - Diversity
- LNG features superior to Diesel
 - Affordability
 - Environmental Responsibility

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5

Reliability, Flexibility & Diversity

- LNG similar to Diesel
 - Units permitted, purchased, installed within short period
 - Locate near load centres on & off grid
 - Reliably operate for 20+ yrs
 - Low capital costs per MW - flexibility re: scale & operation – fuel is the major cost
 - Flexibility re: mine load uncertainties
 - Diversity of Yukon end use opportunities, e.g., transportation, direct heating, district heating

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6

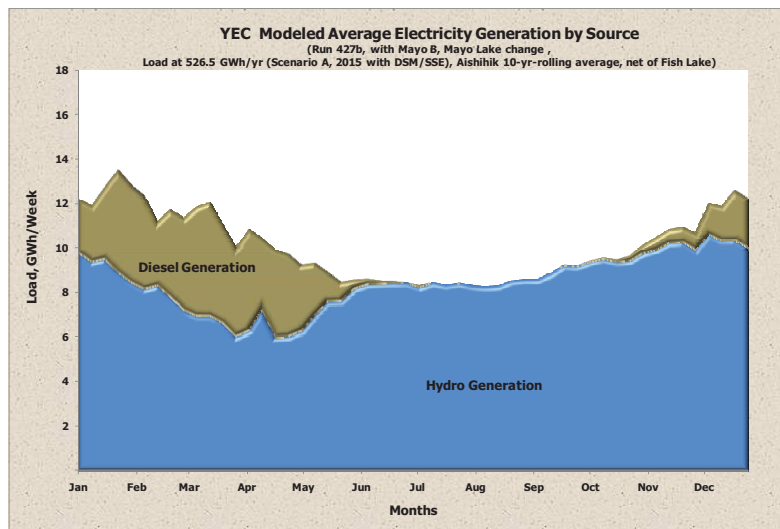
Reliability, Flexibility & Diversity (2)

- LNG flexibility for meeting Yukon hydro grid requirements
 - Isolated grid
 - Firm reserve capacity and peaking,
 - Winter seasonal use,
 - Annual water flow variability,

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7

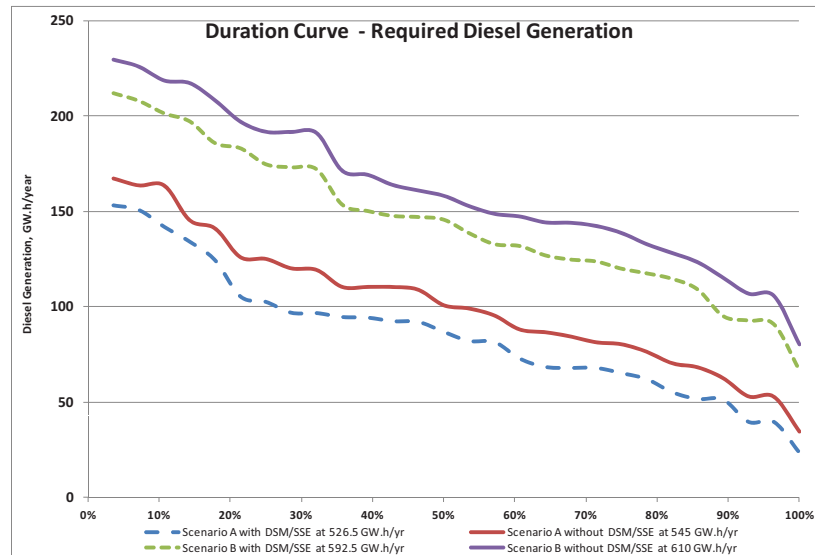
Hydro Grid Seasonal Generation



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8

Hydro Grid Annual Water Variability



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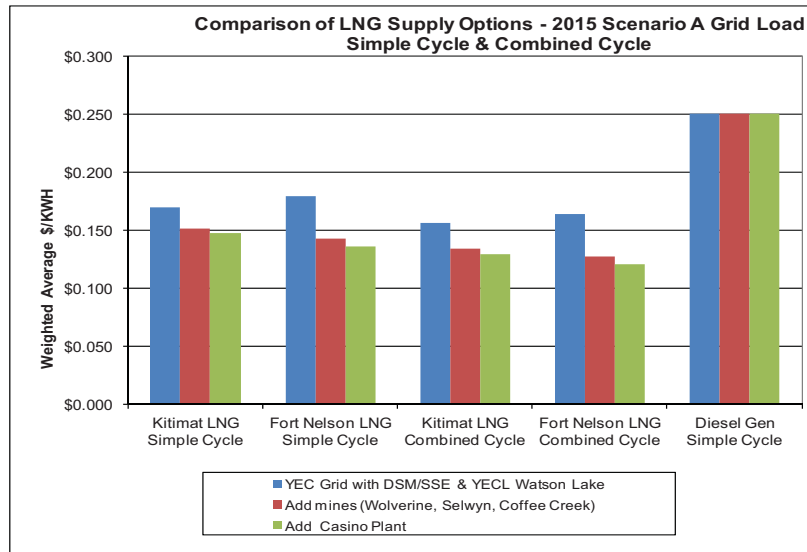
Affordability & Environmental Responsibility

- LNG superior to Diesel
 - Lower costs (fuel cost savings > 50%)
 - Lower emissions (36% to 48% lower)
- LNG can potentially replace diesel as Yukon default power fuel option
- LNG potential for cost savings & emission reductions in other Yukon sectors (transportation and heating)

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10

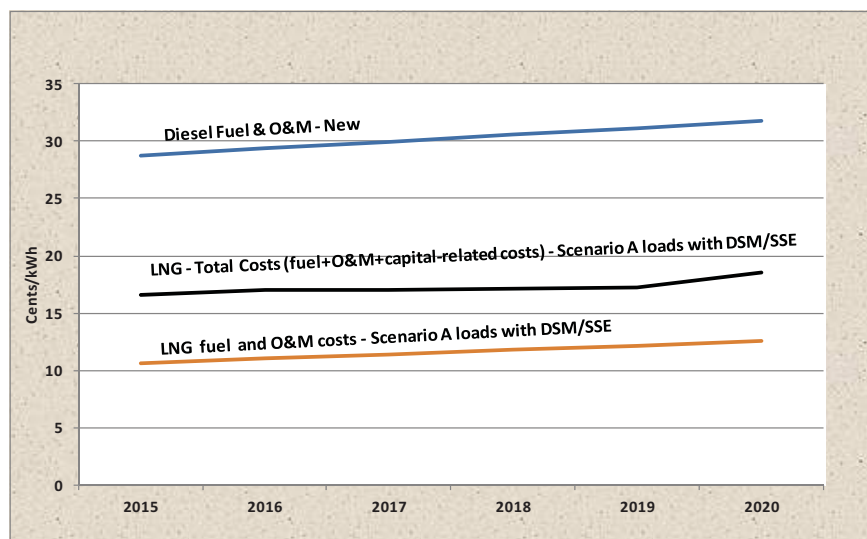
LNG – Less Costly than Diesel



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11

LNG - Less Costly than Diesel



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12

LNG Transition Option – Long term

- Longer-term – Potential Transition to other resources within next 10-20 years
 - Potential Transition to Future Local Natural Gas Supply
 - Potential Transition to New Renewable Resource Development Opportunities.

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13

LNG - Longer Term Transition

- Potential transition to future local natural gas supply
 - Alaska Highway Pipeline Project – potential in service 2020-21 – much lower fuel costs (expect 6-7 cents/kWh in 2010\$), or
 - Yukon gas supplies, e.g., Eagle Plain.

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14

LNG - Longer Term Transition

- Potential transition to new renewable resource development options
 - ❑ Lower cost & lower emission Yukon hydro, wind, geothermal
 - ❑ Subject to connecting new grid loads that can fully utilize new renewable resources over 20-30 or more years
 - ❑ Potential opportunities related to new off grid major mine loads with expected lives of 20+ years

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15

LNG Transition - Conclusions

- Near-Term – Trucked in Supply
 - ❑ Replace diesel as Yukon default power fuel option
 - ❑ Ample potential supplies
 - ❑ Lower costs
 - ❑ Lower emissions
 - ❑ Diversity of sector uses
- Longer-term – Potential Transition
 - ❑ Yukon natural gas supply
 - ❑ Yukon hydro or other renewable resources

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16

Examining the environmental issues and opportunities of LNG for Yukon

Yukon Energy Corporation
LNG Workshop
January 18, 2012

Don McCallum
Morrison Hershfield Ltd.

Presentation Overview

- Transition Strategy Context
- Air Emissions
- Greenhouse Gas Emissions
- Environmental Permitting and Approvals
- Other Related Opportunities with Environmental Benefits

Transition Strategy Context

- LNG is a near-term option to displace diesel (“default” portfolio) for power generation
- LNG’s cost advantages could support YEC’s ability to proceed with planning for renewable resource developments

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Lower Air Emissions

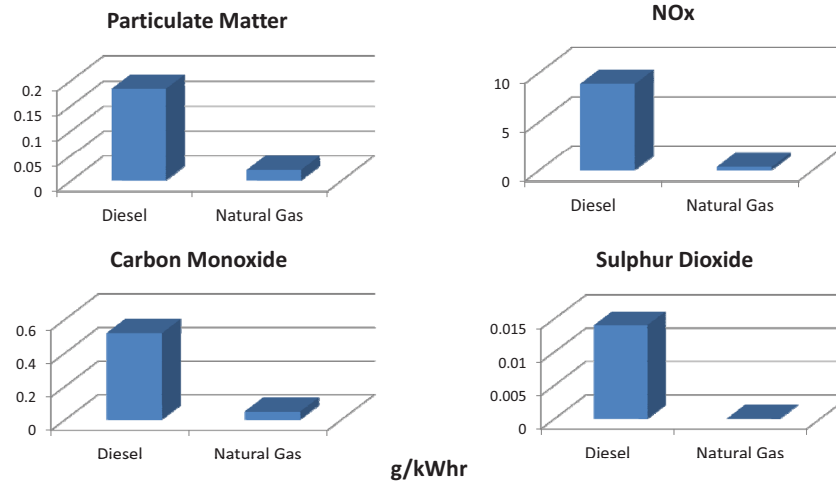
- Natural gas is a cleaner burning fuel compared to diesel resulting in fewer human health-related emissions

	Diesel g/kWh		Natural Gas g/kWh USEPA AP-42	% Reduction	
	YEC -Current	EPA 2015 Std		(compared to current diesel engines)	(compared to 2015 Std)
NOx	8.82	0.67	0.31	97%	54%
Carbon Monoxide	0.52	3.49	0.047	91%	99%
Sulphur Dioxide	0.014	0.014	0.0	100	100
Particulate Matter	0.183	0.027	0.020	89%	26%

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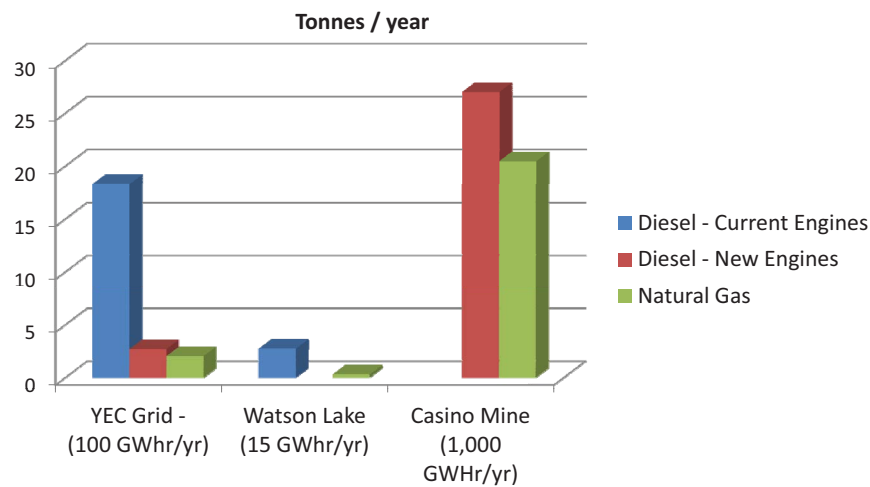
Comparison to Current YEC Diesel Engines



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mh
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Particulate Emission Loadings



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mh
MORRISON HERSHFIELD

Greenhouse Gas Emissions

- Natural gas has a lower carbon content per unit of energy than diesel, resulting in lower greenhouse gas emissions during combustion.

Greenhouse Gas Emissions – Power Generation (Tonnes CO2e / GWhr)		
Diesel	Natural Gas	% Reduction
700	360	49

Diesel emission factor assumes 2.7898 kg of CO2e per L and 4 kWh / L electrical generation efficiency

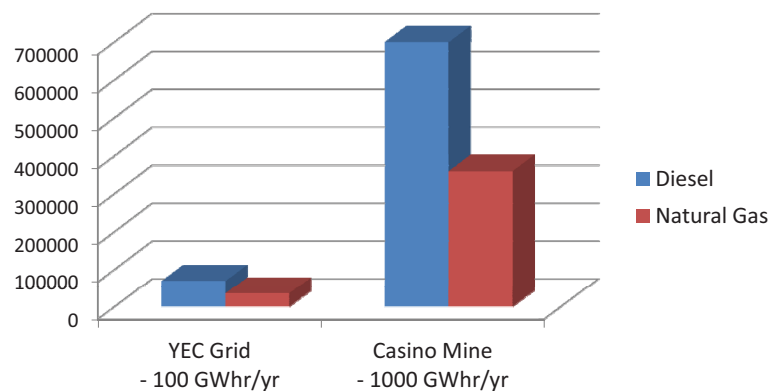
Natural gas emission factor assumes 1.941 kg of CO2e per m3 and 186.7 m3 / MWh (combined cycle operation)

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Greenhouse Gas Emissions – Power Generation

Tonnes CO2e / year



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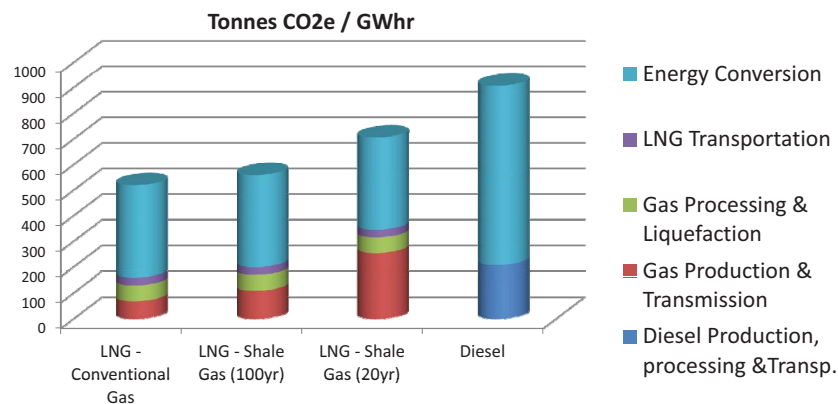
Greenhouse Gas Life Cycle Emissions

- “Upstream” GHG emissions are associated with any resource related to extraction, processing and transportation-related activities.
- Estimating “Life cycle” emissions requires a large number of assumptions and involves high degree of uncertainty.
- Overview assessment is provided here for broad comparison purpose only, assuming:
 - LNG transported from Kitimat
 - Electricity used for liquefaction process is fossil-fuel derived

9



Greenhouse Gas Lifecycle Emission Comparison



Data Sources: Gas production & transmission: US Dept of Energy 2011, Life Cycle Greenhouse gas analysis of natural gas extraction & delivery in the United States; Gas Processing & Liquefaction: PACE 2009, Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results; Diesel lifecycle emission factors: Wang and Santini 2009. GREET (Greenhouse gases, regulated emissions and energy use in transportation) Transportation Fuel Cycle Analysis Model Ver. 1.8.

10



Environmental Permitting & Approval Requirements

- *Yukon Environmental and Socio-Economic Assessment Act (YESAA) Approval*
 - Executive Committee review trigger: “Construction, decommissioning or abandonment of a fossil fuel-fired electrical generating station with a production capacity of 5 MW or more”
 - Use of existing diesel plants may require DO Evaluation only
- *Environment Act Authorizations*
 - Air Emissions Permit
- Depending on plant location, land use authorizations and dispositions may be required

11



Environmental Permitting & Approval Risks

- Relatively little experience with YESAA Executive Committee Screenings
 - 3 completed screenings to date (2 of which were YEC projects)
 - Mayo Hydro Enhancement Project completed YESAA <1.5 yrs
 - LNG Power project arguably less complex than Mayo B
 - DO Evaluation timelines shorter if only unit swaps proposed
- Relatively little air emissions permitting experience of this type in Yukon
- Risks can be mitigated and approvals obtained in reasonable time frame through:
 - Timely consultation and engagement
 - Use of appropriate air emission control technology
 - Coordination and timely communication with Yukon Government

12



Other Potential Opportunities

- Use of waste heat from LNG combined cycle power plant in a District Energy System in Whitehorse to displace furnace oil
- Facilitate the replacement of diesel as a transportation fuel with LNG in some commercial and industrial applications in Yukon
- Facilitate the development of natural gas distribution opportunities for space heating (displacing furnace oil)

13



Summary

- In comparison to the Default Portfolio (Diesel), LNG utilization will result in:
 - Significantly reduced air emissions
- Environmental permitting risks are manageable
 - Process should be initiated soon to meet 2014/2015 commissioning target
- Using LNG for power needs could facilitate other opportunities in transportation and heating sectors

14



ATTACHMENT 2

APPENDIX B OF THE

TECHNICAL VAPOUR DISPERSION REPORT

FROM THE NOVEMBER 2013 LETTER TO YESAB

(Response to UCG-YEC-1-8 (d))

Appendix B

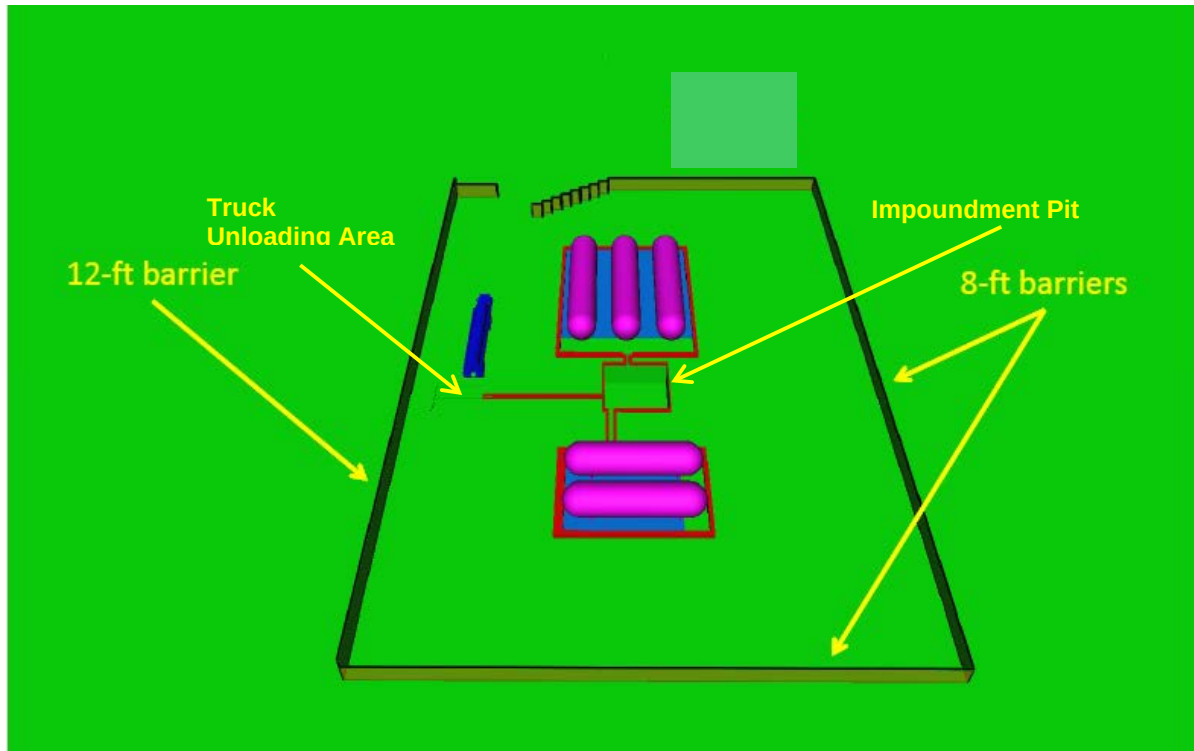
Braemar Engineering

Revised Vapour Dispersion Analysis Report

2013

BRAEMAR
ENGINEERING

Braemar Engineering
9225 Katy Freeway,
Suite 307
Houston, TX 77024



Vapour Dispersion Due to Spill of LNG

prepared for:
Yukon Energy Corporation

REVISION and APPROVALS				
Rev.	Rev. Date	Revision Description	By	Approved
0	11-4-13	Draft Report	DG	
1	11-6-13	Final Report	DG	SAM



TABLE OF CONTENTS

1.0 INTRODUCTION.....	3
2.0 DESCRIPTION OF LNG SPILL AND RESULTANT VAPOUR DISPERSION	3
3.0 CONSEQUENCE OF VAPOUR PLUME DISPERSION	3
3.1 FULL TANK SPILL SCENARIOS.....	4
3.2 TRUCK UNLOADING SPILL SCENARIO.....	7

TABLE OF FIGURES

Figure 1- Proposed 3D layout
 Figure 2- Results of full tank spill scenario in the north tank area
 Figure 3- Results of full tank spill scenario in the south tank area
 Figure 4- Results of tanker unloading spill



1.0 Introduction

Braemar Engineering performed the following analysis of the vapour dispersion resulting from an LNG spill at the proposed LNG receiving, storage and sendout facility at Yukon Energy Corporation's facility in Whitehorse, Yukon Territory.

2.0 Description of LNG Spill and Resultant Vapour Dispersion

If LNG spills from its primary containment, it will flow by gravity to the impounding area, begin to warm and change phase into a gas. This creates a vapour above the released liquid. The vapour is initially heavier than air and immediately begins mixing with the surrounding air which warms the vapour. The vapour warms as it mixes with air, becomes less dense than air (at approximately -100°C) and continues to disperse with the potential for the vapour plume to disperse within the facility boundary if an ignition source is not present. The potential for off-site vapour ignition is near zero as the model has shown that outer limit of the ½ LFL vapour plume footprint for the three (3) liquid spill design cases remains within the facility boundaries.

Canadian Standards Association Standard "Z276-11, Liquefied natural gas (LNG) — Production, storage, and handling" describes design cases for LNG spills. In the case of this project three (3) cases were modeled for this analysis, which were:

- (1) A complete failure and emptying of a storage tank in the north tank area;
- (2) A complete failure and emptying of a storage tank in the south tank area and
- (3) A 10-minute spill of the highest flowrate transfer line which is the tanker unloading line.

3.0 Consequence of Vapour Plume Dispersion

The consequence of a loss of containment was modeled using FLame ACceleration Simulator (FLACS), a Computational Fluid Dynamic (CFD) program designed to model vapour dispersion of LNG vapours¹.

The inputs of the layout of the LNG storage area are shown below. The critical relationships are the distance from the impounding pit to the vapour barrier and the property line and also the distance from the truck unloading station and the property line.

Three (3) cases were evaluated as required by the CSA standard Z276-11. They are:

- (1) The loss of containment from a full LNG 166.5 m³ (north) storage tank;
- (2) The loss of containment from a full LNG 120 m³ (south) storage tank; and
- (3) A design spill of 10-minutes from the largest flowrate in the facility.

¹ CFD modeling performed by Filippo Gavelli, Ph.D., P.E., CFEI, GexCon, Bethesda, MD., October 2013.



The largest LNG flowrate in the facility is the unloading rate of an LNG tanker of 1141 liters per minute.

The results of these three (3) cases show that in all cases the maximum limit of the edge of the vapour plume stays within the property boundary. The outer edge of the vapour plume is $\frac{1}{2}$ of the lower flammability limit (LFL). The vapour barrier is necessary, in some cases, to retain the vapour plume until it has sufficient retention time to warm and mix with the atmosphere to dilute to below the $\frac{1}{2}$ LFL limit required by CSA Z276-11 to be contained within the property boundary limits.

3.1 Full tank spill scenarios

In order to determine the size of the vapour plume at the $\frac{1}{2}$ of the lower flammable limit (LFL), a FLACS computational fluid dynamics model was prepared for this facility. The FLACS software has been validated by an independent body using the Model Evaluation Protocol facilities as described in the NFPA report Evaluating Vapour Dispersion Models for Safety Analysis of LNG. This LNG vapour dispersion model was created for a spill in the LNG storage tank area. The north tank area contains three (3) horizontal 166.5 m³ LNG storage tanks and the south tank area contains two (2) horizontal 120 m³ LNG storage tanks. Each tank area is surrounded by a concrete wall with a concrete floor that drains to the transfer trench that leads into the impoundment pit. From the tank area, there is a trench that leads to an impoundment which is 110% of the volume of the largest tank (1.1 * 166.5 m³) with the dimensions of 8.23 m by 8.23 m and 3.05 m deep. The site is surrounded by a vapour barrier to limit the vapour dispersion distance. There will be vehicle access across the vapour barrier at the north end for the truck entrance point and the south end for the truck exit point. The vapour barrier is not continuous in the north to allow the trucks to pass through and there will be a movable or sliding vapour barrier gate at the south to allow the trucks to exit. Figure 1 below shows the proposed 3D layout with the storage tanks, impoundment pit, truck unloading, and the 2.44 m and 3.66 m vapour barriers.

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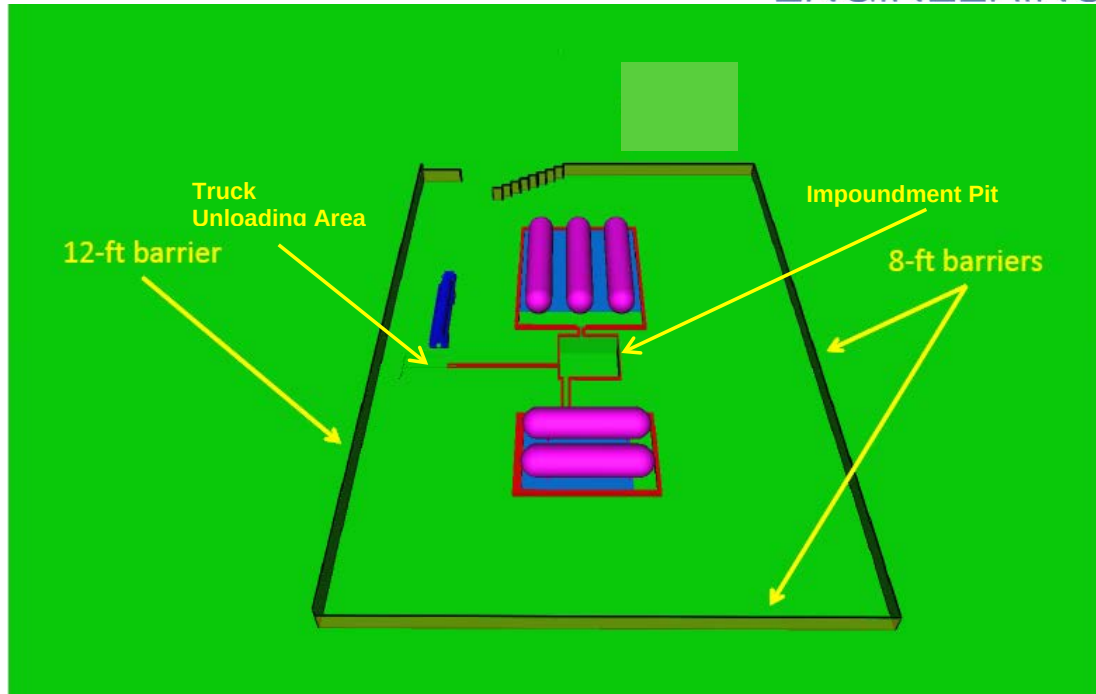


Figure 1 - Proposed 3D layout

The two (2) tank spill scenarios are (1) 166.5 m³ (one full tank) from the north tank area and (2) 120 m³ (one full tank) from the south tank area. In each case the tanks have an internal tank pressure of 50 psig and a 2-inch severed outlet pipeline. The following criteria were used to define the model per NFPA 59A:

- Exclusion distances are calculated based on using wind speeds, relative humidity, and ambient temperatures that provide the maximum vapour dispersion distances, unless these values occur less than 5% of the time based on historical data.
- The computed distances are based on a combination of wind speed and atmospheric stability that provide the largest downwind vapour dispersion distances, or based on a Pasquill-Gifford atmospheric stability category F, or 2 meters/second. The latter was used in this particular model.
- The computed distances are based on the actual liquid characteristics and the maximum vapour outflow rate (the vapour generation rate added to the displacement due to liquid inflow).
- The effects of provisions to detain vapour or mitigate flammable vapour hazards. In this case, these are the vapour barriers that almost surrounds the facility (there is an opening to allow trucks to pass thru the north vapour barrier).

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Figures 2 and 3 below show the results of the full tank spill scenario for the north and south tank areas respectively.

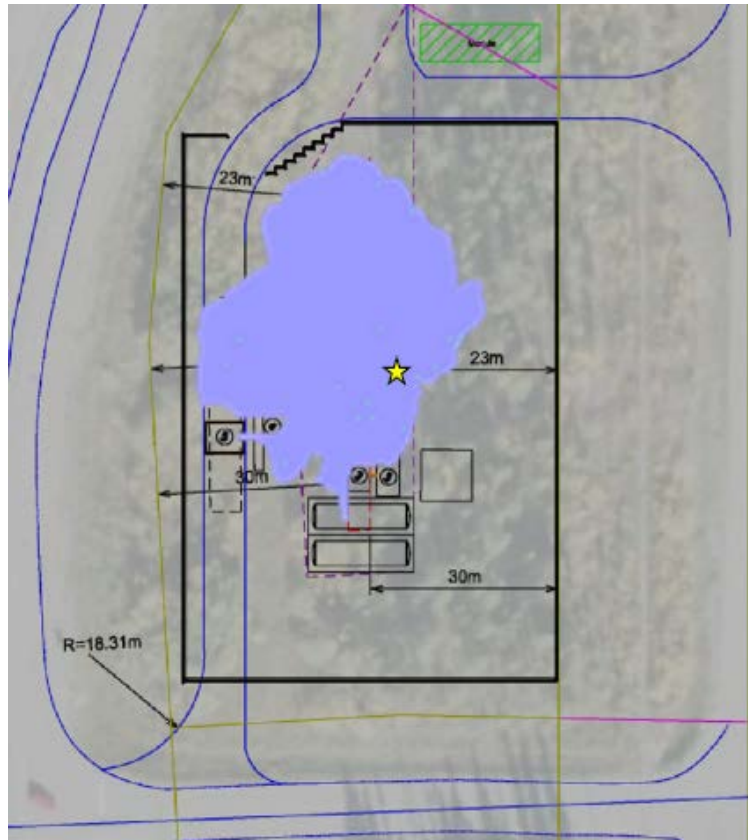


Figure 2 - Results of full tank spill scenario in the north tank area

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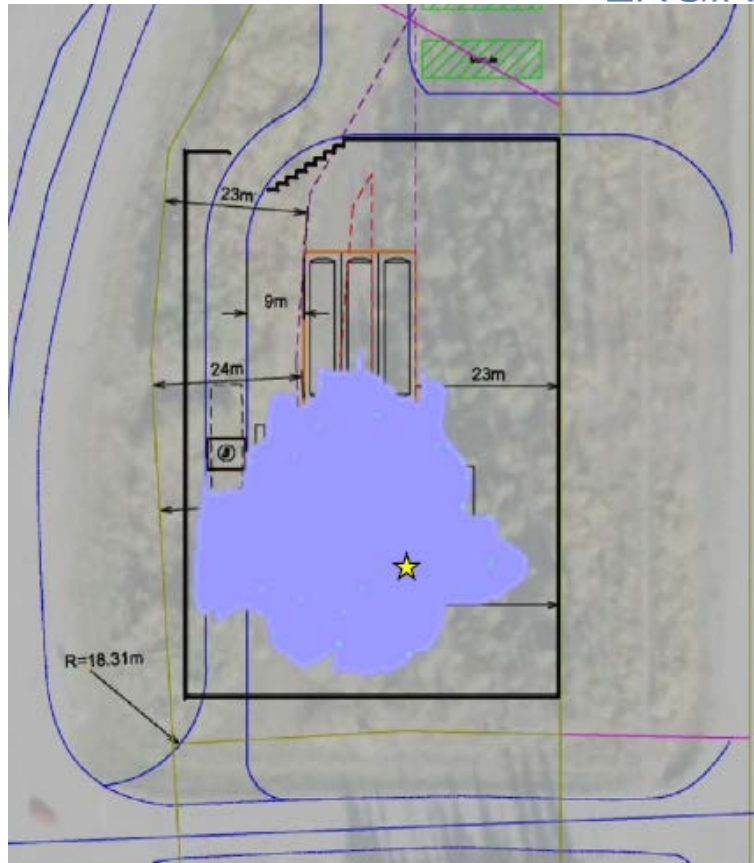


Figure 3 - Results of full tank spill scenario in the south tank area

It is evident under these scenarios that the $\frac{1}{2}$ LFL vapour plume footprint for the liquid spills in the LNG storage tank areas is contained within the facility boundary.

3.2 Truck unloading spill scenario

Similar to the full tank spill scenario, the truck unloading spill scenario was conducted using the FLACS software. This LNG vapour dispersion model was created for a spill in the truck unloading area because the trailer unloading is the highest LNG flowrate scenario. The truck unloading area has a 16 ft by 20 ft sloped pad that leads to a transfer trench that is 1 ft wide and 2 ft below grade to transfer the spill from the truck unloading pad to the impoundment. This is illustrated in the Figure 1 above.

The spill scenario is 1041 l/min (truck), with an internal truck pressure of 50 psig and a piping failure at the truck unloading area. In addition, the impoundment area was modelled as well to provide more accurate vapour dispersion. The same factors that were

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used to define the full tank spill scenario were also used to define the truck unloading spill scenario:

Figure 4 below shows the results of the spill scenario at the tanker unloading area.

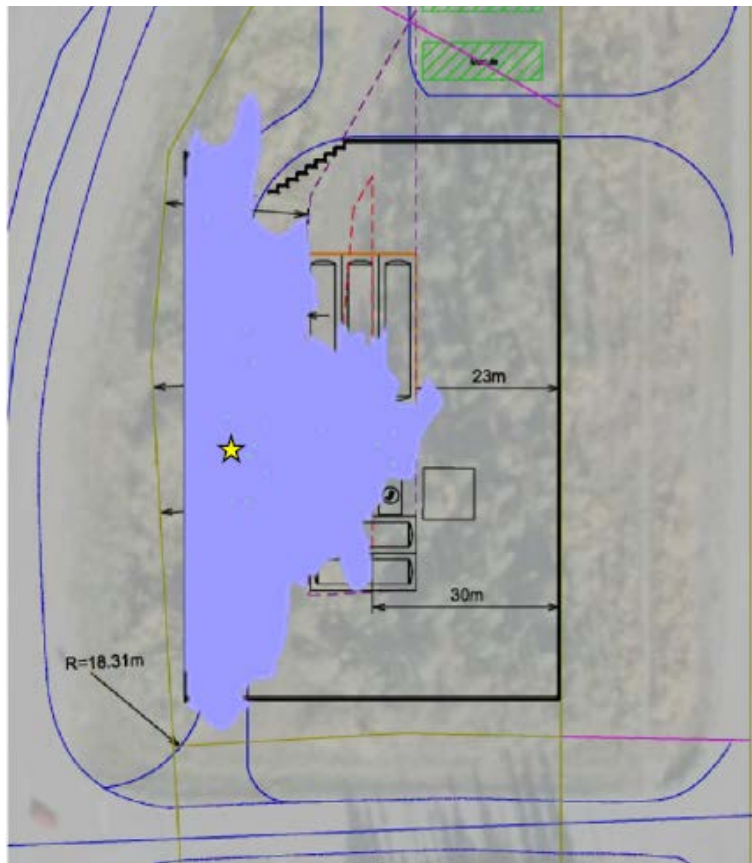


Figure 4 - Results of tanker unloading spill

The simulations show that the limits of the 50% LFL vapour plume footprint for liquid spills in the tanker unloading area remain within the facility boundaries, although, a 3.66 m high vapour dispersion barrier on the west side was used to maintain the vapour plume within the property boundary and the south gate will be solid and closed whenever a tanker is unloading.



within the property boundary and the south gate will be solid and closed whenever a tanker is unloading.

ATTACHMENT 3

APPENDIX E OF THE

2011 20-YEAR RESOURCE PLAN

(Response to YCS/LE-YEC 1-28 (a))

APPENDIX E

Resource Plan Options: Near-Term Assessment

TABLE OF CONTENTS

APPENDIX E – RESOURCE PLAN OPTIONS: NEAR-TERM ASSESSMENT	E-1
1.0 NEAR-TERM CAPACITY REQUIREMENTS & DIESEL-RELATED ENERGY DISPLACEMENT OPPORTUNITIES.....	E-1
1.1 NEAR-TERM RESOURCE OPTIONS	E-2
2.0 ASSESSMENT APPROACH FOR EVALUATING NEAR-TERM OPTIONS.....	E-3
3.0 OPTION ASSESSMENT OVERVIEW	E-7
3.1 INITIAL SCREENING	E-7
3.2 BASELINE PORTFOLIO OPTION: DIESEL AND DSM/SSE	E-8
3.3 SUMMARY PROJECT DESCRIPTION OF OTHER RESOURCE SUPPLY OPTIONS	E-13
4.0 RESOURCE SUPPLY OPTION ASSESSMENT - SUMMARY	E-16
5.0 SUMMARY CONCLUSIONS.....	E-18
ATTACHMENT E1 – DSM/SSE	E1-1
ATTACHMENT E2 - DIESEL	E2-1
ATTACHMENT E3 – HYDRO ENHANCEMENTS	E3-1
ATTACHMENT E4 – NON-DIESEL THERMAL OPTIONS (BIOMASS & LNG)	E4-1
ATTACHMENT E5 – WIND.....	E5-1
ATTACHMENT E5.1 – SHORT-TERM & LONG-TERM ENERGY STORAGE	E5.1-1

LIST OF TABLES

Table E-1: Range of Resource Supply Options & Initial High Level Characterization	E-3
Table E-2: Baseline Portfolio Option Present Value Costs (2010\$million): 2011-2030	E-12
Table E-3: General Description of Near-term Resource Supply Options	E-14
Table E-4: Initial Assessment Summary – Near-Term Resource Supply Options	E-17
Table E1-1: Assumed DSM/SSE Impact on Non-Industrial Load: Reduction in Diesel Energy	E1-6
Table E2-1: Summary of Default Diesel for Near-term Load Scenarios - 2015-17	E2-2
Table E2-2: Diesel Option Present Value Costs (2010\$million): 2011-2030	E2-3
Table E3-1: Potential Impacts of Gladstone and Marsh Lake Hydro Enhancements (assessed at approximate 2015 Scenario A [545 GW.h] and Scenario B [610 GW.h] loads)	E3-6
Table E3-2: Marsh Lake Storage Option Present Value Costs (2010\$million): 2011-2030	E3-9
Table E3-3: Marsh Lake (2015) & Gladstone (2018) Combined Options Present Value Costs (2010\$million): 2011-2030	E3-10
Table E4-1: Diesel Displacement Benefits of Biomass Thermal Plant: 545 GW.h/year Load	E4-4
Table E4-2: Diesel Displacement Benefits of Biomass Thermal Plant: 610 GW.h/year Load	E4-5
Table E4-3: Wood Biomass Option Impacts on Diesel Generation (25 MW plant) (GW.h of diesel displaced by year over 20 year plant life: 2015-2034)	E4-17
Table E4-4 Wood Biomass Thermal 25 MW Plant Portfolio Option Present Value Costs (2010\$million): 2011-2030	E4-21
Table E4-5: Wood Biomass Option Impacts on Diesel Generation (10 MW and 15 MW plant) (GW.h of diesel displaced by year over 20 year plant life: 2015-2034)	E4-24
Table E4-6A Wood Biomass Thermal 10 MW Portfolio Option Present Value Costs (2010\$million): 2011- 2030	E4-28
Table E4-6B: Wood Biomass Thermal 15 MW Portfolio Option Present Value Costs (2010\$million): 2011- 2030	E4-28
Table E4-7: WTE Option Impacts on Diesel Generation (2.2 MW) (GW.h of diesel displaced by year over 25 year plant life: 2014-2038)	E4-38
Table E4-8: WTE Thermal 2.2 MW Portfolio Option Present Value Costs (2010\$million): 2011- 2030	E4-40
Table E4-9: Natural Gas Plant Generation/Diesel Displacement – Base Case, Scenarios A & B: 2015-34	E4-47
Table E4-10: LNG/Natural Gas Option Present Value Costs (2010\$million): 2011-2030	E4-49
Table E5-1: Ferry Hill and Mount Sumanik Monthly Wind Generation Estimates (GW.h)	E5-4
Table E5-2: Ferry Hill Wind Option Impacts on Diesel Generation (21 MW plant at Ferry Hill)	E5-7
Table E5-3: Ferry Hill 21 MW Wind Farm Option Present Value Costs (2010\$million): 2011-2030	E5-9
Table E5-4: Ferry Hill 10.5 MW Wind Farm Option Present Value Costs (2010\$million): 2011-2030 ...	E5-10

LIST OF FIGURES

Figure E-1: Baseline Portfolio: Scenario B with DSM/SSE: 2011-2030 (GW.h/year)	E-10
Figure E-2: Grid Capacity Capability and N-1 Capacity Requirements with & without DSM/SSE – 2011-2030 (MW)	E-11
Figure E-3: Diesel Displacement Benefits 2014-21 – Scenario B (with DSM/SSE)	E-16
Figure E1-1: Scenario B with DSM/SSE: 2011-2030 (GW.h/year)	E1-7
Figure E1-2: Grid Capacity Capability and N-1 Capacity Requirements with & without DSM/SSE – 2011-2030 (MW)	E1-9
Figure E2-1: Diesel Option Cost for Fuel and O&M (cents per kW.h): 2011-2030	E2-4
Figure E3-1: Marsh Lake and Gladstone at 545 GW.h/year (approx. Scenario A at 2015)	E3-4
Figure E3-2: Marsh Lake and Gladstone at 610 GW.h/year (approx. Scenario B at 2015)	E3-5
Figure E3-3: Marsh Lake Costs per kW.h with & without DSM/SSE (Scenario A): 2015-2040	E3-7
Figure E3-4: Marsh Lake & Gladstone Costs per kW.h with & without DSM/SSE (Scenario A): 2015-2040	E3-8
Figure E4-1: Wood Biomass Feedstock Supply Areas in Yukon	E4-13
Figure E4-2: Forecast LCOE for 25 MW Wood Biomass Plant at Whitehorse at Scenario A Load with DSM/SSE – Sensitivity to Mine Extensions (LCOE cents per kW.h of Diesel Displaced – Present Value over 20 Year Life of Project (2010\$)	E4-18
Figure E4-3: 25 MW Wood Biomass Thermal Plant vs. Diesel Fuel & O&M Costs: Annual Cents per kW.h – 2015-20	E4-19
Figure E4-4: Forecast LCOE for 10 MW and 15 MW Wood Biomass Plant at Minto Burn Area at Scenario A Load with DSM/SSE – Sensitivity to Mine Extensions (LCOE cents per kW.h of Diesel Displaced – Present Value over 20 Year Life of Project (2010\$)	E4-25
Figure E4-6: 10 MW and 15 MW Wood Biomass Thermal Plant vs. Diesel Fuel & O&M Costs: Annual Cents per kW.h – 2015-2020	E4-26
Figure E4-7: Summary LCOE (2010\$) of Wood Biomass Plant Options at Scenario A Load with DSM/SSE	E4-31
Figure E4-8: 2.2 MW WTE Thermal Plant vs. Diesel Fuel & O&M Costs: Annual Cents per kW.h – 2015-20	E4-39
Figure E4-9: Summary LCOE (2010\$) of WTE 2.2 MW Option at Scenario A Load with DSM/SSE	E4-42
Figure E4-10: LNG Thermal Plant vs. Diesel Fuel & O&M Costs per kW.h – 2014-2020	E4-48
Figure E5-1: Ferry Hill Annual Wind Costs per kW.h (No DSM/SSE) (LCOE (2010\$): 19.6 c/kW.h (Scenario A) and 19.0 c/kW.h (Scenario B)	E5-8
Figure E5-2: Summary LCOE (2010\$) 21 MW Wind Option, Scenario A load with DSM/SSE	E5-11
Figure E5-3: Summary LCOE (2010\$) 10.5 MW Wind Option, Scenario A load with DSM/SSE	E5-11

1 **APPENDIX E – RESOURCE PLAN OPTIONS: NEAR-TERM ASSESSMENT**

2 Based on the integrated grid generation near-term load forecast scenarios with potential new mine
3 connections (Appendix C), the 2011 Resource Plan's near-term planning objective is to determine the
4 priority resource supply commitments required before the end of 2014 for major investments with
5 anticipated costs of \$3 million or more. This assessment examines possible in-service energy and capacity
6 needs to meet loads out to 2017, and focuses on the integrated grid requirements and options.

7 **1.0 NEAR-TERM CAPACITY REQUIREMENTS & DIESEL-RELATED ENERGY**
8 **DISPLACEMENT OPPORTUNITIES**

9 Based on the 2011 Resource Plan load forecast scenarios (see Appendices C and D), the existing grid
10 system has sufficient capacity and energy today to meet near-term load requirements under the range of
11 scenarios identified, subject to the need for new capacity to replace diesel units projected to be retired
12 and addressing capacity requirements for industrial loads in excess of about 13 MW.

13 The following near-term capacity shortfalls have been identified for the 2011 Resource Plan:

- 14 • Capacity shortfalls related to non-industrial loads (N-1 criterion) begin to emerge in 2015 with
15 approximately 2.8 MW, expanding (before considering DSM/SSE¹) to 18 MW by 2020 and 60.4
16 MW by 2030. Under the LOLE capacity planning criteria (see Appendix D), additional grid capacity
17 would be required in the near-term under the Scenario A and Scenario B in response to mine
18 loads in excess of about 13 MW from late 2013 until approximately 2020 (e.g., in 2015, the
19 capacity shortfall is increased above the non-industrial load N-1 capacity shortfall by
20 approximately 13 MW under Scenario A and 21 MW under Scenario B).
- 21 • Capacity shortfalls under the N-1 criteria (indicated in Figure D-1 of Appendix D, before
22 DSM/SSE) are materially impacted by forecast diesel plant retirements over the planning period
23 (35.6 MW of retirements by 2027, includes all current YEC reliable diesel plant).
- 24 • Forecast capacity shortfalls indicate a requirement in the near-term to either invest in new diesel
25 plant or in alternative sources of low cost capability that can provide reliable peaking and backup
26 capacity for the system.

¹ After DSM/SSE as reviewed in Attachment E1, by 2020 the capacity shortfall is 8.8 MW, and 37.1 MW by 2030.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 The 2011 Resource Plan forecast also indicates that energy supply to meet forecast near-term loads,
2 absent DSM/SSE or other new resource options, will once again need to rely on baseload diesel
3 generation. The required near-term forecast diesel energy generation varies greatly depending on the
4 selected load forecast scenario, e.g., grid **diesel energy generation displacement opportunities**
5 **forecast for 2015-17** under average water year conditions (no DSM/SSE) range as follows:

- | | | |
|---|--|-------------------|
| 6 | • Base Case load (non-industrial load and currently connected mines) | 24-30 GW.h/year |
| 7 | • Scenario A (Base Case plus Victoria Gold) | 99-108 GW.h/year |
| 8 | • Scenario B (Base Case plus Victoria Gold, Carmacks Copper, WHCT) | 158-168 GW.h/year |

9 **1.1 NEAR-TERM RESOURCE OPTIONS**

10 In order to reduce the impact of diesel generation's high incremental costs and emissions, there is
11 opportunity to examine near-term resource alternatives to the use of existing diesel generation facilities
12 for capacity and for energy.

13 The following potentially feasible near-term options (in the context of the ability to be committed by 2014
14 using current proven technology) are reviewed in detail in Appendix E attachments, including each
15 option's ability to advance each of the four key planning principles (reliability, affordability, flexibility, and
16 environmental responsibility):

- 17 1. DSM/SSE (Demand Side Management/Supply Side Enhancement).
- 18 2. Diesel (the current supply default option if no other option developed, including improvements to
19 grid energy storage/reliability).
- 20 3. Hydro Enhancements (e.g., Marsh Lake storage, Atlin storage², Gladstone diversion).
- 21 4. Non-Diesel Thermal Options:
 - 22 a) Biomass (Wood Biomass);
 - 23 b) Waste to Energy (Municipal Solid Waste); and
 - 24 c) Liquid Natural Gas/Natural Gas (LNG).
- 25 5. Wind

26 These options are initially characterized at a high level in Table E-1 in terms of the four key principles,
27 reflecting discussion at the Energy Charrette prior to detailed analysis of potential near-term application
28 in Yukon.

² Due to the BC Government decision recently to designate Atlin River as Class A park (and the expectation that the designated park will include the river), work on the Atlin Storage project has currently ceased.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

Table E-1: Range of Resource Supply Options & Initial High Level Characterization

AVAILABLE OPTIONS		RELIABILITY Reliable winter peak capacity, & reliable development (timing & cost)	AFFORDABILITY c/kW.h (\$2010) if fully utilized	FLEXIBILITY Ratepayer cost risks re Mine Load Reductions	ENVIRONMENTAL RESPONSIBILITY Env. impact mitigation - reduction of GHG Emissions
NEAR-TERM – potentially available start to construction before end of 2014 (available no later than 2017)	DSM/SSE	MEDIUM - depends on uptake and type of DSM/SSE	HIGH - <10 c/kW.h	MEDIUM – reasonably flexible; curtailable as/when needed	HIGH
	Diesel – existing default option	HIGH - low cost peaking & reserve capacity on system; low regulatory risk	LOW - approx 30c/kW.h	HIGH – low capital cost; save fuel & operating cost when load not there (summer/mine shutdown)	LOW - higher GHG & emissions than any other option
	Hydro Enhancements	MEDIUM – reliable winter energy but high regulatory risk	HIGH <10 c/kW.h	MEDIUM – reasonable flexible; - winter storage; long-term value	HIGH
	Thermal – Biomass (incl. waste)	HIGH - baseload energy & capacity (no development planning to date)	MEDIUM - approx 15 c/kW.h; Scalability issues	LOW – not flexible – high capital cost; intended for yr-round energy supply;	HIGH
	Thermal - Liquid Natural Gas (LNG)	HIGH - peaking & reserve capacity; low regulatory risk	MEDIUM/HIGH – < 15 c/kW.h	HIGH - low capital cost; save fuel & operating cost when load not there (summer/mine shutdown)	MEDIUM – 30% to 50% lower GHG emissions than diesel
	Wind	LOW – not add reliable peaking/ reserve capacity; not dispatchable; but low regulatory risk	MEDIUM – approx 15 c/kW.h; includes storage	LOW – not flexible – high capital cost & not dispatchable	HIGH

Note: "Affordability" in this table is assessed assuming adequate load to fully utilize the resource, e.g., greenfield large hydro lifecycle costs of 5 to 11 cents/kW.h assume full use of the resource throughout a 65 year life. In practice, project feasibility for each option depends on forecast lifecycle costs (LCOE) based on forecast utilization of the option over its life.

2.0 ASSESSMENT APPROACH FOR EVALUATING NEAR-TERM OPTIONS

The assessments in the Appendix E attachments provide more detailed analysis of the relative ability of each of the above options to meet the range of potential diesel generation displacement opportunities (including each option's flexibility to accommodate uncertain load outcomes in both the near and longer-term), taking into consideration:

- **Reliability relative to diesel to be in-service when needed and to provide reliable service** – In examining an option's ability to displace diesel generation, reliability requirements for new generation capacity as forecast in Appendix D have been fully considered, including requirements to be in service by a target date (i.e., addresses regulatory approval and other development timing risks) and to provide reliable capacity when operating (i.e., capacity planning criteria requirements), as well as any other requirements (e.g., special energy storage capability needs) to provide ongoing reliable service.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 ○ Due to retirements over the resource planning period, there will be need for significant
- 2 investment in new diesel generation capacity (or a suitable lower cost, lower emission
- 3 alternative that can provide flexible, peaking capacity for the system) to meet capacity
- 4 planning requirements.
- 5 ○ The reliability capability of options are evaluated, compared to diesel, on the basis of:
- 6 ▪ The likely reliability of having the option in service by a near-term target date
- 7 (i.e., a date ranging from late 2013 to 2017); and
- 8 ▪ The option's reliability when operating to meet peak winter load capacity
- 9 requirements.
- 10 ○ In addition, where relevant, any added reliability requirements are considered (e.g., a
- 11 wind supply option, in order not to compromise grid reliability, requires added grid
- 12 energy storage capability to enable very quick adjustments to swings in wind generation
- 13 energy supply).
- 14 • **Affordability relative to diesel (Project Life Cycle Costs)** – In examining an option's ability
- 15 to displace diesel generation, the option's forecast levelized cost of energy ("LCOE") per kW.h is
- 16 evaluated relative to diesel over the option's economic life, including capital and operating costs
- 17 (and any related transmission, storage or capacity costs) as required to match the services
- 18 supplied by the diesel option. Where relevant, risks (other than those addressed under reliability
- 19 and flexibility criteria) related to forecast LCOE are also examined.
- 20 ○ LCOE indicates on a consistent and comparable basis each option's overall costs per
- 21 kW.h in current dollars:
- 22 ▪ This cost is subject to ongoing annual inflation for each subsequent year of
- 23 operation; and
- 24 ▪ This cost does not mean that Yukon Energy or ratepayers would face this specific
- 25 cost per kW.h during each year of operation (as reviewed later, capital intensive
- 26 options will have costs/kW.h above LCOE at the outset, declining over time to be
- 27 less than LCOE; the opposite occurs for costs per kW.h for fuel-intensive
- 28 options)³.

³ For rate setting purposes, in any year the regulated revenue requirement costs of a new generation/transmission project equal O&M costs (including any fuel costs) for that year, annual depreciation, and regulated return for that year on the annual average rate base (blended return on debt and equity applied to mid-year rate base cost). Accordingly, capital cost related impacts on rates are highest in the first year of operation, and decline thereafter over the project life (resulting in capital-related costs per kW.h declining over the life of the project); in contrast, costs subject to ongoing inflation tend to increase over the project life.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 ○ LCOE assessments for each option assume the same cost of capital (6.56% blended cost
- 2 of debt and equity, as last approved by the Yukon Utilities Board (YUB) for YEC's 2009
- 3 GRA) and general inflation at 2% per year.
- 4 ○ The LCOE assessment examines each option's costs **per kW.h of diesel displaced** by
- 5 that option in order to evaluate on a consistent basis each option's net generation benefit
- 6 in displacing diesel requirements under various load scenarios:
- 7 ▪ Each option has a stated capability to generate energy - the LCOE evaluated at
- 8 this full utilization of generated energy (i.e., "**Full Utilization LCOE**") is the
- 9 lowest potential cost per kW.h for that option based on current cost information.
- 10 ▪ However, energy generated by an option that fails to displace diesel generation
- 11 that would otherwise be needed has no current economic value, i.e., it is
- 12 "wasted" energy that fails to save costs for the utility or its ratepayers and has
- 13 no value in meeting forecast load requirements.
- 14 ▪ Accordingly, an option's "**Forecast LCOE**" based on costs per kW.h of diesel
- 15 displaced will typically be higher than the Full Utilization LCOE, to the extent (a)
- 16 that forecast grid loads are unable to fully utilize the option's new generation and
- 17 (b) the new option's costs are not flexible in response to grid load changes.
- 18 ▪ The gap between an option's Full Utilization LCOE and its Forecast LCOE (based
- 19 on diesel displacement under the forecast load scenarios) is an indicator of the
- 20 option's flexibility to accommodate the load variations in the current load
- 21 forecasts, i.e., the bigger this gap is, the less flexible an option is to
- 22 accommodate load variations.
- 23 ▪ The water model analysis used to assess Forecast LCOE accounts for any future
- 24 benefits that arise in savings of hydro use from DSM/SSE (or any other option),
- 25 through increased water storage that can be used in future to displace diesel
- 26 generation.
- 27 ▪ Analysis for the 2011 Resource Plan does not attempt to assess the extent to
- 28 which surplus hydro at any time of the year (including surpluses resulting from
- 29 DSM/SSE or new supply option development) could potentially be used for
- 30 interruptible fuel switching programs such as secondary sales program that can
- 31 provide a net revenue stream for the utility and provide meaningful reductions in
- 32 fossil fuel emissions (on the customer side) for the Yukon. Yukon Energy does
- 33 not plan the grid system (i.e., carry out DSM/SSE or new supply side
- 34 developments) with the aim to create surplus renewable resource conditions –

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 however, when such conditions arise on a temporary or other basis, as occurred
2 in the early 2000's, secondary energy sales will be pursued to secure added net
3 revenue for the utility (which net benefits will flow directly through to reduce
4 rates for Yukon ratepayers using firm electricity).
- 5 • **Flexibility relative to diesel to accommodate load changes** – In examining an option's
6 ability to displace diesel generation, the variability of forecast diesel requirements due to hydro
7 system variability or other factors is fully considered:
- 8 ○ Seasonal and annual variations in hydro generation as reviewed in Appendix D are fully
9 considered by assessment of the option's ability to displace forecast diesel energy.
- 10 ▪ **Seasonal hydro variations** - For example, under even Scenario B relatively
11 high forecast loads for 2015, over 95% of the average diesel displacement
12 opportunities in that year under average water year conditions occur in the
13 seven month period from November to May and over 75% in the five months
14 from January to May.
- 15 ▪ **Annual hydro variations** - Further, "annual average" diesel energy generation
16 estimates reflect averages of widely varying annual water flow conditions, e.g.,
17 "annual average" diesel generation of approximately 101 GW.h (Scenario A at
18 545 GW.h for 2015-2016) includes diesel generation ranging from about 13
19 GW.h/year under extreme high water conditions to about 199 GW.h under
20 extreme low water conditions.
- 21 ○ In addition, forecast load reductions (and related reductions in forecast diesel
22 requirements) after the near-term are also fully considered under each load scenario.
- 23 ▪ As noted above, forecast load reductions facilitate an evaluation of each option's
24 flexibility to accommodate load changes (i.e., one of the four key principles to be
25 addressed when evaluating each generation option).
- 26 ▪ In effect, based on current information, all near-term load scenarios show grid
27 loads falling by about 2020 and serving only non-industrial loads after about
28 2021.
- 29 ▪ While currently connected or potentially connected mines may extend industrial
30 loads beyond 2021 as new mine resources are proven and developed, any mine
31 connected loads beyond 2021 must be considered today to be speculative when
32 assessing new near-term generation projects to be committed by 2014.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 • **Environmental responsibility relative to diesel** – In examining an option's ability to displace
2 diesel generation, the likely impact on greenhouse gas emissions relative to diesel generation is
3 examined as well as any other relevant environmental effects of the option on land, air or water.
- 4 • **Other Factors** – In addition to the above, other factors are considered where relevant in
5 assessing each option relative to diesel, including:
 - 6 ○ Economic development and other socio-economic impacts; and
 - 7 ○ Potential synergies with efforts to meet longer-term power resource planning needs of
8 Yukoners beyond 2017 in a timely and cost-effective way, including protecting options to
9 develop major new renewable resources if new long-term and large industrial load
10 connections so warrant.

11 Consistent with the 2006 Resource Plan, the 2011 Resource Plan provides only a planning level
12 assessment of the near-term resource options, i.e., a review to identify a specific project opportunity
13 based on conclusions regarding need for the project and its selection as a preferred alternative. The 2011
14 Resource Plan recommendations are intended to provide the basis for Yukon Energy to proceed with pre-
15 decision planning stages for each preferred project. Subsequent planning stages for any preferred
16 project, prior to any YEC decision to proceed with construction, include: the final feasibility assessment,
17 costing, design and contract arrangements (and related tendering to obtain final estimated costs);
18 consultation with First Nations and others; all required external reviews, approvals and agreements
19 (includes where relevant Yukon Environmental and Socio-economic Assessment Board (YESAB), Fisheries
20 and Oceans Canada (DFO), Yukon Water Board (YWB) and other regulatory authorities as required, as
21 well as seeking YUB review of near-term projects over \$3 million).

22 **3.0 OPTION ASSESSMENT OVERVIEW**

23 An overview assessment of the near-term grid resource options is provided below. Detailed assessment
24 of specific resource options considered for the near-term are provided in the attachments to this
25 Appendix E. The following overview assessment examines each option in its own, as well as "portfolio
26 options" (where a package of options is combined to meet overall grid capacity and energy
27 requirements).

28 **3.1 INITIAL SCREENING**

29 Reliability considerations affecting option development (i.e., the ability to reliably develop an option in a
30 timely and cost effective manner to meet near-term requirements) are a key pre-requisite for near-term
31 option screening. Accordingly, the initial review and sorting of grid resource options (prior to even

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

considering capacity reliability, affordability, flexibility and environmental responsibility) considered the reasonable ability to develop, licence and construct a resource option within the relevant near-term planning period.

In this respect certain options reviewed and discussed during the 2011 Energy Charrette were immediately ruled out as near-term options (see Appendix F regarding further consideration of these options for the longer-term):

- Greenfield hydro sites (small, medium and large) could potentially be available by 2021 but have planning timelines that prevent being committed by 2014 or available by 2017.
- Geothermal options, which requires resources to be proven through exploration activities.
- Options requiring improved technology to be cost efficient (clean coal, mini nuclear and solar).
- Options that require external action (grid interconnection or pipeline connection).

Options where a near-term commitment (by 2014 for in service by no later than 2017) was initially considered potentially feasible included those options listed in Table E-1 and reviewed in Attachments E-1 through E-5 of this Appendix E.

3.2 BASELINE PORTFOLIO OPTION: DIESEL AND DSM/SSE

The near-term 2011 Resource Plan assessment of grid options from the outset acknowledges that diesel is the current default generation resource option (i.e., the reliable, established and available supply option against which other new supply options must be assessed) and that the DSM/SSE resource option is also a given that will be developed at this time. Accordingly, the near-term resource planning assessment in effect establishes diesel and an assumed DSM/SSE development together as the baseline portfolio option against which all other near-term resource options are to be assessed.

- **Diesel – Existing Supply Default Option** – Diesel is a low cost option to supply grid capacity needed for reserves or occasional use, i.e., simply to replace diesel unit capacity upon retirement of existing units or as otherwise required solely to address grid capacity planning shortfalls. Diesel is also used as the default option in off grid power supply situations. Further, given the large amount of established diesel capacity, diesel remains as the effective default option to supply ongoing peaking and baseload energy requirements not otherwise supplied by existing renewable resources (as reviewed in Appendix D and elaborated on in Attachment E2, existing diesel capacity is more than adequate to supply forecast energy requirements under each of the near-term load forecast scenarios).
- **DSM/SSE** – Unlike other options being assessed, Yukon Energy is planning to proceed with a robust and aggressive DSM/SSE program in the very near-term - based on current Yukon

Appendix E

Resource Plan Options: Near-Term Assessment

Page E-8

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

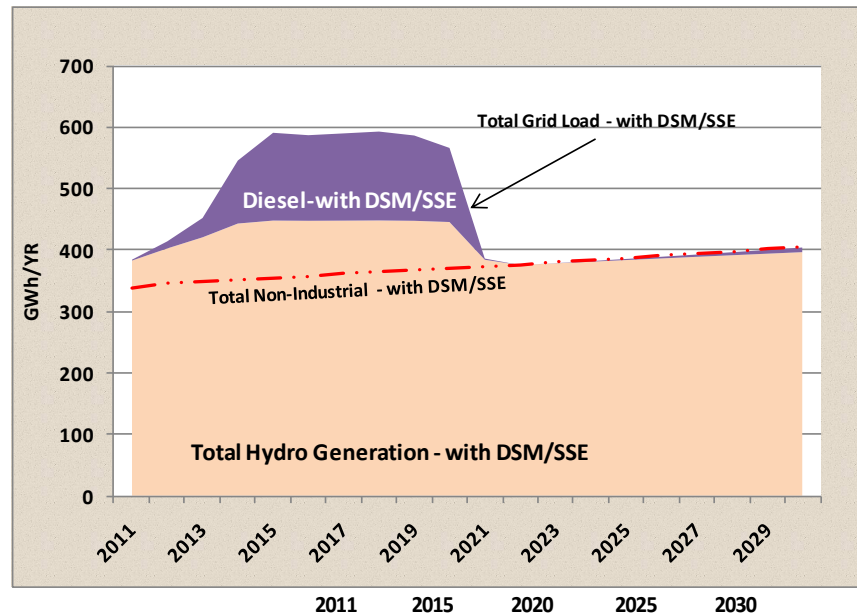
1 Government policy (as set out in the Energy Strategy for Yukon and the Yukon Climate Change
2 Action Plan) and current broad public support for conservation measures (including Yukon
3 Utilities Board directives). A successful DSM/SSE program will effectively reduce the requirements
4 for demand and energy on the system and effectively reduce the diesel available to be displaced.

5 Accordingly, for assessment of all other near-term supply options in Appendix E, diesel and an assumed
6 DSM/SSE development together are established as the baseline portfolio option against which to assess
7 the economics of each other resource options and their effectiveness in displacing diesel generation. The
8 forecast with DSM/SSE and the forecast without DSM/SEE are both typically provided for such
9 assessments to facilitate consideration of the risks and impacts resulting from the assumed DSM/SSE.

10 DSM/SSE as shown in Table E1-1 (Attachment E1) is assumed to be in place when assessing all other
11 near-term resource options under each load scenario, securing a 67% reduction in annual non-industrial
12 grid load growth each year starting in 2013 (i.e., a reduction equivalent to lowering the non-industrial
13 growth from 2.26%/year to about 0.75%/year, a very modest growth rate that is below the low growth
14 scenario in Appendix C of 1.05%/year). Pending completion of the current detailed conservation potential
15 review study, the assumed DSM/SSE is considered to provide a reasonably conservative assessment of
16 overall DSM/SSE impacts over the planning period and to be affordable (low cost), reasonably flexible,
17 reasonably reliable and environmentally responsible. Specific costs for these programs will be developed
18 over the coming year, at which time projected impacts will also be refined.

19 Figure E1-3 shows the extent to which forecast diesel energy generation is expected to be reduced as a
20 result of the assumed DSM/SSE, using the Scenario B load forecast (after 2021, load growth is the same
21 as under the Base Case or Scenario A).

1 **Figure E-1: Baseline Portfolio: Scenario B with DSM/SSE: 2011-2030 (GW.h/year)**



Load/Hydro Supply Gap (GWh/yr)
(Forecast Diesel Generation)

No DSM/SSE	2	158	163	40	83
With DSM/SSE*	2	143	121	2	8

*Assumes DSM/SSE impacts, starting in 2013, equal to 67% of annual non-industrial load growth pre DSM/SSE.

2 The required near-term forecast diesel energy generation varies greatly depending on the selected load
3 forecast scenario, e.g., **grid diesel energy generation displacement opportunities forecast for**
4 **2015-17 under average water year conditions with DSM/SSE range as follows:**

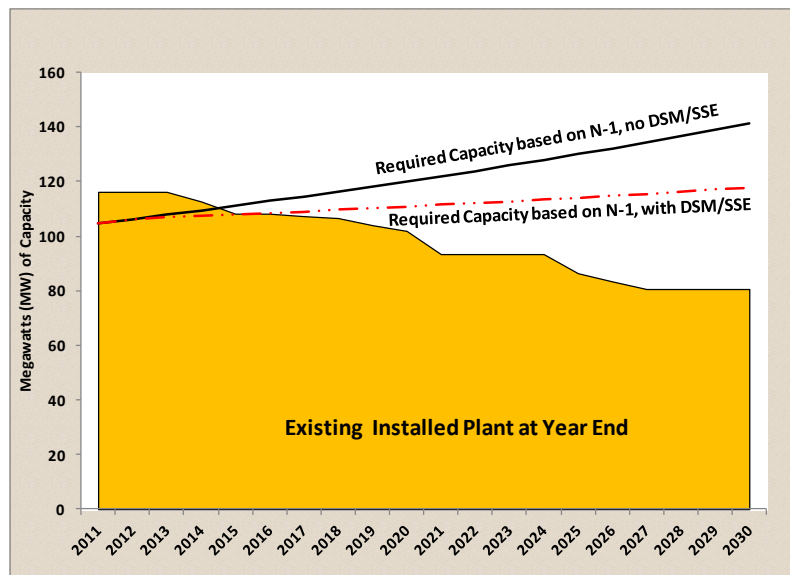
- 5 • Base Case load (non-industrial load and currently connected mines) 13-15 GW.h/year
- 6 • Scenario A (Base Case plus Victoria Gold) 82-85 GW.h/year
- 7 • Scenario B (Base Case plus Victoria Gold, Carmacks Copper, WHCT) 140-143 GW.h/year

8 Figure E1-4 shows the N-1 grid capacity planning MW surplus (shortfall) for 2011-2030 without and with
9 the assumed DSM/SSE.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

**Figure E-2: Grid Capacity Capability and N-1 Capacity Requirements
with & without DSM/SSE – 2011-2030 (MW)**



	2011	2015	2020	2025	2030
Existing Plant (MW)	116.2	108.2	101.9	86.4	80.6
Requirement without DSM/SSE (MW)					
N-1 Requirement	104.7	111.1	120.0	129.9	141.0
Surplus (shortfall) (MW)	11.6	-2.8	-18.0	-43.5	-60.4

As reviewed in Appendix D, the above capacity surplus (shortfall) assessment is based only on forecast non-industrial loads on the integrated grid. Under the LOLE capacity planning criteria (see Appendix D), additional grid capacity would be required in the near-term under Scenario A and Scenario B in response to mine loads in excess of about 13 MW (see Appendix C, Attachment C2, Table C2-2) from late 2013 until approximately 2020; for example, in 2015 without DSM/SSE the capacity shortfall is increased above the non-industrial load N-1 capacity shortfall by approximately 10 MW under Scenario A and 18 MW under Scenario B.

For overall cost comparison of the Baseline Portfolio (diesel with DSM/SSE) to other generation options, the 2011 Resource Plan focuses on a Forecast LCOE and present value analysis as regards diesel fuel and O&M costs per kW.h (2010\$ at approximate 28 cents/kW.h)⁴ and a present value analysis of capital costs for new diesel capacity requirements. An overall present value assessment of these total diesel-related

⁴ Diesel fuel prices are subject to considerable uncertainty due to changing market conditions (e.g., April 2011 and NYMEX futures-based fuel prices were about 10% higher at the outset and 10% lower by 2019 than the fuel prices assumed in the 2011 Resource Plan). New diesel capacity is assumed to cost \$1.0 million per MW (2010\$).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 grid generation costs (2011-2030) for the Baseline Portfolio option under the three near-term load
2 scenarios (with and without assumed DSM/SSE) is provided in Table E-2.

3 **Table E-2: Baseline Portfolio Option Present Value Costs (2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost ⁴	Total PV Costs
No DSM/SSE				
Base Case	111.8	52.8		164.6
Scenario A	227.6	55.9		283.5
Scenario B	304.6	59.1		363.7
With DSM/SSE				
Base Case	30.8	31.9	35.4	98.1
Scenario A	133.9	34.7	35.4	204.0
Scenario B	207.3	38.4	35.4	281.2

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Diesel fuel O&M - assumes 50/50 blend of existing and new units.
3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement.
4. DSM/SSE average annual costs assumed at 7.5 cents/kW.h.
- 4 If Yukon Energy defaults to diesel generation to supply future grid load energy growth, the above costs
5 for added diesel generation to meet forecast loads will have a major impact on future rates in Yukon.
6
- 7 • By way of example, in 2015 under Scenario A with assumed DSM/SSE, 84.9 GW.h of added grid
8 base load diesel generation would add \$26.3 million to fuel and O&M costs at the average
9 incremental fuel and other O&M costs (28 cents per kW.h)⁵ plus approximately \$1.3 million
10 annual capital costs (depreciation and return) on capacity additions required to that date to meet
11 the N-1 capacity planning criteria and LOLE-related added capacity required based on mine loads
12 in excess of 13 MW.
- 13 • Based on forecast Yukon utility sales (grid and off grid) of 504 GW.h⁶ associated with this grid
14 load for 2015 with DSM/SSE, these added diesel costs with costs related to required capacity
15 additions would equal approximately 5.5 cents per kW.h of customer energy use.

⁵ Average of 2009 approved Hydro zone average incremental fuel and other O&M costs of 30 cents per kW.h and assumed new diesel plant fuel and other O&M costs of 26.06 cents. Assumed inflation at 2% per year.

⁶ Assume Grid sales at 484 GW.h/2015 plus approximately 20 GW.h YECL off-grid sales.

1 **3.3 SUMMARY PROJECT DESCRIPTION OF OTHER RESOURCE SUPPLY OPTIONS**

2 Table E-3 provides a summary project description for each non-diesel supply option that is assessed in
3 detail in the 2011 Resource Plan, including estimated scale, potential earliest in-service date, estimated
4 capital cost (2010\$), estimated operating cost (2010\$) per MW.h in 2015, assumed annual generation,
5 and annual grid diesel energy generated or displaced (GW.h) in the 2015-17 time under each load
6 scenario. The non-diesel thermal municipal solid waste to energy option is excluded because further
7 review of the available information indicates that it is not an eligible option meriting detailed assessment
8 at this time (see Attachment E4).

9 The Baseline Portfolio option (Diesel with DSM/SSE) is provided in Table E-3 for reference. This
10 generating capability is in place (subject to ongoing capacity planning requirements). Average diesel
11 energy requirements under each load scenario for the 2015-17 time period are net of assumed DSM/SSE.

12 Each hydro enhancement option improves winter energy generation at existing hydro facilities, through
13 either added winter/fall storage (Marsh and Atlin projects⁷) or diversion of added waters (Gladstone). In
14 addition to the three hydro enhancement projects listed in Table E-3, Yukon Energy continues to pursue
15 amendments to the current Fisheries Act Authorization (FAA) provisions for Aishihik generation which are
16 estimated to provide about 7 GW.h an additional diesel displacement benefits on average at 545 GW.h
17 load level. This diesel displacement benefits vary depending on load in the grid.

⁷ Due to the BC Government decision recently to designate Atlin River as Class A park (and the expectation that the designated park will include the river), work on the Atlin Storage project has currently ceased.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1

Table E-3: General Description of Near-term Resource Supply Options

	PROJECT DESCRIPTION							
	Potential Earliest In- Service (full year)	Estimated Capital Cost (2010\$Million)	Capital Cost per MW (\$million)	Estimated Operating Cost ³ (2010\$/MW.h)	Annual Generation ² (GW.h)	Diesel Energy Displacement 2015-17 ¹ Base Case (GW.h)	Diesel Energy Displacement 2015-17 ¹ Scenario A	Diesel Energy Displacement 2015-17 ¹ Scenario B
Baseline Portfolio (Diesel with DSM/SSE)	NA	NA	\$1.0	\$280/MW.h	Flexible	14	84	142
Hydro Enhancements								
Marsh Lake Storage	2015	\$10.5	NA	\$8/MW.h	6.4	(5)	(6)	(6)
Gladstone Diversion	2018	\$40.0	NA	\$6/MW.h	36.6	NA	NA	(33)
Marsh & Gladstone	2015-18	\$50.5	NA	\$6/MW.h	39.4	NA	(34)	(38)
Non-Diesel Thermal								
Wood Biomass (10 MW)	2015	\$63.8	\$6.4	\$130/MW.h	79.7	(14)	(54)	(65)
Wood Biomass (15 MW)	2015	\$85.5	\$5.7	\$117/MW.h	119.6	NA	(72)	(92)
Waste to Energy (2.2 MW)	2015	\$39.0	\$17.7	\$88-165/MW.h	17.1	(7)	(13)	(15)
LNG/Natural Gas ⁴	2015	\$6-\$55	\$1.5-\$1.83	\$98-\$124/MW.h	Flexible	(14)	(84)	(142)
Wind								
Wind (21 MW + 5 MW DRUPS)	2015	\$93.4	\$4.5	\$38/MW.h	55.6	(14)	(45)	(51)
Wind (10.5 MW)	2015	\$49.5	\$4.9	\$38/MW.h	27.8	(12)	(24)	(26)

1. Load forecasts for 2015-17 period (average) with DSM/SSE - forecast diesel requirement (displacement) assuming average water conditions. Diesel energy is forecast at less than 10 GW.h/yr under all load scenarios from 2021-2030 inclusive. Gladstone estimates assume operation.

2. **Diesel and LNG** respond as required. **Wood biomass** plant operates at 91% annual capacity factor. **Wind** is net of losses, with advanced blade heating.

Hydro enhancements reflect maximum enhancement impact at Whitehorse (Marsh Lake Storage) or Aishihik (Gladstone Diversion) hydro plants.

3. Fuel and O&M costs in \$2010 as apply in 2015. LNG costs include LNG processing & trucking; natural gas cost escalates faster than inflation.

Wind and hydro enhancement reflect estimated annual O&M cost divided by total estimated annual generation.

WTE \$88/MW.h without Heat Revenue, \$165/MW.h without Heat Revenue and Tipping Fees (-\$16.8/MW.h with Heat Revenue and Tipping Fees).

4. LNG plant ranges: 4 MW - Base Case w DSM/SSE, 8 MW - Base Case no DSM/SSE, 22 MW - Scenario A and 30 MW - Scenario B. LNG plant assumed to displace all diesel generation.

2

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 The non-diesel thermal options differ in assumed operation. A 10 to 15 MW biomass plant (minimum size
2 likely to be feasible) is assumed to operate at a high capacity factor (91%) on a year round basis to make
3 effective use of its relatively high capital cost (\$5.7 to \$6.4 million per MW). In contrast, a LNG/natural
4 gas power plant with much lower capital cost (\$1.5-\$1.83 million per MW) is assumed to operate in the
5 same way as a diesel plant, i.e., on an as required basis. Trucked-in LNG is assumed to be used until
6 local natural gas supplies are available; for initial costing, an LNG supply is assumed to be developed at
7 Fort Nelson B.C., with the LNG then trucked to Whitehorse. Waste to Energy has highest capital cost per
8 MW (\$17.7 million/MW with 25% contingency) within thermal plant options.

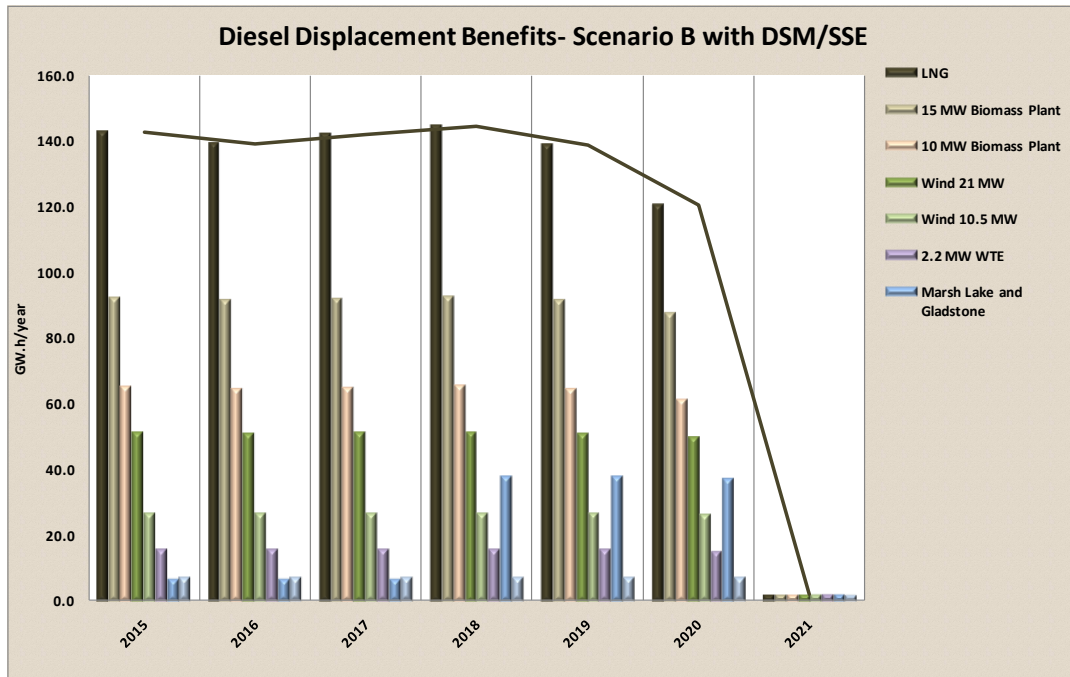
9 A range of wind farm options is shown, including two sites (Ferry Hill near Stewart Crossing and Mount
10 Sumanik near Whitehorse). At most, only one 20 to 21 MW scale wind project could be accommodated
11 on the grid during the planning period, given the non-dispatchable nature of this energy supply option.

12 As reviewed in Table E-3, potential annual diesel energy displacement in 2015-17 varies for each
13 resource supply option and each load forecast scenario. Figure E-3 uses Scenario B (with DSM/SSE) as an
14 indicator of each option's overall impact on reducing diesel generation on the grid from 2014 to 2021
15 under this high near-term load forecast (after assumed DSM/SSE). Each option's separate potential
16 impact to displace diesel is assessed in Figure E-3, and these option impacts would not necessarily be
17 additive if more than option was developed.

18 Focusing on the 2015-19 time period, the LNG option offers the highest potential diesel displacement
19 (approximately 100%), followed by the wood biomass option (46% to 65%), wind at 21 MW (36%), wind
20 at 10.5 MW (19%), WTE at 2.2 MW (11%) and the combination of Marsh & Gladstone (27% if in fact it
21 could be in-service at that time). Some added assessments flowing from Table E-3:

- 22 • The Marsh Lake Storage enhancement offers only 5% displacement.
- 23 • In contrast to Ferry Hill, the Mount Sumanik wind option is currently estimated to offer slightly
24 less diesel displacement (please see Table E5-1).

1 **Figure E-3: Diesel Displacement Benefits 2014-21 – Scenario B (with DSM/SSE)**



2

Scenario B with DSM/SSE, GW.h				
	2015	2020	2025	2030
Diesel Available to be Displaced	142.9	120.6	1.8	7.5
Potential Annual Diesel Displacement:				
Marsh Lake Storage	6.6	6.6	1.5	3.9
Marsh Lake and Gladstone	6.6	36.6	1.8	7.5
10 MW Biomass Plant	64.9	61.2	1.8	7.5
15 MW Biomass Plant	91.9	87.4	1.8	7.5
2.2 MW WTE	15.3	14.6	1.8	5.1
LNG	142.9	120.6	1.8	7.5
21 MW Wind	50.9	49.7	1.8	7.5
10.5 MW Wind	26.4	25.8	1.8	7.5

3

4 **4.0 RESOURCE SUPPLY OPTION ASSESSMENT - SUMMARY**

5 Table E-4 provides a high-level initial assessment summary for each of the non-diesel resource supply
6 options, addressing each key planning principle either directly or indirectly (through indicators that allow
7 assessment of the impacts). Detailed assessment of each eligible resource supply option is provided in
8 the attachments to this Appendix E.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1

Table E-4: Initial Assessment Summary – Near-Term Resource Supply Options

	RELIABILITY		AFFORDABILITY			FLEXIBILITY	ENVIRONMENTAL RESPONSIBILITY		
	Reliability - Winter Peak Capacity	Reliability - In-Service Timing	Forecast LCOE ² (c/kW.h)	Annual Cost 2018 ³ (\$million)	Full Utilization LCOE ⁴ (c/kW.h)	Flexibility	GHG - 2015-17 ⁵ (Displacement) Base Case (tonnes)	GHG - 2015-17 ⁵ (Displacement) Scenario A (tonnes)	GHG - 2015-17 ⁵ (Displacement) Scenario B (tonnes)
Baseline Portfolio (Diesel with DSM/SSE)	yes	yes	28	33.3	28	yes	9,800	58,800	99,400
Hydro Enhancements									
Marsh Lake Storage	some ¹	no	11.4	32.0	8.5	partial	-3,500	-4,480	-4,480
Gladstone Diversion	no	no	NA	NA	5.7	no	NA	NA	-23,100
Marsh & Gladstone	some	no	13.1	26.8	6.2	no	NA	-23,800	-26,600
Non-Diesel Thermal									
Wood Biomass (10 MW)	yes ⁷	unknown	58.4	30.4	17.5	no	-9,800	-37,800	-45,500
Wood Biomass (15 MW)	yes ⁷	unknown	60.8	30.5	15.8	no	NA	-50,400	-64,400
Waste to Energy (2.2 MW) ⁶	yes	unknown	31.5	32.3	13.5	no	-4,900	-9,100	-10,500
LNG/Natural Gas ⁸	yes	likely	18.4	17.9	12.0	yes	-2,940	-17,640	-29,820
Wind									
Wind (21 MW + 5 MW DRUPS)	DRUPS only ¹	likely	40.0	29.9	14.8	no	-9,800	-31,500	-35,700
Wind (10.5 MW)	no	likely	34.7	32.6	15.5	no	-8,400	-16,800	-18,200

1. The 2006 Resource Plan estimated 1.6 MW capacity benefit for Marsh Lake Storage - this has not been reviewed. In 2011 Resource Plan Update assumed 1 MW winter capacity benefit. "DRUPS" is diesel rotary uninterruptible power - it is required for add-on spinning reserve needed on the grid (expected to be needed for 20-21 MW wind farm option, but not for 10 MW wind farm).

2. Assumes Scenario A with DSM/SSE (2010\$) - for diesel, LCOE reflects only fuel and O&M costs; for all other options, LCOE reflects all lifetime costs per kW.h of net generation (i.e., diesel displaced).

3. Scenario A forecast with DSM/SSE. Cost includes all annual costs to ratepayers for the option, including required capacity costs under N-1 and LOLA approx plus diesel fuel and O&M for diesel remaining.

4. Assumes all generation used to displace diesel (2010\$) - for diesel, LCOE reflects only fuel and O&M costs. LNG assumed at 22 MW with 55% Load Factor.

5. Scenarios A and B (see Table E-3 for estimates of diesel generation [displacement]) - assumes 700 tonnes GHG per GW.h of diesel generation. 30% less for LNG, and no GHG for other options. GHG emission reductions may not apply to Base Case for most options (as they not be developed for loads less than Scenario A).

6. The numbers are with Heat Revenues and Tipping Fees. Forecast LCOE without Heat Revenue is 55.6 cents/kW.h, without both Heat Revenues and Tipping Fees is 73.5 cents/kW.h.

7. Thermal generation typically offers reliable peak capacity. However, if Wood Biomass plants to be located at Haines Junction (to use beetle kill standing timber); the thermal plant would be treated the same as the Aishihik hydro plant and excluded from reliable capacity under the N-1 event (loss of transmission connection to Whitehorse).

8. LNG plant ranges: 4 MW - Base Case w DSM/SSE, 8 MW - Base Case no DSM/SSE, 22 MW - Scenario A and 30 MW - Scenario B.

2

1 **5.0 SUMMARY CONCLUSIONS**

2 The Baseline Portfolio (diesel and assumed DSM/SSE) is able to meet the energy and capacity
3 requirements over the 20-year planning period in a reliable and flexible manner.

4 Under the Base Case load forecast with currently connected mine loads, the Baseline Portfolio would also
5 appear to be the only practical approach to constrain diesel requirements – DSM/SSE is assumed under
6 this load forecast to have the potential to reduce present value diesel costs and GHG emissions by over
7 60%, and no other resource supply option has been identified that would add material added benefits
8 unless new mine loads are connected to the grid. Two caveats can be noted to this conclusion: first, the
9 costs and effectiveness of specific DSM/SSE program packages have yet to be considered, pending
10 completion of the current detailed conservation potential review study that is planned to be completed in
11 the fall of 2011. Second, the Base Case load forecast looks only at the grid loads – diesel generation for
12 off grid industrial loads may increase dramatically in the near-term, increasing power-related GHG
13 emissions in Yukon and changing perspectives as to the adequacy of relying only on DSM/SSE related to
14 utility customer loads.

15 When looking at Scenarios A and B with new industrial loads connected to the grid, the Baseline Portfolio
16 raises concerns regarding high costs and high GHG emissions. Review of available resource supply
17 options (beyond the assumed DSM/SSE) indicates little if any sensitivity to whether Scenario A or B
18 specifically emerges – each scenario creates broadly similar challenges.

19 Assessment of near-term resource supply options to reduce costs and/or emissions under Scenario A or B
20 is materially affected by the load forecasts and related demand over the resource planning period as load
21 growth in the near-term will lead to material requirements for costly diesel generation in the period from
22 2014 through 2020, absent development of more affordable and environmentally responsible resource
23 alternatives. The currently forecast loss of all industrial load by 2021 (including currently connected mines
24 and potential new industrial loads reviewed in Appendix C) means that flexibility and robustness of near-
25 term options to address these material forecast changes in circumstances is a key near-term
26 consideration.

27 Based on these overall considerations, and assuming adoption of DSM/SSE, other near-term resource
28 supply options that are fuel intensive (but less costly and with less GHG emissions than diesel) are
29 considered optimal to deal with material near-term but relatively short lived loads – while more capital
30 intensive options that are not considered flexible would best be deferred until there is greater certainty as
31 to load being sustained for a longer time period.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 Current information indicates that LNG offers the best overall near-term opportunity to materially reduce
2 both costs and GHG emissions, thereby assisting Yukoners through a transition period until such time as
3 new legacy renewable supply resource options can be effectively pursued. Where established, LNG would
4 displace diesel as the default option in Yukon – affecting the assessment of future resource choices and
5 also affecting incremental pricing and rate setting in the rate zones where it is utilized.
- 6 • LNG is the only option to offer opportunity to reduce present value diesel costs under Scenarios A
7 and B (projected reductions exceed 35%); LNG would also provide 30% reduction in grid GHG
8 emissions. This option appears to offer high flexibility, and ability to accommodate load changes
9 as well as risks of new hydro enhancement resources becoming available.
 - 10 • While GHG emission reduction is greater with wood biomass options than with LNG, the wood
11 biomass options involve materially higher costs than the Baseline Portfolio with diesel.
 - 12 • While GHG emission reduction is somewhat greater with wind options than with LNG, under all
13 scenarios examined the wind options involve higher present value costs than the Baseline
14 Portfolio with diesel.
 - 15 • LNG offers opportunity to pursue off grid diesel displacement at Watson Lake and at some mine
16 sites, and near-term pursuit of such opportunities could materially increase the GHG emission
17 reduction impacts associated with LNG. Similar off grid opportunities have not been identified for
18 other resource supply options.
 - 19 • Marsh Lake Storage also appears to be suitably flexible enough to proceed in the near-term,
20 given its relatively small cost and impact, if it can in fact secure the necessary permits and
21 approvals.
 - 22 • The Gladstone Diversion offers large scale renewable resource enhancement benefits, but does
23 not appear to be a near-term option. Ongoing planning to seek development of this option is
24 merited.
 - 25 • The Aihishik FAA amendment as proposed by Yukon Energy also continues to be merited.
 - 26 • The wind option offers longer-term benefits and ongoing planning is therefore merited as
27 proposed; commitment to development, however, is not proposed without appropriate sustained
28 loads to utilize the resource effectively.
- 29 More specific summary conclusions on each option are provided below:
- 30 • **Hydro Enhancements** - While hydro enhancements are options that may be pursued in the
31 near-term, these options are not considered reliable to meet any specific in-service target date
32 due to the high degree of regulatory risk involved in development of each enhancement project.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 i. The Marsh Lake Storage project may have reasonable prospects to be committed before
2 2015.
- 3 ii. The Gladstone Diversion project is likely no longer eligible to be committed before 2015
4 (i.e., the specified deadline for projects to be eligible as part of a plan to meet near-term
5 requirements).
- 6 iii. The proposed FAA revisions at Aishihik will continue to be pursued with the regulatory
7 authorities, but there is no clarity today as to the potential feasibility or timing for
8 securing such changes given the current lack of support from the local First Nation.
- 9 In effect, the potential near-term development of any of these enhancements creates added risks
10 for any other near-term resource option (which must address uncertainty as to
11 timing/implementation of these enhancements, as well as the already stated load-related
12 uncertainties and the impact of DSM/SSE). Ongoing expenditures for each of these potential
13 projects are being constrained as required and prudent, pending resolution of key regulatory and
14 local support issues that affect YEC's ability to proceed with each project.
- 15 • **Non-Diesel Thermal Options** - Each non-diesel thermal options has its own specific features
16 and costs that need to be assessed in the context of near-term Yukon grid diesel displacement
17 opportunities.
- 18 i. **Biomass – Wood** - This option is characterized by high costs and lack of flexibility,
19 resulting in the wood biomass thermal option not being a cost effective to develop at this
20 time. Further, due to the high costs noted, there is no apparent basis (assuming current
21 commercial technology) to reconsider this option in the planning period unless very large
22 new baseloads were to be connected to the grid or an intertie connection was to be
23 developed, i.e., until there are conditions to fully utilize all biomass thermal generation
24 over the year on a sustained basis from a 25 MW plant. Monitoring of the
25 commercialization of new technologies may also indicate new opportunities in the future
26 for smaller scale wood biomass thermal plants that are more cost efficient than those
27 currently available.
- 28 ii. **Biomass – Waste to Energy** - This type of facility is not currently considered to
29 provide the required degree of flexible and affordable energy necessary to meet near-
30 term system requirements. Much higher grid loads (to the point where fossil fuel is
31 required for summer generation) and improved technology may improve opportunities at
32 some future time for a limited scale municipal waste base load generation with much
33 reduced GHG emission impacts.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 iii. **LNG - LNG/Natural gas** - This option is essentially very similar to diesel generation as
2 reviewed in Attachment E2, except that it is forecast to use a less costly fuel that has
3 lower GHG and other emissions. This form of thermal generation involves relatively low
4 capital costs, and retains the flexibility and reliability that characterize the diesel thermal
5 option. In effect, natural gas power plants are intended to be operated only when
6 required and (subject to securing fuel supply) can be relatively easily integrated into the
7 Yukon system as conversion or replacement of the current diesel generation plant.
8 Accordingly, and particularly in light of planned retirement of all of YEC's diesel plant over
9 the 20-year planning period and the grid's capacity planning requirements, the
10 LNG/natural gas option can be potentially relevant under all load scenarios.

11 In the event that LNG is to be pursued for near-term development for power generation
12 in Yukon, immediate feasibility work is recommended to determine the optimum way to
13 secure the LNG, the required timing and all related costs. Options to be examined may
14 include development of a small new LNG conversion plant at Fort Nelson (or any other
15 optimum alternate location) as assumed in studies referenced to date, or purchase of
16 LNG from other suppliers. This assessment should also look at the full range of non grid
17 opportunities for LNG to help reduce overall diesel power generation GHG emissions in
18 Yukon.

- 19 • **Wind** - Based on current near-term load forecasts, lack of flexibility with the wind option to
20 accommodate load reductions makes it a high cost option to develop until such time as there is
21 sufficient long-term load expected to be in place as needed to make effective use of this resource
22 to displace diesel generation. Given the relatively low planning and regulatory costs for this
23 option, YEC could still proceed to complete wind monitoring at the two noted sites and also
24 consider proceeding thereafter with work to finalize feasibility assessment and environmental
25 approvals for the preferred site so that the project is ready to proceed when load conditions so
26 allow. In addition, during the feasibility assessment it would be useful to examine staging of
27 development for the preferred wind farm such that a minimum scale option might be defined for
28 initial development that is less sensitive to load fluctuations as currently forecast.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **ATTACHMENT E1 – DSM/SSE**

2 Attachment E1 provides background and assessment for near-term demand side management (DSM) and
3 supply side enhancement (SSE) activities that are assumed to be developed and adopted by Yukon
4 Energy as a key component of the 2011 Resource Plan, i.e., DSM/SSE is assumed to occur concurrent
5 with any of the diesel or non-diesel supply option examined.

6 DSM is distinguished from other near-term options as it is considered to be an option that Yukon Energy
7 would proceed with (albeit the specified programs would depend on the results of a conservation
8 potential review underway and supporting economic and regulatory analysis). The following key context
9 setting factors are noted in this regard:

- 10 • The Energy Strategy for Yukon Strongly supports conservation measures such as DSM as a
11 means of addressing growing demand (and related diesel generation requirements) in Yukon.
- 12 • The Yukon Utilities Board (with encouragement and support from intervenors) has directed that
13 Yukon Energy and Yukon Electrical (Order 2009-2 and Order 2009-8) consult with stakeholders
14 and jointly develop a DSM policy paper (Plan) to be presented as part of the next generation rate
15 application.
- 16 • Generally, there is widespread public acceptance and support for DSM programming and energy
17 conservation; this broad public support was evident at the Yukon Energy Charrette where DSM
18 was considered the most favoured option for YEC to proceed with in the near-term.

19 **BACKGROUND**

20 Demand side management (DSM) is widely recognized in utility resource planning (e.g., BC Hydro Power
21 Smart program, similar programs by Manitoba Hydro and other major utilities) to be feasible at relatively
22 low cost (Full Utilization LCOE on average likely less than 10 c/kW.h) for ongoing implementation with
23 non-industrial and industrial customers. DSM was a major component of the YEC/YECL 1992 Resource
24 Plan, but DSM expenditures were curtailed with closure of the Faro mine in 1993 and had no
25 consideration during the period of sustained hydro surplus following final closure of the Faro mine in early
26 1998. Given the recent re-emergence of forecast baseload diesel generation, DSM is a major component
27 of the 2011 YEC Resource Plan.

28 As part of the joint development of a demand side management plan, YEC, in cooperation with YG and
29 YECL, is currently undertaking a detailed conservation potential review study that is planned to be
30 completed in the fall of 2011. This comprehensive analysis of energy use by customer class and electrical
31 zone will form the basis of the DSM plan to be prepared after the fall of 2011 by establishing a reference

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

case for future electrical use and then identifying the low, medium and high achievable (and cost-effective) DSM potential for different non-industrial customer classes. The review will also determine which DSM technologies are most appropriate for the Yukon in the short and medium term including the potential integration of customer generation (net metering).

In addition to this conservation potential review study, YEC initiated a LED streetlight replacement pilot project in Dawson during October, 2010, and is also participating in the YECL/City of Whitehorse LED streetlight program. Yukon Energy has various other DSM program development activities ongoing throughout 2011, including stakeholder consultation activities and other pilot program planning. At this time, planned pilot projects include a residential energy conservation challenge, offering energy conservation training designed specifically for municipal and First Nation Governments, providing commercial customers with access to energy efficiency training, working with Minto Mine to develop and deliver an audit pilot program, developing opportunities for school age energy efficiency programming, as well as general public education and outreach.

Canadian jurisdictions typically assess DSM program cost effectiveness relative to total resource costs as well as rate impacts. Based on these tests, DSM program costs are required to be competitive with costs of new generation – and often are assessed to be well below costs for new generation, providing the utility with room to adjust for any uncertainty regarding the sustainability, costs and/or effectiveness of DSM energy reductions over the longer-term. Costs also vary depending on the types of DSM methods/programs (e.g., rates, subsidies, standards and codes) selected and the effectiveness of those choices in reaching their energy reduction targets. Ongoing costs associated with DSM (O&M) generally include recurring or consistent program implementation costs, program evaluation costs, and regulatory costs.

DSM requires some lead time before energy savings can be translated into electrical energy available for other demand and the amount of lead time varies by initiative. Typical DSM programs are implemented over a 3 to 5 year period at which time they are usually evaluated and modified based on the results of that evaluation.

YEC also has ongoing investigations to plan and implement feasible supply side enhancement (SSE) programs, including generator enhancements, transmission enhancements, turbine rerunning (both Aishihik units) and initiating a general facilities level audit to establish a baseline for energy use and identify cost-effective energy savings opportunities.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **OPTION ASSESSMENT**

2 For the purposes of the 2011 Resource Plan, the DSM/SSE option is assumed to be implemented
3 reasonably aggressively by Yukon Energy starting in 2013, following completion of the current detailed
4 conservation potential review study and review by the Yukon Utilities Board. Although DSM
5 implementation will address industrial as well as non-industrial loads, with expected DSM impacts
6 reducing forecast industrial loads (as has been the case with BC Hydro and other utilities), the 2011
7 Resource Plan focuses for simplicity solely on assessing potential DSM impacts on the ongoing non-
8 industrial load growth during the planning period.

9 DSM/SSE impacts for the 2011 Resource Plan have been estimated assuming program commencement by
10 2013 to secure a 67% reduction in annual non-industrial load growth each year. This amounts to a
11 reduction of about 5.4 GW.h in 2013 (reflecting the assumed combined impact of SSE and DSM), and this
12 amount grows each year thereafter as needed to remove 67% of the ongoing non-industrial load growth
13 as forecast in the medium load Base Case forecast. It is assumed for simplicity, pending completion of
14 more detailed future analysis and program development, that these reductions apply annually and equally
15 to forecast non-industrial capacity and energy generation loads.

16 Although DSM/SSE impacts are likely to vary on a year-to-year basis and may also require several years
17 to reach potential load reduction levels, the assumed DSM/SSE option which provides estimated
18 reductions based on only non-industrial load DSM (even though YEC is pursuing DSM with mine
19 customers) is considered to provide a reasonably conservative assessment of overall DSM/SSE impacts
20 over the planning period based on available information, including:

- 21 • YEC, YECL and YG are now proceeding with the detailed energy conservation potential review as
22 required to determine by later this year the specific extent and cost/implementation plans for
23 feasible DSM programs to be implemented thereafter.
- 24 • Given the YUB's previous orders and recommendations on DSM, and forecast diesel generation
25 levels, it is reasonable to assume that meaningful and prudent DSM expenditures and actions will
26 be supported by the regulator.
- 27 • BC Hydro currently is required (by the BC *Clean Energy Act*) to meet at least 66% of all load
28 growth through DSM (separate from SSE), and BC Hydro plans to exceed this DSM requirement

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 by a combination of programs, standards and rate structures at unit energy costs for DSM
2 averaging well under 10 cents per kW.h⁸.

3 Table E1-1 shows the estimated annual diesel generation impact of the assumed DSM/SSE under each
4 load scenario from 2011 to 2030, based on YEC's water model. This analysis assumes the DSM/SSE load-
5 related impacts are spread over the non-industrial load relatively evenly (in percent terms) throughout
6 the year. The results are the same for all load scenarios after 2021 (as loads are assumed to be the same
7 at that time, with only non-industrial loads and no mine loads connected). Resulting diesel reductions
8 each year are shown under two headings for each load scenario:

9 • **Diesel as Reduction % of DSM/SSE** - This shows the resulting reduction in diesel generation
10 (due to the assumed DSM/SSE) as a percent of the assumed load reduction due to DSM/SSE,
11 assuming average water years.

12 ○ In general, this percentage is very sensitive to the overall load levels (including mine
13 loads) and the related forecast impact on diesel generation without DSM/SSE, i.e., under
14 Base Case loads, diesel generation displaced by DSM/SSE in 2020 equals only 51% of the
15 DSM/SSE-related load reduction, but under Scenario A this climbs to 84% and under
16 Scenario B to 91%. DSM/SSE that does not reduce diesel generation in effect reduces
17 hydro generation used by the grid.

18 ○ Overall, this percentage highlights the extent to which this option (as with other options)
19 when applied to the Yukon grid under current forecast conditions is not 100% effective in
20 supplying a resource that directly is used only to displace diesel generation. Assessment
21 of the cost effectiveness of DSM/SSE (as with other options) is intended to be based on
22 costs per kW.h of diesel generation displaced (net generation); on this basis, Forecast
23 LCOE may well move above 10 cents/kW.h but is still expected to remain as a relatively
24 affordable option.

25 ▪ The water model analysis (as summarized in Table E1-1 for DSM/SSE impacts)
26 accounts for any future benefits that arise in savings of hydro use from DSM/SSE
27 (or any other option), through increased water storage that can be used in
28 future to displace diesel generation.

⁸ BC Hydro's DSM projections indicate similar material impacts from DSM on load growth in each major customer sector (residential, commercial and industrial); however, for each sector the impacts of specific DSM program components can vary a great deal. In the 2008 DSM program filings, for example, "Codes and Standards" DSM activities accounted for over 50% of the forecast residential DSM impacts, while sector-specific DSM "Programs" accounted for over 60% of the forecast commercial DSM impacts and over 80% of the forecast industrial DSM impacts. DSM "Rate Programs" (the third and final major DSM component in the BCH package) typically accounted for between about 15 and 20% of the DSM impacts in each major customer sector in the 2008 DSM program.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 ▪ Analysis for the 2011 Resource Plan does not attempt to assess the extent to
2 which surplus hydro at any time of the year (including surpluses resulting from
3 DSM/SSE or new supply option development) could potentially be used for
4 interruptible fuel switching programs such as secondary sales program that can
5 provide a net revenue stream for the utility and provide meaningful reductions in
6 fossil fuel emissions (on the customer side) for the Yukon. Yukon Energy does
7 not plan the grid system (i.e., carry out DSM/SSE or new supply side
8 developments) with the aim to create surplus renewable resource conditions –
9 however, when such conditions arise on a temporary or other basis, as occurred
10 in the early 2000's, secondary energy sales will be pursued to secure added net
11 revenue for the utility (which net benefits will flow directly through to reduce
12 rates for Yukon ratepayers using firm electricity).
- 13 • **Diesel reduction percentage** - This shows the resulting reduction in diesel generation (due to
14 the assumed DSM/SSE) as a percent of the forecast diesel generation assuming average water
15 years. In general, this percentage declines sharply as forecast diesel generation without DSM/SSE
16 increases.
- 17 ○ Under Base Case loads, diesel generation displaced by DSM/SSE in 2020 equals 73% of
18 the otherwise forecast diesel generation, but under Scenario A this falls to only 35% and
19 under Scenario B to 26%.
- 20 ○ Overall, this percentage highlights the extent to which non-DSM/SSE options continue to
21 have scope to reduce diesel generation in the event that DSM/SSE is implemented as
22 assumed.
- 23 ○ A key result in this regard for all load scenarios is the limited scope that exists after 2020
24 for any additional resource options to displace any material diesel generation, i.e., the
25 DSM/SSE alone displaces 91% or more of the forecast diesel generation each year from
26 2021 to 2030.
- 27 DSM/SSE costs for specific programs will be estimated over the coming year as specific programs are
28 developed. Although Forecast LCOE in Yukon will exceed Full Utilization LCOE levels (i.e., typically much
29 less than 10 cents per kW.h) seen in other jurisdictions such as BC Hydro, it is expected that Forecast
30 LCOE will continue to be less than for near-term supply options (other than perhaps hydro enhancements
31 as reviewed in Attachment E-3).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 DSM is ranked as reasonably reliable – however, DSM effects on reducing the need for diesel generation
2 are dependent on customers' behavioural response, and are therefore not as reliable as supply options
3 such as diesel generation; in contrast, SSE effects from specific initiatives are expected to be very
4 reliable. DSM/SSE programs are viewed as being reasonably flexible in adapting to major load reductions,
5 in that ongoing costs can be curtailed as and when required. DSM/SSE has a high rank under
6 environmental responsibility as it avoids the environmental effects associated with either diesel
7 generation (i.e., it reduces GHG emissions equal to approximately 700 tonnes per GW.h of diesel
8 generation) or the development of new supply resources.

9 **Table E1-1: Assumed DSM/SSE Impact on Non-Industrial Load: Reduction in Diesel Energy**

Forecast Years	Impact of DSM/SSE on Diesel reduction %						Non- industrial DSM/SSE (GW.h)
	Base Case		Scenario A		Scenario B		
	Diesel Reduction (%)	Diesel Reduction % of DSM/SSE	Diesel Reduction (%)	Diesel Reduction % of DSM/SSE	Diesel Reduction (%)	Diesel Reduction % of DSM/SSE	
2011	0%	0%	0%	0%	0%	0%	0.0
2012	0%	0%	0%	0%	0%	0%	0.0
2013	-16%	46%	-11%	58%	-10%	62%	5.4
2014	-28%	48%	-10%	84%	-9%	87%	10.9
2015	-36%	51%	-14%	85%	-10%	92%	16.6
2016	-46%	51%	-19%	84%	-13%	92%	22.3
2017	-51%	54%	-22%	85%	-16%	92%	28.2
2018	-54%	56%	-25%	86%	-18%	93%	34.3
2019	-58%	59%	-28%	87%	-21%	92%	40.5
2020	-73%	51%	-35%	84%	-26%	91%	46.8
2021	-100%	31%	-100%	31%	-92%	41%	53.2
2022	-100%	36%	-100%	36%	-100%	36%	59.8
2023	-99%	41%	-99%	41%	-99%	41%	66.6
2024	-97%	44%	-97%	44%	-97%	44%	73.5
2025	-96%	48%	-96%	48%	-96%	48%	80.6
2026	-94%	51%	-94%	51%	-94%	51%	87.8
2027	-93%	55%	-93%	55%	-93%	55%	95.2
2028	-92%	58%	-92%	58%	-92%	58%	102.7
2029	-92%	61%	-92%	61%	-92%	61%	110.4
2030	-91%	64%	-91%	64%	-91%	64%	118.3

10

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

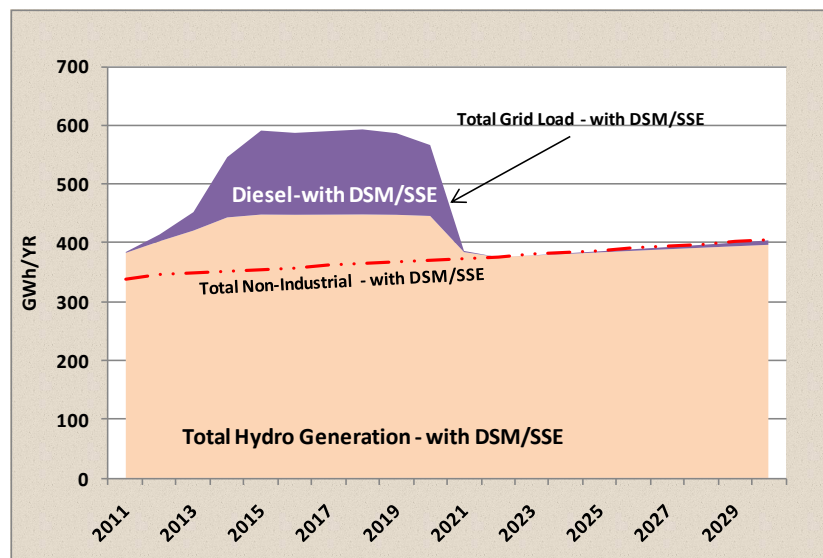
December 2011

1 SUMMARY

2 In summary, the extent to which DSM/SSE may reduce diesel generation has been estimated for the
3 2011 Resource Plan on a reasonably conservative basis under each load scenario, pending completion of
4 the current detailed conservation potential review study. The DSM/SSE option as defined is concluded to
5 be affordable (low cost), reasonably flexible, reasonably reliable and to be environmentally responsible.
6 Specific costs for these programs will be developed over the coming year, at which time projected
7 impacts will also be refined. DSM/SSE as shown in Table E1-1 is assumed to be adopted and in place
8 when assessing all other near-term resource options under each load scenario.

9 Figure E1-1 shows the extent to which forecast diesel energy generation is expected to be reduced as a
10 result of the assumed DSM/SSE, using the Scenario B load forecast (after 2021, load growth is the same
11 as under the Base Case or Scenario A).

12 **Figure E1-1: Scenario B with DSM/SSE: 2011-2030 (GWh/year)**



	2011	2015	2020	2025	2030
Load/Hydro Supply Gap (GWh/yr)					
(Forecast Diesel Generation)					
No DSM/SSE	2	158	163	40	83
With DSM/SSE*	2	143	121	2	8

*Assumes DSM/SSE impacts, starting in 2013, equal to 67% of annual non-industrial load growth pre DSM/SSE.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 The required near-term forecast diesel energy generation varies greatly depending on the selected load
2 forecast scenario, e.g., **grid diesel energy generation displacement opportunities forecast for**
3 **2015-17 under average water year conditions with DSM/SSE range as follows:**

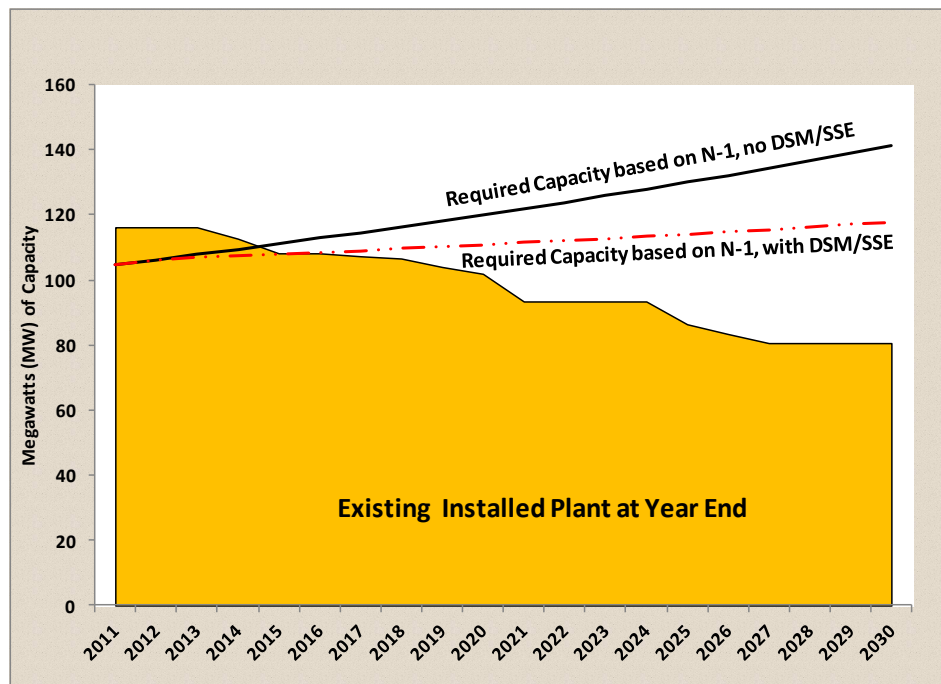
- 4 • Base Case load (non-industrial load and currently connected mines) 13-15 GW.h/year
- 5 • Scenario A (Base Case plus Victoria Gold) 82-85 GW.h/year
- 6 • Scenario B (Base Case plus Victoria Gold, Carmacks Copper, WHCT) 139-143 GW.h/year

7 Figure E1-2 shows projected the N-1 grid capacity planning MW surplus (shortfall) for 2011-2030 without
8 and with the assumed DSM/SSE. As reviewed in Appendix D, this assessment is based only on forecast
9 non-industrial loads on the integrated grid. Under the LOLE capacity planning criteria in the 2006
10 Resource Plan (see Appendix D), additional grid capacity would be required in the near-term under the
11 Base Case, Scenario A and Scenario B in response to mine loads in excess of about 7 MW (see Appendix
12 C, Attachment C2, Table C2-2) from late 2013 until approximately 2020 in 2015; for example, in 2015 the
13 capacity shortfall is increased above the non-industrial load N-1 capacity shortfall by 3 MW under the
14 Base Case, 16 MW under Scenario A and 24 MW under Scenario B.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

**Figure E1-2: Grid Capacity Capability and N-1 Capacity Requirements
with & without DSM/SSE – 2011-2030 (MW)**



	2011	2015	2020	2025	2030
N-1 Requirements (MW)					
without DSM/SSE	11.6	-2.8	-18.0	-43.5	-60.4
with DSM/SSE	11.6	0.4	-8.8	-27.6	-37.1

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **ATTACHMENT E2 - DIESEL**

2 Attachment E2 provides background and assessment of diesel generation as an option to meet future
3 near-term needs of the Yukon integrated grid as well as off grid loads.

4 **BACKGROUND: DIESEL AS YUKON SUPPLY DEFAULT OPTION**

5 Although hydro generation is by far the dominant source of utility-supplied electricity in Yukon, diesel
6 generation facilities account for 57% (44.2 MW) of the reliable capacity to serve the WAF/MD grid winter
7 peak and all of the 8.4 MW of generation capacity (representing about 5% of total Yukon utility electricity
8 generation) to serve five separate "off grid" diesel-served communities as well as any generation
9 currently used to supply "off grid" industrial mine projects.

10 Resource planning options typically focus on the grid rather than off grid communities, reflecting the
11 perceived limitations in displacing diesel generation when it is located off the grid. However, through grid
12 extensions during the past decade Yukon Energy has displaced diesel generation from Dawson City,
13 Stewart Crossing and Pelly Crossing.

14 On the WAF grid, diesel generation has fluctuated widely from 1967 to 2010 as the Faro mine load
15 changed and/or new hydro generation was developed. The history of hydro generation development on
16 the WAF and MD grids demonstrates past initiatives to displace diesel generation when the opportunity
17 arose, and the related impacts and risks when mines were shut down (see Appendix A).

18 From a planning perspective, existing and potential new diesel generation plant is used on the grid as the
19 "last resort" supply to meet grid generation energy requirements after all available renewable energy
20 generation has been fully utilized.

21 Potential future diesel capacity and generation requirements on the integrated grid are reviewed in
22 Appendix D assuming that diesel generation today is still the default supply option in Yukon, i.e., the
23 option first selected when current and committed renewable generation infrastructure is not adequate to
24 meet load requirements. These future diesel generation requirements provide the opportunity to develop
25 alternative electricity generation resources to displace the costs and emissions associated with such diesel
26 generation.

- 27 • **Diesel Role re: Reliable Grid Capacity:** Current YEC diesel plant retirement plans and
28 forecast non-industrial load growth together indicate, absent any new infrastructure beyond that
29 currently committed, grid capacity shortfalls emerging in 2013, and expanding (before consider
30 DSM/SSE) to 18 MW by 2020 and 60 MW by 2030. Under the LOLE criterion in the 2006
31 Resource Plan, additional grid capacity is required related to winter peak mine loads in excess of

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 about 7 MW. As reviewed in Appendix D, maintaining the required quantity of installed reliable
2 capacity is essential to minimize the risk of service disruptions in very cold weather (through
3 unplanned outages or other factors), as well as to supply energy during drought or low water
4 conditions, peak winter periods or (in some instances) during planned system outages. To date,
5 due to low capital cost and ready availability of diesel fuel, diesel generation facilities have been
6 the default option to meet these various capacity-related needs in Yukon.

7 • **Diesel Role re: Reliable Grid Energy:** Although the current diesel infrastructure on the grids
8 is utilized today primarily as reserve capacity to meet peak or short-term emergency needs, these
9 facilities remain available as well to provide base load energy as required, i.e., at 90% utilization
10 over a year, the existing 44.2 MW of grid diesel capacity could potentially provide almost 350
11 GW.h per year of electricity or almost as much as the total 2010 utility generation in Yukon (386
12 GW.h).

13 The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is
14 isolated from other grids outside the territory, means that other non-hydro backup capacity is required to
15 supplement available Hydro in circumstances of low water or drought. With the diminished surplus hydro
16 generation available today, continued reliance on the existing grid system to deal with load growth will
17 mean an increasing need to rely on more costly diesel generation to meet energy loads over the near-
18 term and over the longer-term - particularly to meet winter/spring seasonal generation requirements, and
19 to provide reliable energy generation in drought years.

20 As reviewed in Appendix D (Table D-1 and related text), assessments of diesel displacement
21 opportunities need to fully consider different seasonal and annual water flow conditions that forecast
22 diesel generation has the flexibility to accommodate:

23 • **No material diesel displacement opportunity in summer/fall seasons** - Under even a
24 610 GW.h/year "high" load scenario that approximates Scenario B in 2015, over 95% of the
25 average diesel displacement opportunities still occur in the seven month period from November
26 to May and over 75% in the five months from January to May. The isolated nature of the Yukon
27 grid prevents any "export" sale of surplus summer/fall renewable generation.

28 • **Wide annual variability in water conditions affect diesel displacement opportunities** -
29 "Annual average" diesel energy generation estimates reflect averages of widely varying annual
30 water flow conditions. With loads at a 545 GW.h "medium" load scenario for 2015 (approximates
31 current grid loads with one new mine connected of the size of Victoria Gold), "annual average"
32 diesel generation is approximately 101 GW.h/year. This "average", however, includes diesel
33 generation ranging from 13.5 GW.h/year under extreme high water conditions to 199.3 GW.h

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 under extreme low water conditions. This annual hydro generation variability needs to be fully
2 considered when assessing the diesel displacement impact that any new renewable resource is
3 expected to achieve. The isolated nature of the Yukon grid prevents any “export” sale of surplus
4 renewable generation during high water years.

5 • **Load level impacts on diesel displacement opportunities** – Diesel generation requirements
6 on the Yukon grid vary considerably depending on the assumed grid load level. Three loads
7 reviewed in Table D-1, Appendix D, reflect 2015 grid load scenarios ranging from “low” to “high”,
8 with resulting “average” diesel generation requirements in 2015 varying from 25 GW.h
9 (approximates Base Case load forecast) to 160 GW.h (approximates Scenario B load forecast).

10 Thermal generation has often been viewed as a good mix to have with hydro generation to provide
11 reliable and cost effective peaking and/or periodic supply during low water conditions. In addition to
12 seasonal supply constraints, systems predominantly based on hydro generation resources such as the
13 Yukon grid are vulnerable to drought (low water) conditions, and in these circumstances hydro
14 generation must be supplemented by other reliable forms of generation.

15 • Notably, the requirement for thermal resources to back up hydro resources exists even in
16 interconnected systems such as Manitoba (which continues to include a small amount of thermal
17 generating resources in its power resource plan) and British Columbia (e.g., the Burrard
18 generating station).

19 • Conversely, hydro-based systems such as the Yukon grid must also anticipate flood (high water)
20 conditions, and in these circumstances the need to rely on other reliable forms of generation will
21 be greatly diminished and/or eliminated (a factor that may undermine the cost effectiveness of
22 capital-intensive renewable resource options developed to displace diesel generation).

23 Notwithstanding the reliability of the extensive diesel generation on the grid, Yukon Energy has also been
24 examining additional reliability concerns regarding the grid in response to the current lack of spinning
25 reserve and reliance on load shedding to address loss of generation at any time and avoid network
26 outage. It is neither economical nor practical today to run sufficient spinning reserve on the grid to cover
27 the loss of the largest unit. YEC typically runs 5 MW of spinning reserve, which is the size of the largest
28 diesel generator connected to the grid. The loss of a large unit is infrequent; however, the ability to
29 quickly dispatch and synchronize a back-up unit is critical. Presently, on loss of generation, it can take up
30 to 15 minutes to start up a diesel generator(s) and have it carry full-load.

31 Yukon Energy retained BBA to identify appropriate short-term energy storage technologies that can be
32 integrated to the interconnected grid, requesting a 5 MW, 10 MW and 20 MW optional amounts of
33 storage for 15 minutes (which corresponded respectively to the largest hydro unit (WH 4 at 20 MW) and

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

the duration required to provide replacement diesel generation)⁹. BBA looked at a wide range of potential options, including: conventional battery energy storage system; flow battery system; sodium-sulphur battery system; flywheel energy storage system; ride-through system – electro-magnetic flywheel; diesel rotary uninterruptible power supply; synchronous condensing peaking hydro and pumped storage units; compressed air energy storage; and hydrogen production and storage. The BBA report recommended that YEC pursue two energy storage options:

- The most techno-economic alternative identified by BBA was to convert existing non-base-loaded hydro units to synchronous condenser peaking units. When these generators are not being used in generate mode, they can be used as spinning reserve synchronous condensers (driven as a motor by power from the grid, without water running through it) and, when required, can transition to generate mode in a few seconds (water is let into the turbine to provide power to spin the generator and power is then provided to the grid). An additional benefit of this option is that when the generators are operated in synchronous condenser mode, voltage/VAR support can be provided to the network. Depending on the units selected for conversion and the season, BBA estimated that most of the 20 MW spinning reserve requirement could be met (e.g., two units at Whitehorse could potentially be used during winter, one unit at Aishihik could potentially be used during summer, and one unit at Mayo A could potentially be used year round). Costs and more detailed assessment of options will be examined by Yukon Energy – these options are estimated to be less costly than other alternatives, but (unlike the other option recommended) they do not instantaneously provide back-up power.
- The other alternative recommended by BBA to meet the short-term energy storage requirement was diesel rotary uninterruptible power supply (DRUPS) units. These units are a combination of diesel generator, an induction coupling, and a synchronous machine, and are available in 2.5 MW units at a cost of about \$2 million per MW. In addition to being able to instantaneously provide back-up power, voltage/VAR support to the network is always available. Preliminary engineering was recommended for implementation of a pilot plant near the Whitehorse diesel plant.

Yukon Energy will be examining these options over the balance of 2011.

Diesel generation's established position in Yukon testifies to its current supply default role. A key question is the extent to which this role is challenged today by other available thermal generation options.

⁹ See presentation and expert background paper by Bruce Ledger/BBA at Energy Charrette on "Energy Storage and Yukon to BC Transmission Inter-tie". See Appendix E5, Attachment E5-1 to this 2011 Resource Plan for summary of BBA review of energy storage requirements and options related to integration of a wind farm on the YEC grid.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **OPTION ASSESSMENT**

2 **Overview of Key Features**

3 In general, diesel units have been well-suited in Yukon to meeting reserve capacity requirements and
4 short-term capacity needs during system peaks (where low capital costs are important). Diesel generation
5 has also been well suited to isolated regions where loads are small (such as the Yukon isolated
6 communities not connected to the grid), to sites away from the grid where loads do not have very long
7 lives (such as temporary applications or short lived mines) or to isolated sites where the heat from the
8 operation of the diesels is of economic value (such as in certain industrial operations). Since diesel units
9 can be turned off when they are not needed (and because of the relatively low capital costs), diesel units
10 also can provide a relatively lower risk source of electricity supply if loads are uncertain (as load
11 decreases can be met with operating cost decreases from putting the unit on standby).

12 Diesel generating units offer well established and reliable technology with the following key features
13 relevant to Yukon use:

- 14 • Relatively easy access to reliable fuel supplies as required from competitive world markets (i.e.,
15 no seasonality or other resource-based limitation on generation capability).
- 16 • Relatively low capital costs (approximately \$1.5 million per MW), with plant location near load
17 centres (minimizes transmission requirements).
- 18 • Units that can be permitted, purchased and installed within reasonably short time periods (i.e.,
19 usually well under 2 years) and be reliably operated over an economic life of 20 to 25 years.
- 20 • Relatively high operating costs, e.g., 2009 approved forecast fuel and operating cost average
21 26.4 c/kW.h for YEC and YECL, excluding Old Crow [where the approved forecast fuel and
22 operating cost was 57.3 c/kW.h]; diesel fuel costs constituted all but 3 c/kW.h of these approved
23 forecasts, and are subject to ongoing inflation and market price uncertainty.
- 24 • Environmental impacts related to air emissions (e.g., GHG emissions at approximately 700 tonnes
25 per GW.h, and regulated health-related emission effects¹⁰ re: NOx, SO2 and particulates), noise,
26 and potential fuel spills effects (including storage tank leaks).

27 Diesel unit variations are available for intermittent peaking versus steady base load generation, as well as
28 for other variations (e.g., energy storage benefit options, wind-diesel hybrids, other hybrid variations to
29 facilitate use of other fuels).

¹⁰ Existing diesel units for YEC require a Permit pursuant to Section 12 of the Air Emissions Regulations under the Environment Act and YEC is subject to all applicable requirements and prohibitions under the Environment Act and Air Emissions Regulations; renewal of a Permit for a three year terms requires a YESAA assessment.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

Diesel is a high cost option for utility “base load” operations that are required to provide sustained energy on a regular basis throughout the year (as would be the case if YEC defaults to existing diesel generation units to meet near-term loads not supplied by hydro generation).

- Energy conversion ratios approximate 35% to 37% for reasonably efficient units. Although the most efficient units now in service on WAF have fuel requirements at 3.9 kW.h/litre, new base load diesel unit efficiency would likely approximate 4 kW.h/litre (i.e., at fuel cost of \$0.96 per litre at Whitehorse [as approved for 2009 GRA], fuel cost alone would equal 24 cents per kW.h and non-fuel O&M would likely add a further 2 cents per kW.h plus about \$2.5 per kW as fixed O&M expenses).

- o Using existing diesel facilities (which would be a likely situation until these units must be retired) would involve lower efficiencies and higher incremental operating costs.

- o Approved 2009 average incremental diesel generation costs for the Hydro zone based on use of existing units approximated 30 cents per kW.h, of which fuel constituted 27 cents based on forecast diesel fuel prices ranging from 97.5 c/litre at Dawson to 99.2 c/litre at Faro and average efficiencies ranging from 3.55 to 3.71 kW.h/litre.

- Diesel fuel prices are subject to ongoing inflation and market price uncertainty:

- o Diesel fuel prices increased dramatically between the 1996/97 GRA and the recent 2008/2009 GRA, e.g., YEC's approved average GRA fuel price for the Whitehorse-Aishihik-Faro grid was 29.78 c/litre for 1997 and 99.2 c/litre for 2009. Similarly, YECL's approved GRA fuel price for Watson Lake in 2009 was approximately 3 times the price approved for 1997.

- o Future diesel fuel prices are likely to remain closely tied to future oil prices, given the premium use requirements for this liquid (portable and storable) fuel in transportation and other uses.

- o Considerable uncertainty remains as to how future oil prices will change within any specific time period (e.g., next 10, 20 or 50 years) relative to general inflation. Based on the last approved diesel fuel prices in 2009, after the 2008 price peaks but before the full impact of price declines in 2009, longer-term oil price increases might well be expected to exceed inflation rather than to fall below inflation - however, experience over the period since the 1970s demonstrates the material uncertainties applicable to long-term oil price forecasts.

- o Review of April and October 2011 oil price futures indicates that oil prices are expected to decline from current levels over the period to at least 2019, such that escalation of

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 YEC's approved 2009 diesel fuel prices at a 2%/year inflation rate as is assumed in the
2 2011 Resource Plan results in future diesel prices that are above the current NYMEX
3 futures¹¹.

4 Diesel is a low cost option to supply grid capacity needed for reserves or occasional use, i.e., simply to
5 replace diesel unit capacity upon retirement of existing units or as otherwise required solely to address
6 grid capacity shortfalls. As reviewed in the 2006 Resource Plan, when assessing options simply to address
7 diesel units at end of useful life there are various sub-options that may be considered, e.g., life extension
8 as was pursued in the 2006 Resource Plan for the Mirrlees units on the basis that this was expected to be
9 the least cost option for this specific set of units. As reviewed in Appendix D, experience to date with life
10 extension of two Mirrlees units has indicated various issues that have led YEC to re-examine the options
11 for the two remaining Mirrlees units that would otherwise be retired by 2013.

12 **Projected Costs and Other Impacts**

13 In assessing near-term options for the 2011 Resource Plan, existing diesel units are considered as the
14 default option to supply incremental baseload grid energy over the next decade. Impacts on costs and
15 GHG emissions will be driven primarily by the extent of diesel energy generation required under the load
16 scenarios examined rather than by new diesel generation facility requirements to meet grid capacity
17 shortfalls.

18 Assuming fuel and other O&M costs of 30 cents/kW.h (2010\$) for existing diesel units and that these
19 costs escalate at general inflation, the diesel option non-capital Forecast LCOE for all near-term load
20 scenarios approximates 30 cents per kW.h (and is essentially the same as the Full Utilization LCOE
21 excluding capital costs). For more efficient new diesel units, fuel and other O&M costs are assumed to
22 approximate 26 cents/kW.h (2010\$).

23 Figure E2-1 shows the assumed diesel cost (cents per kW.h) for fuel and O&M by year over the planning
24 period, highlighting how the Forecast LCOE cost at 30 cents for existing units (and approximately 26
25 cents for more efficient new units) is in effect the first year cost for this option, with escalation assumed

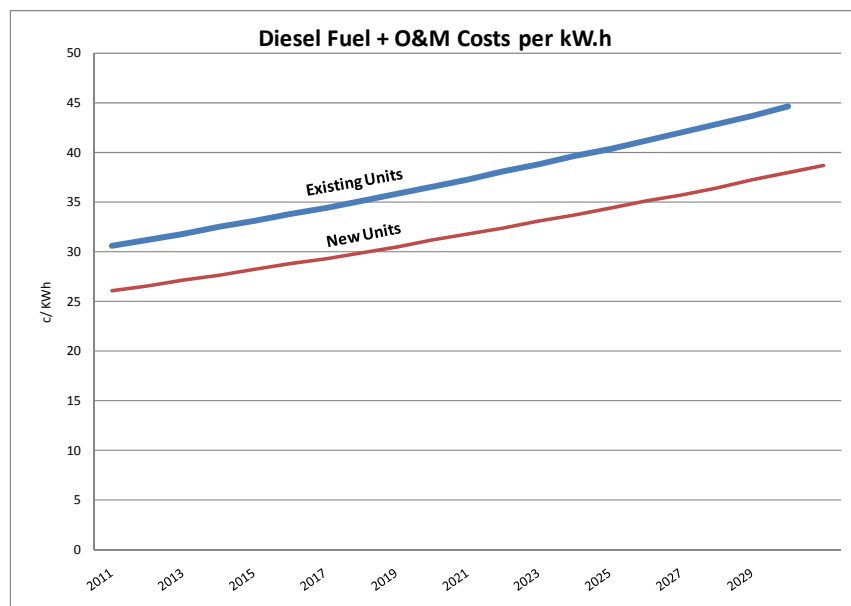
¹¹ NYMEX futures (light sweet crude) as at April 8, 2011 showed a decline from the then current price (\$112.79 per bbl \$US) to \$106.46/bbl as at January 2014 and \$105.18/bbl as of December 2019. Based on the then current value of the Canadian dollar (1.0454 \$US/\$CAN), and allowance for processing and transport (about 40c/litre in 2011\$), the equivalent diesel price forecast in Yukon for YEC would equal \$1.06/l as at April 2011, \$1.10/l as at January 2014 and \$1.10/l as at December 2019. In contrast, escalating a current diesel price [2010\$, based on YEC's 2009 GRA approved prices at Whitehorse] of 96c/litre by 2% per year would result in a 2019 price of 114.7 c/litre. As of October 14, 2011, NYMEX futures (light sweet crude) showed a price of \$88.01 per bbl \$US for 2012 and \$92.55 per bbl \$US for December 2018. Based on the then current value of the Canadian dollar (0.9855 \$US/\$CAN), and the same allowance for processing and transport (\$40c/litre in 2011\$), the equivalent diesel price forecast in Whitehorse, Yukon for YEC would equal \$0.97 per litre in 2012, \$1.01 per litre in 2015, and \$1.05 per litre in 2018. Assuming 2% inflation per year, the equivalent 2010\$ fuel price would be \$0.92/litre for this NYMEX-based 2015 fuel price and \$0.90 per litre for the 2018 NYMEX-base price.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 each year thereafter. As noted, these future costs are subject to considerable uncertainty – April 2011
2 and NYMEX futures-based fuel prices, for example, would be about 10% higher at the outset and 10%
3 lower by 2019 than the fuel prices assumed in the 2011 Resource Plan analysis. For cost assessment in
4 the 2011 Resource Plan, a 50/50 blended cost of 28 cents (existing and new units) is assumed for grid
5 diesel fuel and O&M costs.

6 **Figure E2-1: Diesel Option Cost for Fuel and O&M (cents per kW.h): 2011-2030**



7
8 The existing diesel capacity on the grid (as adjusted from year-to-year by capacity adjustments needed
9 to meet N-1 capacity planning requirements, and with off-peak diesel generation as appropriate under
10 low water conditions [or with LOLE-related added capacity requirements based on mine loads in excess of
11 approximately 13 MW]) can provide reliable energy as needed to meet near-term forecast requirements.
12 Accordingly, capital costs for new diesel capacity required during the near-term planning period are
13 assessed based on capacity shortfalls estimated under the N-1 capacity planning criteria (i.e., based only
14 on non-industrial load requirements) or under LOLE criterion assuming that industrial peak winter loads in
15 excess of 13 MW add directly to the capacity shortfalls otherwise estimated under the N-1 capacity
16 planning criterion.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 Capacity-related near-term requirements under the diesel option are as follows (present values at YEC's
2 2009 approved blended cost of capital of 6.56%/year).
- 3 • After assumed DSM/SSE as reviewed in Attachment E2, the present value (\$2010) of supplying
4 the N-1 capacity shortfall for the entire planning period (to 2030) with new diesel capacity at a
5 cost (\$2010) of \$1.5 million per MW is:
 - 6 o \$31.9 million for capital costs¹²; and
 - 7 o \$31.8 million for related annual costs over the planning period¹³.
 - 8 • The present value (\$2010) of the total capacity capital costs with the LOLE-related added
9 capacity requirements (based on mine loads in excess of 13 MW) is \$2.8 million higher than N-1
10 capacity cost under Scenario A and \$6.6 million higher under Scenario B considering that this
11 added capacity requirements would be available after 2020 to defer new capacity requirements
12 for non-industrial loads under the N-1 criterion (yielding savings in capital costs otherwise
13 forecast based on the N-1 capacity shortfall).
 - 14 • These capacity related cost requirements are in addition to the incremental fuel and O&M energy
15 costs noted earlier. However it is not useful to show these capital costs to address capacity
16 shortfalls on a cost per kW.h basis (including an LCOE per kW.h basis) as these costs are tied to
17 capacity requirements (regardless as to any specific potential generation from such units) rather
18 than to forecast diesel energy generation. By way of example, an estimated Forecast LCOE
19 (2010\$) for the related annual costs over the planning period under the N-1 criterion would
20 approximate 17 cents/kW.h of Base Case forecast diesel generation with DSM/SSE¹⁴; this LCOE
21 would fall to the 3 to 4 cents per kW.h range, however, if the same costs are assessed per kW.h
22 with the higher diesel generation with DSM/SSE under Scenario A or Scenario B load forecasts
23 (this assessment ignores added capital costs that may be required under the LOLE criteria as a
24 result of the increased industrial load under Scenarios A and B relative to the Base Case).
- 25 Table E2-1 summarizes the default diesel generation, costs and GHG impacts for the near-term load
26 scenarios during 2015-17.

¹² With DSM/SSE, this present value cost is similar to the present value cost of \$33.8 million for simply replacing YEC's diesel units at each assumed retirement date. Without DSM/SSE, this present value capital cost is \$52.8 million. For simplicity, these cost estimates assume each annual shortfall is met each year by added new diesel capacity (in practice, additions would likely be lumpier and more sporadic or spread out).

¹³ Related annual costs assume capital costs escalate at 2%/year, with depreciation assuming 25 year life, and return on mid-year rate base at 6.56%/year. Under this assessment, residual undepreciated costs at the end of the planning period are excluded.

¹⁴ Forecast LCOE annual capital costs are lower (at 8 cents/kW.h) with Base Case diesel generation and no DSM/SSE (reflects much higher diesel generation).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

Table E2-1: Summary of Default Diesel for Near-term Load Scenarios - 2015-17

	Base Case	Scenario A	Scenario B
Average Grid Diesel Requirement -2015-17	(average GW.h/yr - average water year conditions)		
with DSM/SSE	14	84	142
no DSM/SSE	26	103	162
Diesel Operating Costs (fuel & O&M)-2015-17	(2010\$ million/yr at 28 c/kW.h)		
with DSM/SSE	3.9	23.5	39.8
no DSM/SSE	7.3	28.8	45.4
Greenhouse Gas Emissions (GHG) in 2015-17	(tonnes/yr at 700 tonnes per GW.h)		
with DSM/SSE	9,800	58,800	99,400
no DSM/SSE	18,200	72,100	113,400
Capacity Capital Costs by 2017	(2010\$ million at \$1.5 million/MW)		
with DSM/SSE	2.8	17.7	30.7
no DSM/SSE	12.2	26.9	39.9
Extreme Grid Diesel Requirement -2015	(GW.h/yr - extreme low water year)		
no DSM/SSE	120	199	264

Assuming that grid capacity shortfalls are addressed, diesel capacity under each near-term load scenario will continue to far exceed any near-term requirements for diesel energy generation (including such requirements as reviewed in Appendix D, Table D-2 before any DSM/SSE impacts)¹⁵.

SUMMARY

In summary, for overall cost comparison of diesel with other generation options the 2011 Resource Plan focuses on an LCOE analysis as regards diesel fuel and O&M costs per kW.h and a present value analysis of capital costs for diesel capacity requirements. An overall present value assessment of total costs (2011-2030) under the three near-term load scenarios (with and without assumed DSM/SSE) is provided in Table E2-2 - to simplify the analysis, a 50/50 blend of existing and new diesel units is assumed when assessing fuel and O&M costs.

¹⁵ Diesel grid capacity in 2015 is forecast at about 41.9 MW under the N-1 capacity planning criterion [before any DSM/SSE impacts and assuming added required capacity would be diesel]; at 90% annual capacity factor, 41.9 MW could supply 330 GW.h per year. After assumed DSM/SSE, diesel grid capacity in 2015 is forecast at about 39 MW under the N-1 capacity planning criteria which could supply 307 GW.h at 90% annual capacity factor. These assessments focus on reliable energy supply – in the event of an extreme low water year, diesel capacity under the N-1 criterion could be inadequate under Scenario A or Scenario B unless units are run during off peak periods as required to store water to meet peak period energy requirements. Ignoring such off-peak use of diesel generation, diesel capacity needed during peak usage weeks under an extreme low water year [assuming no DSM/SSE] in 2015 could approximate 55 MW under Scenario A and 64 MW under Scenario B; however, including LOLE-related added capacity requirements (based on mine loads in excess of 13 MW), diesel capacity in 2015 [no DSM/SSE] would approximate 51.9 MW under Scenario A and 59.9 MW under Scenario B, i.e., added new capacity under LOLE would decrease the risk related to capacity shortfall in an extreme low water years.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **Table E2-2: Diesel Option Present Value Costs (2010\$million); 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost ⁴	Total PV Costs
No DSM/SSE				
Base Case	111.8	52.8		164.6
Scenario A	227.6	55.9		283.5
Scenario B	304.6	59.1		363.7
With DSM/SSE				
Base Case	30.8	31.9	35.4	98.1
Scenario A	133.9	34.7	35.4	204.0
Scenario B	207.3	38.4	35.4	281.2

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Diesel fuel O&M - assumes 50/50 blend of existing and new units.
3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement.
4. DSM/SSE average annual costs assumed at 7.5 cents/kW.h.

- 2 Diesel requirements and costs in off grid communities are projected based on 2009 approved diesel fuel
- 3 costs per kW.h and load growth as reviewed in Appendix C.

1 **ATTACHMENT E3 – HYDRO ENHANCEMENTS**

2 Attachment E3 provides background and assessment of near-term hydro enhancements as an option to
3 meet future needs of the Yukon integrated grid.

4 **BACKGROUND**

5 As reviewed in Appendix F, Attachment F-1, Yukon Energy has carried out ongoing hydro site capability
6 reviews since the 2006 Resource Plan, including assessments that lead to selection of near-term
7 enhancement priorities (Mayo B plus the near-term enhancement projects described below) and an
8 overview assessment of longer-term greenfield site options. Ongoing monitoring is also being carried out
9 of hydro developments being pursued and/or examined in neighbouring areas that might potentially be
10 relevant to Yukon (e.g., Atlin, BC and Skagway, Alaska¹⁶).

11 As reviewed in Table E-1, near-term hydro enhancement options are characterized at a high level today
12 to be reliable as to providing winter energy but facing high regulatory risks (very uncertain today re:
13 ultimate approvals for each project), affordable (low cost), reasonably flexible (i.e., enhancements to
14 winter storage or flows which are specially valued on this grid, small projects, long-term value for system,
15 let alone the timing for such approvals), and environmentally responsible (renewable energy option with
16 low GHG emissions).

17 Specific hydro enhancements to provide added winter flows at the existing Yukon Energy WAF hydro
18 facilities have been under active study by Yukon Energy since 2008. Each potential project requires
19 material further work, and resolution of specific key issues, before it would be submitted for regulatory
20 review. If developed, each project was initially expected to be relatively low cost (Full Utilization LCOE
21 less than 10 c/kW.h for each project, prior to assessment assuming DSM/SSE and specific load
22 scenarios). Summary updates of current status for each of these projects are as follows¹⁷:

- 23 **1. Marsh Lake Storage** – Concept to increase storage level (FSL) in Marsh Lake by 0.3m at a cost
24 of about \$10.5 million (including over \$4 million of potential mitigation) to enhance Whitehorse
25 plant winter net generation (displace diesel generation) and provide added peak winter capacity
26 (1.6 MW estimate in 2006 Resource Plan has not been updated); initial assessment (without
27 considering DSM/SSE) is that the project will on average displace about 6.4 GW.h/year of diesel

¹⁶ At Atlin, the Taku Land Corporation has recently developed a small hydro project to supply power to BC Hydro at Atlin to displace reliance on local diesel generation. At Skagway, interest has been expressed in developing local hydro resource capability to displace diesel generation by cruise ships that dock in Skagway from May through September each year.

¹⁷ Each project's assumed economic life is 65 years; annual O&M in year 1 is assumed at .005 of estimated capital cost.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 generation at Scenario B 2015 loads. Full Utilization LCOE currently estimated at 8.5 cents/kW.h.
2 Earliest in-service assumed for 2015 (YESAA submission in 2012, one year construction);
3 however, timing remains subject to resolution of any specific concerns arising from the ongoing
4 studies and consultations.

5 **2. Gladstone Diversion** – Concept to increase winter generation at the Aishihik plant at a cost of
6 about \$40 million by diversion of water from headwaters of Gladstone Creek into Isaac Creek
7 that flows into Sekulmun/Aishihik Lakes; initial assessments (without considering DSM/SSE) that
8 will displace 32.7 GW.h of diesel generation at Scenario B 2015 load. Full Utilization LCOE
9 currently estimated at 5.7 cents/kW.h. Earliest possible in-service was 2017 (assumed
10 commitment in 2014 and two year construction). However, DFO now needs 2 more years of
11 pathogen studies and further material studies are to be delayed/deferred until Yukon Energy can
12 resolve suitable arrangements with the local First Nation. At this time it is assumed that
13 commitment is deferred beyond 2014 with earliest in-service delayed to 2018; there is a material
14 risk that this project will not proceed in the planning period.

15 These hydro enhancement options are each designed to provide energy benefits, i.e., to displace diesel
16 energy generation. Marsh Lake Storage will provide some added peak winter capacity benefits (e.g., 1.6
17 MW capacity benefit estimated in 2006 Resource Plan, which has not been updated). Gladstone
18 Diversion, however, cannot increase firm peak winter hydro capacity at this time (as the Aishihik plant
19 capacity is not utilized in the N-1 event). For simplicity, economic benefits for each hydro enhancement
20 project are assessed in the 2011 Resource Plan solely on the basis of displaced diesel fuel and O&M costs
21 for each forecast load scenario. Accordingly, forecast diesel capacity cost requirements as set out in Table
22 E2-2 are assumed not to be affected by these options.

23 In addition to the above hydro enhancement projects, YEC also continues to pursue amendments to the
24 current Fisheries Act Authorization (FAA) provisions for Aishihik generation facility¹⁸. YEC estimates that
25 that proposed FAA revisions would provide for an additional 9 GW.h of added annual energy on average
26 from the Aishihik plant, while also providing improved protection for lake whitefish recruitment in the
27 lake over and above the current FAA¹⁹ by restricting the winter water level drawdown. Current provisions
28 limit the regulated drawdown; however, YEC is working through the Aishihik Fish Monitoring Program

¹⁸ Current provisions of the Aishihik FAA require (1) that the minimum daily spring water elevation to be applied to Aishihik remain at or below above 913.0m ASL except as otherwise provided for in paragraph 7 below; and (2) that a ten-year rolling average of minimum daily spring water elevations (the "Ten Year Rolling Average") shall not be lower than 913.7 m ASL. For years 2003 to 2008, the Ten Year Rolling Average shall be modified to reflect only the years after 1999. In addition, the minimum daily spring elevation shall not be lower than 913.7 m ASL more than two years for the period 2003-2007.

¹⁹ The current FAA does not contain any provision for limiting winter drawdown.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

(comprised of representatives from DFO, YG Fisheries, CAFN and YEC under the terms of the existing FAA) to pursue the following revisions to the current FAA:

- Minimum daily spring water elevation of Aishihik Lake remain at or above 913.0 m ASL (Low supply level), except as otherwise provided below.
- Minimum daily spring water elevation of Aishihik Lake remain at or above the Temporary Restriction Level of 913.3 m ASL at least 3 years out of 5 until such time as the AMPT recommends otherwise. A 5-year tracking period will commence with the first occurrence of a winter/spring water level below 913.3 m. Therefore, winter/spring levels shall remain at or above 913.3 m for at least 3 of the subsequent 4 years.
- Winter drawdown through any one whitefish spawning cycle, October/November spawning period to the April/May spring egg hatch, will not exceed 1.2 m.

Yukon Energy also is proceeding to finalize re-submission this summer of the Mayo Lake Storage Enhancement Project for one metre of added licenced drawdown capability at Mayo Lake to provide an average long-term 4 GW.h/year of added hydro generation at Mayo B. This project, which requires an amendment to YEC's Mayo water licence but no new infrastructure, is included in the 2011 Resource Plan as "currently committed" hydro generation capability on the grid; however, regulatory review and approvals for this enhancement have yet to be secured.

OPTION ASSESSMENT

Yukon Energy will continue to pursue regulatory approvals for the Mayo Lake Storage Enhancement Project and the proposed revisions to the Aishihik FAA as each would clearly provide reliable enhanced benefits to ratepayers at minimal incremental costs.

Focusing on the specific new hydro enhancement projects under examination in recent years (Marsh Lake Storage and Gladstone Diversion), regulatory approval risks and uncertainties are apparent. Yukon Energy today cannot rely on any specific in-service targets for any of these projects. Accordingly, prior to proceeding with major additional costs on any specific project in this package, Yukon Energy will seek to address and resolve the regulatory risks and uncertainties specific to that project.

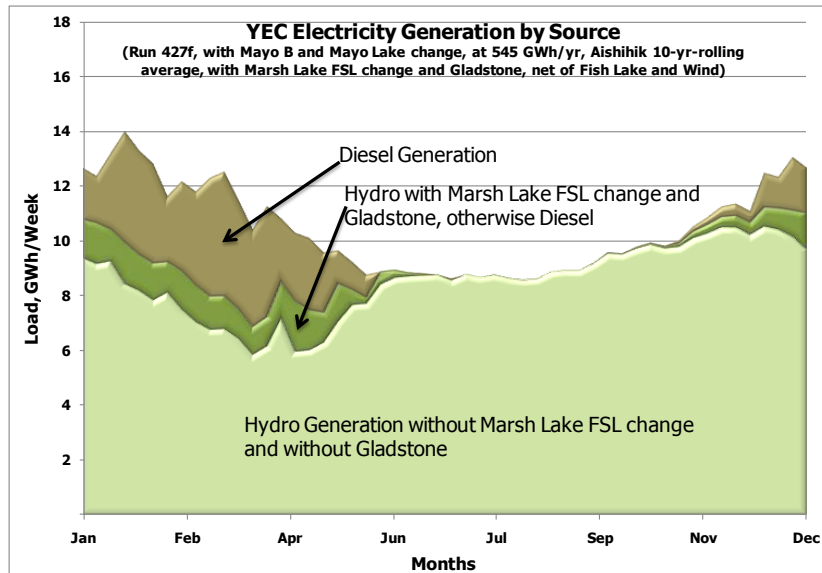
Potential LCOE adjustments and annual costs per kW.h are examined below for the Marsh Lake Storage and Gladstone Diversion projects under the various load scenarios to provide an indication as to near-term affordability impacts for these hydro enhancements if they are in fact approved for development. These two projects currently provide Full Utilization LCOE estimates at 8.5 and 5.7 cents per kW.h

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 respectively, and more information is also currently available on water model impacts for these projects
2 than for the Atlin Storage project.
- 3 Figure E3-1 and Figure E3-2 assess the combined Gladstone Diversion and Marsh Lake Storage project
4 impacts on weekly grid generation (and specifically on diesel displacement) under forecast grid loads
5 approximating Scenario A and Scenario B in 2015 (no DSM/SSE). As expected, diesel displacement is
6 focused in the winter months when the Marsh Lake Storage provides added energy at the Whitehorse
7 hydro plant and the Gladstone Diversion enables additional generation at the Aishihik hydro plant.

8 **Figure E3-1: Marsh Lake and Gladstone at 545 GW.h/year (approx. Scenario A at 2015)**

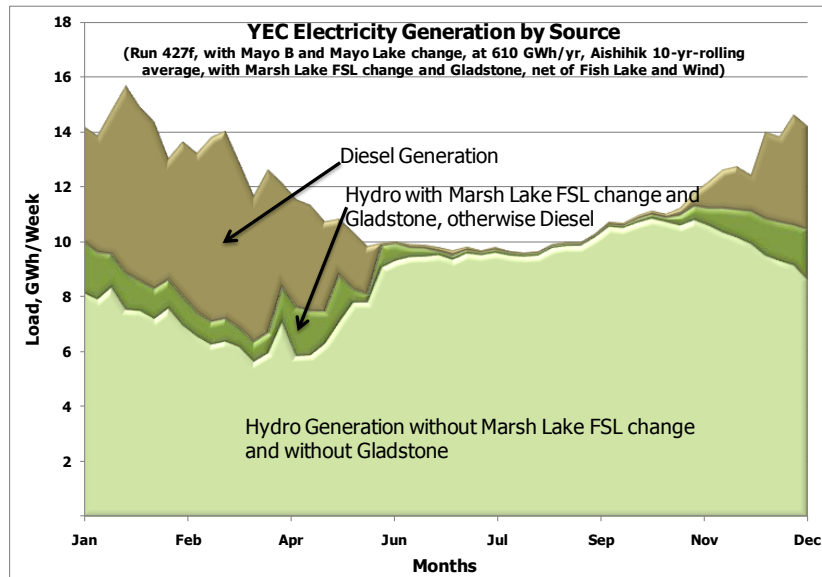


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Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **Figure E3-2: Marsh Lake and Gladstone at 610 GW.h/year (approx. Scenario B at 2015)**



2

3 Table E3-1 summarizes annual adjustments in grid generation (and specifically on diesel displacement)

4 for each project separately and the two projects combined under the same forecast grid loads

5 approximating Scenario A and Scenario B in 2015. This analysis highlights the extent to which the added

6 winter hydro is in fact used to displace diesel generation under each load scenario.

- 7
- 8 • Diesel displacement decreases as loads decrease, e.g., combining Gladstone and Marsh Lake (without DSM/SSE) is forecast on average to displace 38.6 GW.h at Scenario B 2015 loads, versus 33.6 GW.h at Scenario A 2015 loads; under lower load levels (i.e., when no industrial loads and assume DSM/SSE), this added hydro supply will likely yield no material diesel displacement in the period prior to 2030.
 - 12 • Combining the hydro enhancement projects will not necessarily lead to diesel displacement equal to the total of what is estimated for each separate project (although the changes noted in Table E3-1 are relatively minor).
- 13
- 14

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

**Table E3-1: Potential Impacts of Gladstone and Marsh Lake Hydro Enhancements
(assessed at approximate 2015 Scenario A [545 GW.h] and Scenario B [610 GW.h] loads)**

	No Gladstone, no Marsh Lake change	With Gladstone, no Marsh Lake change	Diff.	No Gladstone, with Marsh Lake change*	Diff.	With Gladstone, with Marsh Lake change	Diff.
Approx. Scenario A Load	Run 427b 545 GW.h	Run 427d 545 GW.h		Run 427e 545 GW.h		Run 427f 545 GW.h	
	A	B	C=B-A	D	E=D-A	F	G=F-A
Generation Station (GW.h)							
Whitehorse GS	250.2	245.2	-5.0	256.2	6.0	251.3	1.0
Aishihik GS	112.7	146.8	34.1	112.7	-0.1	146.5	33.8
Mayo A and B GS	80.9	79.8	-1.1	80.8	-0.1	79.7	-1.2
Diesel	101.1	73.1	-28.0	95.2	-5.9	67.5	-33.6
Diesel Displacing (GW.h)		28.0		5.9		33.6	
Approx. Scenario B Load	Run 427b 610.3 GW.h	Run 427d 610.3 GW.h		Run 427e 610.3 GW.h		Run 427f 610.3 GW.h	
	A	B	C=B-A	D	E=D-A	F	G=F-A
Generation Station (GW.h)							
Whitehorse GS	253.1	250.0	-3.0	259.2	6.1	256.1	3.1
Aishihik GS	114.8	151.5	36.6	114.8	0.0	151.2	36.3
Mayo A and B GS	82.2	81.3	-0.9	82.2	0.0	81.4	-0.8
Diesel	160.2	127.5	-32.7	154.1	-6.1	121.6	-38.6
Diesel Displacing (GW.h)		32.7		6.1		38.6	

Note

* Marsh Lake diesel displacing generation separately estimated at about 0.3 GW.h higher levels than shown in these runs.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

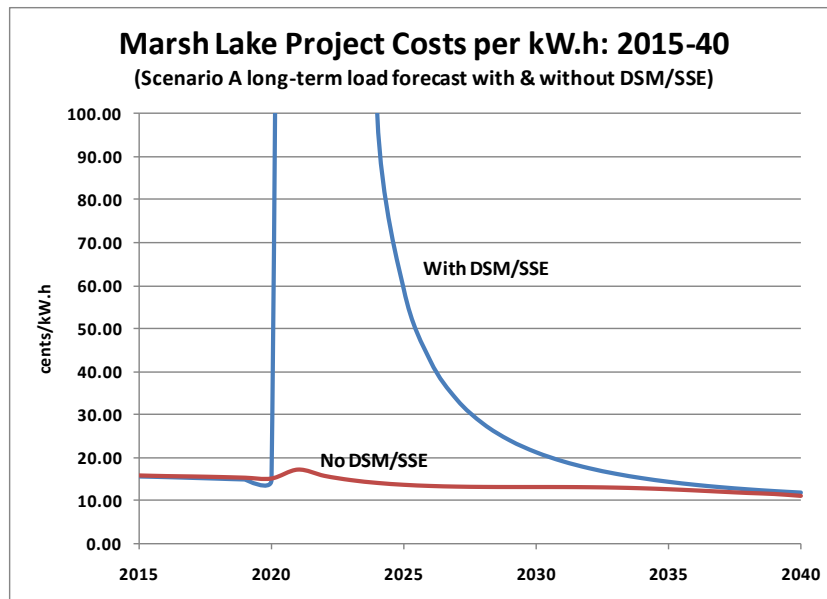
December 2011

1 Marsh Lake Storage is the smallest of the hydro enhancement projects and the one with the earliest
2 potential in-service date. Full Utilization LCOE is estimated at 8.5 cents per kW.h (2010\$). Forecast LCOE
3 (2010\$) for the Marsh Lake Storage project is estimated as follows for in-service by the start of 2015:

- 4 • Base Case 12.1 cents/kW.h with DSM/SSE (8.6 cents without DSM/SSE).
- 5 • Scenario A 11.4 cents/kW.h with DSM/SSE (8.6 cents without DSM/SSE).
- 6 • Scenario B 11.1 cents/kW.h with DSM/SSE (8.5 cents without DSM/SSE).

7 In summary, forecast LCOE varies only minimally for the Marsh Lake Storage Project as load forecast
8 change – the major factor affecting LCOE is the impact of assumed DSM/SSE (which at forecast loads has
9 a major impact on diesel displacement opportunities after 2020). Figure E3-3 shows the estimated costs
10 per kW.h of diesel displaced by Marsh Lake Storage by year from 2015 to 2040 with Scenario A loads
11 with and without DSM/SSE. Near-term costs per kW.h are shown to be well above lifetime Forecast LCOE
12 for a capital intensive hydro project with a 65 year life, i.e., costs per kWh in initial years approximate 16
13 cents per kW.h which is well above Forecast LCOE ranging from 8.6 to 11.1 cents per kW.h.

14 **Figure E3-3: Marsh Lake Costs per kW.h with & without DSM/SSE (Scenario A): 2015-2040**



15

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

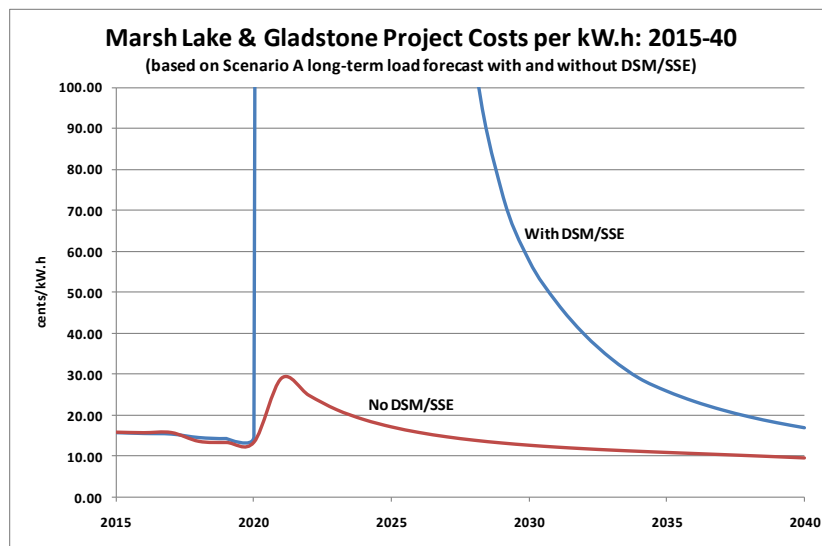
December 2011

1 Gladstone Diversion is the largest of the hydro enhancement projects, but it is no longer eligible for
2 commitment by 2014. If Gladstone Diversion was to be in-service by the start of 2018, in combination
3 with Marsh Lake Storage in-service by the start of 2015, Forecast LCOE (\$2010) is estimated as follows
4 for the different load scenarios:

- 5 • Base Case 15.2 cents/kW.h with DSM/SSE (7.5 cents without DSM/SSE).
- 6 • Scenario A 13.1 cents/kW.h with DSM/SSE (7.2 cents without DSM/SSE).
- 7 • Scenario B 12.8 cents/kW.h with DSM/SSE (7.1 cents without DSM/SSE).

8 In summary, with these two combined projects the overall Forecast LCOE continues to be affected
9 primarily by the impact of assumed DSM/SSE. Figure E3-4 shows the estimated costs per kW.h of diesel
10 displaced by the combined projects by year from 2015 to 2040 with Scenario A loads with and without
11 DSM/SSE – the results are broadly the same as Figure E3-3 with only Marsh Lake Storage, except for the
12 higher costs incurred for many years after 2020 even without DSM/SSE. To be cost effective over the
13 planning period, higher diesel displacement loads would be required beyond 2020 than those projected
14 under the current load scenarios.

15 **Figure E3-4: Marsh Lake & Gladstone Costs per kW.h with & without**
16 **DSM/SSE (Scenario A): 2015-2040**



17
18 Table E3-2 provides an overall present value of the estimated costs required over the 20-year planning
19 period (2011-2030) with the Marsh Lake Storage option (assumed in-service for all of 2015) for the
20 different load scenarios – diesel fuel and diesel added capacity are assumed to be retained for 2011-2014
21 (before the Marsh Lake Storage is established) and as required thereafter. Present value cost savings

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 relative to the diesel option range from \$1.6 to \$4.9 million with DSM/SSE and from \$9.6 to \$11.1 million
2 with no DSM/SSE.

3 **Table E3-2: Marsh Lake Storage Option Present Value Costs (2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁴
No DSM/SSE					
Base Case	102.2	52.8		155.0	-9.6
Scenario A	218.1	54.6		272.7	-10.8
Scenario B	294.7	57.8		352.6	-11.1
With DSM/SSE					
Base Case	29.2	31.9	35.4	96.5	-1.6
Scenario A	130.9	33.5	35.4	199.8	-4.3
Scenario B	203.7	37.2	35.4	276.3	-4.9

1. Costs discounted at 6.56% per year YEC blended cost of capital.

2. Marsh Lake costs. Assumes diesel fuel & O&M units for all diesel not displaced by Project.

3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.

4. See Diesel Portfolio Option Present Value Costs.

- 4 Table E3-3 provides an overall present value of the estimated costs required over the 20-year planning
5 period (2011-2030) with the Marsh Lake Storage option (assumed in-service for all of 2015) combined
6 with Gladstone Diversion option (assumed in-service for all of 2018) for each load scenario – diesel fuel
7 and diesel added capacity are assumed to be retained for 2011-2014 (before the Marsh Lake Storage is
8 established) and as required thereafter. Present value cost impacts relative to the diesel option under
9 Scenarios A show \$0.5 million with DSM/SSE and \$35.5 million cost saving with no DSM/SSE; under
10 Scenario B, \$2.7 million cost saving with DSM/SSE and \$37.4 million cost savings with no DSM/SSE;
11 under the Base Case load forecast, present value cost impacts range from a \$11.9 million cost increase
12 with DSM/SSE to a \$29.1 million cost saving with no DSM/SSE.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

**Table E3-3: Marsh Lake (2015) & Gladstone (2018)
Combined Options Present Value Costs (2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁴
No DSM/SSE					
Base Case	83.9	51.6		135.5	-29.1
Scenario A	193.4	54.6		248.0	-35.5
Scenario B	268.5	57.8		326.3	-37.4
With DSM/SSE					
Base Case	43.8	30.8	35.4	110.0	11.9
Scenario A	134.6	33.5	35.4	203.5	-0.5
Scenario B	205.8	37.2	35.4	278.4	-2.7

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.

2. Marsh Lake & Gladstone costs. Assumes diesel fuel & O&M units for all diesel not displaced by Project.

3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.

4. See Diesel Portfolio Option Present Value Costs.

SUMMARY

In summary, given the relatively low cost, focused enhancement of winter hydro generation, and relatively small scale of Marsh Lake Storage, this project continues under all of the load scenarios examined to be an attractive long-term enhancement if it can be licensed and developed. However, the Gladstone Diversion project may require added loads beyond what is currently forecast with DSM/SSE in order to be cost effective in the planning period.

The Marsh Lake project may have reasonable prospects to be committed before 2015. The Gladstone project, however, is no longer eligible to be committed before 2015 (i.e., the specified deadline for projects to be eligible as part of a plan to meet near-term requirements). The proposed FAA revisions at Aishihik will continue to be pursued with the regulatory authorities, but there is no clarity today as to the potential feasibility or timing for securing such changes given the current lack of support from the local First Nation.

In effect, the potential near-term development of any of these enhancements creates added risks for any other near-term resource option (which must address uncertainty as to timing/implementation of these enhancements, as well as the already stated load-related uncertainties and the impact of DSM/SSE). Ongoing expenditures for each of these potential projects are being constrained as required and prudent, pending resolution of key regulatory and local support issues that affect YEC's ability to proceed with each project.

1 **ATTACHMENT E4 – NON-DIESEL THERMAL OPTIONS (BIOMASS & LNG)**

2 Attachment E4 provides background and assessment of near-term non-diesel thermal options (biomass
3 [waste-to-energy and wood biomass] and LNG) to meet future needs of the Yukon integrated grid under
4 Scenarios A or B (these options would not be considered under only Base Case load forecasts). This
5 attachment has the following sections:

- 6 • Overview – Assessment of Non-Diesel Thermal Options;
- 7 • Wood Biomass;
- 8 • Waste to Energy; and
- 9 • LNG/Natural Gas.

10 **OVERVIEW – ASSESSMENT OF NON-DIESEL THERMAL OPTIONS**

11 Thermal generation is used in many hydro-based jurisdictions to provide reliable and cost effective
12 peaking and/or periodic supply during low water conditions. In addition to seasonal supply constraints,
13 systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to
14 drought (low water) conditions, and in these circumstances hydro generation must be supplemented by
15 other reliable forms of generation²⁰. Conversely, hydro-based systems such as the Yukon grid must also
16 anticipate flood (high water) conditions, and in these circumstances the need to rely on other reliable
17 forms of generation will be greatly diminished and/or eliminated (a factor that may, under some grid load
18 conditions, undermine the cost effectiveness of capital-intensive renewable resource options as well as
19 capital intensive thermal options developed to displace diesel generation).

20 Two very different non-diesel thermal options have been identified for further assessment as regards
21 near-term options:

- 22 • **Biomass** – Biomass thermal generation as discussed at the Energy Charrette, with current
23 established commercial technology, involves a high pressure steam thermal generating plant
24 using solid biomass (wood or municipal garbage) to provide the required heat energy. The
25 biomass options was characterized at the Energy Charrette as high cost (20 to >30 cents per
26 kW.h, with added costs uncertain at smaller scale plants relevant in Yukon in near-term), not
27 flexible (intended for year round operation to be efficient, high cost per useful kW.h when
28 minimal diesel to displace), reliable (baseload energy and capacity – however no development

²⁰ Notably, the requirement for thermal resources to back up hydro resources exists even in interconnected systems such as Manitoba (which continues to include a small amount of thermal generating resources in its power resource plan) and British Columbia (e.g., the Burrard generating station).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 planning to date for Yukon grid), and environmentally responsible (renewable energy option with
2 low GHG emissions). Two specific biomass thermal options were reviewed at the Energy
3 Charrette:

- 4 ○ **Wood biomass** is a thermal option that participants at the Energy Charrette highlighted
5 to be of potential near-term interest in Yukon, particularly as a potential use of spruce
6 bark beetle infestations and/or fire-damaged wood; the concept of distributed
7 cogeneration that produces both electricity and heat was also discussed.
- 8 ○ **Waste to energy** is a separate biomass thermal option that Yukon Energy has been
9 examining to incinerate municipal solid waste in Whitehorse to produce both electricity
10 and heat.
- 11 • **Liquid Natural Gas (LNG)/Natural Gas** – Natural gas thermal generation as discussed at the
12 Energy Charrette uses natural gas reciprocating engines or gas turbines to generate electricity,
13 initially using trucked-in liquid natural gas (LNG). The LNG/natural gas option was characterized
14 at the Energy Charrette as medium cost (approx 15+ cents/kW.h), very flexible (low capital cost,
15 save fuel and operating costs when no loads), very reliable (provides peaking and reserve
16 capacity, low regulatory risk to secure permits/approvals), and environmentally responsible
17 relative to diesel generation (over 30% lower GHG emissions than diesel, but not renewable).

18 Each of these non-diesel thermal options has its own specific features and costs that need to be assessed
19 in the context of near-term Yukon grid diesel displacement opportunities. Accordingly, each non-diesel
20 thermal option is addressed separately below.

21 The LNG/natural gas option in terms of power generation is essentially very similar to diesel generation
22 as reviewed in Attachment E2, except that it is forecast to use a less costly fuel that has lower GHG and
23 other emissions. This form of thermal generation involves relatively low capital costs, and retains the
24 flexibility and reliability that characterize the diesel thermal option. In effect, natural gas power plants are
25 intended to be operated only when required and (subject to securing fuel supply and appropriate new on-
26 site LNG storage) can be relatively easily integrated into the Yukon system as conversion or replacement
27 of the current diesel generation plant. Accordingly, and particularly in light of planned retirement of all of
28 YEC's diesel plant over the 20-year planning period and the grid's capacity planning requirements, the
29 LNG/natural gas option can be potentially relevant under all load scenarios.

30 In contrast, the biomass thermal options being discussed today with conventional technology require
31 development of relatively more capital intensive high pressure steam generation plants that would
32 typically be intended for year round operation in order to secure cost efficient use of the facilities.
33 Accordingly, such options would typically be viewed as potentially relevant only under increased grid

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 loads that provide sufficient opportunity for the biomass generation to displace default diesel generation,
2 i.e., this option would not be relevant under Base Case load forecasts. Further, location of such facilities
3 may be driven by the location of the biomass (to minimize transport costs for the biomass).

4 A key issue in assessing biomass thermal options is the plant size that is feasible based on the available
5 biomass (fuel supply is the limiting factor for waste-to-energy and also affects wood biomass), the
6 forecast load to be supplied (this is a key factor for wood biomass thermal generation), and the higher
7 cost issues associated with development of generating steam-driven thermal plants smaller than about
8 25-35 MW (this factor is reviewed in detail in the wood biomass section below).

9 For use in assessing biomass thermal options, Table E4-1 and Table E4-2 address the diesel generation
10 displacement benefit on the Yukon grid system of a non-diesel fuel thermal energy plant at two different
11 load levels that approximate Scenario A and B forecasts for 2015 (Scenario A pre-DSM/SSE load of about
12 545 GW.h and Scenario B pre-DSM/SSE load of about 610 GW.h) and various plant scale (MW capacity).

13 The analysis examines diesel displacement with the assumed DSM/SSE in place, and shows (at different
14 plant sizes) the extent to which the biomass thermal plant's generation is expected to be used to displace
15 grid diesel generation versus hydro generation.

16 Biomass thermal plants are assumed in these tables to operate at 91% capacity factor on an annual 12
17 month basis; as noted, biomass thermal plants are similar to coal thermal plants in the higher degree of
18 non-fuel capital and operating costs required and the resulting need (to be cost efficient) in many cases
19 to operate as baseload plants at reasonably high annual capacity factors.

20 Biomass thermal plant impact is shown on displacing diesel versus hydro generation at the specified grid
21 load based on the full range of grid water year characteristics as well as the current and committed hydro
22 resources on the grid. The assumed high annual capacity factor results in thermal generation displacing
23 hydro generation when diesel would not otherwise be needed (some of this displaced hydro generation is
24 stored, contributing to estimated winter diesel displacement).

25 Table E4-1 shows that, without DSM/SSE, the grid diesel requirement averaged over all water years at the
26 545 GW.h load is 101.1 GW.h for the year; with the assumed DSM/SSE, the long-term average grid diesel
27 requirement at this load level falls to 84.9 GW.h (diesel with DSM/SSE for 2015). A 25 MW biomass
28 thermal plant operated all year is forecast to displace all this diesel – but, due to the biomass plant
29 operation year round at a 91% capacity factor, 57% of the biomass thermal plant generation would go to
30 displace hydro rather than diesel (which would be very inefficient). In contrast, a 10 MW plant serving
31 the same load would displace 69% of the annual diesel with year round operation (only 33% of the
32 biomass thermal plant output displaces hydro – this “hydro displacement” excludes added hydro storage
33 due to the thermal generation).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

Table E4-1: Diesel Displacement Benefits of Biomass Thermal Plant: 545 GW.h/year Load

Non-Diesel Fuel Plant (Capacity Factor=0.91)	545 GW.h/year				
	Energy (GW.h/yr)			Total Diesel Generation (GW.h/yr)	Total Diesel Reduction (%)
	Total	Displacing Diesel	Displacing Hydro		
	A=B+C	B	C	D=84.9-B	E=B/84.9
W/o Non-Diesel Fuel Plant and w/o DSM/SSE				101.1	
W/o Non-Diesel Fuel Plant, with DSM/SSE (2015)				84.9	16%
10 MW Non-Diesel Fuel Plant	79.7	53.5 <i>67%</i>	26.2 <i>33%</i>	31.4	69%
15 MW Non-Diesel Fuel Plant	119.6	72.2 <i>60%</i>	47.4 <i>40%</i>	12.7	87%
20 MW Non-Diesel Fuel Plant	159.4	83.3 <i>52%</i>	76.1 <i>48%</i>	1.6	98%
25 MW Non-Diesel Fuel Plant	199.3	84.9 <i>43%</i>	114.4 <i>57%</i>	0.0	100%

Table E4-2 shows that, without DSM/SSE, the grid diesel requirement averaged over all water years at the 610 GW.h load is 160.2 GW.h for the year; with the assumed DSM/SSE, the long-term average grid diesel requirement at this load falls to 142.9 GW.h (diesel with DSM/SSE for 2015). A 30 MW biomass thermal plant operated all year would displace all this diesel – but 40% of the biomass thermal plant generation would go to displace hydro rather than diesel (which would be very inefficient). In contrast, a 15 MW biomass thermal plant serving the same load would displace 68% of the annual diesel with year round operation (only 24% of the biomass thermal plant output going to displace hydro).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

Table E4-2: Diesel Displacement Benefits of Biomass Thermal Plant: 610 GW.h/year Load

Non-Diesel Fuel Plant (Capacity Factor=0.91)	610 GW.h/year				
	Energy (GW.h/yr)			Total Diesel Generation (GW.h/yr)	Total Diesel Reduction (%)
	Total	Displacing Diesel	Displacing Hydro		
	A=B+C	B	C	D=142.9-B	E=B/142.9
W/o Non-Diesel Fuel Plant and w/o DSM/SSE				160.2	
W/o Non-Diesel Fuel Plant, with DSM/SSE (2015)				142.9	11%
10 MW Non-Diesel Fuel Plant	79.7	64.9 81%	14.8 19%	78.0	51%
15 MW Non-Diesel Fuel Plant	119.6	91.3 76%	28.3 24%	51.6	68%
20 MW Non-Diesel Fuel Plant	159.4	116.1 73%	43.3 27%	26.8	83%
25 MW Non-Diesel Fuel Plant	199.3	132.9 67%	66.4 33%	10.0	94%
30 MW Non-Diesel Fuel Plant	239.1	142.9 60%	96.2 40%	0.0	100%

In summary, the above tables show the biomass thermal plant scale impacts on reducing diesel generation at the two load levels. Because the biomass thermal option is more capital intensive than diesel or natural gas and is therefore typically intended for baseload year round operation, a smaller plant may be required to match Yukon loads and as a result the overall diesel displacement would be curtailed (i.e., a plant size of 10 MW for the lower Scenario A load, and 15 MW or less for the higher Scenario B load would displace only 68-69% of the forecast diesel in 2015).

For all of the non-diesel thermal options examined, benefits may occur (depending on location) in displacing diesel capacity requirements as well as diesel energy requirements.

WOOD BIOMASS

BACKGROUND

2006 Resource Plan

Yukon Energy's 2006 Resource Plan noted that, similar to coal options for thermal generation, biomass use for thermal generation is subject to the economic constraints related to fixed costs (including fixed operating and maintenance costs). These costs do not fall dramatically for smaller scale operations or loads. In these circumstances, economic viability typically hinges on large and constantly running facilities – factors which are not easily compatible with current Yukon conditions.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 The 2006 Resource Plan noted that biomass generation does not typically become economic unless three
2 key conditions are met (and that to date in Yukon, proposals have not met these three key criteria):

- 3 • The fuel (typically wood) must be available from a source that would otherwise have to pay to
4 dispose of it. Economic biomass generation is not typically possible with a wood product that has
5 a cost to harvest, or even (in at least some cases) that can be delivered to the plant for free;
6 there has to be savings from avoided disposal costs.
- 7 • The wood-fired power actually displaces diesel power.
- 8 • There is a substantial market for power and heat.

9 **Energy Charrette**

10 The Energy Charrette paper and presentation by Fernando Preto provided a current assessment of the
11 wood biomass energy option, including review of biomass conversion technologies, a case study re: the
12 McNeil Generating Station (utility scale biomass fired power plant in Vermont), and biomass energy
13 supply and sustainability in Yukon (including review of net energy content in dead trees by years since
14 death, which is relevant to areas impacted by forest fires or spruce bark beetle infestations). This paper
15 noted the impact of scale on costs for conventional technology, and ongoing work to develop commercial
16 technology suited to smaller scale operations that may be relevant in Yukon. Key features for this option
17 as noted in this background paper and presentation include:

- 18 • Wood biomass generation plant scale of 25 MW is optimum size today using normal Rankine
19 cycle technology (includes high pressure steam thermal generating plant with material staffing
20 requirement that cannot be significantly reduced with smaller plant sizes, i.e., assumes operating
21 staff of about 27 for 25 MW plant).
 - 22 ○ Normal Rankine cycle generally not economically feasible below 10 MW.
 - 23 ○ Other potential technologies are noted to be under development and demonstration, but
24 capital costs per kW are still high for such options and it is necessary to wait on
25 confirmation and demonstration of these promising new technologies.
- 26 • A 25 MW biomass plant was estimated to cost \$86.5 million or \$3.5 million per MW (based on an
27 average for "southern Canada" without adjustment for Yukon costs), and operate about 85% of
28 the time or about 7500 hours per year [187.5 GW.h/year] with a 25 year life; annual wood
29 consumption for this plant was estimated at 210,000 tonnes (40% moisture), or 1.128 tonnes
30 (40% moisture) per MW.h; it was estimated that the resulting power cost would approximate 31
31 cents per kW.h assuming that wood cost of \$200 per tonne (40% moisture) is applicable for

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 harvest of Yukon beetle kill wood with a facility located near Haines Junction. Added details
2 underlying this cost estimate include²¹:
- 3 ○ Approximately 0.68 oven dry tonnes of wood assumed to be required per MW.h;
4 assumed cost at \$200 per tonne (40% moisture) equal to about \$333 per oven dry
5 tonne, implying wood cost at about 22.6 cents per kW.h. The wood cost assumption was
6 based on discussions with Yukon government officials, without detailed analysis of any
7 specific possible development.
 - 8 ○ Fixed costs for plant capital (based on the above capital cost estimate) assumed at 6.8
9 cents per kW.h, and non-fuel and non-capital costs assumed at 1.6 cents per kW.h
10 (implies annual operating cost of about \$3 million for non-fuel and non-capital).
 - 11 ○ Assumed high cost of wood for Yukon case reflects lack of waste biomass from existing
12 forestry operations and need to rely solely on harvest of standing timber (cost for waste
13 biomass used in BC for biomass plants is much lower, e.g., potentially as low as \$20 per
14 tonne).
 - 15 ○ As a general guideline, a smaller biomass thermal plant (e.g., 10 MW rather than 25 MW)
16 would likely see capital cost per MW increase by a factor of 1.4 to 1.6 per MW, i.e., \$86.5
17 million for 25 MW would indicate at least about \$50 million for a 10 MW plant (\$5 million
18 per MW); non-fuel and non-capital costs per year for such a smaller plant would be
19 similar to the \$3 million estimated for the 25 MW plant, as it takes basically the same
20 number of people to run a 10 MW plant as it does to run a 25 MW plant. [Based on these
21 assumptions, a 10 MW plant would involve costs in excess of 36 cents per kW.h
22 assuming operation about 7,500 hours per year].
 - 23 • Biomass used directly for home or other space heating is much more efficient than biomass used
24 to generate electricity that is then used for home or other space heating. Wood pellets and other
25 forms of wood densification offer advantages when biomass needs to be transported to markets
26 for use in home or other space heating.
- 27 Given the high level of interest in the biomass option at the Energy Charrette, additional background
28 information has been examined regarding both Yukon biomass development and BC Hydro assessments
29 of biomass power options.

²¹ Details on these costs estimates as provided by Fernando Preto, personal communication after the Energy Charrette regarding detailed assumption for cost graph at slide 18 of his presentation.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **Other Yukon Biomass Development**

2 There has been longstanding interest in possible fuel uses of deadfall from spruce beetle infestation in
3 the Haines Junction area, e.g., a 2002 CFS report estimated that there were in excess of 250,000
4 hectares of dead standing trees in the Haines Junction area (infestation started in the early 1990s) and
5 still more trees were then under attack; prior outbreaks in the same vicinity in the 1950s and 1970s had
6 yet to recover back to coniferous cover, and very large costs have been previously estimated for
7 conversion, rehabilitation and reforestation of the affected areas. More recently, the Yukon Government
8 has been undertaking a range of bioenergy related initiatives, including:

- 9 • Development of a Bioenergy Strategy – The focus of this work is primarily on heating, although
10 electrical production is also considered.
- 11 • An October 2009 report for the Energy Solutions Centre (ESC)²² provides an overview of biomass
12 opportunities in Yukon, focusing on biomass heating and opportunities for a Yukon biomass wood
13 pellet production facility:
- 14 ○ Concludes that biomass electricity production at this time does not appear to be a
15 reasonable option for Yukon; notes that small scale production facilities that would be
16 needed are relatively new and untested in North America, especially in severe remote
17 northern environments (risk is too high to justify high capital costs). It is noted that the
18 industry is changing quickly and within 2-4 years it could be possible to consider a wood
19 biomass electric facility in Yukon for communities relying today only on diesel generation
20 (e.g., Watson Lake, Old Crow).
- 21 ○ Wood biomass from Yukon forests damaged by fire or spruce beetle infestation is
22 estimated to cost about \$105.28 per dry tonne (zero moisture content), based on an
23 average of seven separate location studies, an assumed haul distance of about 100 km
24 and 1.95 cm per tonne of oven dry biomass. The harvest cost (including chipping) is
25 estimated at \$40.78 per cm (\$79.5 per ODT), and haulage cost is estimated for 100 km
26 at \$13.21 per cm (\$25.8 per ODT).
- 27 ○ A conservative 10% estimate of forests damaged annually by fire or spruce beetle equals
28 71,760 dry tonnes per year (i.e., enough heating energy to meet the entire current
29 heating demand in Yukon on an annual sustainable basis, equivalent in heating value to
30 24 million litres/year of fuel oil or more than 27 million litres/year of propane)²³.

²² PBrand Bioenergy Consulting: "An Economic Evaluation of a Bioenergy Opportunity in Yukon"; October 2009.

²³ Assuming approximately 0.7 ODT required per MW.h, and a 90% plant annual capacity factor, this biomass supply would support a 13 MW power plant.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 ○ Recommends a wood pellet plant with an annual maximum production capacity of 25,000
- 2 to 40,000 tonnes with initial operation only 8 hours/day 5 days per week (at the smaller
- 3 plant size, initial annual production would then approximate 8,300 tonnes); estimate bulk
- 4 wholesale pellet cost of \$215 per tonne, which is estimated to be competitive in local
- 5 markets (current retail price in Whitehorse for pellets imported from BC is about \$375
- 6 per tonne – these pellets retail in Quesnel BC at about \$200 per tonne, although
- 7 transport cost from BC to Whitehorse is about \$115 per tonne).
- 8 • Various other recent studies have evaluated use of biomass for bioenergy based heating
- 9 applications including three Yukon schools and a district heating system option in the city of
- 10 Whitehorse.
- 11 ○ The Whitehorse district heating assessment²⁴ concluded that the most cost effective
- 12 option would use biomass in the form of wood pucks for heat only production (the
- 13 combined production of heat and power was not as cost effective).
- 14 • The Yukon Government has installed a bioenergy boiler system at the Whitehorse Correctional
- 15 Facility to meet base load heating requirements for this new correctional facility (system to be
- 16 operational by winter 2011/2012). The Yukon Government is also working with the municipality
- 17 of Dawson to incorporate a bioenergy boiler system to meet the thermal needs of both the waste
- 18 water treatment facility and the winter time municipal water heating requirements (to use local
- 19 waste wood produced from local milling operations).
- 20 • ESC has worked with CANMET to evaluate the potential for capitalization of the wood gasification
- 21 system currently in place at the Yukon College.

22 BC Hydro Experience

23 As of October 2010, BC Hydro had five wood biomass IPP contracts for power supply purchases, with
24 facilities ranging from 20 MW to 76 MW. BC Hydro recently accepted eight new biomass proposals from
25 its Bioenergy Phase 2 call issued May 31, 2010 – together, these proposals would supply 1,639
26 GW.h/year if final contract are concluded and implemented. In general, existing and potential BC Hydro
27 contracts to purchase biomass thermal generation from independent power producers have tended to be
28 co-located with a forestry operation that has ready access to high quality and relatively low cost fuel as
29 well as situations where waste heat use at other local facilities is typically needed to help the project
30 economics.

²⁴ Stantec Consulting Ltd. and Earthvoice Strategies; "District Energy Systems Pre-Feasibility Study City of Whitehorse, Yukon";
March 8, 2010. Prepared for Energy Solutions Centre.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 BC Hydro's draft 2010 Resource Options Report for its 2011 Integrated Resource Plan provides a current
2 BC assessment related to the biomass power production option²⁵, including:
- 3 • The current volume of biomass potentially available in BC for bioenergy production and existing
4 outside of the demands of the forest industry could support 18,000 GW.h/year for the first 15
5 years (2010-2024) and about 13,000 GW.h/year thereafter (2025-2040), with the dominant
6 biomass supply being from standing timber. Costs of electricity generation from greenfield
7 bioenergy are estimated to be (in 2011 dollars, and using a 6% real cost of capital) \$81/MW.h
8 (i.e., 8.1 cents per kW.h) plus delivered fuel cost; in the current period, the cost of electricity
9 using standing timber is estimated on average at \$167/MW.h as compared to \$105/MW.h when
10 sawmill woodwastes or hogfuel is used.
 - 11 ○ BC Hydro's background report provides the following key assumptions for a hypothetical
12 35 MW wood bioenergy plant in British Columbia:
 - 13 ▪ 1 MW.h requires 0.72 oven dry tonnes of wood biomass;
 - 14 ▪ A greenfield plant costs \$4.56 million per MW of capacity (based on cost for 35
15 MW plant);
 - 16 ▪ Annual costs to operate a biomass plant is 3.5% of capital (excludes wood fuel,
17 depreciation and capital return - based on 35 MW plant);
 - 18 ▪ Plant amortization assumed to be 15 years, recognizing the significant changes in
19 fibre supplies forecast 15-years from present. (It is noted that greenfield
20 bioenergy plants typically require 15-20 years to amortize the cost of new
21 construction); and
 - 22 ▪ Electric capacity factor is normally about 91% (about 8,000 annual operating
23 hours).
 - 24 ○ Based on the above, the average cost for delivery of standing timber biomass is
25 estimated at \$119 per dry tonne (\$86 per MWh); this estimate assumes the generation
26 plant is located near the available fuel supply to minimize transportation costs.
 - 27 ○ BC Hydro did its analysis based on a 35 MW plant size, noting that this size was selected
28 because it represents a plant large enough to take advantage of most economies of scale
29 and secondly that it represents a plant with a fibre requirement that could be sourced

²⁵ Detail provided in background report prepared by Industrial Forestry Service Ltd./ M.D.T. Ltd./ Murray Hall Consulting Ltd.; "Wood Based Biomass Energy Potential of British Columbia", prepared for BC Hydro's Integrated Resource Planning Process; November 2010.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 within many regions of BC. No attempt was made to assess cost adjustments for smaller
2 scale plants.

- 3 • The background report's review of bioenergy supply from dead pine trees notes that these trees
4 are unlikely to remain standing much longer than 20 years after being killed. After about 15
5 years, nearly 60% of the dead pines from beetle kill will have fallen over and started to decay
6 rapidly.

7 **Preliminary Yukon Biomass Energy Evaluation**

8 Following the Charrette, Yukon Energy retained Morrison Hershfield to provide a preliminary evaluation of
9 opportunities to generate electricity in Yukon using wood biomass. A draft letter report provided in June
10 2011 included a feedstock assessment and estimates for electricity production and heat utilization for a
11 25 MW wood biomass thermal plant in Whitehorse (the report notes, from previous studies, that capital
12 and operating costs per unit of production rise steeply when generation capacity falls below 20 MW).

13 The preliminary assessment identifies biomass supplies within a 250 km radius of Whitehorse that could
14 provide sufficient feedstock to maintain a 25 MW electrical generating facility for 20 years (the maximum
15 terms, including renewal, for a timber resource license that would be applicable for this project). Supplies
16 of up to 145,402 ODT²⁶ are estimated to be located in three areas²⁷ (average delivered cost to
17 Whitehorse for this total supply estimated at \$150 per ODT - cost estimates per cm for harvesting and
18 haulage per 100 km are those provided in the PBrand Bioenergy Consulting study in October 2009²⁸):

- 19 • **Haines Junction area beetle-infested forests:** 45,455 ODT estimated at average delivered
20 cost of 142.03 per ODT (180 km west of Whitehorse, assuming harvestable wood within 50 km of
21 Haines Junction);
- 22 • **Fox Lake burn area:** 24,440 ODT estimated at average delivered cost of \$115.87 per ODT (90
23 km north of Whitehorse, assuming harvestable wood within 20 km of Klondike Highway); and
- 24 • **Minto burn area:** 75,508 ODT estimated at average delivered cost of \$165.28 per ODT (260 km
25 north of Whitehorse, assuming harvestable wood within 20 km of Klondike Highway).

26 Assuming conventional combustion technology combined with a Rankine cycle, the report estimates that
27 a 25 MW facility will utilize approximately 140,000 ODT (approximately 308,000 cm) of biomass feedstock
28 per year to generate approximately 197,000 MW.h/year (0.7 ODT per MW.h; 90% plant annual capacity
29 factor). Capital and operating costs (not including feedstock costs) are estimated at \$100 million (\$4

²⁶ Study assumed 1 oven dry tonne (ODT) per 2.2 cm of wood biomass.

²⁷ Other smaller burn areas within the 250 km radius were identified but were not evaluated.

²⁸ Costs per ODT are 12.8% higher than PBrand Bioenergy Consulting's estimates due to higher assumed cm/ODT, i.e., Morrison Hershfield harvest cost is \$89.72/ODT and haulage cost per 100 km is \$29.06/ODT.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 million per MW) and \$4 million per year respectively. Assuming feedstock cost at \$150 per ODT (\$105
2 per MW.h), the report estimates overall electricity cost at \$168 per MW.h²⁹. District heat revenue
3 potential is estimated at only \$1.53 million per year (a reduction in net cost of about \$7.77 per MW.h),
4 reflecting the relatively small demand for heat energy in potentially feasible Whitehorse District Energy
5 applications³⁰.

6 The Morrison Hershfield report identifies lack of feedstock supply security as a significant project risk that
7 will require mitigation prior to project development. The report notes the following regarding feedstock
8 supply issues:

- 9 • There is no history of bioenergy resource use at this scale in Yukon and the current regulatory
10 framework does not adequately provide for long-term (20-year) tenure of the resource.
- 11 • Given the relatively large capital investment required, policy and regulatory changes will be
12 required to provide a project developer with the necessary feedstock security prior to committing
13 the investment.
- 14 • Current stand volumes identified in burn damaged areas reflect total volumes available – actual
15 volumes that a bioenergy licensee will be permitted to harvest could be lower, depending on
16 many factors (including health and safety issue of harvesting dead and decayed stands where
17 brittle trees can easily break unexpectedly during harvesting).
- 18 • Feedstock costs represent approximately 2/3 of the total system costs for a 25 MW biomass
19 plant, and further analysis of harvesting methods, feedstock preparation and transportation
20 logistics will be required to provide a higher degree of cost certainty.

²⁹ Capital costs at \$42.48/MW.h assuming 5.5% real cost of capital amortized over 20 years; non-fuel O&M cost at \$20.30/MW.h.

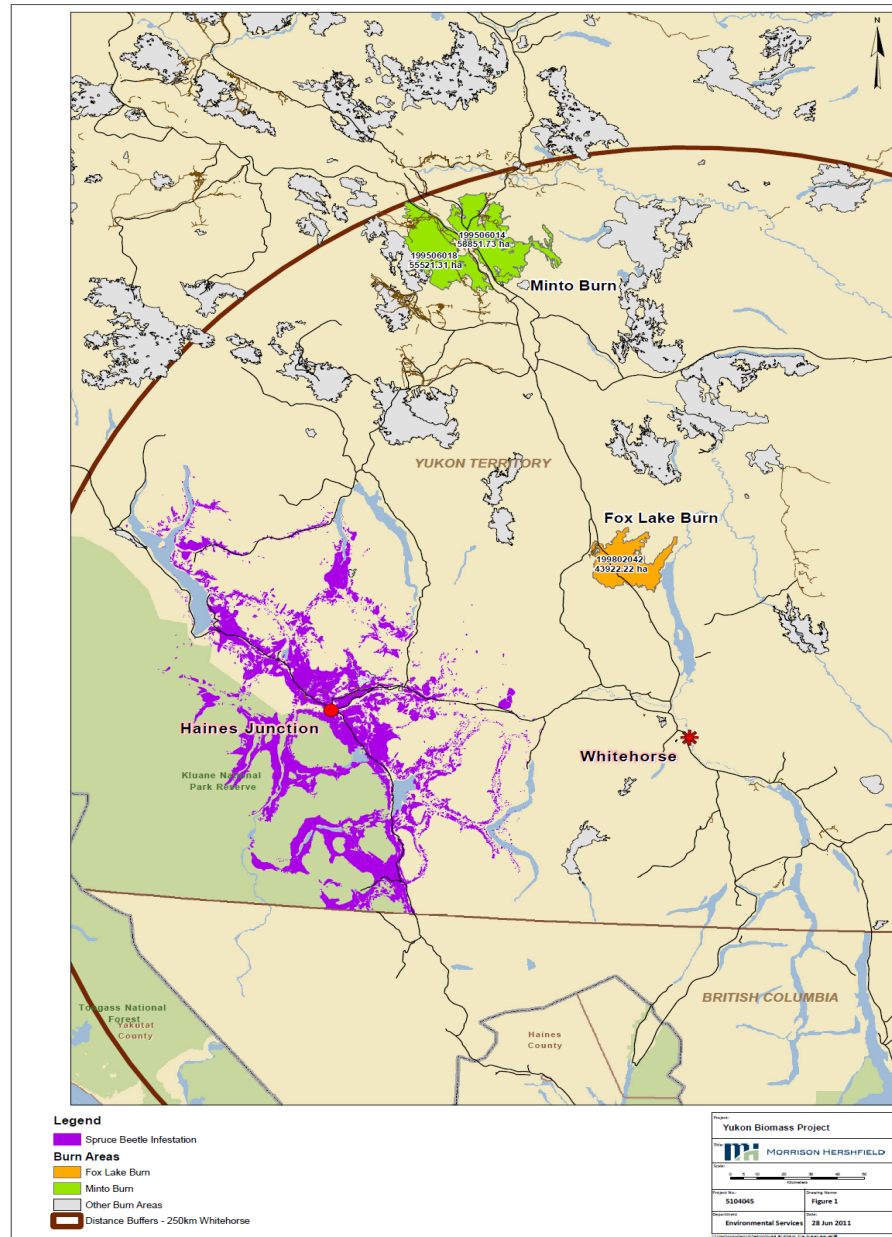
³⁰ Estimates based on Stantec study (2010), zones 1 to 3 (potential heating demand equal to 29,900 MW.h/year).

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20-Year Resource Plan: 2011-2030

December 2011

1

Figure E4-1: Wood Biomass Feedstock Supply Areas in Yukon



2

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 The Morrison Hershfield report notes that this project will require an environmental assessment under
2 YESAA and is expected to trigger an Executive Committee review (>5 MW wood-fired electrical
3 generation station and cutting >20,000 cm of standing or fallen trees). It is further noted that this level
4 of review introduces a degree of scheduling risk to the project,

5 The report provides recommendations to address project risks and uncertainties and facilitate
6 advancement of the project into a detailed planning stage, including: promote the development of a
7 Yukon Bioenergy Policy; incorporate biomass energy option in YEC public consultation; investigate and
8 confirm feedstock availability and costs; assess options for integrating municipal solid waste within a
9 biomass facility; confirm capital and operating costs; and initiate preliminary site investigations.

10 **OPTION ASSESSMENT**

11 **25 MW Wood Biomass Plant**

12 Various studies reviewed above confirm a minimum practical scale for a wood biomass plant at
13 approximately 25 MW, in order to avoid steeply rising capital and operating costs per unit of output
14 associated with smaller scale plants. At the 25 MW plant scale, the Morrison Hershfield report indicates
15 that only a Whitehorse site is likely to be feasible in Yukon as regards adequate biomass feedstock supply
16 at the lowest feasible cost – and that the average cost for delivered feedstock for such a Whitehorse
17 plant would approximate \$150 per ODT to sustain annual generation of 197 GW.h over 20 years using
18 wood biomass feedstock from Haines Junction beetle-kill (about 31% of feedstock), Fox Lake burn area
19 (about 17% of feedstock) and Minto burn area (about 52% of feedstock). A biomass generation plant
20 located at Whitehorse would contribute to grid reliable capacity as well as grid energy to displace diesel
21 generation.

22 Based on the feedstock supply and other project planning risks and uncertainties identified in the
23 Morrison Hershfield report, and the expected need for a YESAB Executive Committee review, it is
24 assumed in the following evaluation that the earliest potential timing for initial operation of a 25 MW
25 facility would be late 2014, i.e., first full year of operation in 2015. This would allow only one year for
26 bioenergy policy and project planning development (including preparation of a YESAB submission by
27 summer 2012), one year for the required YESAB review (to summer 2013), and slightly more than one
28 year thereafter for project construction and start up.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 The economics of a 25 MW wood biomass thermal plant in Whitehorse are assessed below using YEC's
2 LCOE model³¹, the above costing information from the BC Hydro hypothetical 35 MW plant, and the
3 Morrison Hershfield report cost estimates for a 25 MW plant in Yukon.
- 4 Capital costs (2010\$) are estimated in the BC Hydro study at \$4.56 million per MW for a 35 MW plant, as
5 compared with \$4 million per MW in the Morrison Hershfield for a 25 MW plant. For this estimate, the BC
6 Hydro cost per MW for a 35 MW plant appears to provide a conservative contemporary estimate for a 25
7 MW plant, i.e., the BC Hydro cost per MW estimate would tend to climb as plant scale is reduced from 35
8 MW to 25 MW.
- 9 A 20 year plant life is assumed based on the Morrison Hershfield reporting on the likely term of a Yukon
10 forestry license, with annual operation at 8,000 hours per year (199.3 GW.h/year) per the BC Hydro
11 report (91% annual capacity factor).
- 12 Operating and maintenance cost (2010\$) excluding fuel is assumed at \$4 million per year based on both
13 the BC Hydro and the Morrison Hershfield studies for 35 MW and 25 MW plants respectively.
- 14 Wood biomass requirement is assumed at 0.7 ODT per MW.h (reflects Morrison Hershfield estimate, and
15 slightly lower than 0.72 ODT per MW.h estimate in the BC Hydro report); delivered wood cost at
16 Whitehorse is assumed at \$150 per ODT (per Morrison Hershfield report) - equal to \$105/MW.h.
- 17 Using YEC's LCOE model, the above assumptions translate to a Full Utilization LCOE of 16.6 cents per
18 kW.h (2010\$) over a 20 year life. Including \$1.53 million (2010\$) of district heat revenues (per Morrison
19 Hershfield report) reduces this Full Utilization LCOE to 15.8 cents per kW.h.
- 20 A 25 MW plant operating 8,000 hours per year (91% capacity factor) would generate 199.3 GW.h per
21 year. However, as noted earlier, this plant scale far exceeds forecast near-term requirements to displace
22 grid diesel generation even when new mine loads are assumed to be connected to the grid prior to 2021.
23 After 2021, under the assumed load scenarios there is no material opportunity to displace diesel
24 generation until well after 2030.

³¹ Assumes YEC blended return from last GRA (6.56%/year nominal, 4.47%/year real return net of inflation) and LCOE stated in 2010\$. Note that this assumes that the biomass plant is owned and operated by YEC - if, as in BC, such a plant was to be a privately owned by an independent power producer, a higher blended cost of capital would be required plus provision for income tax costs. BC Hydro's analysis assumes a real return of 6% (net of inflation) to all resource options to allow for fair comparisons regardless as to ownership.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 To illustrate impacts on Forecast LCOE over the 20-year assumed economic life for a 25 MW plant in
2 Whitehorse, the analysis below focuses on Scenario A and Scenario B forecast grid loads with the
3 assumed DSM/SSE:

4 • **Scenario A loads** - Table E4-1 showed that under loads approximating Scenario A in 2015 (545
5 GW.h/year) with DSM/SSE, this 25 MW plant would displace 100% of the forecast diesel
6 generation of 84.9 GW.h/year – but, beyond hydro benefits resulting in added winter hydro
7 storage to displace diesel generation (which are included in forecast diesel displacement), 57% of
8 the plant's annual output with this load would go to displacing hydro generation that was
9 otherwise available at no added cost.

10 • **Scenario B loads** - Table E4-2 showed that under loads approximating Scenario B in 2015
11 (610.3 GW.h/year) with DSM/SSE, this 25 MW plant would displace 94% of the forecast diesel
12 generation of 142.9 GW.h/year – but with this load, approximately one-third of the plant's annual
13 output would go to displacing hydro generation that was otherwise available at no added cost
14 and that provides no added winter hydro storage benefits

15 • **Forecast LCOE** - Forecast LCOE (2010\$) range as follows based on a 25 MW plant in
16 Whitehorse operated throughput each year (91% capacity factor) for 20 years, starting in 2015,
17 and expected net generation that displaces diesel generation:

18 ○ 92.5 cents per kW.h for Scenario A with DSM/SSE (assumes all forecast diesel generation
19 is displaced and no district heat revenues – 88.3 cents per kW.h with assumed district
20 heat revenues).

21 ○ 42.2 cents per kW.h for Scenario A with no DSM/SSE (40.3 cents per kW.h with assumed
22 district heat revenues), reflecting the material increase in forecast diesel after 2020 if no
23 DSM/SSE.

24 ○ 60.5 cents per kW.h for Scenario B with DSM/SSE (assumes no district heat revenues –
25 57.7 cents per kW.h with assumed district heat revenues).

26 ○ 35.4 cents per kW.h for Scenario A with no DSM/SSE (33.8 cents per kW.h with assumed
27 district heat revenues).

28 As reviewed in Table E4-3, the very high Forecast LCOE for the 25 MW wood biomass plant option for
29 Scenarios A and B with DSM/SSE reflects the extent to which there are no material diesel displacement
30 opportunities currently forecast after 2020, assuming mine loads end as currently forecast and DSM/SSE
31 reduces non-industrial loads as assumed. Forecast LCOE would be reduced (but still more expensive than
32 Forecast LCOE for diesel generation, regardless of wood costs assumptions) if forecast mine loads under
33 Scenarios A with DSM/SSE were to be extended by 5 to 10 years:

Yukon Energy Corporation

20-Year Resource Plan: 2011-2030

December 2011

- 1 • If assumed mine loads were to be extended sufficiently to maintain 89 GW.h/year of diesel
- 2 displacement (the maximum displaced under Scenario A in any year prior to 2020) to the end of
- 3 2025, Forecast LCOE under Scenario A for a 25 MW plant would be lowered from 92.5 cents per
- 4 kW.h to 55.4 cents per kW.h³².
- 5 • Extending this same level of diesel displacement to 2030 would reduce Forecast LCOE under
- 6 Scenario A to 42.8 cents per kW.h, i.e. this cost would still be materially higher than diesel
- 7 generation costs under Scenario A over the same period³³.

**Table E4-3: Wood Biomass Option Impacts on Diesel Generation (25 MW plant)
(GW.h of diesel displaced by year over 20 year plant life: 2015-2034)**

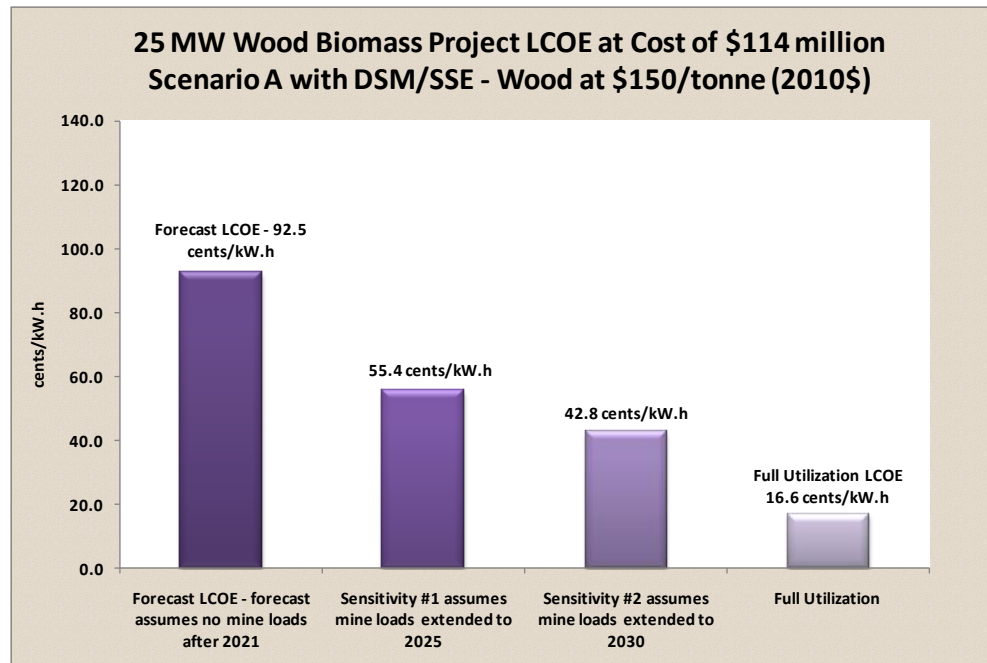
	Scenario A GWh	Scenario B GWh
2015	85	134
2016	82	131
2017	84	133
2018	87	135
2019	89	131
2020	73	119
2021	0	2
2022	0	0
2023	0	0
2024	1	1
2025	2	2
2026	3	3
2027	4	4
2028	5	5
2029	6	6
2030	8	8
2031	9	9
2032	11	11
2033	12	12
2034	14	14

- 11 Figure E4-2 summarizes the 25 MW biomass plant Forecast LCOE (2010\$) under Scenario A with
- 12 DSM/SSE and with the above assumed sensitivity tests assuming mine life extensions to 2025 and 2030.
- 13 Full Utilization LCOE is also shown for comparison.

³² Under Scenario B with DSM/SSE, extending 131 GW.h/year of diesel displacement (per 2019) to the end of 2025 lowers Forecast LCOE from 60.5 cents/kW.h to 37.1 cents/kW.h.

³³ Under Scenario B with DSM/SSE, extending 131 GW.h/year of diesel displacement to the end of 2030 lowers Forecast LCOE to 28.6 cents/kW.h.

1 **Figure E4-2: Forecast LCOE for 25 MW Wood Biomass Plant at Whitehorse at Scenario A Load**
2 **with DSM/SSE – Sensitivity to Mine Extensions (LCOE cents per kW.h of Diesel Displaced –**
3 **Present Value over 20 Year Life of Project (2010\$)**



4
5 In reality, faced with very low diesel displacement after 2020 it would become relevant to assess the
6 option of closing the biomass plant when mine loads disappeared. However, Forecast LCOE would remain
7 high under Scenario A with DSM/SSE and the plant closed at the end of 2020, i.e. Forecast LCOE would
8 be 55.4 cents per kW.h, versus 92.5 cents per kW.h if the plant remained operating as originally assumed
9 above. Extending mine loads sufficiently to maintain 89 GW.h/y of diesel displacement to the end of 2025
10 and then closing the plant would reduce the Forecast LCOE under Scenario A to 43.1 cents per kW.h;
11 extending this displacement to 2030 and then closing the plant would reduce Forecast LCOE to 39.3
12 cents per kW.h, i.e. a cost still materially higher than diesel generation costs under Scenario A over the
13 same period.

14 Aside from the impacts due to shutting down of mine loads, annual operation of a 25 MW wood biomass
15 thermal plant in Whitehorse results in generation costs higher than diesel fuel and operating costs from
16 new plants even in the initial years when forecast mine loads are highest.

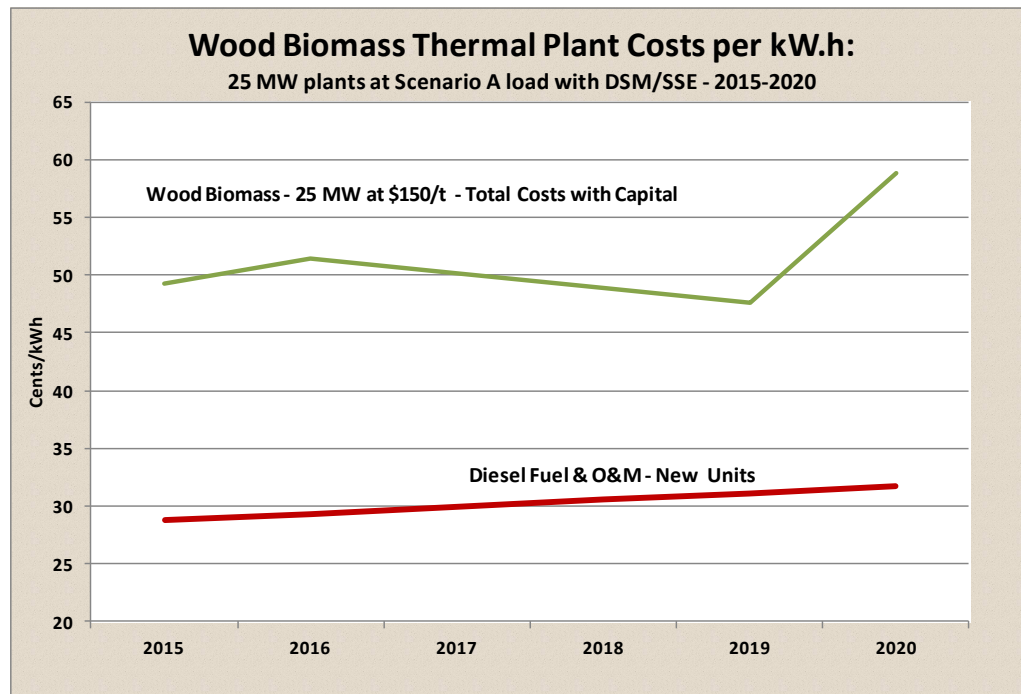
17 By way of example, Figure E4-3 shows costs per kW.h for new diesel plants and a 25 MW wood biomass
18 thermal plant during the brief period 2015-2020 under Scenario A with DSM/SSE when the Victoria Gold

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20-Year Resource Plan: 2011-2030

December 2011

1 mine load is assumed to be connected to the grid. In each year, diesel fuel and O&M costs are less than
2 the wood biomass thermal plant costs at the assumed wood delivery cost of \$150 per ODT.

3 **Figure E4-3: 25 MW Wood Biomass Thermal Plant vs. Diesel Fuel & O&M Costs:**
4 **Annual Cents per kW.h – 2015-20**



5
6 In part, the outcome in Figure E4-3 reflects the extent to which existing and committed hydro generation
7 removes any material opportunity to displace diesel generation during five months of each year at all
8 loads forecast under Scenario A and Scenario B. During the years examined in Figure E4-3 (2015 to
9 2020), fuel and O&M costs account for between 66% (2015) and 71% (2020) of the overall biomass
10 plant annual costs. With full utilization of all generation, biomass plant fuel and O&M costs for this 25 MW
11 plant approximate 13.8 cents per kW.h in 2015 and full costs with capital approximate 21.0 cents/kW.h.
12 However, only 42.6% of this generation is used to displace diesel under 2015 Scenario A loads and, as
13 reviewed below, this results in effective full costs in 2015 of approximately 49.3 cents per kW.h of diesel
14 displaced:

- 15 • Due to this low utilization, the effective fuel and O&M cost per kW.h of diesel generation
16 displaced in 2015 increases to 32.4 cents. Running the plant at lower output levels throughout
17 the year to reduce hydro displacement without reducing diesel displacement (particularly in

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20-Year Resource Plan: 2011-2030

December 2011

- 1 months with ample hydro generation) could reduce somewhat this cost per kW.h of diesel
2 displaced (no attempt has been made to assess this option).
- 3 • The balance of the biomass plant cost shown in Figure E4-3 covers capital costs. Due to the low
4 utilization, depreciation and return in 2015 approximate 16.9 cents per kW.h of diesel generation
5 displaced. Running the plant at lower output levels would not act to reduce this cost per kW.h of
6 diesel displaced in 2015.
- 7 Table E4-4 provides an overall present value of the estimated costs required over the 20-year planning
8 period (2011-2030) with the 25 MW wood biomass thermal plant option located at Whitehorse for load
9 Scenarios A and B – diesel fuel and added capacity is assumed to be retained for the Base Case, for
10 2011-2014 under Scenario's A and B (before the wood biomass plant is established) and for new capacity
11 requirements not covered by the wood biomass plant. As noted, due to the plant's location, full capacity
12 benefits are assigned to the wood biomass plant. Present value costs are as follows:
- 13 Scenario A present value cost is \$398.1 million with DSM/SSE (\$194 million increase from Default Diesel
14 Portfolio) and \$385.2 million with no DSM/SSE (\$101.7 million increase from Default Diesel Portfolio);
15 these costs include present value capacity savings (relative to Default Diesel) of \$25.7 million with
16 DSM/SSE and \$28.1 million with no DSM/SSE.
- 17 Scenario B present value cost is \$413.7 million with DSM/SSE (\$132.5 million increase from Default Diesel
18 Portfolio) and \$417 million with no DSM/SSE (\$53.3 million increase from Default Diesel Portfolio); these
19 costs include present value capacity savings (relative to Default Diesel) of \$29.3 million with DSM/SSE
20 and \$30.2 million with no DSM/SSE.

Yukon Energy Corporation

20-Year Resource Plan: 2011-2030

December 2011

**Table E4-4 Wood Biomass Thermal 25 MW Plant Portfolio Option Present Value Costs
(2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁴
No DSM/SSE					
Base Case	111.8	52.8		164.6	0.0
Scenario A	357.4	27.8		385.2	101.7
Scenario B	388.1	28.9		417.0	53.3
With DSM/SSE					
Base Case	30.8	31.9	35.4	98.1	0.0
Scenario A	353.6	9.0	35.4	398.1	194.0
Scenario B	369.1	9.1	35.4	413.7	132.5

1. Costs discounted at 6.56% per year YEC blended cost of capital.

2. Wood biomass costs (25 MW); wood at \$150/t. Assumes diesel fuel & O&M units for all diesel not displaced by Project.

3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.

4. See Diesel Portfolio Option Present Value Costs.

10 or 15 MW Wood Biomass Plant

The above analysis highlights the extent to which a 25 MW biomass plant would be severely underutilized under currently forecast Yukon grid loads under Scenario A with DSM/SSE while also needing to be located in Whitehorse and thereby incurring high feedstock costs due to haulage requirements from wood supply areas.

To address these issues, a smaller 10 to 15 MW biomass plant scale option is examined which, as reviewed below, would create the option (based on the Morrison Hershfield preliminary feedstock volume and cost estimates noted above) of locating the plant at either the Minto burn area or Whitehorse:

- **Biomass supply options:** Biomass feedstock requirements range from 55,800 ODT per year for a 10 MW plant to 83,700 ODT per year for a 15 MW plant.

These feedstock requirements exceed Morrison Hershfield's estimated supplies at Haines Junction (45,455 ODT/year), but are within the feedstock supplies estimated to be available at Minto burn area (75,506 ODT/year) plus the nearby Fox Lake burn area (24,440 ODT/year).

If the plant is not located at Whitehorse, the least cost location would be at the Minto burn area (due to the large feedstock supply estimate for this location as well as close proximity to the 138 kV CSTP).

- **Whitehorse plant feedstock costs:** Based on the above feedstock supplies and the Morrison Hershfield estimated cost per ODT from each supply area (\$2010 cost of \$89.72/ODT for harvest

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 and \$29.06/ODT per 100 km for haulage), the feedstock cost (2010\$) for a plant in Whitehorse
2 approximates the following:³⁴
- 3 ○ **10 MW plant:** \$131 per ODT (approximates \$104/ODT after assumed district heat
4 offset potentially available for a Whitehorse plant location)³⁵.
 - 5 ○ **15 MW plant:** \$138 per ODT (approximates \$120/ODT after assumed district heat
6 offset potentially available for a Whitehorse plant location).
 - 7 • **Minto burn plant feedstock costs:** Based on the above feedstock supplies and the Morrison
8 Hershfield estimated cost per ODT from each supply area (adjusted for distance to Minto burn
9 and assuming all supplies come first from Minto burn and then from Fox Lake burn at added haul
10 distance of 170 km), the feedstock cost (2010\$) for a plant in the Minto burn area near the
11 Klondike Highway approximates the following (no district heat revenue potential is currently
12 assumed for this plant location):
 - 13 ○ **10 MW plant:** \$96 per ODT (assumes all feedstock from Minto burn area, with average
14 haul distance of 20 km).
 - 15 ○ **15 MW plant:** \$104 per ODT (reflects added haul cost assuming 15,000 ODT supplied
16 from Fox Lake burn).
 - 17 • **Minto burn as least cost location:** Based on the current estimates, the feedstock cost for the
18 Minto burn plant location is lower than for Whitehorse plant location, even if district heat revenue
19 as estimated is assumed only for a Whitehorse site. The cost gap increases as plant size
20 increases from 10 MW to 15 MW.
- 21 In order to reflect the capital and non-fuel O&M cost diseconomies associated with a smaller plant size,
22 plant capital cost per MW are assumed to be 40% higher for a 10 MW plant than for the 25 MW plant
23 (25% higher for a 15 MW plant) and total annual plant non-fuel operating costs are assumed not to be
24 reduced from those estimated for the 25 MW plant (reflecting assumed inability to reduce staff size).
25 Revised Full Utilization LCOEs (2010\$) are provided below for 10 MW and 15 MW plant scales assuming a
26 Minto burn area location for the plant:
- 27 • Using these assumptions, a 10 MW wood biomass plant lifetime at 91 % capacity factor (79.7
28 GW.h/year) and 20 year life has a Full Utilization LCOE of 17.5 cents per kW.h at \$96/ODT wood
29 cost.

³⁴Assumes feedstock supplied first from Fox Lake burn (\$115.87/ODT) and then from Haines Junction (\$142.03/ODT), and last from Minto burn (\$165.28/ODT).

³⁵ The Whitehorse location in contrast to the Minto burn location offers potential district heat revenues (estimated by Morrison Hershfield at approximately \$1.53 million per year (2010\$)). To compare sites, this potential revenue can be viewed as a "cost offset" per ODT of biomass feedstock equal to \$27.4/ODT for a 10 MW plant and \$18.3 per ODT for a 15 MW plant.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 • A 15 MW wood biomass plant lifetime at 91 % capacity factor (119.6 GW.h/year) and 20 year life
2 has a Full Utilization LCOE of 15.8 cents per kW.h at \$104/ODT wood cost.
- 3 The major cost effectiveness issue in the near-term Yukon context is the reality that only a portion of the
4 wood biomass plant output from even a 10 MW sized facility will be useful in helping YEC (and
5 ratepayers) save costs by displacing diesel generation:
- 6 • During Scenario A or B near-term periods when material diesel generation is needed to meet grid
7 loads even after assumed DSM/SSE, less than 100% of a 10 MW or 15 MW plant's annual output
8 would typically be used to displace diesel, e.g., in 2015 with DSM/SSE: under Scenario A less
9 than 70% of the output of a 10 MW plant would be used to displace diesel, and under Scenario B
10 less than 85% (smaller percentages would apply for output of a 15 MW plant).
- 11 • Even more significantly, after 2021 under these scenarios there is no material opportunity to
12 displace diesel under the assumed load until well after 2030.
- 13 • Forecast LCOE (\$2010) based on a 10 MW or 15 MW plant operated throughout each year (91%
14 capacity factor) for 20 years, starting in 2015, and expected net generation that displaces diesel
15 generation range as follows at delivered wood costs of \$119 to \$333 per oven dry tonne:
- 16 ○ 58.4 c/kW.h for Scenario A with DSM/SSE and a 10 MW plant (60.8 c/kW.h with a 15 MW
17 plant)³⁶; and
- 18 ○ 49.5 c/kW.h for Scenario B with DSM/SSE and a 10 MW plant (48.6 c/kW.h with a 15 MW
19 plant).
- 20 In effect, the Forecast LCOE as reviewed above for annual operation over 20 years is considerably higher
21 than projected for equivalent incremental diesel generation, regardless as to plant size assumptions.
- 22 As reviewed in Table E4-5, the very high Forecast LCOE for the wood biomass plant options reflects the
23 extent to which there are no material diesel displacement opportunities currently forecast after 2020,
24 assuming mine loads end as currently forecast and DSM/SSE reduces non-industrial loads as assumed. By
25 way of example, looking at the 15 MW plant and Scenario A loads, Forecast LCOE would be reduced (but
26 still more expensive than Forecast LCOE for diesel generation, regardless of wood costs assumptions) if
27 forecast mine loads under Scenario A were to be extended by 5 to 10 years:
- 28 • If assumed mine loads were to be extended sufficiently to maintain 75 GW.h/y of diesel
29 displacement (see Table E4-5) to the end of 2025, the Forecast LCOE would be reduced from
30 60.8 cents per kW.h to 37.1 cents per kW.h at a wood cost of \$104 per oven dry tonne.³⁷

³⁶ The Forecast LCOE (\$2010) with no DSM/SSE for Scenario A is 29.1 c/kW.h for a 10 MW plant and 29.6 c/kW.h for a 15 MW plant; for Scenario B is 26.7 c/kW.h for a 10 MW plant and 27.2 c/kW.h for a 15 MW plant.

Yukon Energy Corporation

20-Year Resource Plan: 2011-2030

December 2011

- 1 • Extending this same level of diesel displacement to 2030 would reduce Forecast LCOE to 28.8
2 cents per kW.h at a wood cost of \$104 per oven dry tonne.

3 **Table E4-5: Wood Biomass Option Impacts on Diesel Generation (10 MW and 15 MW plant)**
4 **(GW.h of diesel displaced by year over 20 year plant life: 2015-2034)**

	10 MW Plant (79.7 GW.h/y)		15 MW Plant (119.6 GW.h/y)	
	Scenario A	Scenario B	Scenario A	Scenario B
	GWh	GWh	GWh	GWh
2015	54	65	73	92
2016	53	64	71	91
2017	54	65	72	92
2018	55	65	74	92
2019	55	64	75	91
2020	51	61	65	87
2021	0	2	0	2
2022	0	0	0	0
2023	0	0	0	0
2024	1	1	1	1
2025	2	2	2	2
2026	3	3	3	3
2027	4	4	4	4
2028	5	5	5	5
2029	6	6	6	6
2030	8	8	8	8
2031	9	9	9	9
2032	11	11	11	11
2033	12	12	12	12
2034	14	14	14	14

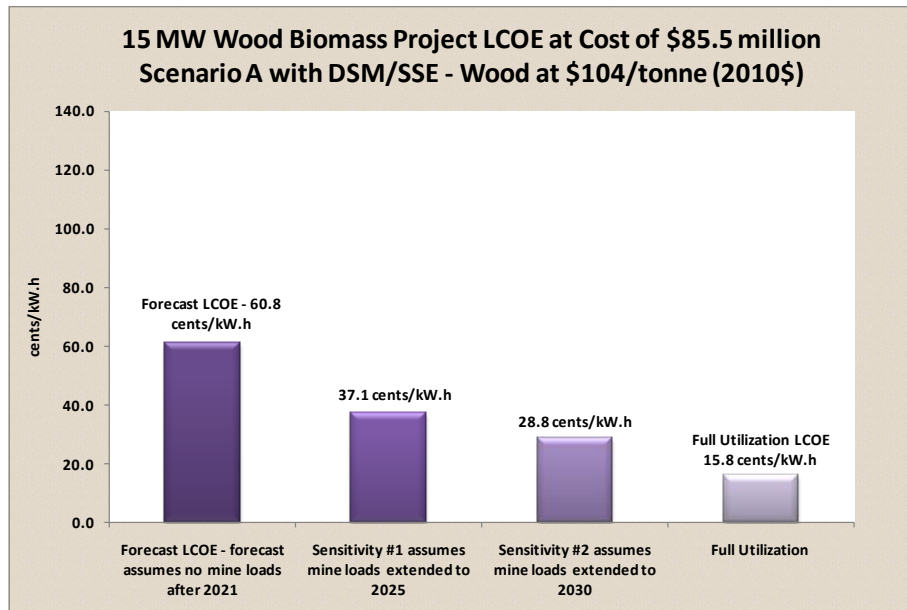
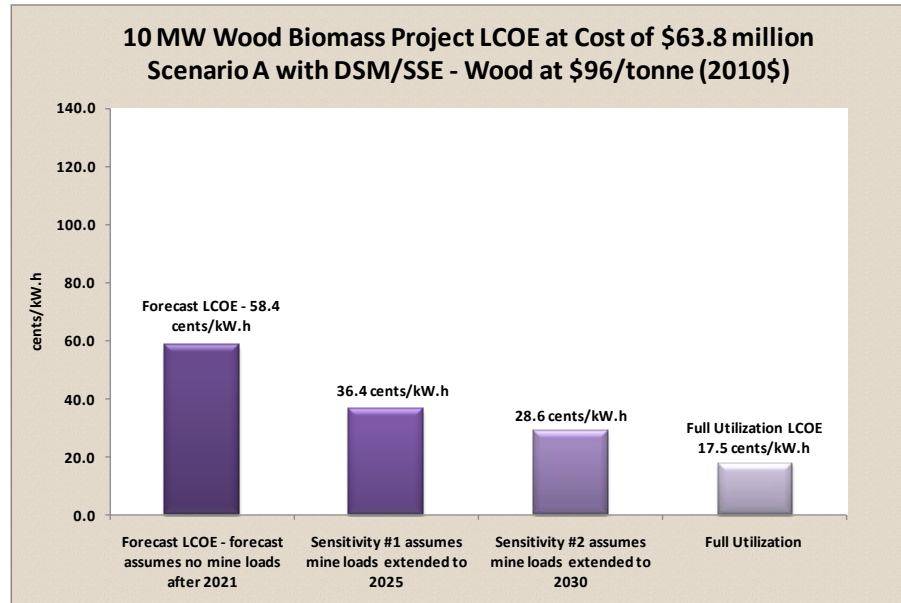
- 5 Figure E4-4 summarizes the 10 MW and 15 MW biomass plant Forecast LCOE (2010\$) under Scenario A
6 with DSM/SSE and with the above assumed sensitivity tests assuming mine life extensions to 2025 and
7 2030. Full Utilization LCOE is also shown for comparison.

³⁷ For a 10 MW plant - If assumed mine loads were to be extended sufficiently to maintain 55 GW.h/y of diesel displacement (see Table E4-5) to the end of 2025, the Forecast LCOE would be reduced from 58.4 cents per kW.h to 36.4 cents per kW.h at a wood cost of \$96 per oven dry tonne; extending this same level of diesel displacement to 2030 would reduce Forecast LCOE to 28.6 cents per kW.h at a wood cost of \$96 per oven dry tonne.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **Figure E4-4: Forecast LCOE for 10 MW and 15 MW Wood Biomass Plant at Minto Burn Area at**
2 **Scenario A Load with DSM/SSE – Sensitivity to Mine Extensions (LCOE cents per kW.h of**
3 **Diesel Displaced – Present Value over 20 Year Life of Project (2010\$)**



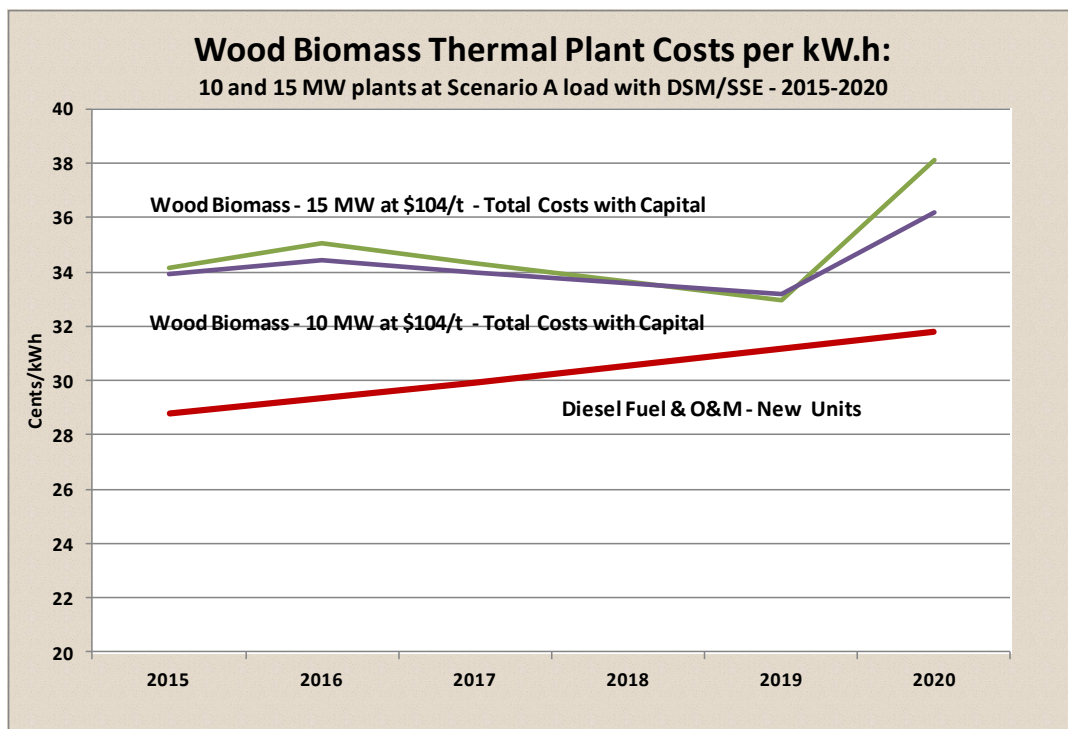
Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 Aside from the impacts due to shutting down of mine loads, annual operation of these wood biomass
2 thermal plants results in generation costs higher than diesel fuel and operating costs from new plants
3 even in the initial years when forecast mine loads are highest.

4 By way of example, Figure E4-6 shows fuel and O&M costs per kW.h for new diesel plants and total costs
5 for a 10 MW and a 15 MW wood biomass thermal plant during the brief period 2015-2020 under Scenario
6 A when the Victoria Gold mine load is assumed to be connected to the grid – in each year, diesel costs
7 are less than the wood biomass thermal plant costs even at the lowest wood delivery costs examined
8 (\$96 per oven dry tonne for the 10 MW plant).

9 **Figure E4-6: 10 MW and 15 MW Wood Biomass Thermal Plant vs. Diesel Fuel & O&M Costs:**
10 **Annual Cents per kW.h – 2015-2020**



11

12 In part, the outcome in Figure E4-6 reflects the extent to which existing and committed hydro generation
13 removes any material opportunity to displace diesel generation during five months of each year at all
14 loads forecast under Scenario A and Scenario B. During the years examined in Figure E4-6 (2015 to
15 2020), fuel and O&M costs account for between 56% (2015) and 62-63% (2020) of the overall annual
16 costs for the 10 and 15 MW biomass plants. With full utilization of all generation, biomass plant fuel and
17 O&M costs for the 10 MW plant approximate 13.0 cents per kW.h in 2015 (11.7 cents for 15 MW plant)

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 and full costs with capital approximate 23.0 cents/kW.h (20.7 cents for 15 MW plant). However, only
2 65.4% of the 10 MW plant's generation is used to displace diesel under 2015 Scenario A loads (86.2% for
3 the 15 MW plant) and, as reviewed below, this results in effective full costs in 2015 of approximately 34
4 cents per kW.h of diesel displaced (same for both 10 MW and 15 MW plants):

5 Due to this utilization, the effective fuel and O&M cost per kW.h of diesel generation displaced in 2015
6 increases to 19 cents. Running the plant at lower output levels throughout the year to reduce hydro
7 displacement without reducing diesel displacement (particularly in months with ample hydro generation)
8 could reduce somewhat this cost per kW.h of diesel displaced (no attempt has been made to assess this
9 option).

10 The balance of the biomass plant cost shown in Figure E4-6 covers capital costs. Due to the utilization as
11 well as high capital cost per MW (for these smaller plants), depreciation and return in 2015 approximate
12 15 cents per kW.h of diesel generation displaced. Running the plant at lower output levels would not act
13 to reduce this cost per kW.h of diesel displaced in 2015.

14 Table E4-6A and Table E4-6B provide an overall present value of the estimated costs required over the
15 20-year planning period (2011-2030) with the wood biomass thermal plant option, at plant scales of 10
16 MW and 15 MW respectively, for load Scenarios A and B – diesel fuel and added capacity is assumed to
17 be retained for the Base Case, for 2011-2014 under Scenario's A and B (before the wood biomass plant is
18 established) and for new capacity requirements not covered by the wood biomass plant. As noted, due to
19 the plant's location, full capacity benefits are assigned to the wood biomass plant. Present value cost
20 changes relative to the Default Diesel Portfolio option range as follows:

- 21 • For a 10 MW plant, Scenario A present value cost increases by \$57 million with DSM/SSE and by
22 \$3 million with no DSM/SSE; Scenario B present value cost increases by \$44 million with
23 DSM/SSE and is reduced by \$10 million with no DSM/SSE.
- 24 • For a 15 MW plant, Scenario A present value cost increases by \$79 million with DSM/SSE and by
25 \$8 million with no DSM/SSE; Scenario B present value cost increases by \$54 million with
26 DSM/SSE and is reduced by \$10 million with no DSM/SSE.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

**Table E4-6A Wood Biomass Thermal 10 MW Portfolio Option Present Value Costs
(2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁴
No DSM/SSE					
Base Case	111.8	52.8		164.6	0.0
Scenario A	243.0	43.5		286.5	3.0
Scenario B	306.8	46.5		353.3	-10.3
With DSM/SSE					
Base Case	30.8	31.9	35.4	98.1	0.0
Scenario A	203.5	22.5	35.4	261.4	57.4
Scenario B	263.7	25.8	35.4	325.0	43.8

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Wood biomass costs (10 MW); wood at \$96/t. Assumes diesel fuel & O&M units for all diesel not displaced by Project.
3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Portfolio Option Present Value Costs.

**Table E4-6B: Wood Biomass Thermal 15 MW Portfolio Option Present Value Costs
(2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁴
No DSM/SSE					
Base Case	111.8	52.8		164.6	0.0
Scenario A	253.5	37.8		291.3	7.8
Scenario B	313.2	40.3		353.5	-10.2
With DSM/SSE					
Base Case	30.8	31.9	35.4	98.1	0.0
Scenario A	230.2	17.4	35.4	283.0	79.0
Scenario B	279.6	19.7	35.4	334.8	53.6

1. Costs discounted at 6.56% per year YEC blended cost of capital.
2. Wood biomass costs (15 MW); wood at \$104/t. Assumes diesel fuel & O&M units for all diesel not displaced by Project.
3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
4. See Diesel Portfolio Option Present Value Costs.

SUMMARY

Lack of feedstock supply security has been identified as a significant project risk that will require mitigation prior to any wood biomass project development in Yukon. Within the range of wood biomass plant options examined to date for Yukon, the least cost option (lowest LCOE) would appear to be a smaller scale plant (10 to 15 MW) located at the Minto burn area. Earliest potential in-service for any

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

biomass plant has been assumed to be late in 2014. Wood biomass options are also noted to be under active consideration for direct use in district or other local heating in Whitehorse and Dawson.

Figure E4-7 summarizes the estimated Full Utilization LCOE and Forecast LCOE (\$2010) at Scenario A load with DSM/SSE for the 25 MW, 15 MW and 10 MW wood biomass plant options reviewed under different mine load sensitivities.

- Forecast LCOE under Scenario A load with DSM/SSE range from 58-61 cents per kW.h for the 10-15 MW plants located at the Minto burn area to 92.5 cents per kW.h for the 25 MW plant located at Whitehorse.
- The smaller plants (10 MW and 15 MW) show broadly similar LCOE for Scenario A load with DSM/SSE, and for each mine load sensitivity examined – with Forecast LCOE dropping sharply as mine loads are extended to the end of 2025, and then extended to the end of 2030.
- Forecast LCOE for the 10 MW and 15 MW plants remain high (approximately 29 cents per kW.h) even under mine load Sensitivity #2 (mine loads extended to end of 2030).
- Forecast LCOE for the 25 MW plant is considerably higher than for the smaller 10 MW or 15 MW plants for Scenario A load with DSM/SSE, and for each mine load sensitivity examined, e.g., Forecast LCOE for 25 MW plant approximates 43 cents per kW.h under mine load Sensitivity #2 (mine loads extended to end of 2030).
- Inclusion of potential district heat revenues for a 25 MW plant located in Whitehorse reduces, but does not materially change, Forecast LCOE (this reflects the relatively small scale of estimated district heat revenues relative to overall plant fuel and other costs). For the smaller plant scales, biomass feedstock cost savings by locating in the Minto burn area more than offset loss of district heat revenues that are assumed to be secured by locating in Whitehorse.

Overall, compared to BC, the above assessment demonstrates the extent to which the Yukon situation affecting biomass thermal plant development is severely impacted by the small scale of the grid load requirement (forcing consideration of less than optimum sized plants from the viewpoint of cost efficiencies), the impact of current hydro generation at forecast loads (removes material opportunity to displace diesel generation for five months of the year and during higher water years), the lack of an established large scale forest industry (with lower cost waste wood supplies plus on-site uses for biomass plant waste heat and power), the absence of intertie capability to sell surplus generation at market prices, and the higher costs in Yukon relative to BC.

In summary, high costs and lack of flexibility due to the factors noted above result in the wood biomass thermal option not being a cost effective option to develop at this time. Further, due to the high costs

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

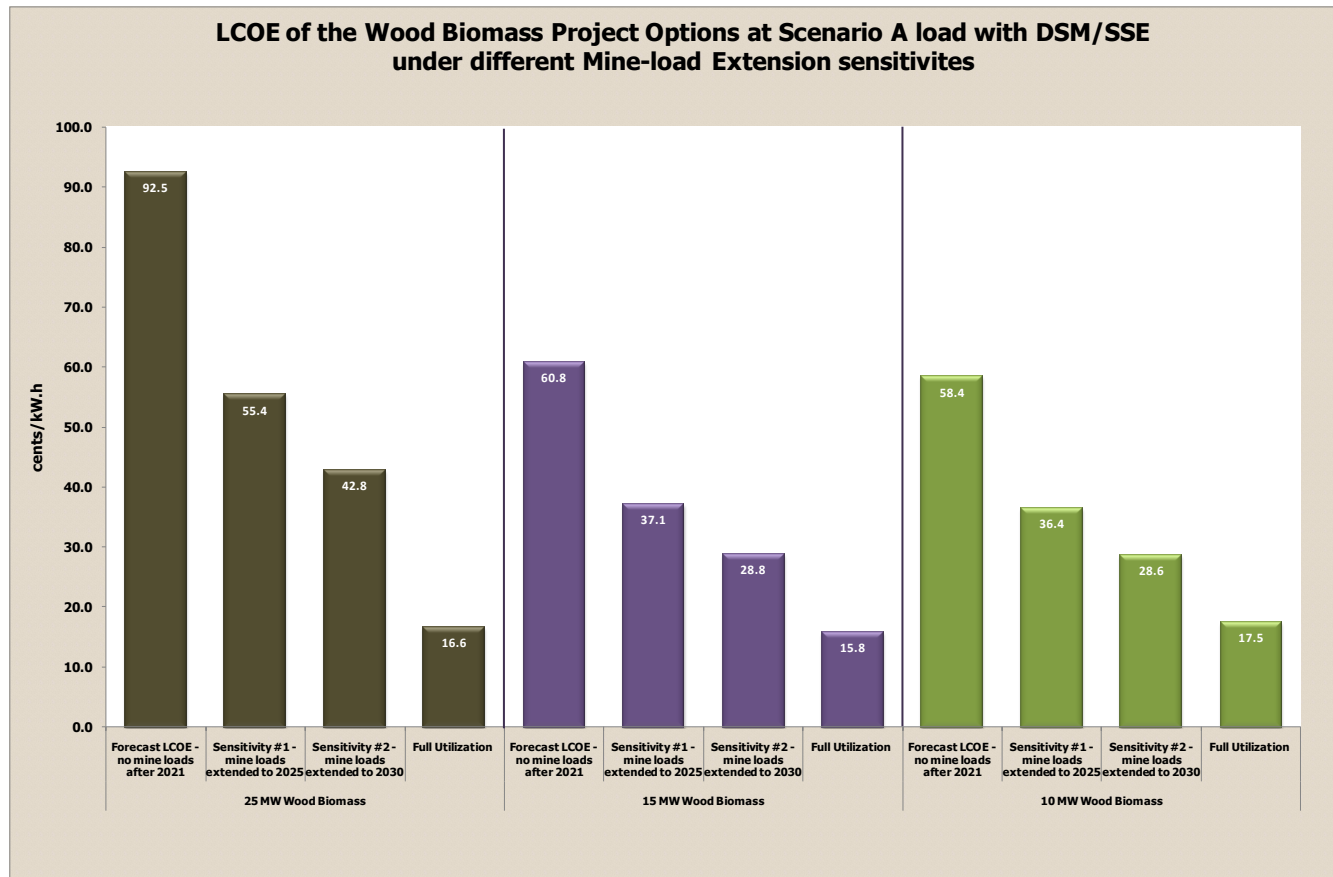
- 1 noted, there is no apparent basis (assuming current commercial technology) to reconsider this option in
- 2 the planning period unless very large new baseloads were to be connected to the grid or an inertia
- 3 connection was to be developed (i.e., until there are conditions to fully utilize all biomass thermal
- 4 generation over the year on a sustained basis from a 25 MW plant) and/or grants or other no cost
- 5 funding were provided sufficient to enable a specific wood biomass project to be cost effective on a
- 6 sustained basis for utility power generation. Monitoring of the commercialization of new technologies may
- 7 also indicate new opportunities in the future for smaller scale wood biomass thermal plants that are more
- 8 cost efficient than those currently available.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1

Figure E4-7: Summary LCOE (2010\$) of Wood Biomass Plant Options at Scenario A Load with DSM/SSE



2

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20-Year Resource Plan: 2011-2030

December 2011

1 **WASTE TO ENERGY**

2 **BACKGROUND**

3 Use of solid municipal waste for thermal generation at smaller plant sizes is subject to the same economic
4 constraints related to fixed costs (including fixed operating and maintenance costs) as reviewed above for
5 wood biomass thermal plants. These costs do not fall dramatically for smaller scale operations or loads
6 and economic viability typically hinges on large and constantly running facilities – factors which are not
7 easily compatible with current Yukon conditions.

8 Location of a waste biomass thermal plant in Whitehorse would enable the new capacity to displace
9 diesel capacity; it would also potentially create opportunities for waste heat use (e.g., district heating).
10 Baseload operation at a high capacity factor, however, would be expected to ensure efficient use of
11 capital and of the waste resource. Sizing of such a facility would initially be based on estimates of
12 available solid municipal waste.

13 **Energy Charrette**

14 The Energy Charrette paper and presentation by Don McCallum provided a summary of assessment work
15 done to that time for Yukon Energy regarding the municipal waste thermal generation option at
16 Whitehorse. Key features for this option as noted in this background paper include:

- 17 • Using conventional technology, facilities could be available in 3-5 years if an aggressive approach
18 to technology selection and regulatory approvals is taken (more than 5 years would be needed if
19 seek to use advanced technology).
- 20 • Approximately 25,000 tonnes per year of municipal solid waste could be available in Whitehorse
21 to generate between 7.5 and 15 GW.h per year of electricity (implies small plant scale at roughly
22 1 to 2 MW). Estimated generation costs are between 15 and 40 cents per kW.h for a Whitehorse
23 plant costing from \$15 to \$30 million (the cost estimates assume the facility receives tipping fee
24 revenue). Additional waste heat (40 GW.h equivalent) could also be provided. The paper notes
25 that the wide cost ranges reflects “current uncertainty in capital and operational costs and energy
26 recovery efficiencies”.
- 27 • Average daily waste volumes generated in winter at Whitehorse can be less than half what is
28 provided in the spring and summer months. The Charrette paper notes, while these facilities can
29 generate firm baseload power the waste volumes in Whitehorse follow seasonal trends that are
30 opposite the seasonal power requirements of the system. In this respect the seasonal variability
31 of waste means that absent alternate or supplementary feedstocks (such as wood waste) a plant
32 would be operating at lowest efficiency during period of highest demand on the system.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 • This option would provide material GHG reduction opportunities, both through avoided methane
2 emissions at the landfill and through reduced diesel generation emissions.

3 See also the wood biomass Background regarding “Other Yukon Experience” for a review of other Yukon
4 biomass development activities and studies, including recent studies and developments regarding district
5 heating using various forms of biomass.

6 **BC Hydro Experience**

7 BC Hydro’s draft 2010 Resource Options Report for its 2011 Integrated Resource Plan provides current
8 BC assessments related to the municipal solid waste power production option. BC Hydro notes that at
9 least 100,000 tonnes per year of municipal solid waste are required to make a waste to energy facility
10 economically feasible; BC Hydro further notes that plants would operate at a high capacity factor with 0.6
11 MWh per tonne conversion (implies minimum plant output of 60 GW.h/year).

12 **Recent YEC Summary Study**

13 In July 2011, Morrison Hershfield provided Yukon Energy with a draft summary report “Waste to Energy
14 Business Case Analysis (DRAFT) – Summary Report” which examined municipal solid waste (MSW) as a
15 feedstock in a thermal process to provide increased firm electrical generation capacity as well as potential
16 use of waste heat (from the generation process) in a future District Heating System in Whitehorse.

17 Total post-recycling MSW potentially available for a Whitehorse waste to energy (WTE) facility is
18 estimated in the report at 27,052 ODT/year; up to an added 5,000 ODT per year of currently unused
19 Haines Junction area sawmill waste is also identified as potentially available at an assumed delivered cost
20 of \$150/ODT. The assumed location of the WTE facility is on the South Access Highway adjacent to YEC’s
21 generation facility. District heat sales from this location are assumed to be limited to Zones #1 and #2 as
22 defined in the Stantec study (excludes downtown Zone #3).

23 This potential MSW feedstock supply and assumed plant location provide the basis for a small power
24 plant (potential options identified range from 1.4 to 2.2 MW, assuming year round operation at annual
25 capacity factor ranging between 88 to 89%. A key factor affecting plant power supply costs is assumed
26 recovery of net revenues from district heat (approximately \$1.6 to \$1.8 million per year) plus tipping fees
27 (range \$1.05 to \$1.36 million/year) and carbon credits (range \$0.03 to \$0.07 million per year)³⁸.

28 Three scenarios were examined in the report for waste to energy (WTE) electricity generation in
29 Whitehorse using controlled air combustion to heat a boiler for steam turbine generation of electricity.

³⁸ A tipping fee of \$54.25 per ODT FOB the plant of MSW and carbon credit revenue at \$25/tonne were assumed for the preliminary analysis (carbon credits based on diesel oil displacement for electricity generation and fuel oil displacement for heating of buildings).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 **1. Scenario 1:** WTE facility with annual capacity of 30,000 ODT MSW - designed to maximize MSW
2 use without supplemental biomass feedstock (means lower utilization of the WTE facility during
3 winter). The report estimates an annual present value cost over the 25 year project life of \$0.18
4 per kWh (\$0.30 per kW.h excluding district heat revenues) based on the following:
- 5 ○ 13.9 GW.h/year total energy generated (562 kW.h/ODT);
 - 6 ○ 1.8 MW generation facility (88% annual capacity factor, using 24,750 ODT/year of
7 MSW);
 - 8 ○ Capital cost at \$38.6 million (\$21.4 million per MW, including 25% contingency);
9 assuming a real cost of capital at 5.5%/year and 25 year operating life, annual capital
10 costs were estimated at approximately \$2.92 million;
 - 11 ○ Operating cost at \$2.68 million/year (after 15% contingency); and
 - 12 ○ Operating revenue at \$3.04 million (excludes power sales), including revenue from
13 district heat at \$1.60 million per year (assumed net revenue after all related costs),
14 assumed tipping fee revenue (\$54.25/ODT) of \$1.34 million/year and revenue from sale
15 of recyclables and carbon credits (\$0.10 million/year).
- 16 **2. Scenario 2:** WTE facility with annual capacity of 20,000 ODT MSW - designed to maximize WTE
17 facility use without supplemental biomass feedstock (means less MSW use in summer). The
18 report estimates an annual present value cost over the 25 year project life cost of \$0.16 per kWh
19 (\$0.31 per kW.h excluding district heat revenues)³⁹ based on the following:
- 20 ○ 10.8 GW.h/year total energy generated (562 kW.h/ODT);
 - 21 ○ 1.4 MW generation facility (88% annual capacity factor, using 19,290 ODT/year of
22 MSW);
 - 23 ○ Capital cost at \$29.61 million (\$21.15 million per MW, including 25% contingency);
24 assuming a real cost of capital at 5.5%/year and 25 year operating life, annual capital
25 costs were estimated at approximately \$2.24 million;
 - 26 ○ Operating cost at \$2.23 million/year⁴⁰ (after 15% contingency); and
 - 27 ○ Operating revenue at \$2.76 million (excludes power sales), including revenue from
28 district heat at \$1.60 million per year (assumed net revenue after all related costs),

³⁹ These estimates appear to exclude approximately \$0.10 million of assumed labour costs – adjusted for this amount, the annual cost becomes \$0.17 per kW.h and \$0.32 per kW.h without district heat revenue.

⁴⁰ As stated – understates correct cost (with 15% contingency) by approximately 0.11 million based on assumed staff cost per person of \$80k per year and 14 persons.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 assumed tipping fee revenue (\$54.25/ODT) of \$1.05 million/year and revenue from sale
2 of recyclables and carbon credits (\$0.11 million/year).

3 **3. Scenario 3:** WTE facility with annual capacity of 30,000 ODT MSW - designed to maximize WTE
4 facility use with 3,800 ODT/year supplemental biomass feedstock in winter. The report estimates
5 an annual cost present value cost over the 25 year project life of \$0.16 per kWh (\$0.27 per kWh
6 excluding district heat revenues)⁴¹ based on the following:

- 7 ○ 17.07 GW.h/year total energy generated (593 kW.h/ODT);
- 8 ○ 2.2 MW generation facility (89% annual capacity factor, using 24,990 ODT/year of MSW
9 and 3,790 ODT of wood biomass);
- 10 ○ Capital cost at \$39.0 million (\$17.7 million per MW, including 25% contingency);
11 assuming a real cost of capital at 5.5%/year and 25 year operating life, annual capital
12 costs were estimated at approximately \$2.94 million;
- 13 ○ Operating cost at \$2.58 million/year⁴² (after 15% contingency but including \$0.57 million
14 for wood supply at \$150 per ODT); and
- 15 ○ Operating revenue at \$3.29 million (excludes power sales), including revenue from
16 district heat at \$1.79 million per year (assumed net revenue after all related costs),
17 assumed tipping fee revenue (\$54.25/ODT) of \$1.36 million/year and revenue from sale
18 of recyclables and carbon credits (\$0.15 million/year).

19 In summary, annual cost of electricity production for 13.9 to 17.1 GW.h/year generation from MSW and
20 biomass is estimated in the report to range between \$0.16-\$0.18 per kW.h, assuming district energy
21 sales (cost increases to between \$0.27-0.31 per kW.h if no district energy sales).

- 22 • With district energy sales, the highest generation scenario (Scenario 3) is the least cost option on
23 a per kW.h basis, while Scenario 1 has the highest cost per kW.h.
- 24 • With no district energy sales, the above cost ranking is retained for Scenario 3 (as least cost
25 option); however, Scenario 2 has the highest cost per kW.h.

⁴¹ These estimates appear to exclude approximately \$0.10 million of assumed labour costs – adjusted for this amount, the annual cost becomes \$0.17 per kW.h and \$0.28 per kW.h without district heat revenue.

⁴² As stated – understates correct cost (with 15% contingency) by approximately 0.11 million based on assumed staff cost per person of \$80k per year and 14 persons.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **OPTION ASSESSMENT**

2 For preliminary planning assessment purposes, a WTE facility is assumed to be developed by late 2014
3 within the feedstock and power generation scale ranges examined by the most recent Morrison Hershfield
4 study (i.e., between 1.4 – 2.2 MW); this facility is assumed to be located adjacent to YEC's existing
5 Whitehorse generation facilities, with capital costs, operating costs, district heating sales and other
6 revenues generally as assumed in the Morrison Hershfield (MH) study (except that wood costs are
7 assumed at \$75/ODT rather than \$150/ODT⁴³ and corrected labour costs are adopted as noted). The
8 WTE is assumed to have a 25 year economic life, and YEC's blended cost of capital at 6.56% (4.47% real
9 cost of capital net of inflation).

10 Full Utilization LCOE (2010\$) based on the above assumptions is as follows for each of the three WTE
11 options examined⁴⁴:

- 12 • **1.8 MW facility generating approximately 13.9 GW.h/year** (as defined in Scenario 1 of
13 MH study [MSW maximized – no wood biomass]):
 - 14 ○ Full Utilization LCOE of 15.8 cents/kW.h with district heat sales; and
 - 15 ○ Full Utilization LCOE of 27.1 cents/kW.h with no district heat sales, 36.6 cents/kW.h with
16 no tipping fees and no district heat sales.
- 17 • **1.4 MW facility generating approximately 10.8 GW.h/year** (as defined in Scenario 2 of
18 MH study [WTE utilization maximized, no wood biomass]):
 - 19 ○ Full Utilization LCOE of 14.3 cents/kW.h with district heat sales; and
 - 20 ○ Full Utilization LCOE of 28.7 cents/kW.h with no district heat sales, 38.2 cents/kW.h with
21 no tipping fees and no district heat sales.
- 22 • **2.2 MW facility generating approximately 17.07 GW.h/year** (as defined in Scenario 3 of
23 MH study [MSW and WTE utilization maximized, supplement with 3,800 ODT/year wood biomass
24 at \$75/ODT cost]):
 - 25 ○ Full Utilization LCOE of 13.5 cents/kW.h with district heat sales and with tipping fees; and

⁴³ Only 3,800 ODT are assumed to be required, and this supply is stated to be available from the Haines Junction area from sawmill and harvest residues that are currently not utilized. Based on costs per ODT assumed for the wood biomass plant assessment and 180 km haul distance, haul costs would approximate \$52.31/ODT, leaving \$22.68/ODT to cover any other costs or charges for collection of sawmill and harvest residues, i.e., the WTE case differs materially from the wood biomass plant case where a full harvest cost of \$89.72/ODT was also required.

⁴⁴ The Full Utilization LCOE costs per kW.h for the 1.4 and 1.8 MW options differ from MH study annual cost estimates per kW.h due to a lower real cost of capital (4.47% versus 5.5%) and (for the 1.4 MW option) the corrected labour cost. For the 2.2 MW option, Full Utilization LCOE also differs from the MH study annual cost estimates per kW.h due to the 3,800 ODT of wood biomass costs being reduced by 50% and the corrected labour cost.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 ○ Full Utilization LCOE of 23.7 cents/kW.h with no district heat sales, 31.4 cents/kW.h with
2 no tipping fees and no district heat sales.

3 In summary, Full Utilization LCOE costs for the above three WTE options range between 13.5 and 15.8
4 cents per kW.h with district heat revenues, between 23.7 and 28.7 cents per kW.h with no district heat
5 revenues, and between 31.4 and 38.2 cents per kW.h with no district heat revenues and no tipping fees.
6 Reflecting the assumed wood biomass costs at \$75/ODT, the 2.2 MW option has the lowest Forecast
7 LCOE both with and without district heat revenues.

8 Forecast diesel generation displacement was examined for these three WTE options based on a grid load
9 of 545 GW.h/year that approximates Scenario A loads in 2015⁴⁵. The following observations are noted:

- 10 • Forecast diesel displacement increases as plant scale increases, i.e., the 2.2 MW plant provides
11 the highest diesel displacement and the 1.4 MW plant provides the lowest diesel displacement,
12 reflecting the differing levels of annual generation.
- 13 • In addition to directly displacing diesel during winter and spring months, each WTE option
14 displaces average water year hydro generation from May until early December, with some (but
15 not all) of this hydro displacement being stored and used to displace diesel during December to
16 early May. The 1.4 and 2.2 MW options minimize the share of annual WTE generation being used
17 to displace hydro, while the 1.8 MW option has roughly 50% of its generation during the five
18 low-diesel generation months from June to October inclusive.

19 Based on the above considerations, subsequent assessment has focused on the 2.2 MW option (as it is
20 has the biggest diesel displacement and lowest Full Utilization LCOE cost per kW.h). Table E4-7 Forecast
21 LCOE (2010\$) for the 2.2 MW WTE facility in Whitehorse over a 25 year life is as follows, assuming first
22 full year of operation in 2015 (district heat revenue is assumed in all Forecast LCOE - based on the earlier
23 analysis, the WTE facility feasibility appears to be contingent on substantially securing this assumed
24 revenue):

- 25 • Forecast LCOE is 44.7 cents/kW.h under Base Case loads with DSM/SSE (19.9 cents/kW.h with
26 no DSM/SSE).
- 27 • Forecast LCOE is 31.5 cents/kW.h under Scenario A loads with DSM/SSE (17.6 cents/kW.h with
28 no DSM/SSE; costs with DSM/SSE are 73.5 cents/kW.h before offset revenues for tipping fees
29 (17.9 cents per kW.h) and district heat revenues (24.1 cents per kW.h).

⁴⁵ The same load and diesel generation with and without DSM/SSE as assumed in the Table E4-1 assessment of 10 MW to 25 MW scale biomass plant impacts on diesel displacement after DSM/SSE.

Yukon Energy Corporation

20-Year Resource Plan: 2011-2030

December 2011

- 1 • Forecast LCOE is 28.8 cents/kW.h under Scenario B loads with DSM/SSE (16.8 cents/kW.h with
2 no DSM/SSE); costs with DSM/SSE are 67.1 cents/kW.h before offset revenues for tipping fees
3 (16.4 cents per kW.h) and district heat revenues (21.9 cents per kW.h).

4 **Table E4-7: WTE Option Impacts on Diesel Generation (2.2 MW)**
5 **(GW.h of diesel displaced by year over 25 year plant life: 2014-2038)**

	Base Case	Scenario A	Scenario B
	GW.h	GW.h	GW.h
2014	7	13	14
2015	7	13	15
2016	7	13	15
2017	7	13	15
2018	7	13	15
2019	8	13	15
2020	5	13	14
2021	0	0	2
2022	0	0	0
2023	0	0	0
2024	1	1	1
2025	2	2	2
2026	2	2	2
2027	3	3	3
2028	4	4	4
2029	4	4	4
2030	5	5	5
2031	5	5	5
2032	6	6	6
2033	7	7	7
2034	7	7	7
2035	7	7	7
2036	8	8	8
2037	8	8	8
2038	9	9	9

7 As reviewed in Table E4-7, the high Forecast LCOE for the WTE 2.2 MW option reflects the extent to
8 which there are no material diesel displacement opportunities currently forecast after 2020, assuming
9 mine loads end as currently forecast and DSM/SSE reduces non-industrial loads as assumed. By way of
10 example, looking at the Scenario A loads, Forecast LCOE would be reduced if forecast mine loads under
11 Scenario A were to be extended by 5 to 10 years:

- 12 • If assumed mine loads were to be extended sufficiently to maintain 13 GW.h/y of diesel
13 displacement (see Table E4-7) to the end of 2025, the Forecast LCOE would be reduced from
14 31.5 cents per kW.h to 22.3 cents per kW.h; costs are 52.1 cents/kW.h before offset revenues
15 for tipping fees (12.7 cents per kW.h) and district heat revenues (17.1 cents per kW.h).

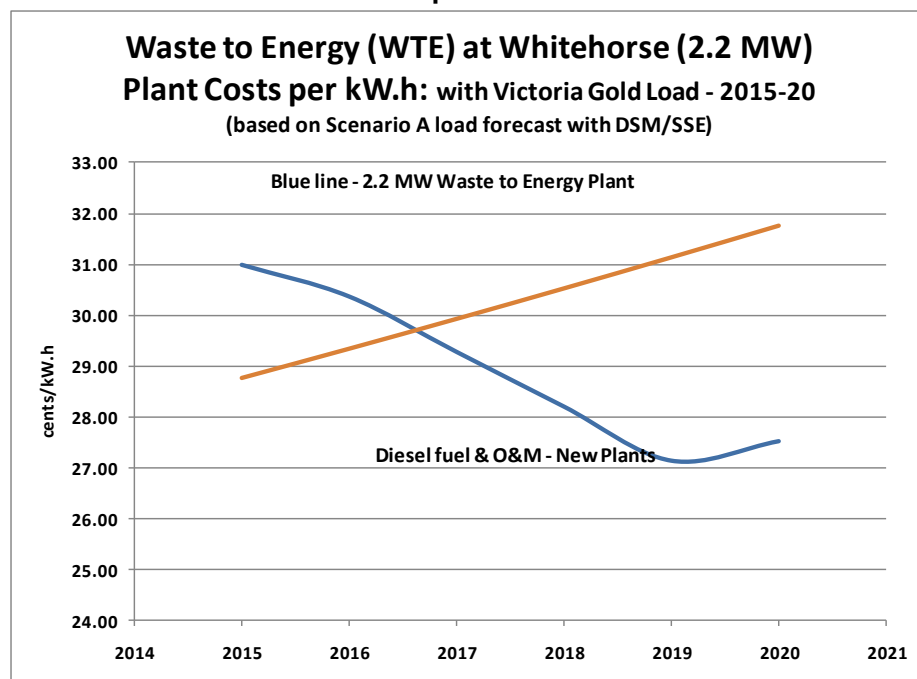
Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 • Extending this same level of diesel displacement to 2030 would reduce Forecast LCOE to 19.0
2 cents per kW.h; costs are 44.3 cents/kW.h before offset revenues for tipping fees (10.8 cents per
3 kW.h) and district heat revenues (14.5 cents per kW.h).

4 Aside from the impacts due to shutting down of mine loads, Figure E4-8 shows fuel and O&M costs per
5 kW.h for new diesel plants and total costs for a 2.2 MW WTE thermal plant during the brief period 2014-
6 2020 under Scenario A when the Victoria Gold mine load is assumed to be connected to the grid.
7 Reflecting the capital intensive nature of the WTE annual costs, annual costs for the WTE option initially
8 (2014) approximate 35 cents per kW.h of diesel displaced, declining to 30.5 cents per kW.h of diesel
9 displaced by 2019. During the period to 2020, WTE annual costs per kW.h of diesel remain above diesel
10 fuel and O&M costs until after 2018.

Figure E4-8: 2.2 MW WTE Thermal Plant vs. Diesel Fuel & O&M Costs:
Annual Cents per kW.h – 2015-20



13
14 Table E4-8 provides an overall present value of the estimated costs required over the 20-year planning
15 period (2011-2030) with the 2.2 MW WTE thermal plant option for load Scenarios A and B – diesel fuel
16 and added capacity is assumed to be retained for 2011-2013 under Scenario's A and B (before the WTE
17 plant is established) and for new capacity requirements not covered by the WTE plant. As noted, due to
18 the plant's location, full capacity benefits are assigned to the WTE plant. Present value cost changes
19 relative to the Default Diesel Portfolio option range as follows:

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20-Year Resource Plan: 2011-2030

December 2011

- 1 • Base Case present value cost is increased by \$11.9 million with DSM/SSE and is reduced by \$4.5
- 2 million with no DSM/SSE;
- 3 • Scenario A present value cost is increased by \$4 million with DSM/SSE and is reduced by \$9.8
- 4 million with no DSM/SSE; and
- 5 • Scenario B present value cost is increased by \$1.6 million with DSM/SSE and is reduced by \$11.9
- 6 million with no DSM/SSE.

**Table E4-8: WTE Thermal 2.2 MW Portfolio Option Present Value Costs
(2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁵
No DSM/SSE					
Base Case ⁴	109.9	50.2		160.1	-4.5
Scenario A ⁴	220.6	53.1		273.7	-9.8
Scenario B ⁴	295.5	56.3		351.8	-11.9
With DSM/SSE					
Base Case ⁴	45.1	29.5	35.4	110.0	11.9
Scenario A ⁴	140.7	32.0	35.4	208.1	4.0
Scenario B ⁴	211.7	35.7	35.4	282.8	1.6

1. Costs discounted at 6.56% per year YEC blended cost of capital.

2. Assumes diesel fuel & O&M cost for remaining diesel generation.

3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.

4. Plant estimates assume 2.2 MW at Whitehorse.

5. See Diesel Portfolio Option Present Value Costs.

SUMMARY

A 2.2 MW WTE facility could potentially be in operation by late 2014 in Whitehorse using MSW supplemented during winter with minimal (3,800 ODT) wood biomass sawdust and harvest residues, and with plant heat used to provide district heat net revenues approximating \$1.8 million per year.

Figure E4-9 summarizes the estimated Full Utilization LCOE and Forecast LCOE (\$2010) per kW.h of diesel displaced at Scenario A load with DSM/SSE for this facility (annual generation approximating 17.1 GW.h for 25 years) reviewed under different mine load sensitivities.

- Forecast LCOE of 31.5 cents/kW.h under Scenario A load with mine loads ending in 2021.
 - LCOE costs are 73.5 cents/kW.h before offset revenues for tipping fees (17.9 cents per kW.h) and district heat revenues (24.1 cents per kW.h).

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20-Year Resource Plan: 2011-2030

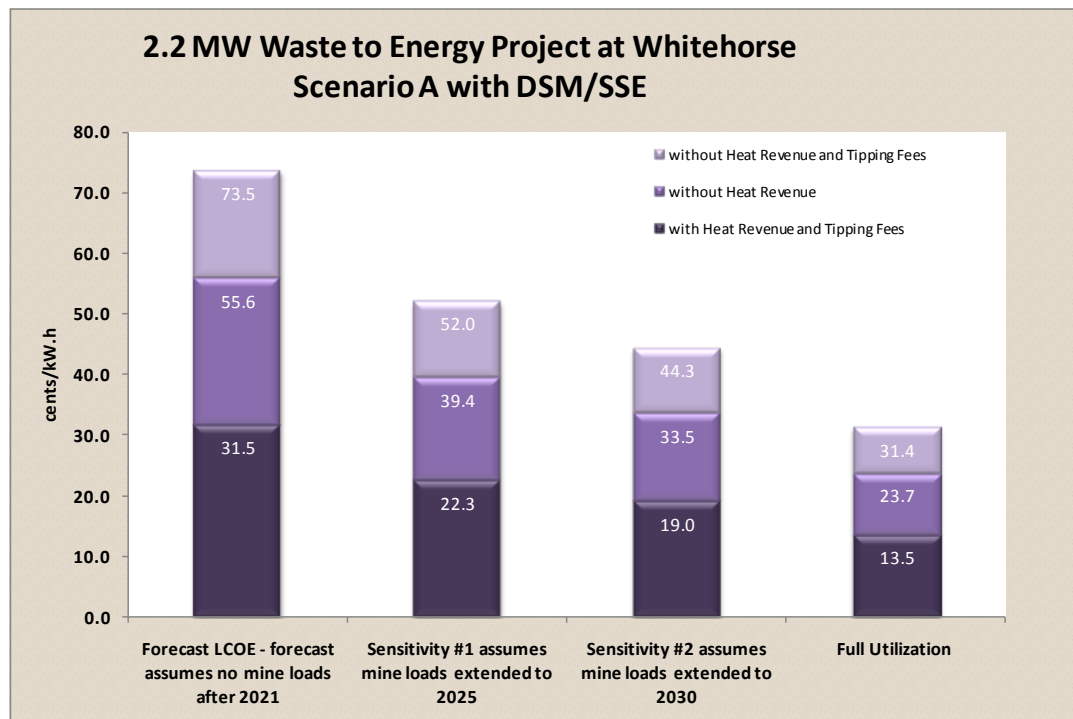
December 2011

- 1 ○ As reviewed in Figure E4-7, annual costs (net of tipping fees, district heat and other non-
- 2 power revenues) for the WTE option during the period when mine loads are connected
- 3 initially (2015) approximate 31 cents per kW.h of diesel displaced, declining to 27.1 cents
- 4 per kW.h of diesel displaced by 2019.
- 5 ○ Table E4-8 shows that overall present value cost of the WTE option portfolio to the end
- 6 of 2030 exceeds the cost of the default diesel portfolio over the same period under Base
- 7 Case, Scenario A or Scenario B loads with DSM/SSE (but is less costly than diesel under
- 8 Base Case, Scenario A or Scenario B loads with no DSM/SSE), reflecting the higher
- 9 forecast diesel generation after 2021 with no DSM/SSE.
- 10 • Forecast LCOE drops to 22.3 cents/kW.h under mine load Sensitivity #1 (mine loads extended to
- 11 end of 2025), and to 19.0 cents/kW.h under mine load Sensitivity #2 (mine loads extended to
- 12 end of 2030).
- 13 ○ This change in LCOE reflects the added ability to utilize WTE generation to displace diesel
- 14 generation after 2020.
- 15 ○ Without extension of load levels after 2020, the value of the WTE facility to displace
- 16 diesel generation is greatly reduced.
- 17 • District heat revenues are assumed throughout the LCOE analysis, and commitments to provide
- 18 such sales may limit ability to curtail plant operation in years when no material diesel
- 19 displacement opportunities exist.
- 20 Without new mine loads as assumed in Scenario A or Scenario B, annual diesel displacement under Base
- 21 Case load with assumed DSM/SSE is forecast to be less than half of the plant's annual generation for 24
- 22 of the 25 operating years (2014-2038) - and the plant's present value costs would be \$11.9 million higher
- 23 than the diesel costs displaced over its life.
- 24 With new mine loads connected as assumed in Scenario A or Scenario B, 70 to 90% of the plant's annual
- 25 generation would go to displace diesel during the first seven operating years - however, the plant's
- 26 present value costs would still be \$1.6 to \$4 million higher than the diesel costs displaced over its life.
- 27 Extension of the life of these connected mine loads to 2025 or longer could potentially provide sufficient
- 28 sustained utilization of the WTE facility to create present value cost savings relative to the diesel costs
- 29 displaced.

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20-Year Resource Plan: 2011-2030

December 2011

**Figure E4-9: Summary LCOE (2010\$) of WTE 2.2 MW Option at Scenario A
Load with DSM/SSE**



LNG/ NATURAL GAS

BACKGROUND

Yukon to date has relied upon diesel as the default low capital cost flexible and reliable electricity generation source. In areas where natural gas is available, however, diesel would be displaced by lower cost natural gas resources. Alaska, for example, has devoted considerable time and energy to natural gas generation given the availability of gas in many key communities. Accessible natural gas is expected today to offer dramatically lower incremental fuel costs than diesel fuel, e.g., 2020-21 (\$2010) fuel costs per kW.h of 6-7 cents versus the 24-25 cent range currently applicable for most of Yukon⁴⁶.

Current natural gas and oil market conditions have created a major divergence between natural gas and diesel fuel prices (on an energy equivalent basis) to the point where natural gas can be considered as a potential resource to displace diesel generation in Yukon, using trucked-in liquid natural gas (LNG) that,

⁴⁶ At a gas price (2010\$) of \$7 per MMBTU in 2020-21 (i.e., a price consistent with January 2011 BC Hydro mid-price forecasts, taking into account potential impacts of shale gas), natural gas thermal generation fuel costs for simple cycle options could approximate 6 cents/kW.h (lower costs would apply to combined cycle options).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 after LNG processing and the required transport, may still be materially less costly than diesel generation.
2 Trucked-in LNG, with its added costs, would be used until such time as local natural gas supplies are
3 made available through the Alaska Highway Pipeline Project (AHPP), pipeline access from NWT (e.g.,
4 Canol road route) and/or development of Yukon natural gas supplies such as the Eagle Plains resource⁴⁷.
- 5 Natural gas generating units offer well established and reliable technology with many of the same key
6 features relevant to Yukon use as noted in Attachment E2 for diesel generation. Other than being
7 forecast to use a less costly fuel that has lower GHG and other emissions, natural gas units retain the
8 flexibility and reliability that characterize the diesel thermal option. Key features of this option include:
- 9 • Relatively low capital costs, e.g., approximately \$1.2-1.5 million per MW for simple cycle unit
10 installed with all related facilities) with options for “scalable” generation over a wide range of
11 sizes, as well as options for combined cycle and cogeneration (with associated higher capital
12 costs at about \$1.8 million per MW).
 - 13 • Units that can be permitted, purchased and installed within reasonably short time periods (i.e.,
14 usually well under 2 years) and be reliably operated over an economic life of 20-25 years; units
15 can also be located at load centres (minimize transmission requirements).
 - 16 • Operating costs that are mostly composed of fuel cost that is subject to ongoing inflation and
17 market price uncertainty.
 - 18 ○ Simple cycle operation fuel efficiencies of approximately 35% to over 40% (8.5-9.5 Mcf
19 per MW.h), with non-fuel O&M costs at 1-2 cents/kW.h over a wide range of plant scales
20 relevant to Yukon; simple cycle operating flexibility (including ability to achieve full
21 production relatively quickly).
 - 22 ○ Combined cycle operation offers higher fuel efficiencies (approximately 48-52% or about
23 7.3 Mcf per MW.h for electricity generation at potentially relevant plant sizes for the
24 Yukon grid), but slightly increases plant non-fuel operating costs (still likely 1-2 cents per
25 kW.h); compared to simple cycle, longer start-up times are required for the steam plant
26 in combined cycle options, i.e., this option typically would be limited to continuous base
27 load operation rather than intermittent or peaking operation.
 - 28 • Cleaner environmental impacts than with diesel generation, e.g., GHG for simple cycle operation
29 at approximately 30-34% less than diesel fuel (about 456 to 500 tonnes per GW.h)⁴⁸; regulated

⁴⁷ See Appendix F, Attachment F2 review of pipeline/natural gas supply event possibilities. The Alaska Highway Pipeline Project (AHPP) may bring natural gas along the Alaska Highway by 2020-21, radically changing the default option in Yukon for electricity generation.

⁴⁸ 34% estimate (and 456 tonnes per GW.h estimate) per internal working papers prepared for Oil and Gas Resource Branch, Yukon Department of Energy, Mines and Resources.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 health air emission effects re: NOx, SO2 and particulates also typically materially lower than
2 diesel fuel emissions; reduced potential concerns re: fuel spills effects (including storage tank
3 leaks) compared with diesel fuel.

4 In effect, natural gas power plants are intended to be operated only when required and (subject to
5 securing fuel supply) can be relatively easily integrated into the Yukon system as conversion or
6 replacement of the current diesel generation plant. Accordingly, and particularly in light of planned
7 retirement of all of YEC's diesel plant over the 20-year planning period and the grid's capacity planning
8 requirements, the LNG/natural gas option can be potentially relevant under all load scenarios.

9 Natural gas thermal generation as discussed at the Energy Charrette⁴⁹ uses natural gas reciprocating
10 engines or gas turbines to generate electricity, initially using trucked-in liquid natural gas (LNG). The
11 LNG/natural gas option was characterized at the Energy Charrette as medium cost (approx 15+
12 cents/kW.h), very flexible (low capital cost, save fuel and operating costs when no loads), very reliable
13 (provides peaking and reserve capacity, low regulatory risk to secure permits/approvals), and
14 environmentally responsible relative to diesel generation (over 30% lower GHG emissions than diesel, but
15 not renewable.

16 Aside from accessibility, a key factor affecting this option is natural gas prices which are subject to
17 ongoing inflation and market price uncertainty. The following observations derive from BC Hydro's latest
18 (January 2011) Integrated Resource Plan natural gas price forecast⁵⁰:

- 19 • Supply softness has driven gas prices to historically low levels; shale gas is expected to
20 contribute to ongoing low prices although uncertainty about environmental issues and timing of
21 development of new shale gas reserves means BC Hydro is considering different scenarios with
22 relatively large price ranges.
- 23 • BC Hydro's High gas price scenario assumes prices around \$10/MMBTU escalating to about
24 \$13/MMBTU by 2027 (\$2010); assumes shale gas either cannot be developed due to
25 environmental concerns or is very slow to develop.
- 26 • BC Hydro's Low gas price scenario assumes prices (\$2010) around \$4/MMBTU escalating to about
27 \$5.5/MMBTU by 2027.
- 28 • BC Hydro's Mid gas price scenario assumes prices (\$2010) start around \$4/MMBTU and escalate
29 to about \$7/MMBTU by about 2020 and about \$7.5/MMBTU by 2027.

⁴⁹ See papers and presentations by David Dunn (Natural Gas) and Cam Osler (Diesel and Thermal Generation Options).

⁵⁰ BC Hydro Integrated Resource Plan: "Long-Term Natural Gas Price Forecast" by Dave Ince. BC Hydro notes that natural gas prices are the single biggest variable contributing to spot market electricity prices affecting BC Hydro's market region.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 LNG import to Yukon has recently been identified as an available near-term gas supply option prior to
2 AHPP or other local Yukon gas supply development - and use of LNG would ensure that the thermal
3 electricity generation so developed could switch to less costly local gas supplies as soon as they become
4 available.

5 Developers of the Casino mine project (Western Copper Corporation) have recently identified natural
6 gas/LNG as the likely preferred option for onsite electricity generation by 2018-19 to supply a 1,000
7 GW.h/year mine load that remains relatively stable throughout the year and is expected to continue for
8 20+ years⁵¹. Using combined cycle generation and price forecasts similar to BC Hydro's Mid gas price
9 scenario, electricity generation costs for the Casino mine are expected to be under 10 cents/kW.h with
10 access to AHPP natural gas and in the 11-15 c/kW.h range prior to AHPP assuming reliance on liquefied
11 natural gas (LNG) imported to Yukon (likely by ship and truck through Skagway).

12 Electricity generation using LNG at the Selwyn and MacTung mine projects has been estimated to be less
13 costly (by more than 10 cents per kW.h) using LNG from Fort Nelson, BC, rather than diesel fuel⁵². These
14 studies, along with those by the Casino mine developers examining the option of LNG truck-in from Fort
15 Nelson to Casino, provide estimates of potential LNG conversion and truck-in costs from Fort Nelson.

16 New equipment and retrofit of existing diesel engines can provide a range of options for LNG/natural gas
17 use, including options for dual fuel (diesel/natural gas) operation.

18 **OPTION ASSESSMENT**

19 LNG is examined as a near-term supply option for Yukon utility thermal electricity generation at
20 Whitehorse by as early as late 2014 under Scenario A or Scenario B grid loads, i.e., in the event that new
21 mine loads such as Victoria Gold are to be connected to the grid at that time. Potential LNG opportunities
22 under Base Case loads are also examined.

23 For initial assessment (prior to more detailed review and optimization studies), an LNG supply for trucking
24 to Whitehorse is assumed to be developed in the Fort Nelson area using a small scale LNG plant with
25 incremental costs for LNG conversion, trucking and related costs (e.g., truck loading/unloading facilities,
26 storage at the power plant, a vaporizer or re-gasifier and all related indirects) assumed at 7 cents per
27 kW.h for the range of potential uses being considered⁵³. These costs estimates, which reflect the external
28 Yukon Government and industry sources noted, are considered adequate for initial pre-feasibility

⁵¹ Personal communication with Cameron Brown, V.P. Engineering, Western Copper Corporation.

⁵² LNG cost estimated at 17.2 cents/kW.h versus diesel cost at 28.6 cents/kW.h (internal working papers prepared for Oil and Gas Resource Branch, Yukon Department of Energy, Mines and Resources).

⁵³ Cost estimates based on internal working papers prepared for Oil and Gas Resource Branch, Yukon Department of Energy, Mines and Resources, and for Western Copper; trucking non-capital costs are estimated at slightly over 60% of these costs.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 assessments; however, the assumed LNG supply used in the current assessment presumes timely
2 development of a new LNG plant in Fort Nelson at a capital cost that may well exceed \$30 to \$50 million.
3 If the LNG option is to be pursued for near-term development for power generation in Yukon, immediate
4 feasibility work will be required to determine the optimum way to secure the LNG, the required timing
5 and all related costs. Options may include development of a small new LNG conversion plant at Fort
6 Nelson (or any other optimum alternate location) as assumed in studies referenced to date, or purchase
7 of LNG from other suppliers (as is being planned for the Casino mine project being developed by Western
8 Copper Corporation). In this regard, Yukon Energy and Western Copper Corporation have agreed to work
9 together and share information on assessing near and longer-term options.
- 10 For the below Scenario A analysis below LNG costs assume 22 MW combined cycle generation units at
11 Whitehorse (50% energy efficiency [6.562 Mcf/MW.h] and 44% average annual plant capacity factor)
12 with LNG supplied by truck from Kitimat at cost of 2.7 cents per kW.h (2010\$) for all LNG supply costs
13 other than LNG fuel; cost of LNG fuel at assumed natural gas price in BC plus \$3/MMBtu (2010\$) to
14 reflect conversion costs and impact of export pricing; assumed BC gas price at \$5.5/MMBtu in 2015
15 (\$6.07/MMBtu after inflation), \$6.60/MMBtu in 2020 (\$8.05/MMBtu after inflation) and \$7.45/MMBtu in
16 2030 (\$11.07/MMBtu after inflation). Although combined cycle provides opportunity for waste heat sales
17 in Whitehorse, no waste heat revenue offsets assumed with LNG option in this analysis.
- 18 Reflecting Tables E4-1 and E4-2, natural gas plant scales required to displace all diesel generation
19 requirements are assumed at 22 MW for Scenario A loads and 30 MW for Scenario B loads⁵⁴. A 4 MW
20 plant is assumed for Base Case load with DSM/SSE (8 MW with no DSM/SSE).
- 21 Table E4-9 indicates the average (for all water years) annual capacity factors that result for operation of
22 the assumed natural gas plants each year over an assumed 20-year plant life under each load scenario
23 with DSM/SSE (plant operation is assumed to occur only as needed to displace the diesel generation that
24 would otherwise be required).
- 25 Plant capital cost (2010\$) range from \$4.8 million (4 MW), to \$26.4 (22 MW) and \$36.0 (30 MW) million.

⁵⁴ Under either Scenario A or B, LNG thermal plant operation to displace diesel generation will typically be concentrated almost entirely in seven months (November to May); however, as noted in the Attachment E2 review of the diesel option, off-peak and summer generation is expected to be used during extreme low water years in order to meet non-hydro generation requirements with the available non-hydro plant capacity.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

**Table E4-9: Natural Gas Plant Generation/Diesel Displacement – Base Case,
Scenarios A & B: 2015-34**

	Base Case with DSM/SSE		Scenario A with DSM/SSE		Scenario B with DSM/SSE	
	Generation- Diesel Displaced*	Annual Capacity Factor** (4 MW)	Generation- Diesel Displaced*	Annual Capacity Factor** (22 MW)	Generation- Diesel Displaced*	Annual Capacity Factor** (30 MW)
2015	15.2	43.4%	84.9	44.0%	142.9	54.4%
2016	13.4	38.3%	81.7	42.4%	139.3	53.0%
2017	14.7	42.1%	84.1	43.6%	142.0	54.0%
2018	16.2	46.1%	86.6	44.9%	144.7	55.1%
2019	17.6	50.4%	89.1	46.2%	138.9	52.8%
2020	8.7	24.8%	72.5	37.6%	120.6	45.9%
2021	0.0	0.0%	0.0	0.0%	2.0	0.7%
2022	0.0	0.0%	0.0	0.0%	0.0	0.0%
2023	0.3	0.8%	0.3	0.1%	0.3	0.1%
2024	1.0	2.8%	1.0	0.5%	1.0	0.4%
2025	1.8	5.1%	1.8	0.9%	1.8	0.7%
2026	2.7	7.7%	2.7	1.4%	2.7	1.0%
2027	3.7	10.7%	3.7	1.9%	3.7	1.4%
2028	4.9	13.9%	4.9	2.5%	4.9	1.9%
2029	6.1	17.5%	6.1	3.2%	6.1	2.3%
2030	7.5	21.5%	7.5	3.9%	7.5	2.9%
2031	9.0	25.8%	9.0	4.7%	9.0	3.4%
2032	10.7	30.5%	10.7	5.5%	10.7	4.1%
2033	12.5	35.6%	12.5	6.5%	12.5	4.7%
2034	14.4	41.0%	14.4	7.5%	14.4	5.5%

* Generation assumed to equal 100% displacement of forecast diesel generation

** Average hourly generation over the year as % of plant capacity

Based on the above cost assumptions, cost of energy for the new 30 MW natural gas plant at only a 54% capacity factor (reflecting the 2015 assumed load under Scenario B) equals 15.5 cents per kW.h (2010\$). Forecast LCOE (2010\$) over the 20 year life of plant equals 17.5 cents per kW.h under Base Case forecast loads with DSM/SSE (4 MW plant), 18.4 cents per kW.h under Scenario A forecast loads with DSM/SSE (22 MW plant), and 17 cents per kW.h under Scenario B forecast loads (30 MW plant) with DSM/SSE.⁵⁵

The minimal change noted between Full Utilization LCOE and Forecast LCOE demonstrates the LNG/natural gas option's high flexibility to adapt to major changes in loads. These LCOE include recovery of capital costs for the new power plant – excluding capital costs, the assumed fuel and O&M costs

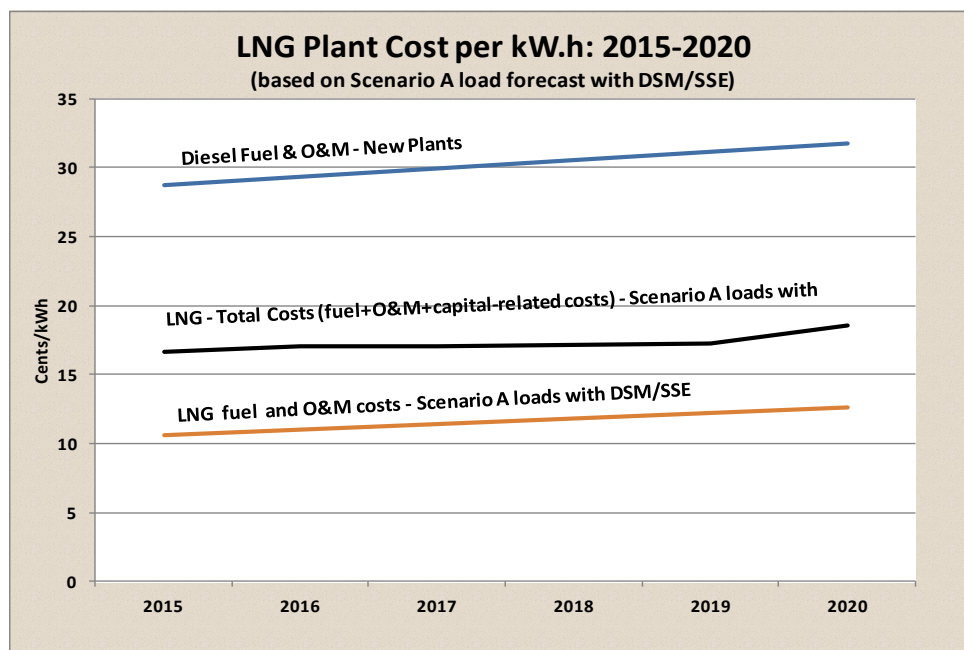
⁵⁵ With no DSM/SSE, Forecast LCOE (2010\$) over the 20 year life of plant equals 14.4 cents per kW.h under Base Case forecast loads (8 MW plant), 14 cents per kW.h under Scenario A forecast loads (22 MW plant), and 14.1 cents per kW.h under Scenario B forecast loads (30 MW plant)

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 (including LNG processing and trucking) approximate (2010\$) 11 cents per kWh in 2015 and 13 cents per
2 kW.h in 2020. By way of example, Figure E4-10 shows costs per kW.h for new diesel plants and a 22 MW
3 LNG/natural gas thermal plant during the brief period 2014-2020 under Scenario A when the Victoria Gold
4 mine load is assumed to be connected to the grid – in each year, diesel costs are well above the
5 LNG/natural gas thermal plant costs (including capital as well as fuel and other O&M for the LNG plant).

Figure E4-10: LNG Thermal Plant vs. Diesel Fuel & O&M Costs per kW.h – 2014-2020



7

8 The assumed natural gas plant capacity additions would fully address the 16 MW added capacity planning
9 LOLE increment estimated to be required under Scenario A and the further 8 MW of added capacity
10 planning LOLE increment estimated to be required under Scenario B, resulting as well in deferral of some
11 new N-1 capacity planning additions requirements (see Appendix E, Section 1).

12 Table E4-10 provides an overall present value of the estimated costs required over the 20-year planning
13 period (2011-2030) with the LNG/natural gas option for load Scenarios A and B – diesel fuel and added
14 capacity is assumed to be retained for the Base Case, for 2011-2014 under Scenario's A and B (before
15 the LNG plant is established) and for new capacity requirements not covered by the LNG plant. Present
16 value cost savings relative to the diesel option for Scenarios A and B respectively range from \$145 to
17 \$180 million with DSM/SSE, including \$35.4 million present value cost for DSM/SSE, and from \$166 to
18 \$202 million with no DSM/SSE.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

Table E4-10: LNG/Natural Gas Option Present Value Costs (2010\$million): 2011-2030

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only ⁵
No DSM/SSE					
Base Case ⁴	66.0	43.7		109.7	-54.9
Scenario A ⁴	134.9	30.7		165.6	-117.9
Scenario B ⁴	177.7	23.8		201.5	-162.2
With DSM/SSE					
Base Case ⁴	23.6	31.9	35.4	90.9	-7.2
Scenario A ⁴	98.1	11.4	35.4	145.0	-59.1
Scenario B ⁴	139.6	5.2	35.4	180.2	-100.9

Notes:

- Costs discounted at 6.56% per year YEC blended cost of capital.
- Assumes diesel fuel & O&M units for all diesel not displaced by Projects.
- Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.
- LNG estimates assume 4 MW for Base Case with DSM/SSE, 8 MW for Base Case w/o DSM/SSE, 22 MW for Scenario A and 30 MW for Scenario B.
- See Diesel Portfolio Option Present Value Costs.

Further work is proceeding to refine and optimize the LNG/natural gas option, including consideration of potential use of existing YEC Whitehorse diesel plant facilities for the LNG units, options to secure LNG supplies, and other related near-term opportunities to reduce costs and emissions by using LNG to displace diesel generation at YECL's Watson Lake facility as well as at the Selwyn and Mactung mine site facilities.

The schedule required to secure the necessary LNG facilities and arrangements in time for potential in-service in late 2014 assumes that long-lead equipment orders would likely need to be placed in spring 2013 with actual construction/installation starting in spring/summer 2014. Pre-feasibility and feasibility assessments, along with related arrangements for securing LNG supplies, would accordingly likely need to be completed before the end of 2012.

SUMMARY

In summary, LNG/natural gas is essentially very similar to diesel generation as reviewed in Attachment E2, except that it is forecast to use a less costly fuel that has lower GHG and other emissions. This form of thermal generation involves relatively low capital costs, and retains the flexibility and reliability that characterize the diesel thermal option. In effect, natural gas power plants are intended to be operated only when required and (subject to securing fuel supply) can be relatively easily integrated into the Yukon system as conversion or replacement of the current diesel generation plant. Accordingly, and particularly in light of planned retirement of all of YEC's diesel plant over the 20-year planning period and

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 the grid's capacity planning requirements, the LNG/natural gas option can be potentially relevant under
- 2 all load scenarios.
- 3 In the event that LNG is to be pursued for near-term development for power generation in Yukon,
- 4 immediate feasibility work is recommended to determine the optimum way to secure the LNG, the
- 5 required timing and all related costs. Options to be examined may include development of a small new
- 6 LNG conversion plant at Fort Nelson (or any other optimum alternate location) as assumed in studies
- 7 referenced to date, or purchase of LNG from other suppliers (as is being planned for the Casino mine
- 8 project being developed by Western Copper Corporation).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **ATTACHMENT E5 – WIND**

2 Attachment E5 provides background and assessment of near-term wind options to meet future needs of
3 the Yukon integrated grid under Scenarios A or B (this option would not be considered under only Base
4 Case load forecasts).

5 **BACKGROUND**

6 Wind turbine capability as a generation resource option in general, and specifically in Yukon for grid
7 application, was reviewed at the Energy Charrette⁵⁶. As reported, Yukon Energy has been demonstrating
8 this technology at Yukon's two wind turbines on Haeckel Hill, approximately 14 km west of Whitehorse,
9 that were installed in 1993 (150 kW) and 2000 (660 kW) - while in BC, the 2008 BC Hydro Clean Energy
10 Call BC Hydro wrapped up in 2010 with levelized plant gate prices (25 year contracts) ranging from
11 \$90/MW.h to \$121.2/MW.h, with capital costs (2010\$) close to \$3.2 million per MW. Wind energy has a
12 capacity factor that typically varies between 20-40% of total installed capacity. In Yukon, wind speeds
13 are highest in the winter months – however, higher potential icing losses during winter may reduce
14 energy production during these months.

15 As discussed at the Energy Charrette, wind is generally assessed to be not reliable as to delivery of power
16 (not add to peaking capacity, not storable, needs added costs to provide related storage [see Attachment
17 E5.1 for detailed discussion of energy storage requirements related to wind as a non-dispatchable
18 resource]), medium cost (Full Utilization LCOE at 15+ cents/kW.h), not flexible (capital intensive option,
19 not dispatchable, high costs per net kW.h of useful energy when minimal diesel to displace⁵⁷), but
20 relatively low on regulatory risk as to approvals, and environmentally responsible (renewable energy
21 option with very low GHG emissions).

22 Development of wind energy on the Yukon grid is subject to constraints related to the need to provide
23 required grid reliability when connecting a non-dispatchable resource that is available only subject to
24 wind availability. Yukon Energy has been examining appropriate short-term energy storage technologies
25 that can be integrated to the grid in order to improve system reliability and avoid reliance on load
26 shedding to avoid network outage in the event of loss of generation on the system at any time. As

⁵⁶ See background paper and presentation at Energy Charrette by Mark Green (Natural Power) on Wind.

⁵⁷ As noted in greater detail in Appendix D and Attachment E2, even under near-term high load scenarios such as Scenario B there is only a requirement to displace diesel over 7 months of the year (November to June) and over the remaining 5 months of the year under average water conditions the hydro system is fully capable of meeting load requirements on the system. In this sense, the economic benefits of an option consider the amount of useful energy (i.e., diesel displaced); high cost generation used to displace lower cost hydro is not considered useful. To the extent that 15 cent/kW.h wind resources displace low cost hydro generation in the summer (when additional generation is not required) then this energy is not considered useful or economic.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 reviewed in Attachment E5.1⁵⁸, the BBA study has provided the following with regard to the implications
2 of connecting wind generation to the grid:

- 3 • A constant spinning reserve capacity equivalent to the wind farm capacity would be required to
4 be available at all times on the grid. Yukon Energy currently typically has only about 5 MW of
5 spinning reserve on the grid. Existing non-base-loaded hydro units could potentially be converted
6 to synchronous condenser peaking units to provide most of a 20 MW spinning reserve that would
7 be appropriate for the grid at this time. However, as reviewed in Attachment E5.1, in order to
8 provide the spinning reserve necessary for introduction of 20 MW of non-dispatchable wind to the
9 Yukon grid, Yukon Energy would likely also require diesel rotary uninterruptible power supply
10 (DRUPS) units (estimated cost of \$2 million per MW). For the purpose of the current initial 2011
11 Resource Plan review, it is assumed that a 20 MW or 21 MW wind farm would require a
12 concurrent added short-term energy storage investment for DRUPS units of at least 5 at an
13 estimated cost of at least \$10 million.
- 14 • The BBA study also noted a normal need with wind generation for longer-term storage (at least 2
15 days, and preferably 4 days, as reviewed in Attachment E5.1), and that even with pumped
16 storage, a wind farm of more than 15% of the average load demand on the grid would be
17 difficult to integrate. BBA commented that YEC currently does not appear to have such storage.
18 Notwithstanding the BBA report, Yukon Energy's initial assessment is that the overall hydro grid
19 may potentially have sufficient storage to absorb 20 MW of wind energy at low-head and then
20 return the stored water at peak, and this matter will require further review. The 2011 Resource
21 Plan does not include any costs for providing such storage in the event that the wind option is
22 developed.

23 Wind will not contribute any firm capacity additions (although the assumed DRUPS energy storage at \$10
24 million will contribute 5 MW of added diesel capacity), and full consideration of this deficiency will require
25 that Yukon Energy continue to provide new diesel (or other) capacity for the balance of the capacity
26 shortfall.

27 Yukon Energy has been looking at two potential sites (Ferry Hill located across the river from Stewart
28 Crossing, and Mount Sumanik located near Whitehorse immediately to the west of Haeckel Hill), each of
29 which would offer broadly similar capabilities and provide approximately 20 MW of wind capacity. Given
30 the grid constraints noted above to connection of non-dispatchable wind generation to the Yukon grid,
31 only one of these sites would be expected to be eligible for development during the planning period.
32 Development at either site is subject (among other considerations) to satisfactory results from one year

⁵⁸ As noted in Attachment E5.1, further wind generation resources cannot be integrated into YEC's existing system (at the scale of generation being considered) absent development of both short-term and long-term energy storage.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

of further wind monitoring (this monitoring was planned to start this spring at Ferry Hill; no firm plans have yet been made to also do such additional monitoring at Mount Sumanik, although it now seems likely that this would be advised prior to any final selection as between these sites). Following completion of satisfactory additional monitoring, three years are assumed to be required to come into service (one year for environmental review and approvals, two construction seasons), such that the earliest potential in-service is estimated at late 2014 or 2015.

Current information on the Ferry Hill and Mount Sumanik wind farm site options is summarized below (variations in part reflect differences in the sites, and in part reflect differences in the two studies [Ferry Hill study was done by Natural Power in late 2010, the Mount Sumanik study was updated by AECOM in early 2011]. Table E5-1 summarizes the estimated energy generation by month for each option – each study highlighted ongoing uncertainties regarding likely net generation pending further wind monitoring and also related to uncertainty on ice build-up on turbine blades in winter months.

- **Ferry Hill (21 MW):** a 21 MW wind farm assuming 14 GE 1.5 MWxle wind turbines; gross annual energy capability estimated at 68.70 GW.h before losses, and 55.60 GW.h after all losses (includes 9% downtime, icing losses averaging 7.8%, and other losses – average capacity factor approximates 30.2%). Capital costs (2010\$) estimated at \$83.42 million (\$3.97 million per MW) before consideration of spinning reserve or other added energy storage requirements (see below), including 10% contingency and provision for turbine de-icing system, transmission/substation improvements (with transmission connection to Stewart Crossing south substation), development and permitting, engineering/construction management at 12% and owner's costs at 7%). Annual operating costs (2010\$) estimated at \$2.1 million (about \$38/MW.h). Financial analysis assumes 25 year life.
- **Mount Sumanik (20 MW):** a 20 MW wind farm assuming 10 Vesta V90 2 MW wind turbines; gross annual energy capability estimated at 56.65 GW.h before losses, 47.12 GW.h after all losses with modest blade heating and 50.33 GW.h after all losses with advanced blade heating (includes 5% downtime – average capacity factor approximates 26.9% with modest blade heating and 28.7% with advanced blade heating). Capital costs (2010\$) estimated at \$85.6 million (\$4.28 million per MW), including 10% contingency and provision for turbine de-icing system, transmission/substation improvements, access, development and permitting, engineering/construction management at 12% and owner's costs at 7% - no provision for added spinning reserve or other energy storage). Annual operating costs (2010\$) estimated at \$43/MW.h. Financial analysis assumes 20 year life.
- **A 10.5 MW option at Ferry Hill** was also examined – energy generation was estimated at 50% of the 21 MW option; capital costs estimated at \$49.52 million (\$4.72 million per MW) with

Yukon Energy Corporation

20-Year Resource Plan: 2011-2030

December 2011

transmission connection only to Stewart Crossing north substation. The 10.5 MW option costs roughly 19% more than the 20 MW option on a per-kW basis due to high fixed costs associated with civil and electrical construction.

- **A 10 MW option at Mount Sumanik** was also examined – energy generation was estimated at 50% of the 20 MW option; capital costs estimated at \$49.79 million (\$4.98 million per MW). The 10 MW option costs roughly 16% more than the 20 MW option on a per-kW basis due to high fixed costs associated with civil and electrical construction.

Table E5-1: Ferry Hill and Mount Sumanik Monthly Wind Generation Estimates (GW.h)

Ferry Hill (21 MW)						Mount Sumanik (20 MW)					
Month	Gross Energy (GW.h)	Monthly Icing Losses (%)	Net Energy after all losses (GW.h)	Overall Losses	Using formula	Month	Gross Energy (GW.h)	Monthly Icing Losses - No Blade Heating (%)	Net Energy after all losses (GW.h)	Monthly Icing Losses - Blade Heating (GW.h)	Monthly Icing Losses - Blade Heating- Enercon De-Icing Est. (GW.h)
Jan	9.48	20.90%	6.74	-28.90%	6.738	Jan	6.76	50%	3.21	4.82	5.59
Feb	6.83	4.10%	5.88	-13.91%	5.455	Feb	3.75	40%	2.13	2.85	3.19
Mar	7.82	2.00%	6.88	-12.02%	6.764	Mar	5.83	15%	4.70	5.12	5.32
Apr	4.06	0.00%	3.65	-10.10%	3.688	Apr	3.33	10%	2.84	3.00	3.08
May	3.27	0.00%	2.93	-10.40%	2.994	May	5.30	0%	5.03	5.03	5.03
Jun	2.57	0.00%	2.31	-10.12%	2.379	Jun	4.07	0%	3.87	3.87	3.87
Jul	2.90	0.00%	2.6	-10.34%	2.677	Jul	2.72	0%	2.59	2.59	2.59
Aug	3.28	0.00%	2.95	-10.06%	3.013	Aug	3.48	0%	3.31	3.31	3.31
Sep	4.32	13.70%	3.35	-22.45%	3.409	Sep	2.46	10%	2.11	2.22	2.28
Oct	6.84	12.20%	5.4	-21.05%	5.419	Oct	6.79	25%	4.84	5.65	6.04
Nov	8.12	24.60%	5.5	-32.27%	5.523	Nov	6.31	50%	3.00	4.50	5.22
Dec	9.20	10.60%	7.39	-19.67%	7.379	Dec	5.85	50%	2.78	4.17	4.84
Annual	68.70		55.60		55.44	Annual	56.65		40.41	47.12	50.33

In assessing each 20 MW+ wind site, \$10 million is added to the capital cost to provide for a minimum 5 MW of DRUPS to ensure adequate spinning reserve to integrate the site on the grid. In assessing a 10 MW or 10.5 MW options, it is assumed that this added DRUPS cost is not required i.e., YEC is assumed to have adequate spinning reserve on the grid to accommodate a 10 to 10.5 MW wind farm. Uncertainty remains as to the added costs that would be required for short and long-term energy storage on the grid to accommodate any specific wind farm project.

OPTION ASSESSMENT

Although there are two wind sites under evaluation, it is currently expected that only one 20-21 MW scale site can be accommodated on the grid during the planning period. Assessment of the wind option is therefore based on the Ferry Hill 21 MW site as it currently is estimated to provide the lowest cost option (this may change after ongoing further monitoring and assessment of the two sites). As reviewed below, the Full Utilization LCOE for the Ferry Hill 21 MW site is 14.8 cents per kW.h, and is lower than the Full Utilization LCOE for the Mount Sumanik 20 MW site at 16.8 cents per kW.h for the best option assessed to date at that site (i.e., with advanced blade heating).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 • At 100% absorption (i.e., all power generated is used to displace diesel generation that would
2 otherwise be required) the Ferry Hill project is estimated to generate approximately 55.6 GW.h
3 per year (this is only an indicative estimate, pending further site monitoring), and to have a Full
4 Utilization LCOE (2010\$) over a 25 year life of 14.8 cents/kW.h (assumed capital cost \$2010,
5 including \$10 million for DRUPS spinning reserve, at \$93.42 million).
- 6 • In contrast, at 100% absorption (i.e., all power generated is used to displace diesel generation
7 that would otherwise be required) the Mount Sumanik project is estimated to generate at most
8 (i.e., with advanced blade heating) approximately 50.33 GW.h per year (this is only an indicative
9 estimate, pending further site monitoring), and to have a Full Utilization LCOE (2010\$) over a 25
10 year life of 16.8 cents/kW.h (assumed capital cost \$2010, including \$10 million for DRUPS
11 spinning reserve, at \$95.6 million). (The AECOM study in fact uses a 20 year life for the LCOE
12 estimate – on a 20 year life, the LCOE is 18.5 cents per kW.h.)
- 13 Similarly, assessment of a smaller 10-10.5 MW initial stage wind farm development is also based on the
14 Ferry Hill site:
- 15 • A 10.5 MW option for initial development at the Ferry Hill site has an estimated capital cost of
16 \$49.55 million with no DRUPS requirement has a Full Utilization LCOE (2010\$) over 25 year life of
17 15.5 cents per kW.h; and
- 18 • A 10 MW option for initial development at the Mount Sumanik site has an estimated capital cost
19 of \$49.79 million with no DRUPS requirement has a Full Utilization LCOE (2010\$) over 25 year life
20 of 17.3 cents/kW.h, which is a higher LCOE than the 16.8 cents per kW.h estimated for the 20
21 MW Mount Sumanik site with the \$10 million DRUPS assumed requirement, and also higher than
22 the LCOE for the 10.5 MW Ferry Hill site option.

Ferry Hill Site Assessment

- 24 Wind farm options are assessed assuming in-service in late 2014 (first full operating year in 2015) and a
25 25 year economic life.
- 26 Projected diesel displacement under Scenarios A and B for a 21 MW wind farm option is estimated to be
27 materially lower than this 100% absorption level (e.g., in 2015 with assumed DSM/SSE, about 45
28 GW.h/year under Scenario A loads and 51 GW.h/year under peak Scenario B loads, falling to the 0-2
29 GW.h range by 2021 after industrial loads are forecast to be reduced and still less than 10 GW.h in
30 2030). Forecast LCOE (2010\$) based on a \$93.42 million cost, estimated annual operating costs and
31 expected net generation that displaces diesel range from 36.5 to 40.0 c/kW.h (Scenarios B and A

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 respectively). In effect, this Forecast LCOE is higher than projected for equivalent incremental diesel
2 generation⁵⁹.

3 Table E5-2 reviews projected Ferry Hill wind farm diesel displacement by year (GW.h) over 25 years
4 [2015-2039] with and without the assumed DSM/SSE for Scenario A and Scenario B. The impact of
5 assumed DSM/SSE on diesel displacement after 2020 is highlighted, showing the impact when mine loads
6 are not connected at any material level.

7 Figure E5-1 shows annual wind costs per kW.h over 25 years [2015-2039] for load forecast scenarios
8 without DSM/SSE [the same graph is not as meaningful if DSM/SSE included]. This graph highlights the
9 extent to which wind, as a capital intensive option, under normal utility revenue requirement costing will
10 have high costs per kW.h in the initial years of operation, e.g., under Scenario B loads costs per kW.h
11 remain above 20 cents per kW.h until after 2025 even though the Forecast LCOE (2010\$ average over
12 the 25 year life) is 19.0 cents per kW.h.

13 As reviewed in Table E4-3, the high Forecast LCOE for the Ferry Hill wind farm option in excess of 30
14 cents per kW.h with assumed DSM/SSE reflects in part the extent to which there are no material diesel
15 displacement opportunities currently forecast after 2020, assuming mine loads end as currently forecast
16 and DSM/SSE reduces non-industrial loads as assumed. By way of example, looking at the Scenario A
17 loads with DSM/SSE, Forecast LCOE would be reduced (but still 24 cents/kW.h or more) if forecast mine
18 loads under Scenario A were to be extended by 5 to 10 years:

- 19 • If assumed mine loads were to be extended sufficiently to maintain 46 GW.h/y of diesel
20 displacement (see Table E5-1) to the end of 2025, the Forecast LCOE would be reduced from
21 40.0 cents per kW.h to 26.5 cents per kW.h.
- 22 • Extending this same level of diesel displacement to 2030 would reduce Forecast LCOE to 21.3
23 cents per kW.h⁶⁰.

24 Without the assumed DSM/SSE, the displaced diesel generation would be much higher (particularly after
25 2020) and the Forecast LCOE for the 21 MW wind farm would fall slightly below 20 cents per kW.h under
26 Scenarios A and B.

⁵⁹ Without DSM/SSE, the estimated LCOE ranges from 19.0 to 19.6 c/kW.h (Scenarios B and A respectively).

⁶⁰ Extending 46 GW.h/y diesel displacement for a further 8 years, to the end of the 25 year life (2038), would reduce the Forecast LCOE to 17.9 cents per kW.h.

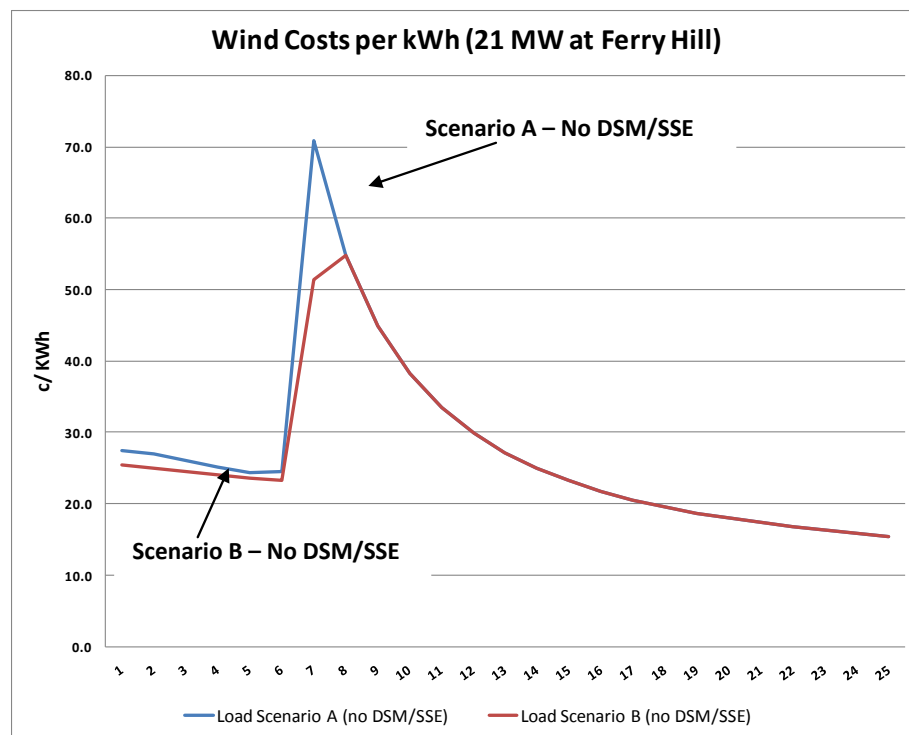
Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 Table E5-2: Ferry Hill Wind Option Impacts on Diesel Generation (21 MW plant at Ferry Hill)

	Diesel reduction with Wind and No DSM/SSE (compared to without Wind)		Diesel reduction with Wind and With DSM/SSE (compared to without Wind)	
	Scenario A GWh	Scenario B GWh	Scenario A GWh	Scenario B GWh
2015	48	51	45	51
2016	48	51	45	51
2017	49	52	45	51
2018	49	52	46	51
2019	50	52	46	51
2020	49	51	43	50
2021	17	23	0	2
2022	21	21	0	0
2023	25	25	0	0
2024	29	29	1	1
2025	33	33	2	2
2026	36	36	3	3
2027	39	39	4	4
2028	41	41	5	5
2029	43	43	6	6
2030	45	45	8	8
2031	47	47	9	9
2032	48	48	11	11
2033	49	49	12	12
2034	50	50	14	14
2035	51	51	16	16
2036	51	51	19	19
2037	51	51	21	21
2038	52	52	23	23
2039	52	52	24	24

Figure E5-1: Ferry Hill Annual Wind Costs per kW.h (No DSM/SSE)
(LCOE (2010\$): 19.6 c/kW.h (Scenario A) and 19.0 c/kW.h (Scenario B))



The 20 or 21 MW wind farm options would add only 5 MW towards capacity planning increments estimated to be required under Scenario A or Scenario B, i.e., the capacity resulting from the 5 MW minimum DRUPS assumed in the assessment.

Table E5-3 provides an overall present value of the estimated costs required over the 20-year planning period (2011-2030) with the Ferry Hill 21 MW wind farm option for load Scenarios A and B – diesel fuel and added capacity is assumed to be retained for all energy and capacity requirements not displaced or address by the wind option. With the assumed DSM/SSE, there are no present value cost savings relative to the diesel option over the 20 years for Scenarios A and B respectively - the wind option would instead increase present value costs modestly (by \$16.6 million under Scenario B and \$23.7 million under Scenario A). With no DSM/SSE, wind would provide modest present value benefits relative to diesel over the 20 years (ranging from \$22 to \$27 million). This analysis reflects the extent to which diesel is still required under the assumed combination of wind and DSM/SSE, i.e., between 2015 and 2020, the remaining annual diesel generation ranges from 29.5 to 42.9 GW.h/year under Scenario A and from 70.9 to 93.7 GW.h/year under Scenario B.

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

1 **Table E5-3: Ferry Hill 21 MW Wind Farm Option Present Value Costs**
2 **(2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁴
No DSM/SSE					
Scenario A	211.6	49.6		261.2	-22.3
Scenario B	284.0	52.8		336.8	-26.9
With DSM/SSE					
Scenario A	163.8	28.5	35.4	227.8	23.7
Scenario B	230.2	32.1	35.4	297.8	16.6

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.

2. Wind costs. Assumes diesel fuel & O&M units for all diesel not displaced by Project.

3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.

4. See Diesel Portfolio Option Present Value Costs.

3 Forecast LCOE (2010\$) for the 10.5 MW wind option (which is also examined under Base Case loads)
4 range as follows:

- 5 • Base Case load: 52.9 cents/kW.h with DSM/SSE (21.3 cents/kW.h with no DSM/SSE);
- 6 • Scenario A load: 34.7 cents/kW.h with DSM/SSE (18.8 cents/kW.h with no DSM/SSE); and
- 7 • Scenario B load: 32.5 cents/kW.h with DSM/SSE (18.2 cents/kW.h with no DSM/SSE).

8 Table E5-4 provides an overall present value of the estimated costs required over the 20-year planning
9 period (2011-2030) with the Ferry Hill 10.5 MW wind farm option for each load scenario – diesel fuel and
10 added capacity is assumed to be retained for all energy and capacity requirements not displaced or
11 address by the wind option. With the assumed DSM/SSE, there are no present value cost savings relative
12 to the diesel option over the 20 years for Base Case, Scenarios A and B loads respectively - the 10.5 MW
13 wind option would instead increase present value costs (by \$29.7 million under the Base Case, \$17.7
14 million under Scenario A, and \$15 million under Scenario B). With no DSM/SSE, wind would provide
15 modest present value benefits relative to diesel over the 20 years (ranging from \$1 to \$10 million).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

**Table E5-4: Ferry Hill 10.5 MW Wind Farm Option Present Value Costs
(2010\$million): 2011-2030**

PV 2010\$ million ¹	PV Energy Costs ²	PV Capacity Capital Costs ³	DSM/SSE Cost	Total PV Costs	Change from Diesel Only (LOLE proxy) ⁴
No DSM/SSE					
Base Case	109.4	54.1		163.6	-1.0
Scenario A	215.7	59.5		275.2	-8.2
Scenario B	290.4	63.3		353.7	-10.0
With DSM/SSE					
Base Case	59.2	33.2	35.4	127.8	29.7
Scenario A	147.3	39.0	35.4	221.7	17.7
Scenario B	217.7	43.0	35.4	296.2	15.0

Notes:

1. Costs discounted at 6.56% per year YEC blended cost of capital.

2. Wind costs. Assumes diesel fuel & O&M units for all diesel not displaced by Project.

3. Includes present value (2010\$) capital cost of assumed LOLE-related added capacity requirements (based on mine loads in excess of 13 MW) as well as N-1 capacity requirements where these are prime requirement. Includes costs and benefits of new resource option impacts on reliable capacity requirements where relevant.

4. See Diesel Portfolio Option Present Value Costs.

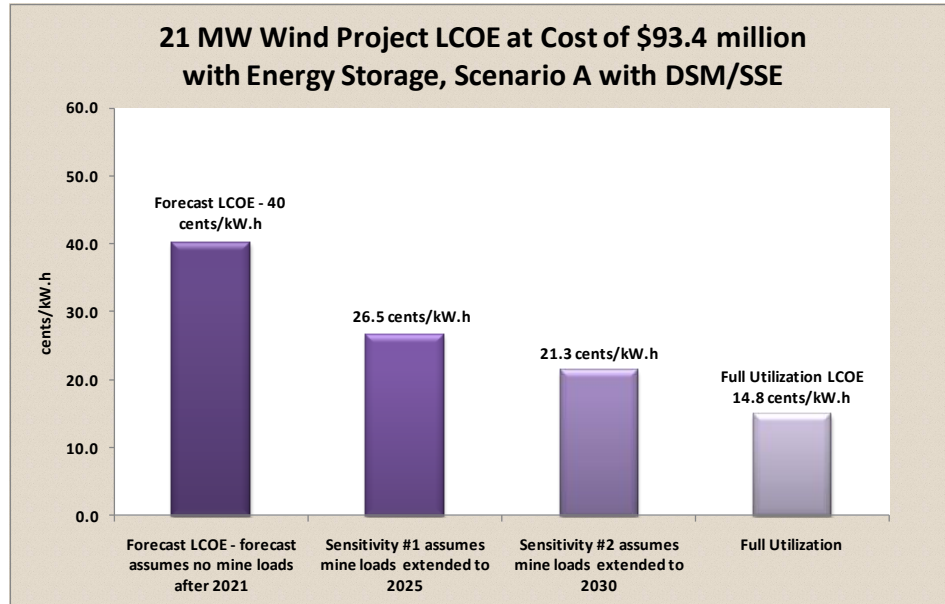
SUMMARY

Figure E4-11 and Figure E4-12 provide a summary, for the 21 MW and 10.5 MW Ferry Hill wind options respectively, of the Forecast LCOE (2010\$) for Scenario A with DSM/SSE under different mine load extension sensitivities.

In summary, based on current near-term load forecasts, lack of flexibility with the wind option to accommodate load reductions makes it a high cost option to develop until such time as there is sufficient long-term load expected to be in place as needed to make effective use of this resource to displace diesel generation.

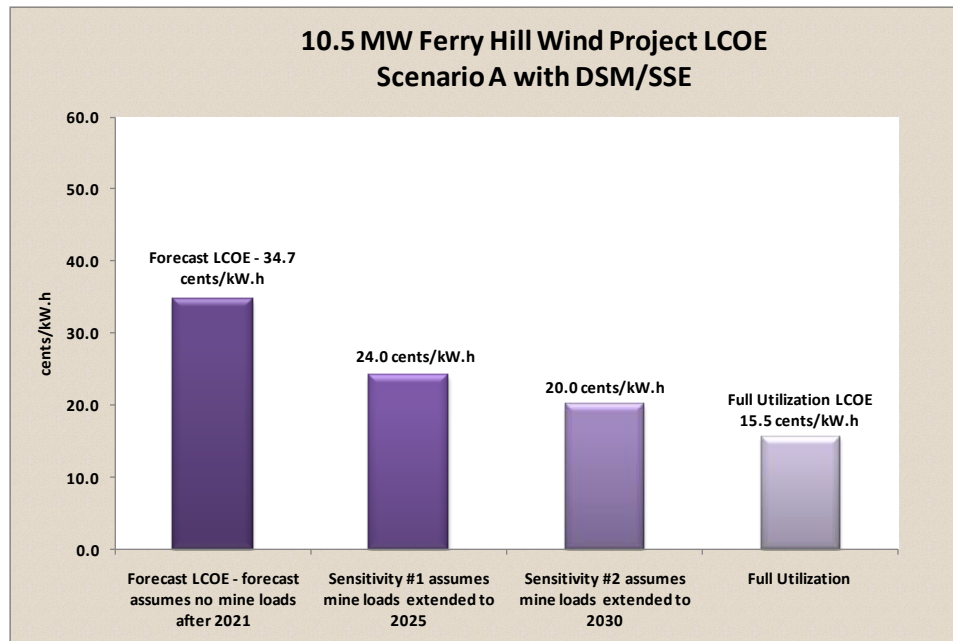
Given the relatively low planning and regulatory costs for this option, YEC could still proceed to complete wind monitoring at the two noted sites and also consider proceeding thereafter with work to finalize feasibility assessment and environmental approvals for the preferred site so that the project is ready to proceed when load conditions so allow. In addition, during the feasibility assessment it would be useful to examine staging of development for the preferred wind farm such that a minimum scale option might be defined for initial development that is less sensitive to load fluctuations as currently forecast.

1 **Figure E5-2: Summary LCOE (2010\$) 21 MW Wind Option, Scenario A Load with DSM/SSE**



2

3 **Figure E5-3: Summary LCOE (2010\$) 10.5 MW Wind Option, Scenario A Load with DSM/SSE**



4

1 **ATTACHMENT E5.1 – SHORT-TERM & LONG-TERM ENERGY STORAGE**

2 Renewable energy sources that are intermittent and non-dispatchable do not provide reliable capacity or
3 energy; in order to compensate for loss of supply, surplus energy must be stored and available at a
4 moment's notice so that the system can better address instantaneous supply and demand needs.

5 As noted in Attachment E2, Yukon Energy retained BBA to identify appropriate short-term energy storage
6 technologies that can be integrated to the interconnected grid. As part of this study, BBA specifically
7 reviewed the storage requirements to support a non-dispatchable production such as wind, and noted
8 that wind needs to be supported by both spinning reserve (to be maintained always at a reserve capacity
9 equivalent to the wind farm capacity) and long-term hydro storage (equivalent to a few days of wind
10 production, typically minimum of 2 days, preferably 4 days) to meet the load cycle of customer power
11 demand. In this respect, wind generation options will drive additional and related requirements for both
12 short-term and long-term energy storage on the grid.

- 13 • **Requirement for short-term spinning reserve to address moment to moment**
14 **inconsistency in wind (i.e., variations in wind speed)** - BBA's review noted that YEC would
15 be required to maintain a constant spinning reserve capacity equivalent to the wind farm capacity
16 which would be required to be available at all times. As reviewed in Attachment E2, YEC currently
17 lacks sufficient spinning reserve to address loss of generation on the system at any time, and relies
18 on load shedding to avoid network outage; accordingly, YEC is examining short-term energy
19 storage options. As also reviewed in Attachment E2, the BBA study identified two options: (a)
20 convert existing non-base-loaded hydro units to synchronous condenser peaking units, and (b)
21 provide diesel rotary uninterruptible power supply (DRUPS) units. The first of these options is
22 under active consideration to provide a major portion of the enhanced reliability related to the
23 current hydro grid; it is currently estimated that introduction of 20 MW (or more) non-dispatchable
24 wind to the grid would require additional DRUPS units (estimated cost of \$2 million per MW) to
25 ensure that the overall spinning reserve is always equivalent to the wind farm capacity. For the
26 purpose of the current initial review, it is assumed that a 21 MW wind farm would require a
27 concurrent added short-term energy storage investment for DRUPS units of at least 5 to 10 MW
28 (estimated cost of \$10 to \$20 million); in contrast, an initial 10 MW (or less) stage of wind
29 development might potentially not require any concurrent added DRUPS units (assuming that at
30 least 10 MW of existing non-base-loaded hydro units are converted to synchronous condenser
31 peaking units).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 • **Requirement for longer-term storage in circumstances where non-dispatchable power**
2 **is not available (i.e., the case of the wind stopping for hours or days)** – The BBA report
3 notes that wind is best integrated into hydro system that already has large amounts of available
4 storage such that when wind production is high water can be stored and when the wind stops
5 stored water can then be relied upon to supply the system. In this respect, BBA states that
6 industry experience is to have hydro storage capacity at least equal to wind farm production over a
7 period of a few days (minimum of two days, preferably four days).
 - 8 ○ The BBA report notes obvious storage limitations on the current Yukon grid hydro
9 system. While multi month storage is available this storage is required to address the
10 seasonality of flows that exist, i.e., high spring inflows stored over summer (when there
11 are lower load requirements) in order to compensate for low winter inflows (when peak
12 load requirements occur).
 - 13 ○ In short, current available grid hydro storage is not consider sufficient in the BBA report
14 (and is otherwise required for the operational purposes noted) – while further storage
15 may be added (through pursuit of enhancements such as Marsh Lake), the BBA report
16 notes that it is expected that more storage would still be desirable if a wind farm as
17 connected to the grid, and observes that an in-depth hydrological study could help to
18 identify opportunities for operational optimization and additional storage that would be
19 useful for wind farm integration.
 - 20 ○ BBA notes that even with pumped storage, a wind farm of more than 15% of the
21 average load demand would be difficult to integrate. Geological and hydrological studies
22 would be needed to identify suitable pumped storage locations in the Yukon. BBA
23 observes that construction of a new hydro reservoir storage system would likely take
24 most of a decade, and that pumped storage is generally the least cost option only for
25 large-scale energy storage (greater than 50 MW).
 - 26 ○ BBA concludes as following regarding wind farm integration with the YEC system:
27 "...unless there is sufficient daily water storage to absorb the wind energy at low-load,
28 and then return the stored water at peak, there appears to be little economic advantage
29 to having a wind farm connected....Stochastic production, such as wind, needs to be
30 compensated with sufficient hydro storage, which does not appear possible with the YEC
31 hydro system. It would be worthwhile to have an in depth investigation into the storage
32 capacity of the hydro system."

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030

December 2011

- 1 ○ Yukon Energy's initial assessment is that, notwithstanding the BBA report, the overall
- 2 hydro grid may potentially have sufficient storage to absorb 20 MW of wind energy at
- 3 low-head and then return the stored water at peak, and this matter will require further
- 4 review.

ATTACHMENT 4

**DRAFT SCREENING REPORT AND
RECOMMENDATION FOR THE
WHITEHORSE DIESEL – NATURAL GAS
CONVERSION PROJECT**

(Project Assessment 2013-0115)

Draft Screening Report and Recommendation

Project Assessment 2013-0115

Yukon Energy Corporation Ltd. Whitehorse Diesel – Natural Gas Conversion Project



March 19, 2014

Prepared by
Executive Committee
Yukon Environmental and Socio-economic Assessment Board

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PREFACE

Yukon Energy Corporation (YEC) is proposing the construction of a new natural gas generating station to replace its diesel generating units scheduled for retirement, adjacent to YEC's existing primary power generating station, the Whitehorse Rapids Generating Station (WRGS).

The Project lies within the traditional territories of the Kwanlin Dün First Nation (KDFN) and the Ta'an Kwäch'än Council (TKC), and within a developed part of Whitehorse. The Project will involve approximately 0.9 ha of Public Utility zoned Government of Yukon lands and 0.61 ha of private land (railway right-of-way) belonging to the White Pass and Yukon Railway.

The Project involves the installation of liquefied natural gas (LNG) truck offloading, storage vapourization, and combustion infrastructure and includes the planning and construction phase from 2013-2014 and the operations/modifications phase from 2014 on. YEC proposes to replace two of its diesel generating units (with a total generating capacity of 9.1 MW) with three natural gas generating units (with a total capacity of 13.2 MW), providing an additional 4.1 MW to the Yukon electrical grid. Two of the units (8.8 MW capacity) are anticipated to be in service by the fourth quarter of 2014, and the third unit (4.4 MW capacity) anticipated to be within a few years.

The Executive Committee of the Yukon Environmental and Socio-economic Assessment Board (YESAB) has assessed the environmental and socio-economic effects of the proposed project pursuant to the *Yukon Environmental and Socio-economic Assessment Act* (YESAA).

The draft screening report is available on the YESAB Online Registry (www.yesab.ca/registry, YESAB Project No. 2013-0115) or from the YESAB Head Office at Suite 200 – 309 Strickland Street, Whitehorse YT.

Comments may be made in writing and must be received on or before Tuesday April 22, 2014. Comments may be submitted via:

- The internet by uploading them to the YESAB Online Registry (www.yesab.ca/registry, YESAB Project No. 2013-0115)
- Email: yesab@yesab.ca
- Fax: (867) 668-6425 or toll-free (866) 389-1633
- Mail: Suite 200 – 309 Strickland Street, Whitehorse, Yukon Y1A 2J9
- Hand Delivery during regular business hours to the YESAB Head Office at Suite 200-309 Strickland Street, Whitehorse

The Executive Committee recognizes the technical support provided by AECOM and Risknology in preparing this draft screening report.

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EXECUTIVE SUMMARY

This draft screening report is the outcome of the Executive Committee's assessment of the Whitehorse Diesel – Natural Gas Conversion Project proposed by Yukon Energy Corporation (YEC). The purpose of the Project is the construction of a new natural gas generating station and associated activities adjacent to YEC's existing primary power generating station, the Whitehorse Rapids Generating Station (WRGS). The Project will produce 13.2 MW, which will provide an additional 4.1 MW to the Yukon electrical grid upon the decommissioning of the two diesel generators (total of 9.1 MW capacity) YEC intends to replace.

This draft screening report is being released for public comment and:

- describes the Project and the screening approach;
- summarizes the matters considered during the screening;
- identifies potential effects of the Project and outlines terms and conditions that mitigate potentially significant adverse environmental and socio-economic effects of the Project;
- considers the public comments received on the project proposal; and
- provides the Decision Bodies with a recommendation arising from the screening, and the reasons for that recommendation.

Pursuant to s. 50(3) of YESAA, before submitting a proposal to the Executive Committee, a proponent is required to consult any First Nation in whose traditional territory the Project will be located or might have significant environmental or socio-economic effects, as well as the residents of a community in which the Project will be located or might have significant environmental or socio-economic effects. Based on the information provided in the proposal, the Executive Committee determined that for the purposes of s. 50(3), the Proponent was required to consult:

- the Kwanlin Dün First Nation (KDFN) and Ta'an Kwäch'än Council (TKC), being the First Nations in whose territories the Project "will be located or might have significant environmental or socio-economic effects"; and
- the residents of Whitehorse, being the community in which the Project "will be located or might have significant environmental or socio-economic effects."

In a letter dated August 23, 2013, the Executive Committee determined that, in its opinion, with respect to the Whitehorse Diesel – Natural Gas Conversion Project proposed by YEC, the Proponent met their statutory consultation requirement under s. 50(3) of YESAA.

The Executive Committee has employed a valued component based assessment methodology to assess the environmental and socio-economic effects of the Project. The Executive Committee has identified the Valued Environmental and Socio-economic Components (VESECs) for the Project to be air quality, safety, economics, wildlife and aesthetics

The Executive Committee considered all the YEC commitments, contained within the proposal (Appendix C in this report), in its assessment of potential effects. These commitments become legal obligations as they form part of the Executive Committee's recommendations and subsequent Decision Documents and part of regulatory instruments. The Executive Committee notes that the relatively few recommendations are indicative of the comprehensiveness of YEC's commitments.

This report addresses Project and cumulative effects on these VESECs. These VESECs are introduced and relevant issues are highlighted. Potential effects are subsequently characterized and their significance is discussed. For each VESEC, mitigative measures that address the significant adverse effects are presented and a final determination is made. The Executive Committee has identified mitigation for all significant adverse effects identified in this report.

As a result of this assessment, the Executive Committee recommends to the Government of Yukon, the Decision Body, that the Whitehorse Diesel – Natural Gas Conversion Project be allowed to proceed without a review, subject to terms and conditions identified in this report. The Executive Committee has determined that this project will have significant adverse environmental and/or socio-economic effects in Yukon that can be mitigated by these terms and conditions. Recommended terms and conditions are summarized in Section 12.

The draft screening report is available on the YESAB Online Registry (www.yesab.ca/registry, YESAB Project No. 2013-0115) or from the YESAB Head Office at Suite 200 – 309 Strickland Street, Whitehorse YT. Comments may be made in writing and must be received on or before Tuesday April 22, 2014.

TABLE OF CONTENTS

TABLE OF CONTENTS	I
LIST OF FIGURES	V
LIST OF TABLES	VI
ACRONYMS AND ABBREVIATIONS.....	VII
1.0 INTRODUCTION	1
1.1 Legislative Context for the Assessment	1
1.2 Screening Chronology	3
1.3 Consultation Requirements under YESAA	6
1.4 Access to Assessment Documentation	7
1.5 Environmental and Socio-economic Assessment Methodology.....	7
1.5.1 Matters to be Considered	8
1.5.2 Determining the Significance of Adverse Effects	9
2.0 PROJECT OVERVIEW.....	11
2.1 Proponent Information	11
2.2 Project Description.....	11
2.2.1 Changes to the Scope of the Project.....	11
2.2.2 Scope of the Project	12
2.2.3 Temporal and Spatial Boundaries of Project.....	14
3.0 ENVIRONMENTAL AND SOCIO-ECONOMIC SETTING	18
3.1 Existing Environmental Setting	18
3.1.1 General Physiography, Surficial Geology and Soil Conditions	18
3.1.2 Climate.....	19
3.1.3 Air Quality	19
3.1.4 Noise Levels	20

3.1.5	Surface Water	20
3.1.6	Groundwater	21
3.1.7	Vegetation	21
3.1.8	Wildlife.....	22
3.2	Existing Socio-economic Setting	22
3.2.1	Population	22
3.2.2	Land Use.....	23
3.2.3	Resource Use	23
3.2.4	Recreation.....	24
3.2.5	Social and Cultural Context	24
3.2.6	Heritage Resources	24
4.0	CONSIDERATION OF ALTERNATIVES	25
4.1	Alternatives to the Project.....	25
4.2	Alternative Ways of Undertaking the Project	26
4.3	Consideration of Alternatives to Avoid or Minimize Significant Adverse Effects.....	27
5.0	SCOPE OF ASSESSMENT	28
5.1	Consideration of Comments Received	28
5.2	Consideration of Activities Outside Yukon	29
5.3	Consideration of Hydraulic Fracturing in Yukon	30
5.4	Consideration of Change in Project Scope	32
5.5	Consideration of the Purpose of the Project.....	33
5.6	Valued Environmental and Socio-economic Components	34
6.0	AIR QUALITY	36
6.1	Overview	36
6.1.1	Air Quality Effects Assessment Context	36
6.2	Common Air Contaminants.....	37
6.2.1	Consideration of the SENES Report.....	37
6.2.2	Legislative Context: Common Air Contaminants	38
6.2.3	Effects Characterization.....	38

6.2.4	Significance Determination	40
6.3	Greenhouse Gas Emissions	40
6.3.1	Consideration of CO ₂ Equivalent Value	41
6.3.2	Effects Characterization	42
6.3.3	Significance Determination	42
6.4	Water Vapour Plumes.....	43
6.4.1	Effects Characterization	43
6.4.2	Significance Determination	44
6.5	Effects Monitoring	44
6.6	Cumulative Effects	45
7.0	SAFETY	46
7.1	Site Design	46
7.1.1	Effects Characterization	46
7.1.2	Significance Determination	49
7.2	Accidents and malfunctions.....	49
7.2.1	Characterization of LNG	50
7.2.2	Risks of Spills or Leaks Leading to Fire	52
7.2.3	Risk of Cryogenic Burns and Asphyxiation	54
7.2.4	Significance Determination	54
7.3	Training.....	55
7.3.1	Effects Characterization	56
7.3.2	Significance Determination	56
7.4	Transport	57
7.4.1	Effects Characterization	57
7.4.2	Significance Determination	59
7.5	Cumulative Effects	60
8.0	ECONOMICS.....	61
8.1	Overview	61
8.1.1	Capital Costs	61
8.1.2	Loading Forecasts	63
8.1.3	Operational Costs	65

8.2	Effects Characterization	68
8.3	Significance Determination	69
8.4	Cumulative Effects	69
9.0	WILDLIFE	71
9.1	Overview	71
9.2	Effects Related to Migratory Birds	71
9.3	Significance Determination	72
9.4	Terms and Conditions	73
9.5	Cumulative Effects Assessment.....	73
10.0	AESTHETICS.....	74
10.1	Overview	74
10.2	Effects Characterization	74
10.3	Significance Determination	75
10.4	Terms and Conditions	75
10.5	Cumulative Effects Assessment.....	76
11.0	RECOMMENDATION	77
12.0	TERMS AND CONDITIONS OF RECOMMENDATION.....	77
13.0	SIGNATORY PAGE.....	78
	APPENDIX A BIBLIOGRAPHY	80
	APPENDIX B COMMENTS ON THE PROPOSAL	84
	APPENDIX C PROPONENT COMMITMENTS	91

LIST OF FIGURES

Figure 1 Executive Committee Screening Process 4

Figure 2 Project Study Area 15

Figure 3 Project Study Area Context..... 16

Figure 4 Project Construction Footprint..... 17

Figure 5 Flammability Limits for Methane 51

Figure 6 Capital cost and natural gas fuel cost savings sensitivity 69

LIST OF TABLES

Table 1 Potential Project Authorities Required	2
Table 2 Chronology of Screening.....	5
Table 3 Project Scope	12
Table 4 Project Schedule	14
Table 5 Comments Regarding Activities Outside Yukon	29
Table 6 Comments Regarding Hydraulic Fracturing in Yukon.....	30
Table 7 Valued Environmental and Socio-economic Components.....	35
Table 8 Yukon Air Quality Standards.....	38
Table 9 YEC Emission Rates Comparison	39
Table 10 Comparison of Emission Factors	42
Table 11. Typical Chemical Composition of LNG	50
Table 12. Auto-ignition Temperatures of Fuels at Standard Conditions	51
Table 13 Comparison of Risks of Fuel Sources.....	52
Table 14 Comparison of Project Costs vs. Costs for New Diesel Generating Units.....	62
Table 15 Forecast Base-Case Grid Default Diesel Generation Requirement (2013-2030)	64
Table 16 Summary of Utility Operations	65
Table 17 Comments on Fuel Costs Estimates.....	66
Table 18 Comments on Costs Projections.....	67

ACRONYMS AND ABBREVIATIONS

Activity Regulations	Assessable Activities, Exceptions and Executive Committee Projects Regulations
BOG	Boil off gas
°C	Degrees Celsius
cm	Centimetre
CAC	Common air contaminants
CCTV	Closed-circuit television
CO	Carbon monoxide
CO ₂ e	Carbon dioxide equivalent
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
CPAWS	Canadian Parks and Wilderness Society
CSA	Canadian Standards Association
dBa	Decibel A-weighting
DFO	Department of Fisheries and Oceans Canada
DSR	Draft screening report
EA	Effects assessment
EBA	Engineering Consultants Ltd., A Tetra Tech Company
Executive Committee	Executive Committee of the Board
ESA	Expanded site area
ft	Foot/feet (as a measurement)
GHG	Greenhouse gases
GPPR	<i>Gas Processing Plant Regulation</i>

GWh	Gigawatt hour
GWP	Global warming potential
h	Hour
ha	Hectare(s)
KDFN	Kwanlin Dün First Nation
kg	Kilogram
km	Kilometre
km ²	Square kilometre
kV	Kilovolt
L	Litre
L/s	Litre per second
Leq	Energy equivalent sound level
LNG	Liquefied natural gas
LSA	Local study area
m	Metre
m ³	Cubic metre
m ³ /s	Cubic metre per second
MAP	Mean annual precipitation
MASL	Metres above sea level
MBG	Metres below ground
mm	Milimetres
ms ⁻¹	Metre per second
m ³ /s	Cubic metres per second
mw	Megawatt

NAPS	National Air Pollution Surveillance
NFPA	National Fire Protection Association
NO _x	Nitrogen oxides
NO ₂	Nitrogen dioxide
N ₂ O	Nitrous oxide
NPRI	National Pollutant Release Inventory
OCP	Official Community Plan
PM _{2.5}	Fine particulate matter
PPBV	Parts per billion per volume
PPM	Parts per million
Project	Whitehorse Diesel – Natural Gas Conversion Project
Proponent	Yukon Energy Corporation (YEC)
SARA	<i>Species At Risk Act</i>
SO ₂	Sulfur dioxide
TKC	Ta'an Kwäch'än Council
TSP	Total suspended particulate matter
ug/m ³	Microgram per cubic metre
VESECs	Valued environmental and socio-economic components
VOCs	Volatile organic compounds
WAF	Whitehorse-Aishihik-Faro grid
WD	Whitehorse diesel unit
WRGS	Whitehorse Rapids Generating Station
WTGS	Whitehorse Thermal Generating Station

YCS	Yukon Conservation Society
YEC	Yukon Energy Corporation
YECL	Yukon Electrical Company Limited
YESAA	<i>Yukon Environmental and Socio-economic Assessment Act</i>
YESAB	Yukon Environmental and Socio-economic Assessment Board
YG	Government of Yukon
YUB	Yukon Utilities Board
YOR	YESAB Online Registry

PART I BACKGROUND

1.0 INTRODUCTION

The *Yukon Environmental and Socio-economic Assessment Act* (YESAA) requires that Decision Bodies consider the recommendation arising from a screening conducted under YESAA and issue a Decision Document, prior to taking any action that would enable a project to be undertaken.

The purposes of this report are to provide relevant Decision Bodies with a recommendation arising out of the screening, and the reasons for that recommendation.

This draft screening report is being released for public comment and:

- describes the Project and the screening approach;
- summarizes the matters considered during the screening;
- identifies potential effects of the Project and outlines terms and conditions that mitigate potentially significant adverse environmental and socio-economic effects of the Project;
- considers the public comments received on the project proposal; and
- provides the Decision Bodies with a recommendation arising from the screening, and the reasons for that recommendation.

1.1 LEGISLATIVE CONTEXT FOR THE ASSESSMENT

YESAA sets out a process to assess the environmental and socio-economic effects of projects and other activities in Yukon, or that might have effects in Yukon. The Executive Committee of the Yukon Environmental and Socio-economic Assessment Board (YESAB) is responsible for assessing large, complex projects identified under the *Assessable Activities, Exceptions and Executive Committee Projects Regulations* (Activity Regulations). A screening by the Executive Committee is required for the Whitehorse Diesel – Natural Gas Conversion Project because:

- Yukon Energy Corporation (YEC or the Proponent) proposes to undertake activities listed in Schedule 3 of the Activity Regulations. Specifically, s. 25 states:

Construction, decommissioning or abandonment of ...

(b) a fossil fuel-fired electrical generating station with a production capacity of 5 MW or more;

- the activities are proposed to be undertaken in Yukon; and
- an authorization or the grant of an interest in land by a government agency, independent regulatory agency, municipal government or First Nation is required for the activity to be undertaken.

Decision Bodies and required authorizations were identified based on information in the project proposal and information submitted to the Executive Committee. The Government of Yukon has been identified as a Decision Body for this Project. The potential authorizations required for the Project are listed in Table 1.

Table 1 Potential Project Authorities Required

Responsible Agency	Act/Regulation	Authorization(s) Required
Government of Yukon Department of Energy, Mines and Resources	<i>Territorial Lands (Yukon) Act</i> <i>Land Use Regulation</i> <i>Oil and Gas Act (Yukon)</i> <i>Gas Processing Plant Regulation</i>	Land Use Permit Land Disposition Facility License Construction Authorization Operation Authorization
Government of Yukon	<i>Public Utilities Act</i>	Energy Project Certificate Energy Operation Certificate
Government of Yukon Department of Environment	<i>Environment Act</i> <i>Storage Tank Regulations</i> <i>Air Emissions Regulation</i>	Amendment to existing Hazardous Substances Aboveground Storage Tank Permit Amendment to existing Air Emissions Permit
Government of Yukon Department of Community Services	<i>Boiler and Pressure Vessel Act</i> <i>Gas Burning Devices Act</i> <i>Electrical Protection Act</i> Canadian Electrical Code	Approval and Registration of Design Gas Installation Permit Electrical Permit
Government of Yukon Department of Highways and Public Works	<i>Dangerous Goods Transportation Act</i> <i>Dangerous Goods Transportation Regulations</i> <i>Highways Regulation</i>	Permit for transport of dangerous goods Sign Permit
Government of Yukon Department of Justice	<i>Land Titles Act</i>	Land Title Registration
City of Whitehorse	<i>Zoning Bylaw</i> Development Agreement Regulations Bylaw (Bylaw 2012-15) Subdivision Bylaw (Bylaw 2012-16)	Development Permit Authorization to subdivide

Government of Canada	Canadian Aviation Regulation TP 312 Standards and Recommended Practice	Transport Canada Obstacle Clearance Form
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1.2 SCREENING CHRONOLOGY

The assessment process and timelines for screenings are set out in the *Rules for Screenings Conducted by the Executive Committee*. An overview of the Executive Committee screening process is illustrated in Figure 1. All tasks required of the Executive Committee during this screening have been completed within the timelines and process prescribed under the *Screening Rules*.

The chronology of the Whitehorse Diesel – Natural Gas Conversion Project screening is set out in Table 2, which provides an outline of key assessment dates and stages. For more detailed assessment information, please visit the YESAB Online Registry (YOR) at www.yesab.ca/registry or the YESAB Document Registry located at the YESAB Head Office.

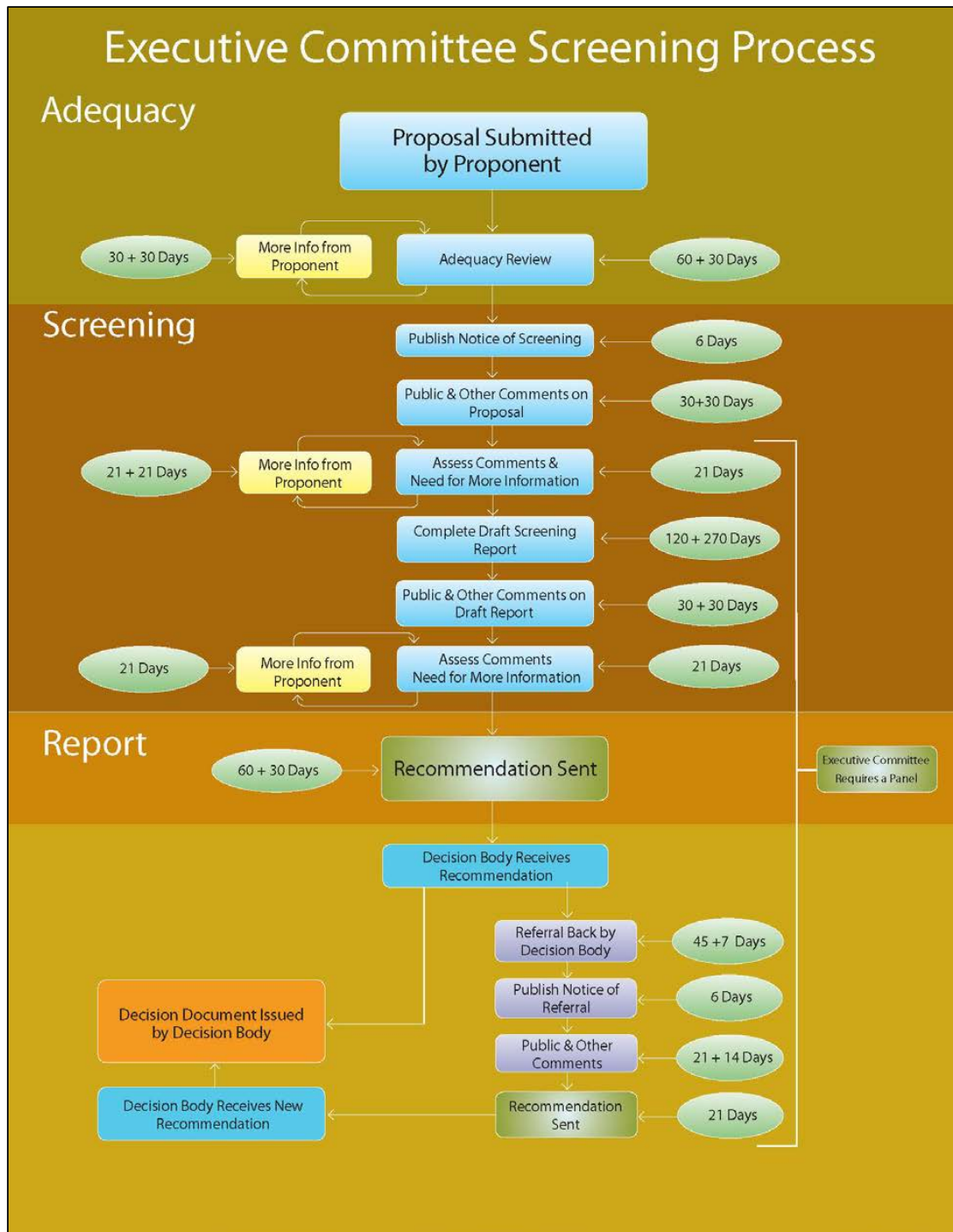


Figure 1 Executive Committee Screening Process

Table 2 Chronology of Screening

Adequacy Review Period	
August 8, 2013	YEC submits proposal to Executive Committee.
August 23, 2013	Executive Committee notifies YEC that they have met their consultation requirements under s. 50(3) of YESAA.
October 22, 2013	Executive Committee issues Supplementary Information Request.
October 25, 2013	YEC submits response to Supplementary Information Request.
November 1, 2013	Executive Committee determines proposal is adequate to commence screening.
Screening	
November 5, 2013	Executive Committee issues Preliminary Statement of Scope of Project.
November 5, 2013	Executive Committee commences public comment period (November 5 to December 6, 2013).
November 12, 2013	YEC submits notice of amendments to project scope.
November 13, 2013	Executive Committee issues public notice regarding the change in scope, and requests clarification from YEC.
November 15, 2013	YEC submits additional proposal information.
November 19, 2013	Executive Committee requests further clarification.
November 20, 2013	YEC provides further clarification.
November 20, 2013	Executive Committee issues a public notice advising of the change in project scope and extends the public comment period to December 20, 2013.
December 11, 2013	Executive Committee holds a public meeting on the Project in Whitehorse.

December 18, 2013	Executive Committee extends public comment period to January 10, 2014.
January 10, 2014	Public comment period ends.
January 13, 2014	Executive Committee begins considering comments received.
January 21, 2014	Executive Committee issues Request for Supplemental Information to YEC.
January 29, 2014	YEC provides response to request.
February 6, 2014	Executive Committee holds technical meeting related to safety issues.
February 7, 2014	Executive Committee determines supplemental information to be adequate.
March 19, 2014	Executive Committee issues a draft screening report.

1.3 CONSULTATION REQUIREMENTS UNDER YESAA

Pursuant to s. 50(3) of YESAA, a proponent is required to consult any First Nation in whose traditional territory the project will be located or might have significant environmental or socio-economic effects, as well as the residents of any community in which the project will be located or might have significant environmental or socio-economic effects, before submitting a proposal to the Executive Committee. This duty to consult is to be exercised in the manner described in s. 3 of YESAA.

Before commencing a screening of a project, the Executive Committee must determine whether, in its opinion, the proponent has consulted First Nations and the residents of communities in accordance with s. 50(3) of YESAA.

Based on the information provided in the proposal, the Executive Committee determined that for the purposes of s.50(3) of YESAA, the Proponent was required to consult:

- the Kwanlin Dün First Nation (KDFN) and Ta'an Kwäch'än Council (TKC), being the First Nations in whose territories the Project "will be located or might have significant environmental or socio-economic effects"; and
- the residents of Whitehorse, being the community in which the Project "will be located or might have significant environmental or socio-economic effects."

The Executive Committee considered the information provided by the Proponent in the project proposal and letters from KDFN (YOR 2013-0115-016-1) and TKC (YOR 2013-0115-019-1) indicating their views

that the Proponent's requirements under s. 50(3) had been satisfied. The Executive Committee determined that, in its opinion, the Proponent had consulted with the above-noted First Nations and community residents of Whitehorse in accordance with s. 50(3) of YESAA. The Executive Committee notified the Proponent in writing of its determination on August 23, 2013.

1.4 ACCESS TO ASSESSMENT DOCUMENTATION

As required by s. 118 of YESAA, YESAB maintains a register that contains all documents produced, collected or received by the Executive Committee in relation to this screening. The register can be accessed electronically through the YESAB Online Registry (YOR) www.yesab.ca/registry, or in person at the YESAB Head Office in Whitehorse.

1.5 ENVIRONMENTAL AND SOCIO-ECONOMIC ASSESSMENT METHODOLOGY

The Executive Committee has employed a valued component based assessment methodology to assess the environmental and socio-economic effects of the Whitehorse Diesel – Natural Gas Conversion Project. The assessment methodology is outlined below.

- Determine project scope that accounts for all proposed activities through all stages of the Project (i.e. construction and operation).
 - o Include activities identified in the proposal and any other activity that it considers so likely to be undertaken in relation to an activity so identified and sufficiently related to it to be included in the Project.
- Give full and fair consideration to scientific information, traditional knowledge and other information provided during the assessment (s. 39 of YESAA).
- Determine the scope of assessment based on:
 - o Matters to be considered (as described further in Section 1.5.1)
 - o Views and information provided during the assessment.
 - o Key issues identified.
 - o Valued Environmental and Socio-economic Components (VESECs).
- Consider baseline information.
- Evaluate the proponent's approach to modeling and predicting changes from baseline caused by project activities.
- Determine spatial and temporal overlap between project activities and values. For example, the use of heavy machinery may occur spatially within wildlife habitat and temporally when wildlife is known to be using that habitat (e.g. summer habitat).
- Characterize potential project effects.
 - o The consequence of overlap between an activity and a value is an effect, which can be either positive (i.e. beneficial) or negative (i.e. adverse).

- Consider the proponent's assessment of adverse effects and their conclusions.
- Evaluate the effectiveness of mitigation measures proposed by the proponent and non-discretionary legislation that may mitigate these effects.
- Determine the significance of adverse project effects. (as described further in Section 1.5.2)
- Specify terms and conditions to mitigate significant adverse project effects so that they are no longer significant. Terms and conditions may include:
 - o alternatives to the project or alternative ways of undertaking or operating it;
 - o mitigative measures; and
 - o measures to compensate.
- Characterize the residual effects of project activities, and how they interact.
- Determine whether there are residual significant adverse effects that require additional terms and conditions.
- Identify the spatial and temporal boundaries for cumulative effects to particular VESECs.
- Identify projects for which proposals have been submitted to YESAB and other existing or proposed activities occurring within these boundaries.
- Determine the spatial and temporal overlap between all activities and VESECs.
- Conduct a cumulative effects assessment.
- Consider the proponent's assessment of adverse cumulative effects and their conclusions.
- Evaluate the effectiveness of mitigation measures proposed by the proponent and non-discretionary legislation that may mitigate these cumulative effects.
- Specify terms and conditions to mitigate significant adverse cumulative effects.
- Determine whether there are residual significant adverse cumulative effects that require additional terms and conditions.

1.5.1 Matters to be Considered

The scope of the assessment encompasses the matters considered in the screening. Consistent with s. 42 of YESAA, the Executive Committee considers:

- the purpose of the project;
- all stages of the project;
- the significance of any environmental or socio-economic effects of the project that have occurred or might occur in or outside Yukon, including the effects of malfunctions or accidents;
- the significance of any adverse cumulative environmental or socio-economic effects that have occurred or might occur in connection with the project in combination with the effects of:

- o other projects for which proposals have been submitted under s. 50 (1); or
 - o other existing or proposed activities in or outside Yukon that are known to the Executive Committee from information provided to it or obtained by it under YESAA.
- alternatives to the project, or alternative ways of undertaking or operating it, that would avoid or minimize any significant adverse environmental or socio-economic effects;
- mitigative measures and measures to compensate for any significant adverse environmental or socio-economic effects;
- the need to protect the rights of Yukon Indian persons under final agreements, the special relationship between Yukon Indian persons and the wilderness environment of Yukon, and the cultures, traditions, health and lifestyles of Yukon Indian persons and other residents of Yukon;
- the interests of residents of Yukon and of Canadian residents outside Yukon;
- the need for effects monitoring; and
- the capacity of any renewable resources likely to be significantly affected by the project to meet present and future needs.

1.5.2 Determining the Significance of Adverse Effects

To determine if a particular effect is significant, the Executive Committee examines the characteristics of the effect as well as the context, or circumstances, within which the effect would occur. Criteria for determining what may constitute a significant effect include the following factors:

- Magnitude: This refers to the magnitude of the effect. Low magnitude effects may have no impact, while high magnitude effects do have an impact.
- Probability: This refers to the likelihood that an adverse effect will occur.
- Geographic Extent: This refers to the extent of change over the geographic area of the project. The geographic extent of effects can be local or regional. Local effects may have a lower impact than regional effects.
- Duration and Frequency: This refers to the length of time the effect lasts and how often the effect occurs. The duration of an effect can be short-term or long-term. The frequency of an effect can be frequent or infrequent. Short-term and/or infrequent effects may have a lower impact than long-term and/or frequent effects.
- Reversibility: This refers to the degree to which the effect is reversible. Effects can be reversible or permanent. Reversible effects may have a lower impact than irreversible or permanent effects.
- Context: This refers to the ability of the environment to accept change. For example, the effects of a project may have an impact if they occur in areas that are ecologically sensitive with little resilience to imposed stresses.

YESAA requires that the Executive Committee recommend mitigations to address significant adverse effects of a project, including cumulative effects, in order to recommend that a project proceed. This draft

screening report contains the Executive Committee's recommended mitigations for all significant adverse effects of the proposed project.

2.0 PROJECT OVERVIEW

2.1 PROPONENT INFORMATION

Yukon Energy Corporation (YEC) is a public utility owned by the Government of Yukon through the Yukon Development Corporation. YEC has an installed generation capacity of approximately 129 MW. Of this, 92 MW is installed capacity at three hydro facilities: Whitehorse, Aishihik and Mayo. A further 0.8 MW is installed wind generation. The remaining 36 MW is installed diesel thermal generating capacity of which 25 MW is installed in the Whitehorse Rapids Generating Station (WRGS). YEC's wholesale customer, Yukon Electrical Company Limited (YECL), distributes power to 89 percent of Yukon retail customers, while YEC distributes power to the other 11 percent (approximately 1,900 customers) located primarily in Dawson City, Mayo and Faro.

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2.2 PROJECT DESCRIPTION

The purpose of the Project is the construction of a new natural gas generating station and associated activities adjacent to YEC's existing primary power generating station, the WRGS. The proposed project will produce 13.2 MW, which will provide an additional 4.1 MW to the Yukon electrical grid upon the decommissioning of the two diesel generators (total of 9.1 MW capacity) YEC intends to replace.

The Project lies within the traditional territories of the Kwanlin Dün First Nation (KDFN) and the Ta'an Kwäch'än Council (TKC), and within a developed part of Whitehorse, along Robert Service Way. The Project will involve approximately 0.9 ha of Public Utility zoned Government of Yukon lands.

2.2.1 Changes to the Scope of the Project

The proposal was submitted on August 8, 2013. On November 1, 2013, the Executive Committee determined the proposal to be adequate and on November 5, 2013 commenced the public comment period. On November 12, 2013, the Proponent advised the Executive Committee in writing that they were proposing to modify the layout of the expanded site area (ESA). In particular, the Proponent proposed a reduction in the operational project footprint, and an increase in the height of the vapour retention wall. On November 15, 2013, YEC submitted a revised project proposal. The Executive Committee revised the project scope, and extended the public comment period to accommodate a minimum 30-day period to review the project proposal.

2.2.2 Scope of the Project

Project scoping is conducted in accordance with s. 51 of YESAA and Part 4 of the *Rules for Screenings Conducted by the Executive Committee*. Section 51 of YESAA states, in part:

... the executive committee shall determine the scope of a project to be assessed by it, and shall include within the scope of the project, in addition to any activity identified in the proposal, any other activity that it considers likely to be undertaken in relation to an activity so identified and sufficiently related to it to be included in the project.

Table 3 shows the scope of the Project assessed by the Executive Committee in this screening.

Table 3 Project Scope

Project Component	Activities
Site preparation	- Clearing of up to 1.5 hectares of land (approximately 0.9 ha of Government of Yukon land to be purchased by YEC and minor clearing on White Pass and Yukon Railway land for road and utility crossing) using power-driven machinery. - Addition of sand and granular material to level and compact the site as required. - Building of access: - new all-weather access from Miles Canyon Road for truck offloading and access to the expanded site area. - Re-design of drainage infrastructure at a nearby location to manage surface water runoff coming off the Robert Service Way.
Natural gas generating units and related infrastructure	- Installation of three new 4.4 MW natural gas modular reciprocating generating units and related facilities. Two units are planned to be in service in the fourth quarter of 2014 and the third one to follow within a few years. Related infrastructure includes: - fluid transfer station; - small substation to receive power from generating units; and - switchgear module.
Storage and vaporization of LNG	- Construction of liquefied natural gas (LNG) storage station (primary containment): - The expanded site area will be designed to accommodate up to three 166.5m³ and two 120 m³ (739.5 m³ total capacity) horizontal single containment vacuum jacketed bullet tanks and foundations. The tanks have a stainless steel inner tank and carbon steel outer

	tank, and are considered the primary containment system. - o Installation of two LNG pumps and foundation for third pump. • Construction of LNG vaporization station. • Construction of flare system.
Truck offloading station	• Construction of LNG truck offloading station including: - o spill collection system; and - o shed for monitoring equipment and washroom facilities for driver. • Construction of secondary containment area (206 m³) and trench from offloading station to secondary containment area.
Other related infrastructure	• Construction of related infrastructure between YEC's main power station and the expanded site area including: - o Utility trench and piping network for natural gas, fire suppression water, glycol/water heating system and hydrants. Heating of existing diesel-generator facility with natural gas system. Heating of new natural gas facility with glycol/water heating system. - o Electric service for streetlights and security systems. • Installation of distribution line and communication line to bring power from the new substation to the existing substation and connect to the grid. • Installation of fences around perimeter and gates at both ends of the new access through the expanded site area. • Installation of vapour barrier around expanded site area: eight feet high on the north, east and south sides, and 12 feet high on the west side.
Transportation of LNG	• Transportation of LNG by trucks within Yukon. Two main truck configurations may be utilized: Tridem units with a 54 000 L capacity or A-train units with a 95 000 L capacity. • Delivery of LNG by two to three trucks per week is anticipated during operation.
Decommissioning	• Decommissioning of two Mirrlees diesel power-generating units of 9.1 MW total capacity and ancillary equipment.
Waste management	• Disposition of used oil, lubricants, construction waste and other hazardous materials.

2.2.3 Temporal and Spatial Boundaries of Project

In addition to specifying the activities included in the scope of the Project, it is important in the assessment to have a clear understanding of the temporal and spatial boundaries of the Project. These boundaries define the time periods and sequencing of activities as well as the area within which activities, and their effects, are proposed to occur.

Temporal Boundaries

There are two main stages for the Project: planning/construction, and operations/modifications. The details and timeline for these stages, as provided in the proposal, are set out in Table 4.

Table 4 Project Schedule

Phase and Schedule	Details
Planning/construction (2013-2014)	- Design, equipment purchase and contracting. - Construction of expanded site area and component delivery (May 2014), clearing, grubbing, grading site, construction of utility trench. - Installation of modules, LNG storage and transfer facilities (October 2014), delivery of LNG. - Commissioning of facility (November/December 2014). - Decommissioning of diesel generating units.
Operations/modifications (2014-ongoing)	- New generating units have economic life of 40 years. - Purchase and installation of third natural gas 4.4 MW generating unit when required. - The site is planned as a long-term power generating facility; therefore no decommissioning of existing facilities is expected at this point.

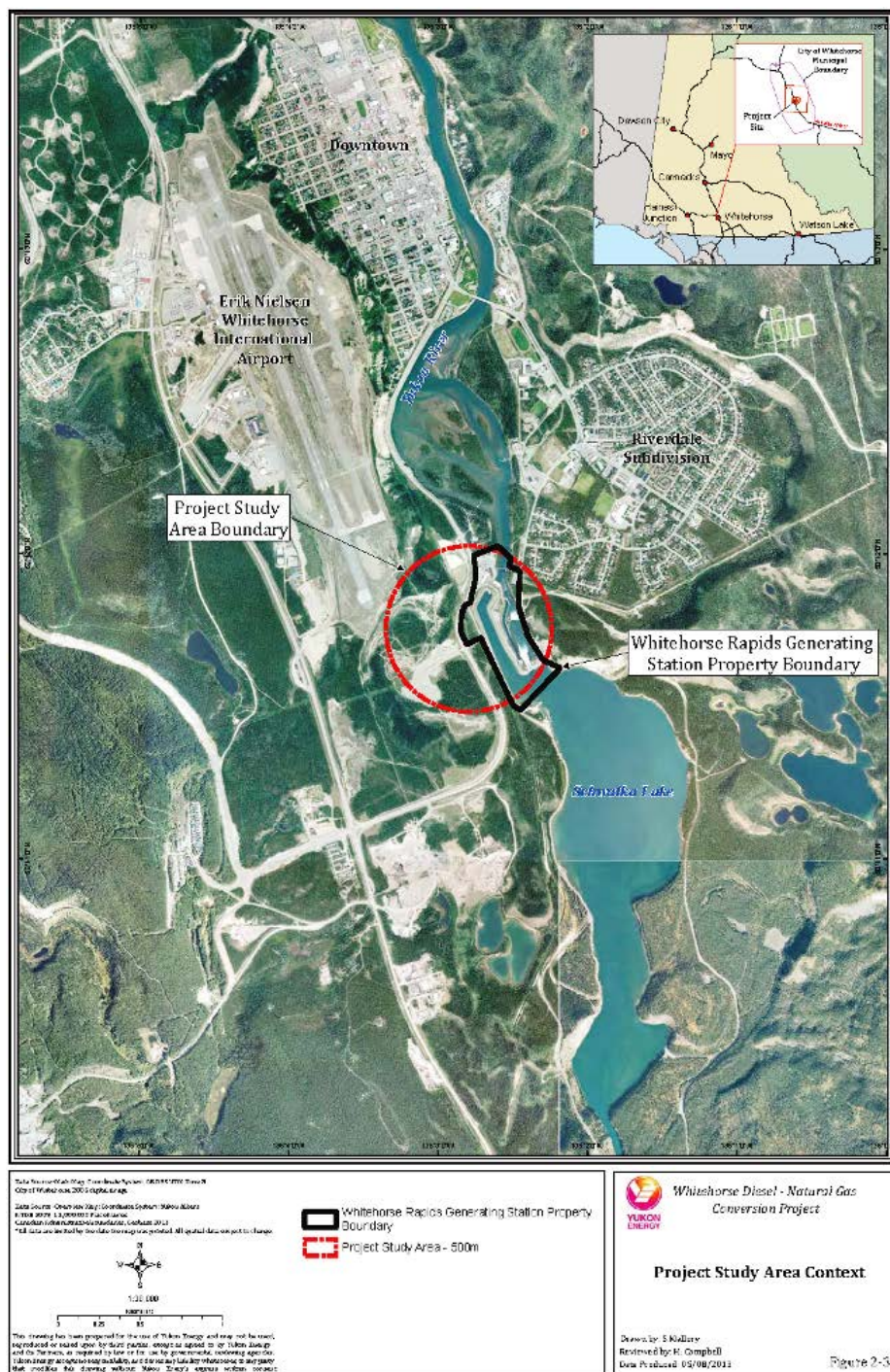
Spatial Boundaries

YEC examined potential environmental and socio-economic effects for the valued components within a 500-metre radius surrounding the project construction footprint; the area within this radius is defined as the project study area (PSA). To maintain consistency, the term will also be used in this report. The following figures, taken from the project proposal, describe the spatial extent of project activities, showing the PSA:

- Figure 2 Project Study Area
- Figure 3 Project Study Area Context
- Figure 4 Project Construction Footprint



Figure 2 Project Study Area. The PSA includes a 500-metre radius surrounding the project construction footprint. Note the expanded site area at the centre of the project study area.



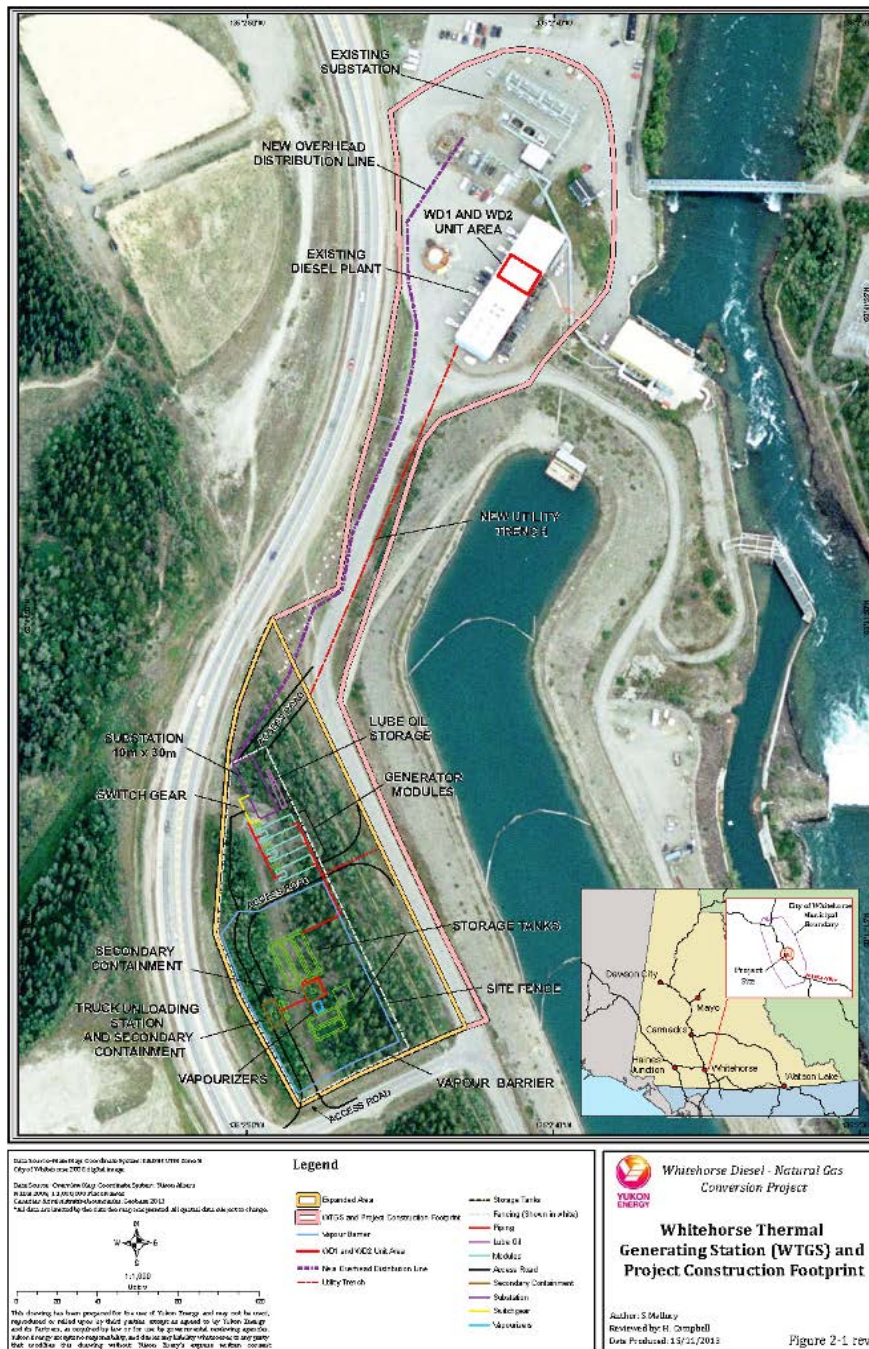


Figure 4 Project Construction Footprint

3.0 ENVIRONMENTAL AND SOCIO-ECONOMIC SETTING

Information in this section is either directly reproduced or summarized from the proposal and subsequent additional proposal information.

3.1 EXISTING ENVIRONMENTAL SETTING

The project study area (PSA) is located in the Yukon Southern Lakes Ecoregion, within the Boreal Cordillera Ecozone. The Boreal Cordillera Ecoregion is characterized by plateaus and rolling uplands separated by wide and U-shaped valleys and occupies the southern Yukon and northern half of British Columbia.

The Project is located in Whitehorse, within an anthropogenic ecosystem impacted by human activity and developments, including the existing Whitehorse Rapids Generating Station (WRGS), roads, gravel pits and other activities (Gartner Lee Limited 2006). The following is a description of the general physiography, surficial geology, soil conditions, climate, and air quality of the Whitehorse region as well as water resources, vegetation, and wildlife of the area.

3.1.1 General Physiography, Surficial Geology and Soil Conditions

Many of the soil materials in the ecoregion were deposited by glaciers, glacial rivers and glacial lakes. Dominant soil materials are derived from volcanic rocks, limestone reefs and clastic sediments produced from glacial lakes. Soils tend to be slightly alkaline and can be classified as eutric brunisols (Yukon Ecoregions Working Group 2004).

The Project is located within the Yukon River valley. The flat terrain in this area consists mainly of glacial sediments with a veneer of organic material covering sand and gravel of glaciofluvial origin. Till is expected to be present under a sequence of silt, sand and gravel deposits. The till generally found within the Yukon River valley mainly consists of dense greenish grey clast (gravel to cobble size) supported by silt. In the vicinity of the WRGS, bedrock may be found at a depth of 16 to 18 metres (EBA 2013) and consists of Miles Canyon Basalt, which is part of the Alligator Lake volcanic complex.

Whitehorse lies in a sporadic permafrost region, where permafrost underlies less than 25 percent of the ground. It is rare to uncover permafrost during excavations. Glaciolacustrine soil is more likely to overlay permafrost than fluvial and glaciofluvial deposits. In Whitehorse and the surrounding area most permafrost has been found below glaciolacustrine deposits (Mougeot GeoAnalysis 1998). As a result, it is highly unlikely that permafrost underlies any portion of the PSA (which is of fluvial origin). Recent geotechnical investigations on the Ta'an Kwäch'än Council (TKC) property to the south of the construction footprint did not encounter permafrost (EBA 2013).

3.1.2 Climate

The Yukon Southern Lakes Ecoregion is located in the Upper Yukon – Stikine Basin Climatic Zone between the St. Elias Coast Mountains to the west and Cassiar Mountains to the east (Whal, et al. 1987).

The mountains create a rain shadow over Whitehorse, which results in low precipitation. Summer precipitation accounts for one-third to one-half of all precipitation in Whitehorse. Historical precipitation records indicate that the months with the greatest level of precipitation are June to August (Environment Canada 2012).

Temperatures in Whitehorse tend to be very cold in the winter months with mild summers (Environment Canada 2012). The climate drivers in Whitehorse are warm air masses from the coast and cold Arctic air from the north (Whal, et al. 1987). The mixture of these two air masses can commonly create temperature inversions. Arctic inversions can hang over low-lying areas of Whitehorse, such as the neighbourhood of Riverdale, in the winter (G.J. Bull and Associates 2005).

The predominant wind direction in Whitehorse is from the southeast (Environment Canada 2012). These winds originate from the Gulf of Alaska (Yukon Ecoregions Working Group 2004). Data from Environment Canada shows that calm conditions (zero or near-zero wind speeds) are experienced over 19.6 percent of the time.

Ice fog occurs naturally when water vapour encounters very cold air (approximately -30 ° C) (American Meteorological Society n.d.), and in Whitehorse occurs during late fall and winter along the Yukon River, including at the WRGS. Due to the close proximity to the Yukon River it is possible that ice fog will occur within the PSA.

The Whitehorse Climate Change Adaptation Plan (Hennessey and Streicker 2011) indicates that climate in Whitehorse is changing, and based on historic climate data has identified climate trends for Whitehorse. Temperatures are rising in the Whitehorse area (particularly in winter), freeze-up is occurring later in the season, break-up is occurring earlier in the season, and the number of frost-free days is increasing. Historical records also indicate a slight increase in precipitation.

3.1.3 Air Quality

Ambient air quality data in Whitehorse is monitored from a station located in downtown Whitehorse and operated by Environment Canada and Government of Yukon Department of Environment. The data from the downtown Whitehorse monitoring station located at 1091-1st Avenue is used as National Air Pollution Surveillance (NAPS) data and is quality controlled, assured and standardized by Environment Canada and YG for inclusion into the Canada-wide air quality database. Today sulfur dioxide (SO₂), nitrogen dioxide (NO₂), ozone, fine particulate matter and carbon monoxide (CO) are measured continuously (Environment Canada 2011). For the Whitehorse monitoring site, only PM_{2.5}, CO, and NO₂ have long-term data collection records.

Data indicates that the maximum ambient levels of CO, NO₂, and PM_{2.5} in Whitehorse are well below ambient air quality standards adopted by Government of Yukon in 2010. Due to forest fires in the area in 2004, 2005, and 2009, the data for NO₂ and PM_{2.5} are anomalously high and are not

representative of typical levels of these contaminants in Whitehorse. Similarly, the 24-hour average NO_2 concentrations were also anomalously higher in 2004 and 2005 than in 2001 to 2003. However, the maximum NO_2 concentrations recorded in 2004/2005 were still only 20 percent of the 1-hour average ambient air quality standards of 400 ug/m^3 and 23 percent of the 24-hour average standard of 200 ug/m^3 . A similar pattern occurs for $\text{PM}_{2.5}$ concentrations over the period for 2001 to 2009 (YOR 2013-0115-005-1).

3.1.4 Noise Levels

In October 2012, Yukon Energy Corporation (YEC) completed monitoring of background noise using a sound level meter at one location in proximity to the closest permanent residence to the project footprint. The noise meter was in place for a period of approximately five days from October 17, 2012 to October 22, 2012 and the monitoring program consisted of 120 hours of continuous hourly noise measurements at the specified monitoring location.

Results of the monitoring program indicate that background noise at the monitoring site during the monitoring period was dominated by local vehicle traffic and sounds of nature, consisting of wind, dog and bird noises and the influence of the Yukon River. Traffic noise was dominated by vehicles travelling along Robert Service Way, with contributions from local traffic along Nisutlin Drive and Alsek Road. Airplane traffic from Erik Nielsen Whitehorse International Airport was also a significant source of transient noise, especially during the morning (8:00 to 9:00) and afternoon (11:00 to 13:00 and 16:00 to 19:00) periods when most commercial flights occur. Typically, these events lasted fewer than five minutes and caused spikes in baseline noise (1-minute Leq) values of approximately 5 to 15 dBA.

L_{90} , used as a measure of ambient noise and representing the noise level exceeded for 90 of the time, eliminates the influence of short-term transient events such as airplane flyovers. The L_{90} for the monitoring site is approximately 45 to 48 dBA, indicative of a quiet residential area.

3.1.5 Surface Water

There are no watercourses located within the expanded site area (ESA). The Yukon River is, however, within the PSA, east of the ESA.

The surface water system in Whitehorse is characterized by deglaciation features such as kettle topography, as well as the Yukon River (Yukon Ecoregions Working Group 2004). Whitehorse sits along the upper reaches of the Yukon River, the drainage point for many of the watersheds in the area. The PSA straddles the dividing line between the Yukon River South Watershed and the Yukon River North Watershed (Gartner Lee Limited 2006).

At Whitehorse, the Yukon River has an annual average flow rate of $251.7 \text{ m}^3/\text{s}$, while daily averages range from $644.8 \text{ m}^3/\text{s}$ to $89.9 \text{ m}^3/\text{s}$ (YOR 2013-0115-057-1). The highest rates are usually recorded in the summertime after the snow cover has melted. Suspended solids and turbidity tend to be higher in spring when increased stream flow from melting snow accelerates bank erosion and overland sedimentation. However, metals primarily associated with suspended solids are not usually available for uptake by fish and other aquatic organisms and are not a concern (LGL Limited 2012).

In 2009, 108 surface water quality samples were collected from 10 monitoring stations in Yukon, providing data for the water quality index. Two of the stations with sufficient data for analysis are located on the Yukon River sites above and below Whitehorse, at the Marsh Lake dam and the confluence with Takhini River respectively (closest available data in proximity to the PSA). The Yukon River achieved a water quality index measure of “excellent” at both sites, which indicates aquatic life is not threatened or impaired and measurements never or rarely exceed water quality guidelines. This indicates that urbanization has not had a significant detrimental effect on the Yukon River at Whitehorse (LGL Limited 2012).

Surface water at the ESA is influenced by the raised railway bed that is approximately 2 m above the rest of the ESA. Field investigations at the project footprint undertaken in May 2013 also indicated a prominent elevation break running north-south down the center of the ESA. The break follows a grass swale that also divides the vegetation zones and ends at the north end of the ESA in a large cobble infiltration gallery for stormwater. At the time of the investigation the basin was completely dry.

3.1.6 Groundwater

The municipal water supply for Whitehorse is drawn entirely from the Selkirk Aquifer in Riverdale. The Selkirk Aquifer is an unconfined to semi-confined glaciofluvial sand and gravel aquifer set within the Chadburn Lake buried river valley (Gartner Lee Limited 2006). Some of the wells which tap this aquifer are less than 30 m deep, and are recharged by Schwatka Lake and Hidden Lakes. This wellfield is situated less than 1 km northeast of the WRGS, on the east bank of the Yukon River. The Engineering Services Department of the City of Whitehorse is currently leading a wellhead protection study for the wellfield, and confirms that the capture zone for the wellfield does not include the WRGS or the project study area. Groundwater from overburden aquifers is also used as the water supply for rural residential subdivisions south of the PSA, with the closest being approximately seven kilometres to the south.

YEC has a well at the WRGS that provides water to the headquarters office building. A sample collected September 11, 2012 indicates compliance with all of the Canadian Drinking Water Quality standards (AECOM 2012).

In general, the groundwater quality in the PSA is expected to be good given its location immediately down-gradient of Schwatka Lake. Groundwater is generally north flowing, from Schwatka Lake to the Yukon River downstream of the hydroelectric dam. Locally, the flow direction is strongly controlled by the 20-metre elevation difference between the power canal and the river downstream of the generating station. Groundwater beneath the WRGS discharges to the west bank of the Yukon River close to or not far downstream of the hydroelectric dam.

3.1.7 Vegetation

Open coniferous and mixed woodland forests dominate the flora of the Yukon Southern Lakes Ecoregion (Yukon Ecoregions Working Group 2004). Due to human activity and historical fires, the majority of forested land in the Whitehorse region is in mid-to-mature several stages (40 to 120 years old) (Applied Ecosystem Management Ltd. 1999).

Ecosystem mapping was the primary source of information used to describe vegetation associated with the PSA, and indicates that the project footprint lies within a Willow-Shrub Birch Ecosystem. Willow-Shrub Birch Ecosystems are non-forested areas with willow and shrub birch meadows; variable grass, sedge or lichen may also be present depending on the site moisture regime (Gartner Lee Limited 2006).

Site investigations undertaken in May 2013 indicate two distinct zones of vegetation within the project footprint: a primarily pine stand and a shrub willow stand. The pine stand consists of mostly undisturbed vegetation with some kinnikinnick and soapberry in the understory. The shrub willow stand has some immature poplars with understory predominantly comprised of grasses. The two vegetation areas are divided by a grass swale that runs north south.

3.1.8 Wildlife

The importance of habitat to species may be classified through mapping of Wildlife Key Areas, i.e., locations used by wildlife for important, seasonal life functions. Wildlife Key Areas have been identified for waterfowl, raptors, and grouse, various ungulates, wolf, woodland caribou, mountain goat, black bear, grizzly bear, sheep, beaver, and muskrat (Yukon Environment 2009). No Wildlife Key Areas, as defined by are located within the PSA.

The Yukon Southern Lakes region supports a large avian population (Yukon Ecoregions Working Group 2004). Forest birds and neotropical migrants, however, are the only groups with habitat within the PSA. At least five species of song birds have been observed in the tree canopy of the ESA.

Potential species at risk have their range within the PSA, including birds, mammals, and amphibians. Specifically, the species at risk with ranges potentially overlapping the PSA are: Common Nighthawk, Olive-sided Flycatcher, Bank Swallow, Horned Grebe, Little Brown Bat, Western Toad, and Dune Tachinid Fly (YOR 2013-0115-057-1). Although there is potentially suitable habitat within the PSA (based on the vegetation structure and composition), this habitat is highly fragmented and disturbed due to the various anthropogenic sources such as off-road vehicles, vehicle traffic, roads and the airport.

3.2 EXISTING SOCIO-ECONOMIC SETTING

3.2.1 Population

In the early 20th century, migration in and out of the Yukon was quite high largely due to fluctuations in the economy related to the mining industry and highway construction. The population has stabilized over the past 50 years and population shifts that occur in response to mining and resource development are not as prominent (City of Whitehorse 2010). Since 2003, the Yukon and Whitehorse populations have been growing, and over the last 10 years, the annual rate of growth has ranged from 0.7 to 3.4 percent, with an annual average of 1.7 percent (Yukon Bureau of Statistics 2011).

The Yukon Bureau of Statistics population projections predict ongoing growth in both Whitehorse and Yukon over the next 10 years. These projections are based on observed trends in the following defined reference periods: June 2009-June 2011; June 2006-June 2011; and June 2001-June 2011. These projections do not account for any specific future changes in business or government projects which

could affect the population (Yukon Bureau of Statistics 2011). Opening or closure of a large mine, for example, may result in deviation from these projections.

The City of Whitehorse has also been planning for residential growth. The increasing population and shrinking average household size is expected to have a direct impact on the number of housing units required. As of 2006, there were 8 631 dwelling units within Whitehorse limits, with an average of 2.4 people per household (City of Whitehorse 2010). Based on the Yukon Bureau of Statistics population projection, over 2 500 new dwelling units may be required in Whitehorse by 2021.

3.2.2 Land Use

The ESA is located along Robert Service Way, just over 2 km south of the centre of downtown Whitehorse. The ESA is zoned Public Utilities in the 2010 Whitehorse Official Community Plan and the Whitehorse Zoning Bylaw.

Properties owned by TKC and the City of Whitehorse are located west of Robert Service Way and partially within the boundaries of the PSA. The property owned by TKC is southwest of the project footprint. There are no buildings or other structures currently on the ESA. Approximately 50 percent of the ESA is cleared with several informal trails and old roads crossing the site. The property owned by the City of Whitehorse is north-west of the project footprint. It is primarily cleared and there are no structures on the property. The cleared area of the City of Whitehorse property is used as an unofficial snow dump during the winter months. The City of Whitehorse is considering the option of building a municipal services building on the property.

Robert Service Campground, City of Whitehorse-owned baseball diamonds and the airport are located north of the project construction footprint (Figure 4). Miles Canyon Road and the power canal for the WRGS are located west of the project footprint. Vacant Government of Yukon land zoned for Environmental Protection is located south of the project footprint.

The nearest residences are across the Yukon River in Riverdale 500 m northwest of the ESA at the edge of the PSA. The Riverdale subdivision has a population of approximately 4 885 residents. There are five dwellings within the PSA. The Project is partially within the Chadburn Lake Park Reserve.

3.2.3 Resource Use

There is one open trapping concession within the ESA (#288) and one closed trapping concession (#409). There are no additional concessions within the PSA. Government of Yukon, Department of Environment has indicated that trapping concession #288 does not have a registered license holder at this time. There are no outfitting concessions within the project footprint or the PSA. There are no quartz claims, placer claims, designated agricultural applications, leases, or dispositions within the project footprint or PSA.

3.2.4 Recreation

A portion of the Yukon River Loop Trail, used for hiking, dog walking, mountain biking, sightseeing, and as a cross-country ski route, runs through the PSA and project footprint, along the eastern boundary of the project footprint. Each August, the Yukon River Loop Trail Marathon proceeds along the network of loop trails in the area, through Robert Service Campground and past the WRGS and power canal, before proceeding along Schwatka Lake. The Yukon River Loop Trail also acts as a connector route to the Millennium Trail. The Millennium Trail connects several recreational resources such as the Whitehorse skate park, Parks Canada's SS Klondike National Historical Site, Robert Service Campground and whitewater paddling resources (City of Whitehorse 2007).

Other recreation uses in the area surrounding the Project include baseball diamonds, networks of old roads and informal trails, Robert Service Campground, and various events.

3.2.5 Social and Cultural Context

The PSA is located within the traditional territories of the Ta'an Kwäch'än Council and the Kwanlin Dün First Nation. In particular, the PSA southwest of the project footprint overlaps an area of TKC Settlement Land.

3.2.6 Heritage Resources

There are no known or recorded heritage sites within the PSA or the project footprint, but a few sites have been recorded in the vicinity of the area. The PSA has not received a great deal of heritage survey and assessment efforts. However, there have been a small number of archaeological surveys conducted in the vicinity with recorded artifact sites located near the outer edge of the PSA comprised mostly lithics, isolated materials, and historic sites. Identified areas with potential for heritage resources are also outside the PSA. A segment of the White Pass and Yukon Railway route is located within the project footprint.

4.0 CONSIDERATION OF ALTERNATIVES

Section 50(2) of YESAA requires a proponent, when preparing their proposal, to consider alternatives to the Project, or alternative ways of undertaking or operating the Project, that would avoid or minimize any significant adverse environmental or socio-economic effects. Similarly, s. 42(1)(e) of YESAA directs the Executive Committee to consider these matters in the assessment. The following sections identify alternatives to the Project (Section 4.1), alternative ways of undertaking the Project (Section 4.2) and consideration of alternatives to the Project (Section 4.3).

4.1 ALTERNATIVES TO THE PROJECT

The purpose of the Project is essential for establishing a basis for the development of a range of reasonable project alternatives and assists with the identification and eventual selection of a preferred alternative. The Executive Committee provides further consideration of the project purpose in Section 5.5.

Yukon Energy Corporation (YEC) considered two alternatives to the Project including:

- deferring replacement and continuing to use the existing WD1 and WD2 Mirrless diesel units; and
- installing new high-efficiency diesel engine replacements.

YEC explained that deferring replacement of the existing generators would result in unreliable generation capacity, insufficient generation capacity to meet forecasted thermal capacity requirements, higher operations cost (due to fuel cost and ongoing maintenance) and higher air emissions due to the inefficiencies of the existing units. Due to these reasons, the Executive Committee has not considered this option further as an alternative to the Project.

YEC explained that installing new high-efficiency diesel units would provide reliable generation capacity that is sufficient to meet forecasted thermal capacity requirements. The capital costs of new high-efficiency diesel units would be less than the proposed natural gas units. However, YEC concluded that the new diesel units would have higher estimated fuel cost and produce more air emissions than the proposed natural gas units. The Executive Committee has considered the new high-efficiency diesel units replacement as an alternative to the Project. The new high-efficiency diesel units replacement alternative was considered as a method to avoid or minimize significant adverse environmental or socio-economic effects.

YEC concluded in their effects assessment that the Project would not result in significant adverse effects based on the option chosen.

Comments received during the public comment period outlined concerns that other options were not considered as alternatives to the Project. The following excerpts from comments outline this concern:

before passing final judgement on this proposal, YESAB should ensure that YEC has considered imaginative alternatives to fossil fuel generators. YESAB should also make sure that it has in hand the actual usage projections that YEC is using for its business case – are these actually in concert with the purpose of the project, i.e., peaking for short-term non-industrial load growth?

(YOR 2013-0115-132-1)

YCS does, however, also believe that there are other viable alternatives to provide baseload electricity generation employing conservation, load management and the development of renewable power sources that match the demand for electricity and that would be far better investments than entrenching and expanding our reliance on dirty fossil fuels.

(YOR 2013-0115-180-1)

It is understood that the operation of these new turbines is planned only for emergency purposes and to meet periodic peak demands and they will not be operated on a continual basis to meet every day demands. Should power demands exceed the average daily hydro supply, the Project Proponent is encouraged to consider the development of green or sustainable options that do not rely on carbon sources whether diesel or natural gas, such as wind power and/or solar power.

(YOR 2013-0115-177-1)

The Executive Committee considered if other renewable power sources such as wind power, solar power, hydro power and/or demand side management were viable alternatives to the Project and requested additional information from YEC (YOR 2013-0115-030-1, 2013-0115-220-1). YEC responded that thermal generation is the only power generation option available in sufficient quantity to meet reliable generation capacity requirements. YEC described the purpose of the Project as:

capacity to meet Yukon Energy's reserve capacity planning criteria, including reserve capacity for seasonal low water periods and drought years while supplying short-term non-industrial load growth and peak winter demand, with the least cost impact on Yukon ratepayers.

(YOR 2013-0115-057-1)

Further discussion of the purpose of the Project is provided in Section 5.5. YEC has committed to exploring and developing additional renewable generation supply options to reduce both diesel and liquefied natural gas (LNG) requirements wherever possible as the requirement for default diesel generation increases (YOR 2013-0115-057-1). Currently, the Executive Committee is satisfied that thermal generation options are the only alternatives to meet the purpose of the Project. Although the Executive Committee is sympathetic to the interests in developing additional renewable or sustainable options for generating or conserving power, there are other forums for these very important energy policy discussions.

4.2 ALTERNATIVE WAYS OF UNDERTAKING THE PROJECT

YEC identified various ways of undertaking the Project including:

- Alternative communities/locations within the Whitehorse-Aishihik-Faro (WAF) grid to construct the LNG storage facility and natural gas units;
- Alternative locations along Robert Service Way to construct the LNG storage facility and natural gas units; and
- Alternative capacity 54 000 L capacity Tridem unit trailers for LNG transport.

The Executive Committee requested additional information from the Proponent to better understand how locating the LNG storage facility and natural gas units in other communities on the WAF grid would avoid or minimize significant adverse effects that may be identified. YEC indicated that Whitehorse was the nearest practical WAF grid location for LNG deliveries from Alberta or British Columbia. Whitehorse is the largest load centre on the WAF grid, and it offers efficiencies being close to existing infrastructure and personnel. Other communities were considered to not be cost effective or practical (YOR 2013-0115-057-1).

The Executive Committee requested additional information regarding installing the LNG storage facility and natural gas units at the Takhini Substation (also referred to as the "Mayo Road Substation") located along the North Klondike Highway, approximately 7.5 km north of the intersection with the Alaska Highway. YEC responded that the Takhini Substation was not the preferred option as project efficiencies related to being close to established infrastructure and personnel would be lost. YEC also identified that waste heat and boil off gas (BOG) associated with the storage of LNG and natural gas units could not easily be utilized for other purposes such as heating YEC buildings and infrastructure. (YOR 2013-0115-220-1)

The Executive Committee has considered the alternative locations as alternatives that would avoid or minimize significant adverse effects that are identified. The Executive Committee has also considered the using Tridem trailers as an alternative to the proposed A-train 95 000 L trucks proposed. Further consideration of these alternatives is discussed in the following section.

4.3 CONSIDERATION OF ALTERNATIVES TO AVOID OR MINIMIZE SIGNIFICANT ADVERSE EFFECTS

The Executive Committee has concluded that the Project will result in significant adverse effects to birds and aesthetics in Sections 9.0 and 10.0 and has identified terms and conditions that will mitigate those effects.

The installation of new high-efficiency diesel units at the proposed expanded site area as an alternative to the Project could minimize or avoid significant adverse effects on birds and aesthetics. However, the Executive Committee recognizes the Project is adjacent to the existing YEC substation and associated YEC infrastructure. The area has been previously disturbed by human activities, including major land alterations due to the construction of Robert Service Way and the Whitehorse Dam.

Alternative locations considered are generally situated in less disturbed areas where wildlife may be more prevalent. Locating the Project in other communities or at the Takhini Substation would likely cause greater effects to wildlife populations. Locating the LNG facility in other communities or at the Takhini substation would minimize the effects to aesthetics values.

Due to the disturbed nature of the ESA and the proximity to existing YEC infrastructure, the Executive Committee has determined that terms and conditions can mitigate significant adverse effects to birds and aesthetics as proposed.

5.0 SCOPE OF ASSESSMENT

The scope of assessment identifies the matters considered in the screening. It is determined by considering the matters set out in s. 42 of *Yukon Environmental and Socio-economic Assessment Act* (YESAA) (outlined above in Section 2.5.2). The Executive Committee has employed a valued component based assessment methodology to assess the environmental and socio-economic effects of the Project.

The Valued Environmental and Socio-economic Components (VESECs) are identified, in part, on views and information submitted during the adequacy review stage and public comment period. In identifying VESECs, the Executive Committee considered comments received during the screening and other technical input.

5.1 CONSIDERATION OF COMMENTS RECEIVED

The Executive Committee solicited comments from Government of Yukon (YG), Kwanlin Dün First Nation (KDFN) and Ta'an Kwäch'än Council (TKC) during the adequacy review stage to support the determination if there was sufficient information to draft a scope of the Project and commence the screening. YG, KDFN and TKC provided comments that in their view the proposal contained sufficient information to commence the assessment (YOR 2013-0115-29-1, 2013-0115-31-1, 2013-0115-32-1).

The public comment period for the Project was from November 5, 2013 to January 10, 2014. The Executive Committee received over 130 comments during the course of the public review (Appendix C). The Executive Committee also held a public meeting in Whitehorse on December 11, 2013 where additional comments were received. A transcript of the meeting was produced (YOR 2013-0115-162-1, 2013-0115-163-1).

The Executive Committee recognizes the public interest in the Project and thoughtful considerations provided. The Executive Committee has considered the concerns raised in the comments and, throughout this report, has quoted specific excerpts and referred to comments received.

Issues raised during the public comment period were related to:

- Purpose of the Project
 - o Back-up and base load requirements
 - o Economics (proposed savings, rising cost of LNG, cost of the Project)
- Project scope
 - o Hydraulic Fracturing
 - o Life cycle assessment
- Consideration of alternatives
 - o New diesel generators instead of LNG
 - o Renewable energy instead of fossil fuel (Hydro, wind, solar, hydrogen)
- Safety

- o Design standards
- o Accidents (natural events – flooding, dam breach, earthquake, forest fire)
- o Training (fire fighters, operators, drivers)
- Air Emissions
 - o Greenhouse gas emissions (all phases – transport, boil-off gases, leaks, combustion)
- Aesthetics
 - o Landscaping requirements, City of Whitehorse, Official Community Plan (OCP)
 - o Visual (power line, vapour barrier), noise

The Executive Committee recognizes that the majority of comments received opposed the Project proceeding, as proposed, and has considered those comments. However, some of the concerns raised in the comments are outside the legislative authority of what the Executive Committee can consider when conducting a YESAA screening. These matters are addressed in Sections 5.2 and 5.3.

5.2 CONSIDERATION OF ACTIVITIES OUTSIDE YUKON

The Executive Committee received many requests to consider activities related to natural gas extraction, liquefaction, and transportation processes in jurisdictions outside Yukon as part of the Project (Table 5).

Table 5 Comments Regarding Activities Outside Yukon

YOR Reference Number	Description
2013-0115-077-1	Request for scope change from YCS, 2013_12_05
2013-0115-079-1	Email J. Harwood Dabbs, 2013_12_08
2013-0115-090-1	Byhand, S. Miller-Wright, 2013_12_11
2013-0115-093-1	Email P Davis, 2013_12_12
2013-0115-109-1	Comments S. Wright, 2013_12_17
2013-0115-115-1	Email J Taggart, 2013_12_18
2013-0115-129-1	YCS response to change in scope, 2014_01_03
2013-0115-130-1	Comment - Lois Johnston, 2013-12-28
2013-0115-143-1	YCS Analysis on Lifecycle Assessments, 2014_01_07
2013-0115-157-1	Email P Huber, 2014_01_09

2013-0115-174-1	Email C. McNutt, 2014_01_10
2013-0115-179-1	Comment TKC, 2014_01_10
2013-0115-181-1	Comment J Maissan, 2014_01_10
2013-0115-191-1	Email A McCorkell, 2014_01_10
2013-0115-200-1	Email J Maissan, 2014-01-10

The Yukon Conservation Society (YCS) submitted a letter dated December 4, 2013 (YOR 2013-0115-077-1) requesting the scope of the Project be expanded to include activities outside of Yukon. The Executive Committee concluded, in its December 9, 2013 letter to YCS, the following:

First, we would like to clarify that the provisions of YESAA are only applicable to activities occurring in Yukon except in the limited situation contemplated in s. 93(1). The official title of YESAA is "An Act to establish a process for assessing the environmental and socio-economic effects of certain activities in Yukon". As the title suggests, the Act provides authority to YESAB to assess activities that occur in Yukon. The Act does not provide YESAB the authority to make recommendations to regulatory bodies outside of Yukon.

As such, sections 42 and 51 of YESAA should be read with these limits in mind. Given these limits, the Executive Committee will not include natural gas extraction, processing and liquefaction in the scope of the Project as these activities occur outside of Yukon, and thus, beyond the authority of the Executive Committee to consider.

(YOR 2013-0115-081-1)

5.3 CONSIDERATION OF HYDRAULIC FRACTURING IN YUKON

The Executive Committee received many requests to consider activities related to hydraulic fracturing in Yukon as part of the Project (Table 6).

Table 6 Comments Regarding Hydraulic Fracturing in Yukon

YOR Reference Number	Description
2013-0115-051-1	Email K. Mercks, Nov 4, 2013
2013-0115-062-1	Email Request for Extension P Davis, 2013_11_21
2013-0115-071-1	Comment A Reid, 2013_12_01
2013-0115-072-1	Email L. Klauserova, 2013_12_02

2013-0115-077-1	Request for scope change from YCS, 2013_12_05
2013-0115-084-1	Comment R. Annett, 2013_12_11
2013-0115-088-1	Comment J. Plaisonce, 2013_12_12
2013-0115-097-1	Email E. Heuer, 2013_12_13
2013-0115-109-1	Comments S. Wright, 2013_12_17
2013-0115-115-1	Email J Taggart, 2013_12_18
2013-0115-119-1	Email L. Leon, 2013_12_19
2013-0115-128-1	Comment M Saunders, 2014_01_01
2013-0115-135-1	Email S. Binette, 2014_01_02
2013-0115-136-1	Email R and M Griffiths, 2014_01_03
2013-0115-153-1	Comment A. Milani, 2014_01_09
2013-0115-157-1	Email P Huber, 2014_01_09
2013-0115-167-1	Email A Belke, 2014_01_09
2013-0115-170-1	Email D. Roberts, 2014_01_09
2013-0115-171-1	Email E Huber, 2014_01_09
2013-0115-172-1	Email J Edwards, 2014_01_09
2013-0115-173-1	Email M Berkman, 2014_01_09
2013-0115-174-1	Email C. McNutt, 2014_01_10
2013-0115-178-1	Comment S. Guimond, 2014_01_10
2013-0115-180-1	Comment YCS, 2014_01_10
2013-0115-184-1	Comment S Smith, 2014_01_10
2013-0115-185-1	Comment G Haase, 2014_01_10
2013-0115-189-1	Byhand G Bemis, 2014_01_10

2013-0115-192-1	Email C. Burke, 2014_01_10
2013-0115-195-1	Email G. Lalena, 2014_01_10
2013-0115-196-1	Email G. Niedermeyer, 2014_01_10
2013-0115-199-1	Email J. Gulick, 2014_01_10
2013-0115-204-1	Email P. Becker, 2014_01_10
2013-0115-208-1	Email S. Jones, 2014_01_10
2013-0115-209-1	Email YCS, 2014_01_10
2013-0115-214-1	Email CPAWS, 2014_01_09

Yukon Conservation Society (YCS) submitted a letter dated December 4, 2013 (YOR 2013-0115-077-1) requesting the scope of the Project be expanded to include hydraulic fracturing activities in Yukon. The Executive Committee concluded, in the December 9, 2013 letter to YCS, the following:

There are two main reasons why the Executive Committee believes that hydraulic fracturing is not sufficiently related to this Project so as to be included in the assessment of it. First, the Project proposal identifies both an immediate source, Jumping Pound near Calgary Alberta, as well as the Fort Nelson area as a potential future source of liquefied natural gas for the proposed facility. Second, there is currently a moratorium on hydraulic fracturing in Yukon, and thus, no possibility of sourcing the proposed facility with LNG from a Yukon location. The possibility of hydraulic fracturing as an activity connected to this Project is simply too remote and speculative for the Executive Committee to include it in its assessment. As such, the Executive Committee will not amend its scope of assessment for this Project.

(YOR 2013-0115-081-1)

5.4 CONSIDERATION OF CHANGE IN PROJECT SCOPE

On November 12, 2013, Yukon Energy Corporation (YEC) submitted changes to the project scope. The letter stated:

Yukon Energy has determined that some amendments are necessary to its original Project Proposal for the Whitehorse Diesel Natural Gas Conversion Project. We would like to notify the Executive Committee that modifications to the layout of the Expanded Site Area have resulted from Yukon Energy's ongoing engineering and planning efforts to define and secure the lands required for the project. These layout modifications represent changes to original Project Proposal and the Executive Committee's Draft Statement of Project Scope.

(YOR 2013-0115-053-1)

The site layout required amendment to exclude facilities to be constructed on the White Pass and Yukon Route lands. The amended site layout would not require any lease or facility encroachment on the White Pass and Yukon Route lands.

The Executive Committee responded to the proposed scope change in a letter to YEC dated November 13, 2013 stating:

...Project 2013-0115 is now in the public comment period of the screening process. Although we received notice of the change in scope of Project No. 2013-0115 on November 12, 2013, we note that the revised vapour dispersion analysis in Appendix B of your letter indicates that you were aware of the potential change in scope during the adequacy review period of the screening process. Unfortunately, the modifications to the project proposal were not brought to the attention of Executive Committee in a timely manner in order to enable us to conduct a thorough and well-informed adequacy review and to avoid confusion.

Lastly public participation in assessments conducted by YESAB is one of the principle tenets underlying the Yukon Environmental Socio-economic Assessment Act. For this reason, YESAB affixed the first public comment period in the Rules for screenings at a minimum of 30 days and up to a maximum of 60 days. The Executive Committee is dedicated to upholding this principle. As such, once we have received an adequate revised project proposal we will give the public and interested persons a minimum of 30 days and up to a maximum of 60 days from the date that the project scope is modified to provide comments.

(YOR 2013-0115-055-1)

YEC provided an amended project proposal reflecting the site layout amendment to the Executive Committee on November 18, 2013 (YOR 2013-0115-057-1). After determining the amended project proposal was adequate, the Executive Committee extended the public review period an additional thirty days (YOR 2013-0115-060-1). The scope of the Project reflects the amended site layout as proposed by YEC.

5.5 CONSIDERATION OF THE PURPOSE OF THE PROJECT

YEC outlined the purpose of the Project as:

The Project will ensure that Yukon Energy maintains the infrastructure necessary in the next few years to address the YUB's recommended reserve capacity planning criteria requirements, has reserve capacity for seasonal low water periods and drought years, and is able to meet short term non-industrial load growth and peak demand with the least impact on ratepayers.

(YOR 2013-0115-057-1)

YEC indicated that thermal energy is required to meet unplanned system outages, drought conditions, and planned system outages. YEC forecasted future thermal energy requirements based on:

- long-term average hydro generation from existing YEC hydro facilities, and
- consideration of different scenarios of Yukon growth.

YEC's load forecast is discussed further in Section 8.1.2.

During the public comment period, the Executive Committee received comments regarding YEC's project purpose and that the LNG units may be proposed to meet baseload demand that is beyond the purposes outlined in the proposal.

For example, the following two comments represent these objections:

Yes, YEC does need some form of generation that can quickly be brought online. However, before passing final judgement on this proposal, YESAB should ensure that YEC has considered imaginative alternatives to fossil fuel generators. YESAB should also make sure that it has in hand the actual usage projections that YEC is using for its business case– are these actually in concert with the purpose of the project, i.e., peaking for short-term non-industrial load growth?

(YOR 2013-0115-132-1)

After investing \$35 million in LNG infrastructure, Yukon Energy might decide to use LNG not just for backup, but as a primary energy source, which could then discourage development of renewable energy infrastructure

(YOR 2013-0115-153-1)

As a result of the concerns identified, the Executive Committee requested additional information on aspects related to the purpose of the Project including thermal unit load forecast, comparing load forecast with historical diesel use, capital costs of LNG and diesel generators, project economic forecasts, and alternatives to the Project (YOR 2013-0115-217-1). YEC updated and corrected forecast figures in the Proposal and provided additional clarification of the economic forecasts and consideration of alternatives to the Executive Committee (YOR 2013-0115-220-1). The Executive Committee is satisfied the construction of a natural gas generating station will meet the purpose of the Project as outlined by YEC in the proposal.

5.6 VALUED ENVIRONMENTAL AND SOCIO-ECONOMIC COMPONENTS

To assess the potential effects of the Project, the Executive Committee identified VESECs potentially affected by the Project. VESECs were identified by the Executive Committee considering the proposal, comments received during the screening, and technical input from experts. Table 7 sets out the VESECs considered in this assessment and the corresponding sections of the report.

PART II EFFECTS ASSESSMENT

Part II presents the Executive Committee's effects assessment (EA) for the Project. The valued environmental and socio- economic components set out in Table 7 have been considered.

Table 7 Valued Environmental and Socio-economic Components

Values	Sections
Air Quality	6.0
Safety	7.0
Economics	8.0
Wildlife	9.0
Aesthetics	10.0

For each valued component, an overview of the component is provided, followed by the effects characterization analysis and significance determination. Mitigative measures are specified where required. Potential cumulative effects are examined, and a final determination is made of the significant adverse effects on each valued component.

6.0 AIR QUALITY

This section addresses potential effects of the Project on air quality. An understanding of the environmental and socio-economic setting for air emissions is provided, and potential adverse effects are characterized and discussed in the context of the proposal, stakeholder comments, relevant legislation and proposed mitigation strategies. The Executive Committee concludes that compliance with relevant legislation, and proposed mitigation strategies will effectively eliminate, reduce or control significant adverse effects on air quality. Pursuant to s. 42(2)(a) of YESAA, the Executive Committee has determined that effects monitoring regarding air emissions is required.

6.1 OVERVIEW

Yukon Energy Corporation (YEC) is proposing to install two natural gas generators to replace two diesel burning generators (WD1 and WD2) originally installed in 1968 and scheduled to be retired in 2014 and 2015 respectively. Two of the natural gas generators will be installed in late 2014 and the third will be installed as required to meet grid capacity.

Project activities that may impact air quality include the use of three new natural gas generators at the Whitehorse Thermal Generating Station (WTGS), as well as the transport of LNG within Yukon. The following effects that could impact air emissions are considered in the assessment:

- Common air contaminants (CACs)
- Greenhouse gas (GHG) emissions
- Increased water vapour

Air quality has environmental and socio-economic value in terms of human health and safety and quality of life. The atmosphere is an important pathway for the transport of contamination to the freshwater, terrestrial and human environments.

6.1.1 Air Quality Effects Assessment Context

In 2011, SENES Consultants conducted an air quality modeling report of CACs including: carbon monoxide (CO), nitrogen dioxide (NO₂), sulfur dioxide (SO₂) and Particulate Matter (PM_{2.5}) in support of YEC's permit renewal for the diesel generators at Whitehorse Thermal Generating Station (WTGS) (YOR 2013-0115-005-1). The Executive Committee considers the 2011 SENES report to describe conditions in Whitehorse based on modeling the use of seven diesel generators at the WTGS. The SENES modeling however did not include a thorough assessment of GHG constituents considered in Section 6.3 or water vapour emissions outlined in Section 6.4. As such, the Executive Committee has used a comparative approach between options when determining if the Project will result in significant adverse effects. The alternative chosen for the comparative analysis is the continued use of diesel generators at WTGS; however, rather than considering the generators to be retired, new diesel generators are considered as the continued use of existing generators is not viable.

6.2 COMMON AIR CONTAMINANTS

The Project has the potential to result in adverse effects on air quality in terms of CACs being released from the exhaust of the natural gas generators. Pollutants in exhaust emissions have the potential to decrease ambient air quality. Values that may be affected by ambient air quality include the health and safety of individuals living and working in the area, plants, wildlife and infrastructure.

Although natural gas burns more cleanly than diesel; both diesel and natural gas generators emit exhaust into the atmosphere. Diesel exhaust is a complex mixture of combustion products that contains substances known to be or suspected of being carcinogenic. These include: benzene, formaldehyde, arsenic mercury compounds, and selenium compounds. Natural gas primarily consists of methane, a GHG that will be characterized in Section 6.3.

Examples of CAC emission from both sources may include: total particulate matter(PM), inhalable particulate matter (PM) less than or equal to 10 microns (PM₁₀), respirable PM less than or equal to 2.5 microns (PM_{2.5}), SO_x, NO_x, CO_x, ground level ozone (O₃), and volatile organic compounds (VOCs). Once these toxic substances are in the atmospheric environment, they can result in poor ambient air quality. Further detail of diesel and natural gas emissions is provided in Section 6.2.3 .

6.2.1 Consideration of the SENES Report

The dispersion modeling analysis for diesel generators within the Air Quality Assessment of the SENES report (YOR 2013-0115-005-1) determined that the highest ambient air quality impacts for most contaminants were confined to the immediate vicinity of the power plant along the western edge of the property line.

The following points summarize key findings of the SENES 2011 report:

- The predicted concentrations for the three gaseous contaminants (i.e. CO, NO₂ and SO₂) considered would remain within the limits set by the Yukon Ambient Air Quality Standards under a worst-case drought operations (diesel generators running at maximum) scenario.
- Similarly, YEC's emissions combined with an assumed background PM_{2.5} concentration of 8.0 µg/m³ would, also under a worst case drought scenario, remain below the limits of the Yukon standards everywhere in Whitehorse. The exception is at the maximum point of impingement along the western edge of the facility property line where emission limit will be exceeded for two days of the year.
- The incremental contribution of YEC's emissions to ambient air quality levels in most areas of Whitehorse would remain at or below about 2 µg/m³ (less than seven percent of the standard), for the worst case drought scenario.

(YOR 2013-0115-005-1)

Further, SENES's study compiled a community emission inventory as part of an air quality assessment for the City of Whitehorse. The community inventory indicates that YEC operations in Whitehorse contribute a relatively small to insignificant amount of emissions in terms of both CACs and GHGs. Most emissions in Whitehorse (as with other Yukon communities) are dominated by mobile sources and heating using either fuel oil or wood stoves. With the exception of NO_x emissions, the contribution of

YEC operations to total community emissions of common air contaminants in 2007 was less than one percent (YOR 2013-0115-005-1). The Executive Committee is of the opinion that YEC's contribution to total community emissions have not changed significantly since 2007.

6.2.2 Legislative Context: Common Air Contaminants

In 2010, Environment Yukon adopted the Yukon Ambient Air Quality Standards for SO₂, O₃, total suspended particulate matter (TSP), CO, PM_{2.5} and NO₂ (Table 8). These are in line with Canada-Wide Minimum Standards.

Table 8 Yukon Air Quality Standards

Pollutant	Time Frame	Yukon Air Quality Standards		
		µg/m ³	ppm ³	ppbv ⁴
Sulphur Dioxide (SO ₂)	Annual	30	--	11
	24 Hour	150	--	57
	1 Hour	450	--	172
Nitrogen Dioxide (NO ₂)	Annual	60	--	32
	24 Hour	200	--	106
	1 Hour	400	--	213
Carbon Monoxide (CO)	8 Hour	5,800	5	--
	1Hour	15,000	13	--
Particulate Matter (PM _{2.5})	24 Hour	30	--	--

6.2.3 Effects Characterization

In terms of common air contaminants, natural-gas is the cleanest of the fossil fuels. The combustion of natural gas results in the release of similar pollutants (for example, CO, NO_x, particulate matter, SO_x and VOCs); however, with the exception of CO, the emissions contain small amounts compared to the combustion of other fossil fuels (e.g., diesel) (Table 9).

Table 9 compares the mass emissions resulting from new natural gas and diesel generating options (YOR 2013-0115-040-1) and based on the worst-case scenario (i.e., five of the seven diesel YEC generators running simultaneously during periods of stagnant atmospheric conditions) considered in SENES 2011. The results demonstrate that with the exception of CO, and possibly volatile organic compounds (VOC), air emissions from natural gas generators will be lower than that of diesel.

Table 9 YEC Emission Rates Comparison

Generation Option	Unit	Air Emissions					
		CO	NOx	SO ₂	PM ₁₀	PM _{2.5}	VOC
New LNG	[kg/MWh]	4.06	1.8477	0.003	0.04	0.02	0.91
	[kg/h]	17.78	8.08	0.01	0.16	0.08	3.96
New Diesel	[kg/MWh]	0.66	11.40	n/a*	0.15	n/a*	0.85
	[kg/h]	2.90	50.16	n/a*	0.66	n/a*	3.74

*n/a – not available

Increasing CO Emissions

Increasing CO will result in decreased ambient air quality in project area. CO gas forms primarily when carbon fuels are not completely burned. CO is an odourless and invisible gas; however is poisonous if inhaled as it binds to red blood cells and prevents the transport of O₂ in the body.

As with the other identified pollutants, the vast majority of CO emissions in Whitehorse result from mobile and heating sources. Baseline CO levels in Whitehorse (2011 SENES Report) are well below the applicable standards. When modelled in consideration of severe drought (YEC diesel generators running at a maximum), and at the maximum point of impingement (located at the western edge of the YEC facility property line), the air quality index remained less than 20 percent of the Yukon Ambient Air Quality Standard.

Although the use of natural gas generators will result in an overall increase in CO emissions, the level will remain below the applicable Yukon Ambient Air Quality Standards.

Increased VOC Emissions

VOCs are organic compounds containing one or more carbon atoms that have high vapour pressures and therefore evaporate readily to the atmosphere. VOC emissions result from natural and anthropogenic sources. Natural sources of VOC include vegetation, forest fires, and animals. The largest anthropogenic sources derive from the transportation sector, as well as the use of solvents and solvent containing products, and industrial sources. VOCs resulting from electric power generation in Canada account for less than one percent (Environment Canada 2013b).

Depending on the specific compound and concentration levels, VOCs have the potential to have direct toxic effects on humans, ranging from carcinogenesis to neurotoxicity. For example, individual VOCs such as benzene and dichloromethane have been assessed to be toxic under the *Canadian Environmental Protection Act*, 1999. As noted in the project proposal, all trace contaminants (such as benzene) have been effectively removed through the natural gas liquefaction process. Similar effects occur on all VOC contaminants which freeze at higher temperatures than the target cryogenic temperatures (YOR 2013-0115-057-1).

At this time VOCs are not regulated in the Yukon. Although VOC emissions will still be emitted as a result of the proposed project, emissions of VOCs from stationary utility generators are generally low. The average emissions from a stationary diesel engine is approximately 0.4 grams per MW/h (YOR

2013-0115-005-1), and is less than the hourly VOC emissions from one snow machine (2148 grams/h) or less than seven snowblowers (at 275 grams/h) (YOR 2013-0115-057-1).

6.2.4 Significance Determination

In determining the significance of the above noted effects, the Executive Committee has considered the following non-discretionary legislation:

- Yukon Ambient Air Quality Standards
- *Canadian Environmental Protection Act, 1999*

Further, the Proponent has committed to continue with two monitoring programs:

- The National Pollutant Release Inventory (NPRI) - an annual exercise of its operational emissions to ensure they meet the threshold for required reporting under this national reporting program.
- Yukon Environment- monitoring and reporting required under Air Emissions Permit No. 60-010, including total annual thermal energy production, engine run time hours, and total emission masses of criteria air contaminants and GHGs.

The Project will result in the release of CO and VOC emissions. CO levels remained within regulatory limits under worst-case scenario modeling. VOC levels remained relatively low as well.

The Executive Committee considered that the duration of effects will be long as they will occur over the course of the life of the Project. Based on the unknown extent to which thermal energy will be required, the frequency and geographic extent of effects are difficult to be determined. However, even when considered with respect to the worst-case scenario, the magnitude of effects is relatively low. This is further supported because of the relatively small contribution YEC's operations have on the City of Whitehorse's overall ambient air quality (accounting for less than one percent for most pollutants). As such, the Executive Committee has determined that the Project will not result in significant adverse effects to air quality due to CACs considering the mitigations proposed by the Proponent and compliance with non-discretionary legislation.

6.3 GREENHOUSE GAS EMISSIONS

GHG emissions will result from natural gas combustion and transport of LNG in Yukon. GHG are gaseous components of the atmosphere that contribute to the "greenhouse effect". Some greenhouse gases occur naturally in the atmosphere, while others result from human activities. Naturally occurring greenhouse gases include, but are not limited to, carbon dioxide, methane, nitrous oxide, water vapour and ozone; however, human activity can increase the rate that these gases are produced. Continued warming from the release of GHGs into the atmosphere is expected to have substantial impacts on the environment, human health and the economy. For example, Environment Canada outlines the following potential impacts due to GHGs (Environment Canada 2013c):

- Environmental impacts
 - o Overall average annual temperatures are expected to increase.

- o Global warming will decrease snow, sea ice and glacier coverage, resulting in rising sea levels and increased coastal flooding. Rising temperatures will also thaw permafrost in the Arctic.
- o Storms and heat waves are likely to increase in frequency and severity.
- Human health impacts
 - o People living in Canada's northern communities, and vulnerable populations such as children and the elderly, are expected to be the most affected by the changes.
 - o Increased temperatures and more frequent and severe extreme weather events could lead to increased risks of death from dehydration and heat stroke, and injuries from intense local weather changes.
 - o There may be an increased risk of respiratory and cardiovascular problems and certain types of cancers, as temperatures rise and exacerbate air pollution.
 - o The risk of water, food, vector and rodent borne diseases may increase.
- Economic impacts
 - o Agriculture, forestry, tourism and recreation could be affected by changing weather patterns.
 - o Human health impacts are expected to place additional economic stress on health and social support systems.
 - o Damage to infrastructure (e.g., roads and bridges) from extreme weather events is expected to increase.

6.3.1 Consideration of CO₂ Equivalent Value

At this time, Yukon and Canada do not have specific legislation addressing GHG emissions. Combustion-related GHGs for both diesel and natural gas consist of CO₂, CH₄ and N₂O. For comparison purposes, GHG emissions are calculated in terms of how much CO₂ would be required to produce a similar warming effect over the chosen time horizon. This is called the carbon dioxide equivalent (CO₂ eq) value and it is calculated by multiplying the amount of gas by its associated global warming potential (GWP) (Environment Canada 2013d). For example, based on a 100 year time horizon, the 2012 and 2013 Intergovernmental Panel on Climate Change (IPCC 2007, IPCC 2013) reports state that methane GWP is between 21 and 25 times the GWP of CO₂.

The Executive Committee requested information from YEC and retained expertise to provide a comparison of GHG emissions resulting from the Project and the alternative of new diesel generators. The Executive Committee considered comments received during the public review period including the contribution from local experts (YOR 2013-0115-144-1, 2013-0115-183-1, 2013-0115-209-1). Several calculation methods to predict GHG emissions were used for the comparison.

In consideration of Table 10 below, the Executive Committee will rely on the Environment Canada calculation method for two reasons.

1. The Environment Canada guidelines were developed for projects in Canada; and

2. The Environment Canada method is generally consistent with the US 40 CFR Part 98 and the approach YEC took to estimate CO₂ emissions;

The Executive Committee considered the US EPA calculation method and notes that although the 20-year time horizon for both the 4th edition and 5th edition IPCC CO₂ equivalent emission factors for natural gas is higher than diesel emissions, the two fuel types remain close.

Table 10 Comparison of Emission Factors

Calculation Method	Fuel	Emissions			CO ₂ e			
		CO ₂ (kg/MW)	CH ₄ (kg/MW)	N ₂ O (kg/MW)	5 th ed 100 yr	5 th ed 20 yr	4 th ed 100 yr	4 th ed 20 yr
Environment Canada	N. Gas	504	0.009	0.0009	505	505	504	505
	Diesel	666.9	0.027	0.0054	669	671	669	671
US 40 CFR Part 98	N. Gas	452.53	0.00854	0.00854	455	456	455	456
	Diesel	631.25	0.0256	0.00512	634	635	633	635
US EPA AP-42	N. Gas	425.92	5.61	0.00854	619	911	546	832
	Diesel	705.59	0.0386	0.00512	708	710	708	710
YEC	N. Gas	432.11	0.0107	0.0107	436	436	436	436
	Diesel	978.97	0.00475	0.00475	981	981	981	981
	ICPP GWG Multipliers			CO ₂	1	1	1	1
				CH ₄	34	86	21	72
				N ₂ O	298	268	310	310

6.3.2 Effects Characterization

The combustion of both diesel and natural gas generators result in GHG emissions. Natural gas has a chemical composition that is predominately methane (87-99 percent by volume) along with smaller volumes of ethane and propane (Environment Canada 2013a). Methane in particular is of concern in relation to climate change due it being a shorter-lived GHG (meaning that it has a much greater impact in the short-term) and its high Global Warming Potential (GWP).

Government of Yukon (YG) produced a Climate Change Action Plan in 2009, and released a Progress Report in 2012. The 2012 Progress Report outlines a target that by 2020, there will be a 20 percent reduction in on-grid diesel power generation. Further, the 2012 Climate Change Action Plan Progress Report commits to sector-specific targets (including the electricity sector). It is unknown when the sector-specific targets will come into place.

6.3.3 Significance Determination

The comparison in Table 10 demonstrates that for the same amount of electricity generated, natural gas generators will produce less GHG emissions (as CO₂e) than diesel generators. The Executive

Committee recognizes that there are no specific GHG standards or legislative requirements in Yukon to monitor GHG emissions. The 2012 Climate Change Action Plan Progress Report indicates that sector-specific targets will be developed.

The Executive Committee also recognizes that there are uncertainties with the estimated Project GHG emissions. As noted in Section 6.2.4, the Proponent has committed to continue with two emissions monitoring programs, which includes monitoring GHGs. The Executive Committee has further addressed project uncertainties surrounding potential effects to air quality from GHGs through effects monitoring (detailed in Section 6.5).

The Executive Committee considered that the duration of effects will be long (over the course of the life of the Project). However, although the frequency and extent of effects are difficult to be determined, consideration was given under worst case scenario operations. The magnitude of effects is relatively low in consideration of the small footprint YEC's operations have on the Whitehorse's overall ambient air quality (accounting for less than one percent for greenhouse gases).

The Executive Committee has determined that the Project will not result in significant adverse effects to air quality due to GHGs considering the mitigations proposed by the Proponent and compliance with non-discretionary legislation.

6.4 WATER VAPOUR PLUMES

The Project may increase the occurrence of water vapour plumes, because natural gas has a greater amount of hydrogen molecules than diesel, particularly in winter months (i.e., ice fog). This has the potential to result in the increased frequency and extent of vapour plumes/ice fog from the WTGS. Increased ice fog has the potential to reduce visibility in the local area.

6.4.1 Effects Characterization

Estimated water vapour emissions were outlined in AECOM's report and concluded that emissions will be greater for natural gas generators than for equivalent diesel generators. Water vapour plumes may occur when the atmosphere is limited in absorbing increased moisture generated by the Project. Factors such as humidity, wind speed and temperature influence ice fog conditions. Ice fog occurs naturally when water vapour encounters very cold air (approximately -30°C) (American Meteorological Society n.d.), and in Whitehorse is likely to occur during winter along the Yukon River.

According to YEC's project proposal:

The water vapour emissions in a maximum operational scenario would be increased by nearly one half with the Project compared to what would occur with the existing facility, and by nearly 30% with the Project compared to what would occur if diesel generation was used to replace WD1 and WD2 with 13.4 MW of new capacity.

(YOR 2013-0115-057-1)

The Executive Committee notes that YEC will rarely be required to operate as outlined in the worst case scenario. Furthermore, the generation of ice fog will be limited to periods of extreme cold weather. The

frequency and duration of ice fog is dependent upon several factors; including how long the units are run, when the units are run, existing weather conditions, etc. The frequency and duration that the generators are run are further dependent on factors such as consumer demand, hydro outage and transmission outage. As such, it is not possible to accurately estimate the frequency and duration of ice fog.

In their submission, YEC estimated that the extent of ice fog may extend for several hundred metres. As taken from YEC's information response provided on October 25, 2013:

Any vapour from the engines at the Whitehorse Thermal Generating Station (WTGS) needs to be viewed in the context of the significant water vapour emission sources located near the facility, such as the large year-round open water leads on the Yukon River directly downstream of the two hydro plants. Any observer in the area of the Whitehorse Rapids Dam on a cold morning or in the deep cold of winter can clearly see the valley-filling contribution of water vapour (and resulting fog) that is emitted by the Yukon River. Other proportionally significant contributors to water vapour emissions in the area include the daily contributions of the 1,000 or more passenger vehicles and home heating appliances from the over 2,000 residential units located in nearby Riverdale.

(YOR 2013-0115-039-1)

6.4.2 Significance Determination

As taken from the project proposal, the Proponent has committed to the following mitigation to assist to reduce or eliminate potential effects to air quality:

Yukon Energy will commit to monitoring road conditions along Robert Service Way adjacent to the WTGS in cooperation with the City of Whitehorse and/or Yukon Government Public Works departments during ice fog conditions to determine whether conditions along Robert Service Way are impacted by the operations of the WTGS. If such impacts occur, it is clear that there are technically and economically feasible ways to address such effects and Yukon Energy will work with the appropriate authorities to ensure appropriate response mechanisms are in place.

(YOR 2013-0115-057-1)

While the duration and frequency of effects is difficult to determine due to several factors, the extent of effects will be localized to the project area, and the overall risk is low. The Executive Committee has determined that the Project will not result in significant adverse effects to air quality due to water vapour plumes considering the mitigations proposed by the Proponent and compliance with non-discretionary legislation.

6.5 EFFECTS MONITORING

In consideration of comments received, the absence of established GHG standards and the absence of monitoring results in Whitehorse (existing conditions are based upon modelling results), there are uncertainties with respect to the emissions from the Project. Government of Yukon commented that although the modeling in the 2011 SENES report provides pollutant dispersion, it is limited to data inputs

and assumptions (YOR 2013-0115-148-1). Results from monitoring will test the model results, which will provide more certainty for future modelling and development. Pursuant to s. 42(2)(a) of YESAA, the Executive Committee has determined that effects monitoring regarding air emissions is required.

The following effects monitoring terms and conditions are required:

1. The Proponent shall report on the operation and duration of natural gas generators to the appropriate regulator.
2. The Proponent shall work with the appropriate regulators to develop a monitoring program for air emissions. At a minimum, the following constituents should be monitored: CO, VOCs, NO_x, SO_x and PM.
3. The Proponent shall include in the monitoring program GHG emissions identified by the appropriate regulator such as CO₂, CH₄ and N₂O.

6.6 CUMULATIVE EFFECTS

The proposed project will have residual effects on air quality. Residual effects are considered to include the release of air pollutants into the atmospheric environment from the combustion of natural gas.

Vehicle emissions, forest fires, home heating, other industrial sources and long-range atmospheric transport of pollutants can all play a role in local air quality. In this context, air quality is representative of the cumulative contributions of point and non-point source air pollution and can be impacted by various emissions sources, atmospheric processes, plant and animal respiration, circulation patterns and local weather.

The potential for cumulative effects on air quality has been considered within the City of Whitehorse. The YEC generating facilities are located in close proximity to the Riverdale, the Robert Service Campground, the Millennium Trail, and other outdoor recreational trails and facilities such as seasonal hockey rinks. Existing activities in the area include heating of homes with fuel and wood, vehicle use both for local traffic and on the Alaska Highway, the Whitehorse airport, the Schwatka Lake aerodrome, and a variety of commercial and industrial activities. In the event that a threshold is exceeded, YEC and regulators will determine the appropriate response to address the Project's cumulative contribution.

The Executive Committee has determined that compliance with non-discretionary legislation, YEC's continued monitoring and reporting under the aforementioned programs, and conformance with effects monitoring will not result in significant adverse cumulative effects.

7.0 SAFETY

This section addresses concerns and effects surrounding safety as it relates to the public and employees at the Whitehorse Rapids Generating Station (WRGS). Safety was identified as a valued component in consideration of the potential adverse effects to human life and well-being from risks associated with the use and storage of LNG at the WRGS. In addition to considering hazards directly associated with LNG, the effects assessment considers the geographical and socio-economic context within which the Project will operate. LNG has not previously been used as a fuel source within Yukon, and therefore the Executive Committee considers matters surrounding safety of particular importance. The Executive Committee concludes that compliance with relevant legislation and proposed mitigation strategies will effectively eliminate, reduce or control significant adverse effects on safety.

The Project's location is in relatively close proximity to a residential neighbourhood (approximately 500 m), five schools (within 1.5 km), the main hospital (2.5 km), the airport (500 m), one of only three accesses to downtown Whitehorse, the float plane base (800 m) and the Whitehorse Rapids power plant (300 m). Several comments during the public comment period indicated concerns regarding the location of the Project. Safety is discussed as a valued component particularly considering that the location of the Project is in relative proximity to various publicly used and accessible areas.

Project activities will occur in accordance with Canadian Standard Association Z276-11 *Liquefied Natural Gas: Production, Storage and Handling*, which according to the proposal, "establishes essential requirements and minimum standards for the design, installation and safe operation and maintenance of LNG facilities." The Project and proposed activities will also be subject to the requirements under the *Yukon Oil and Gas Act*, and *Gas Processing Plant Regulation* (GPPR). In determining the potential effects of the Project to safety, the Executive Committee considered the physical properties of LNG, the safety record of LNG facilities, the proposed facility's design, and the regulations and human factors for the operation of a safe and secure LNG facility.

The Executive Committee considered effects to safety as they relate to the following factors:

- Site Design
- Accidents and Malfunctions
- Training
- Transport

7.1 SITE DESIGN

This section addresses safety concerns as they relate to the proposed site design, including safety measures as they pertain to specific equipment use.

7.1.1 Effects Characterization

Industry standards and regulatory requirements respecting safety in the LNG industry include four elements: primary containment, secondary containment, safeguard systems and separation distances. All the components and the design of the facility follow the requirements in the CSA Standard Z276-11.

Primary Containment

Containment is defined as the safe storage and isolation of LNG (e.g. storage tanks). Primary containment is the most important requirement for containing LNG. The primary containment for the Project's LNG consists of horizontal single containment vacuum jacketed bullet tanks and foundations. Up to three 166.5 m³ and two 120 m³ tanks will be installed. As described above, the tanks have a stainless steel inner tank and carbon steel outer tank and each tank will sit on a two-pedestal foundation. The tanks are manufactured in accordance with the National Fire Protection Association (NFPA) 59A and American Petroleum Institute 620 standard.

The CSA Z276-11 standard requires that LNG storage tanks have product retention valves, excess product loss detection, gas detection and remote activated isolation that is integrated with the storage container system. The Proponent has indicated that all requirements respecting the storage tanks will follow the applicable code, and tanks will be spaced accordingly (Appendix C).

Secondary Containment

Secondary containment, the second layer of protection, ensures that if a leak or spill occurs from the primary containment, the LNG can be contained and isolated. The Project's secondary containment system consists of LNG sub-impoundments, paving, curbs (dikes), and LNG transfer trenches. These secondary containment measures will be located wherever LNG is stored, processed, or unloaded. Paving beneath storage tanks will be graded to direct LNG to towards a transfer trench, while curbing will prevent LNG from flowing off the paved area, guiding it toward the trench. The trench will be designed to minimize the amount of material that must be cooled down as the spill travels to the impoundment basin. In turn, minimizing the mass of material will minimize vaporization of the spilled LNG as it travels to the impoundment.

The storage tanks (primary containment) will sit on a raised area approximately six inches high above a trough that leads into the transfer trench. If there is a leak from the storage tanks, LNG will flow by gravity to the transfer trench, and on to the main impoundment area. At this impoundment, or secondary containment pit, the physical properties of LNG cause it to warm and change phase into a gas, creating a vapour cloud above the released liquid; this will be further discussed in Section 7.2.

The secondary containment system must comply with regulatory requirements and industry standards, including CSA Z276-11. The standards to which secondary containment systems must comply include the prevention of off-site migration of LNG spills and releases; the ability to address a total LNG storage tank failure (designed to hold 110 percent of the entire contents of a LNG storage tank); and the impoundment area must be designed to contain a 10-minute spill, based on the largest flow rate of the facility.

Safeguard Systems

The third component of a safe and secure LNG facility involves safeguard systems. The goal of safeguard systems is to minimize the release of LNG and mitigate the effects of a release (Foss 2006). Safeguard systems consist of multiple layers of safety systems, technology, equipment and human factors.

The Project's safeguard systems include fire and gas hazard detectors, emergency shutdown valves, and fire suppression systems. Detectors will be installed at the storage tank area where emergency call points, sirens and beacons will be integrated in the system to alert personnel in the event of an emergency. The fire and gas detection control systems will automatically trigger an emergency shutdown for specified events. Emergency shutdown valves will be located in the liquid and vapor lines, at the unloading bays and LNG pump outlets. This set-up will allow for the isolation of the system in an emergency. The fire suppression system is comprised of multiple components that will be located in specific locations. These components include fire extinguishers, fire proofing of critical structures at process areas, designated restricted areas, and management controls to minimize potential ignition sources where gas may be present.

The LNG facility and all associated equipment will be controlled and monitored from a centralized, and existing, control room. In addition to the mitigative role of safety systems, safe practices procedures are considered in the overall safeguard system of the LNG facility. These include safe work practices, procedural training and drills for plant personnel. Safe practices also include preventative and corrective maintenance to ensure safety equipment is in proper working order and available in the event of an emergency.

Safeguard systems also involve site security features. The proposed LNG facility will be fenced by a seven foot high security fence, with an additional one foot of razor wire at the top. A closed-circuit television (CCTV) system will monitor the facility, which will have adequate lighting. The CCTV system will be connected to the existing 24-hour control room.

The CSA Z276-11 requires a fully contained protective enclosure around major components of the facility. The Proponent has stated that the expanded site area (ESA) will be completely fenced on all sides, and secured from unauthorized public access. Access to the substation will also be controlled through additional fencing within the ESA.

Separation Distance

The fourth component of safety systems in the site design is safe separation distances. In the event of the accidental release of LNG, safety zones around a facility must be adequate to protect the public from personal injury, property damage, or a fire. Separation distances ensure that LNG facilities are sited at a safe distance from adjacent public, private and industrial areas. Separation distances, which must comply with CSA Z276-11, are based primarily on LNG vapour dispersion and thermal radiation contours.

A vapour retention wall is included in the facility design to ensure that any vapour cloud from the accidental release of LNG is contained within the ESA. The wall will be approximately 244 m (800 ft) long and 2.4 m (8 ft) high on the north, east and south sides, and 3.6 m (12 ft) high on the west side. The vapour retention wall will retain the vapour plume until the LNG is warmed, mixes with the atmosphere and dilutes to below one half of the Lower Flammability Limit, as required by CSA Z276-11. Effects related to vapour clouds, their behaviour, are discussed in further detail in Section 7.2.

7.1.2 Significance Determination

The Executive Committee has considered the requirements of the relevant non-discretionary legislation and industry standards. These requirements include application of the GPPR which adopts the Canadian Standards Association CSA Z276-11. The Government of Yukon Oil and Gas Branch states that the application of the GPPR and CSA 276-11:

establishes essential requirements and minimum standards for the design, installation, and safe operation” and describes many parameters such as safety policies, spill and leak control, spacing, pressure relief, security, instrumentation, electrical classification, fire protection, training, corrosion, etc. The Gas Processing Plant Regulation exceeds these requirements and requires additional performance expectations be satisfied.

(YOR 2013-0115-148-1)

The four elements for the protection of the safety of both workers at the LNG facility and that of the community around the facility are described in detail above. The Proponent has indicated that all site and equipment design and use will be in accordance with the regulatory requirements and industry standards (Appendix C). These regulatory requirements, in particular CSA Z276-11 and the GPPR, are extensive, providing requirements for mitigation and safety measures, in addition to strict stipulations for the placement, design, and engineering of equipment (e.g. storage tanks, piping, etc.).

Although details of the final site design, engineering and layout are not finalized, the Proponent has committed to following the standards that require the Project to be designed in such a manner that necessitates the safe operation of the facility. These standards are accepted across the industry for the safe operation of LNG-related projects. Safe separation distances and equipment requirements, as described above, significantly reduce, if not eliminate, the likelihood for adverse effects to safety as they relate to the various components of the site design. In addition to the requirements respecting site design, the Project will also be subject to further and ongoing safety reviews at the regulatory, construction and operation phases.

The Executive Committee has determined that the Project will not result in significant adverse effects to safety considering the mitigations proposed by the Proponent and compliance with non-discretionary legislation.

7.2 ACCIDENTS AND MALFUNCTIONS

It is widely accepted that the greatest hazards associated with LNG include pool fires, flammable vapour clouds, and flameless explosions from the accidental release of LNG. Other hazards include the risk of cryogenic burns and asphyxiation due to oxygen depletion. This section begins with an overview of the relevant characteristics of LNG, before discussing in detail the potential adverse effects to safety resulting from an accident or malfunction at the proposed LNG facility.

Section 7.6 of the project proposal addresses accidents and malfunctions. Accidents and malfunctions are also discussed throughout the project proposal, in comment submissions, and other documentation related to the effects assessment on safety.

7.2.1 Characterization of LNG

Hazards due to LNG result from its cryogenic temperature, flammability and vapour dispersion characteristics. LNG is a natural gas which has been cooled to an extremely cold temperature (approx. -162.2°C) and condensed into a liquid (FERC 2010). It is a colourless, odourless, non-corrosive, non-toxic, non-flammable cryogenic liquid at normal atmospheric pressure. LNG is predominantly methane (87-99 percent by volume). The remaining percentage (by volume) is made up of ethane and heavier hydrocarbons (International Group of Liquefied Natural Gas Importers 2009) (Table 11). In comparison to natural gas at room temperature and normal atmospheric pressure, LNG takes up only about 1/600th of the volume of natural gas. As LNG is an extremely cold liquid, it is not stored under pressure (University of Houston Law Center, Institute for Energy Law & Enterprise 2003).

Table 11. Typical Chemical Composition of LNG

Chemical	Chemical Formula	Low	High
Methane	CH ₄	87%	99%
Ethane	C ₂ H ₆	<1%	10%
Propane	C ₂ H ₈	>1%	5%
Butane	C ₄ H ₁₀	>1%	>1%
Nitrogen	N ₂	0.1%	1%
Other Hydrocarbons	Various	Trace	Trace

The boiling point of LNG, typically -162°C, is when gas becomes a liquid. When LNG comes into contact with an environment warmer than itself, such as water, air, land, etc. (e.g. in the event of a leak or spill), it begins to boil at the point of contact. LNG is warmed to convert it back to its gaseous state (natural gas). If LNG is released (i.e. through a leak or spill), LNG begins to warm, returning the liquid to a gas. Initially, the vapours are heavier than air and will remain close to the ground; however, as the methane rapidly warms and reaches temperatures of approximately -110°C, the vapour rises. As LNG vapourizes, the cold vapours condense the moisture in the air. This will often form a white vapour cloud until the gas is warmed by ambient air, dilutes and disperses. A vapour cloud can only ignite if it encounters an ignition source within its flammability range (University of Houston Law Center, Institute for Energy Law & Enterprise 2003).

Natural gas is flammable, but LNG is not. This is due to the lack of oxygen in the liquid. A fire requires a fuel source, oxygen and an ignition source. The flammable range, expressed as the lower flammable limit (LFL) and the upper flammable limit (UFL), is the range of a concentration of a gas or vapour that will burn if it comes into contact with an ignition source. The flammability limits for methane are 5% LFL and 15% UFL (by volume in air) (Figure 5). When the concentration exceeds the UFL, it cannot burn

because there is not enough oxygen present (e.g. in a closed, secure storage tank where the concentration is approximately 100 percent methane). When the concentration is below the LFL, it cannot burn because there is not enough methane present (e.g. leakage of small amounts of LNG in a well-ventilated area) (International Group of Liquefied Natural Gas Importers 2009).

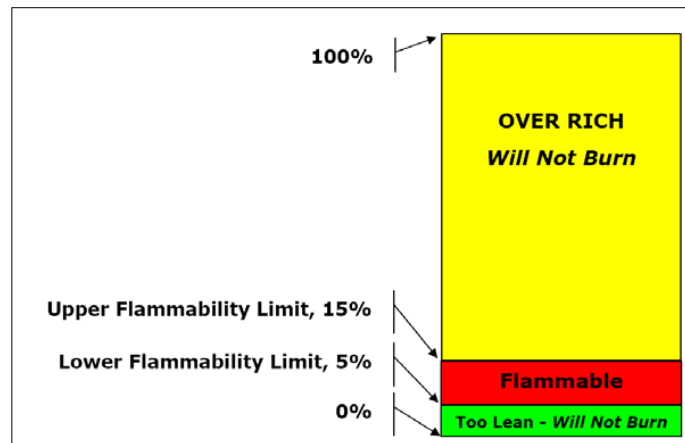


Figure 5 Flammability Range for Methane

The auto-ignition temperature is the lowest temperature at which a flammable gas or vapour will ignite spontaneously without a spark or flame (ignition source) being present. Temperatures higher than the auto-ignition temperature will cause ignition over a shorter exposure time. The auto-ignition temperature in an air-fuel mixture of about 10 percent methane is approximately 540°C, thereby requiring a strong source of thermal radiation, heat, hot surface or ignition source such as a spark, flame, or static electricity. As the concentration of methane decreases (e.g. through evaporation or removal), so does the auto-ignition temperature. For comparison, Table 12 shows the auto-ignition temperature of other fuels (University of Houston Law Center, Institute for Energy Law & Enterprise 2003).

Table 12. Auto-ignition Temperatures of Fuels at Standard Conditions

Fuel	Auto-ignition Temperature (°C)
LNG (primarily methane)	540
Natural Gas	599
Liquefied Petroleum Gas (LPG)	454 - 510
Ethanol	422
Methanol	463

Gasoline	226-471
Diesel Fuel	260-371

The methane in LNG has a flame temperature of 1 330°C (gasoline has a flame temperature of 1 027°C) and therefore LNG burns very hot, hotter than gasoline. Further, LNG burns quickly, at a rate of approximately 12.5 m²/minute (gasoline burns at a rate of 4 m²/minute) (International Group of Liquefied Natural Gas Importers 2009). Table 13 provides a summary of risks related to LNG in comparison with other fuel sources.

Table 13 Comparison of Risks of Fuel Sources (YOR 2013-0115-099-1)

Properties	LNG	LPG	Gasoline	Fuel Oil
Toxic	No	No	Yes	Yes
Carcinogenic	No	No	Yes	Yes
Flammable Vapour	Yes	Yes	Yes	Yes
Forms Vapour Clouds	Yes	Yes	Yes	No
Asphyxiate	Yes, in the cloud	Same as LNG	Yes	Yes
Extreme Cold Temperature	Yes	Yes, if refrigerated	No	No
Other health hazards	None	None	Eye irritant, narcosis, nausea, others	Same as Gas
Detonation	No	Yes	Yes	Yes

*LPG - liquefied propane gas

7.2.2 Risks of Spills or Leaks Leading to Fire

Fires may occur at LNG facilities in the presence of a combustible gas or liquid, oxygen, and an ignition source. LNG leaks from piping, storage and transfer infrastructure could result in flammable gas clouds (vapour clouds), pool fires, or exposure to the cryogenic LNG. These, in turn, could result in death or serious injury. Fire could also trigger fires in other on-site locations.

This section will address issues and risks associated with the result of an LNG spill or leak, including vapour cloud dispersion; vapour cloud ignition; and pool fires.

Vapour cloud dispersion

A release of LNG can be in the form of a small leak or a spill. If a small leak occurs, once the LNG comes into contact with the warmer environment (i.e. ambient air temperature) it begins to boil at the point of contact. LNG is warmed and converts back to its gaseous state (natural gas). As the LNG vapourizes, it condenses any humidity (water) in the atmosphere making it a visible plume or cloud of natural gas. As this cloud continues to take on energy from the surroundings, it will begin to rise and will dissipate in the atmosphere as natural gas is lighter than air. The visibility of the natural gas cloud throughout this process adds a level of certainty to predict the behavior and identify any hazards.

Vapour cloud ignition and thermal radiation

If a vapour cloud with oxygen content within the flammable limit comes in contact with an ignition source that exceeds the auto-ignition temperatures, the vapour will ignite. Modeling for vapour dispersion analysis is a common risk assessment practice in the LNG industry. Models incorporate conservative assumption to account for the variability in vapour cloud behavior and environmental conditions that may be encountered.

If an LNG spill becomes ignited, a pool fire will result. In the event of a pool fire, the CSA Standard Z276-11 provides radiation (or thermal) flux limits at various locations. Code requires that thermal flux be modeled to ensure that a thermal radiation level of 5 kW/m^2 is kept within the property line that can be built upon. For reference, thermal radiation of 4 kW/m^2 results in second degree burns if someone is standing within this radiant heat zone for a period of 30 seconds.

Yukon Energy's modeling of the high impact radius found that the worst case probable scenario is failure of either a storage tank or trailer tank, resulting in a spill and/or fire. The model follows and is accepted by CSA Z276-11 standards. YEC used a model called FLACS (by Gexcon) to model and confirm that the 50% LFL boundary limit is within the property limit, as required by CSA Z276-11. The FLACS model incorporates site-specific physical characteristics, such as slope, surface type, obstacles (e.g. trees and the proposed vapour barrier wall), wind speed and temperature. Two design spill scenarios were modelled as per the formula found in CSA Z276-11. The results of this model show that at the property line (of the ESA), the dispersion of the vapour cloud would contain only 50 percent of the lower flammable limit.

Environment Canada submitted comments that included modeling of the worst-probable case scenario using a PHAST-TnT model, which concluded that the high impact radius extended beyond the ESA boundary (YOR 2103-0115-161-1). In a technical meeting held February 6, 2014, it was concluded that Environmental Canada's model was not representative of the Project as the model did not account for site-specific information and was based on an explosion occurring. It was agreed in the meeting that for an explosion to occur, confinement of the vapour cloud would be necessary. The Project has been designed in a way that vapour confinement is not possible. As a result it was agreed that an explosion of a vapour cloud was not a credible scenario.

The Executive Committee requested Risknology to review the YEC vapour dispersion and high-impact radius model. Risknology concluded that there was insufficient information to validate the approach of the models because the details of the YEC modeling were not included in the proposal. Risknology recommended that a:

quantitative risk analysis (QRA) be carried out on the facility. A QRA would provide greater completeness in identification of accident scenarios considered in the permitting process, the ability to address the potential for exposure of neighboring land use sites, including the generation facility and staff, road and travelers and the nearby public school students and faculty.

(YOR 2013-0115-228-1)

The Executive Committee notes that this recommendation is consistent with the comment from Government of Yukon Oil and Gas Branch that a hazard and risk assessment will be required during the regulatory approval process.

The assessment of vapour cloud dispersion and the high impact radius have demonstrated that potential impacts from the modeled accidents are within the confines of the ESA, and meet the requirements of CSA Z276-11. Further, the flammable vapour clouds that could be generated by a design spill, to a LFL of 50 percent or less, are confined to the facility's property line.

7.2.3 Risk of Cryogenic Burns and Asphyxiation

In the event of a release, LNG's cryogenic nature poses a hazard as contact with human skin will cause freezing of the tissues at the point of contact. In addition to direct contact with cryogenic liquids, contact with the metals at cryogenic temperatures and cold gas can cause skin damage.

Cryogenic burns can be life threatening. The risk of cryogenic burns can be reduced with the use of appropriate protective gear. LNG (and the vapourized natural gas derived back from it) does not contain an odour so leaks cannot be detected by smell. These hazards are restricted to the facility personnel and to within the facilities boundaries; in other words, cryogenic burns are limited to the immediate point of release. Public access to the facility is restricted; the compound is fenced and secured to control access. The Proponents have indicated that personnel working near the LNG supply lines and storage tanks must always wear personal protective equipment including cryogenic gloves, a face shield, safety glasses and safety footwear.

Asphyxiation occurs when the body becomes severely deprived of oxygen such as when LNG vapours dilute oxygen concentration to below 15 percent. Impaired behaviour occurs when LNG vapour reaches concentrations of 28.2 percent and death at concentrations of 71.3 percent (Woodward and Pitbaldo 2010). These high concentrations are present only immediately within the ESA and standard safety measures ensure that workers on-site have a low risk of being exposed. As such, it is extremely unlikely that asphyxiation may result in the event of an accidental spill or release of LNG. As the danger zone is in the visible cloud, it is possible to avoid it, and as a result there is a low likelihood of asphyxiation. Furthermore, there are no unventilated/confined areas in which LNG will become an asphyxiant.

7.2.4 Significance Determination

The Executive Committee has considered the requirements of the relevant non-discretionary legislation and industry standards. These requirements include application of the GPPR which adopts the Canadian

Standards Association CSA Z276-11. The Government of Yukon Oil and Gas Branch states that the application of the GPPR and CSA 276-11:

establishes essential requirements and minimum standards for the design, installation, and safe operation" and describes many parameters such as safety policies, spill and leak control, spacing, pressure relief, security, instrumentation, electrical classification, fire protection, training, corrosion, etc. The Gas Processing Plant Regulation exceeds these requirements and requires additional performance expectations be satisfied.

(YOR 2013-0115-148-1)

There is general agreement among LNG experts (YOR 2013-0115-225-1) regarding the risks associated with potential LNG fire. The industry, in addition to the relevant regulations and standards, has evolved to ensure the safe operation of LNG facilities. Furthermore, the physical and chemical properties are well understood and incorporated into equipment and site design and engineering. The safeguards inherent to site and equipment design greatly reduce the likelihood of an accident or malfunction resulting in significant adverse effects to employees, the public, and infrastructure outside the boundaries of an LNG facility.

The vapour dispersion analysis and high impact radius indicate that all risks can be mitigated in accordance with CSA Z276-11. The site plan is such that the likelihood of significant adverse effects to safety is low.

The Proponent has noted that they will adhere to the appropriate LNG storage and transfer protocols, and will use equipment that meets or exceeds the safety and industry standards (Appendix C). In addition to the requirements regarding the storage, handling, and use, the regulations and industry code address mitigative measures in the unlikely event of a spill or leak.

In summary, LNG leaks, spills and the potential effects will be systematically addressed and planned for during all phases of the Project. The demanding regulatory requirements include comprehensive management, prevention, and contingency planning, such that the adverse effects discussed in this section are highly unlikely. The safe operation of LNG facilities is supported by the industry's safety record, which is regarded as having the best safety record of any of the energy industries (Sovacool 2008).

The Executive Committee has determined that the Project will not result in significant adverse effects to safety considering the mitigations proposed by the Proponent and compliance with non-discretionary legislation.

7.3 TRAINING

Training plays a key role for the safe and secure operation of an LNG facility. This includes emergency preparedness and training in the transport, handling, and storage of LNG. It is important that all those involved with the operation of an LNG facility understand the hazards of the fuel involved, and be prepared in the event, however likely or unlikely, of an emergency. LNG fires behave differently than those which are fueled by other substances, and therefore safety practices and training must be planned for accordingly.

The Proponent has committed to ensuring that their employees are trained for the safe handling, transport, and storage of LNG. Employees and contractors will receive training specific to LNG and will be required to adhere to appropriate occupational health and safety regulations.

7.3.1 Effects Characterization

Safeguard systems for the LNG facility include safe practice procedures, including procedural training and drills for plant personnel. The GPPR stipulates requirements for a staffing plan and training program. This includes license requirements for the specification of staff competencies, training programs, safety practices, and emergency procedures. CSA Z276-11 also requires the Proponent to employ safe work practices. To achieve this, the CSA Standard contains several clauses specifying the content and frequency of the training employees must complete.

The Proponent has committed to internal employee and contractor training to address the needs and requirements of the proposed LNG facility. Employees will be taking an online course and a custom-designed course to address the training needs with respect to the integration of an LNG facility at the WRGS. YEC also has a Hazardous Materials Spill Contingency Plan, which covers incidents related to all spills at their facilities. The plan is comprehensive and contains requirements for roles, documentation, information and individual substance response (Appendix C).

Emergency Response Training

YEC is working with local and regional emergency response officials in consideration of the new use of LNG in the territory. YEC noted in the project proposal that the Fire Marshal's Office is currently undertaking training specific to LNG. The Fire Marshal's comments confirmed that the Office has developed first response training specific to LNG. This has included the Deputy Fire Marshal's training at the Massachusetts Firefighting Academy, which according to the comments, offers one of the most comprehensive LNG safety and emergency response training programs in North America. The Fire Marshal's Office noted that they will be training the Whitehorse Fire Department for response to the LNG-related project and road tankers. The Fire Marshal Office stated that they have established a memorandum of understanding with the Whitehorse First Department regarding mutual aid incidents (YOR 2013-0115-148-1).

The Yukon Fire Marshal's Office uses the National Fire Protection Association Codes, and its specific references to Liquid Natural Gas Fire Protection and Installation Requirements. In addition, the involved fire departments follow Emergency Response Guidelines as identified in the Canadian Transport Emergency Centre Guide 115 for propane.

7.3.2 Significance Determination

The Executive Committee has considered the requirements of the relevant non-discretionary legislation and industry standards. These requirements include application of the GPPR which adopts the Canadian Standards Association CSA Z276-11.

Section 13.5 of the CSA Z276-11 outlines the basic requirements and minimum standards for the safe operation and maintenance of LNG plants and for personal training. Some of the requirements within this

section include the contents of training plans and the frequency of training for all employees; the documentation of each employee's training; and the specifics in which supervisory personnel must be trained. In addition to the requirements of CSA Z276-11, the GPPR stipulates that the competencies required for every staff's position must be met, as per the staffing plan required in s.28(1).

The safe operation of an LNG facility involves multiple levels of preparedness, design and maintenance. Adequate training for personnel will reduce the likelihood of an LNG-related accident or malfunction. Training will also reduce the magnitude of an adverse effect in the unlikely event of an accident, as employees will know how to best respond to the particular conditions of an emergency. Furthermore, the Proponent is working with local emergency response officials to ensure they are also prepared to respond to issues specific to LNG.

The Executive Committee has determined that the Project will not result in significant adverse effects to safety considering the mitigations proposed by the Proponent and compliance with non-discretionary legislation.

7.4 TRANSPORT

The transport of LNG from the delivery truck to the WRGS' on-site storage has the potential to result in leaks and spills through human error or equipment failure. Leaks and spills may subsequently lead to adverse effects as described in Section 7.2.

Numerous safety designs and requirements for the transport and transfer of LNG exist. These include driver training; emergency procedures; tanker volume restrictions; and physical and chemical characteristics of the LNG.

Transportation of LNG falls under the jurisdiction of federal transport authorities. The transport company will haul the LNG under *the Transportation of Dangerous Goods Regulations* (Classification 2.1 - flammable gas). The transport company is responsible for all permitting and reporting of controlled or uncontrolled release while the LNG is in their custody.

Yukon Energy has secured a minimum five-year LNG supply of up to 250 m³/day from Shell Canada's Jumping Pound LNG production facility outside of Calgary. The delivery of LNG over the proposed project lifespan, however, may also include other sources in northern British Columbia, or other potential supplies in the area (i.e. local bulk supply). From Calgary, LNG will be transported in double-jacketed, tank-type transport equipment that maintains a vacuum between the tank walls to stabilize the extremely low LNG temperature.

7.4.1 Effects Characterization

Safety of Tanks

The transport of large volumes of fuel, in this case LNG, poses potential concerns to safety and the environment if there is a release. Risks of release may occur through accidents, human error and/or failure of the tanks that carry the LNG. Double-walled cryogenic tanks on a tanker truck are inherently stronger than the design of similar liquid transporters (Shelley 2007) and typically have a number of safety components. The inner pressure vessel of the tank is constructed with high-strength

characteristics and made from nickel steel or aluminum alloys. The outer vessel is made of carbon steel and not exposed to the cryogenic temperatures. Between the outer jacket and the inner pressure vessel there is several inches of insulation in a vacuum environment. Further, control equipment for loading and unloading (i.e. piping, valves, gauges, pump, etc.) and safety apparatus (i.e. pressure relief valve, burst disk, gas detectors, safety shut-off valves, etc.) make up some of the safety features (Shelley 2007, Federal Transit Administration Clean Air Program n.d.).

The double-walled construction of the tanker truck design provides added safety with respect to fuel spills as a result of a tank rupture during an accident. In the event a vessel is ruptured and LNG is spilled, the LNG will boil and vapourize as it comes into contact with the warmer air/surfaces. A high volume spill will cause a pool of LNG to accumulate. As the ground under the pool cools, the boiling rate will decrease (Shelley 2007). Vapour clouds resulting from the spilled LNG will initially be heavier than ambient air and will travel along the ground surface in the direction of prevailing winds until it becomes less dense and rises and/or disperses. An LNG spill as a result of an accident during transport has a high probability of fire because a flammable natural gas vapour/air mixture will be formed in the vicinity of the LNG pool. Additionally, the presence of ignition sources such as electrical sparking, hot surfaces, or possibly a fuel fire as a result of the accident increases the likelihood of a fire in this situation. The heat release rate from an LNG pool fire is approximately 60 percent greater than that of a gasoline pool fire of equivalent size (Shelley 2007). However, the explosion of an LNG tanker is "highly unlikely" (Federal Transit Administration Clean Air Program n.d.).

Another hazard may occur if there is a rupture of the vessel adjacent to a waterbody causing a large spill of LNG onto the water. LNG will float if spilled on water and will rapidly vapourize (International Group of Liquefied Natural Gas Importers 2009). LNG vapourizes five times more quickly in water than on land and due to its dispersing characteristics, clean-up (such as that with a diesel spill) would not be required. If large volumes of LNG are released on water, vapourization may occur too quickly and, if there is mixing of LNG and water, a rapid phase transition can occur.

Road Safety

Roads and access to the facility may not be currently designed to accommodate the proposed Tridem trailers and A-trains. Kwanlin Dun First Nation identified a concern that the Robert Service Way and the entrance to and exit from the facility may increase risks to safety (YOR 2013-0115-182-1). Government of Yukon Department of Highways stated in their comments on the Project that they did not have any concerns (YOR 2013-0115-148-1). The Executive Committee recognizes that the Project may increase risks to safety at the Alaska Highway turn-off onto the Robert Service Way and at the entrance and exit to the facility particularly during rush hour periods and/or icy conditions.

Two types of transportation equipment may be used: Tridem trailers and A-Trains. Tridem trailers have a 54 000 L capacity, while the double trailer A-Train has a 95 000 L capacity. A-Trains are not currently approved for use in Alberta and British Columbia, but are approved to supply Whitehorse along the Alaska Highway. Tridem trailers may be used in the interim.

Off Loading

Unloading of the LNG upon delivery will be performed by trained facility operators. Truck drivers will also be trained and authorized to operate valves and move hoses for unloading operations. During unloading,

a single truck will be secured in the loading bay, turned off with the wheels choked. Vapour pressure will be controlled by a pressure control valve. A vapour line maintains minimum tanker vapour pressure and ensures adequate flow rate between the tanker and the storage tank. Emergency shutdown valves are provided in the liquid and vapour lines, to and from the unloading bay and LNG pump outlets. This isolates the system in the event of an emergency. When the tanker is confirmed empty by both the automatic stoppage of the LNG pump (when it senses a no flow reading) and the facility operator. Hoses are then disconnected with appropriate procedures, and the tanker will depart. The unloading bay area will include a spill collection system to transport any potential spilled LNG to an impoundment area.

A washroom facility and monitoring equipment will be made available for truck drivers as off-loading is expected to take two to four hours. AECOM noted in their review of the proposal that the Draft LNG Vehicle Fueling Station Standard (code item 7.2) requires that all LNG equipment and fueling shall be located not less than 7.5 m from the nearest important building not associated with the LNG equipment, building openings, from the adjoining property line that can be built upon, sidewalk or road and not less than 15 m from containers containing flammable gas or liquid (YOR 2013-0115-037-1).

7.4.2 Significance Determination

The Executive Committee has considered the requirements of the relevant non-discretionary legislation and industry standards. These requirements include application of the GPPR which adopts the Canadian Standards Association CSA Z276-11.

The safety and design requirements for LNG transport trucks are extensive, including pressure control systems, double-walled vacuum sealed tankers, and safety shut-off valves. The double-wall of LNG tankers is more durable than those designed for the transport of other liquid fuels, decreasing the likelihood of fuel spills from a tank rupture during an accident. YEC has committed to construct and operate the Project in compliance with CSA 276-11 standards (Appendix C).

Road design and safety requirements for fuel delivery to the facility are regulated through the *Highways Act* and regulations. Government of Yukon Department of Highways has indicated that they have no concerns with the project and have licensed the use of Tridem trailers and A-trains for use in the Yukon. City of Whitehorse has indicated that the proposed access road locations and vehicle usages will be subject of approval from the City Engineer (YOR 2013-0115-177-1).

The LNG transfer process, as per the CSA Z276-11 Draft Vehicle Fuelling Station Standard, is also extensively regulated with multiple safety protocols, equipment features, and requirements for operators of the transfer and transport. These measures act together to reduce both the likelihood and magnitude of potential adverse effects to safety from the transport of LNG.

The Executive Committee has determined that the Project will not result in significant adverse effects to safety considering the mitigations proposed by the Proponent and compliance with non-discretionary legislation.

7.5 CUMULATIVE EFFECTS

The proposed project will have residual effects on safety. Residual effects are considered to include the low risk of accidents or malfunctions to occur. The potential for cumulative effects on safety has been considered within the City of Whitehorse. The YEC generating facilities are located in close proximity to Riverdale, the Robert Service Campground, the Millennium Trail, and other outdoor recreational trails and facilities such as seasonal hockey rinks. The mitigation measures proposed by the Proponent and compliance with non-discretionary legislation are considered by the Executive Committee as adequate to address potential cumulative effects on safety. As a result, the Executive Committee is satisfied that the residual effects of the Project, in combination with the effects of other projects or activities will not result in significant adverse cumulative effects on safety.

8.0 ECONOMICS

This section addresses potential effects of the Project on Yukon Energy Corporation's (YEC) utility ratepayers. The Executive Committee has identified three categories of factors related to project economics:

- Capital costs
- Loading Forecasts
- Operational costs

Potential adverse effects are characterized and discussed in the context of the project proposal, the Proponent's December 9, 2013 application to the Yukon Utilities Board (YUB) (YEC 2013), public comments received during the assessment, and relevant legislation. The Executive Committee concludes that the Project will not result in significant adverse effects to utility ratepayers.

8.1 OVERVIEW

Yukon's electrical energy is primarily supplied by hydroelectric power plants at Whitehorse, Aishihik, and Mayo. This is supplemented by diesel generating plants in Whitehorse and Faro, a plant in Dawson City, and diesel plants in most other communities. The 138kV Whitehorse – Aishihik – Faro and the 69kV Mayo – Dawson City power grids are connected into a single Yukon power grid by the Carmacks – Stewart Crossing transmission line. The integrated Yukon power grid is not connected to power grids of any other jurisdiction.

The integrated Yukon grid now has a generation capacity of approximately 138 MW which can, subject to transmission capacities, be distributed anywhere within the grid. The sources of electrical capacity in Yukon are as follows (YEC 2012a):

- 92 MW of YEC hydroelectric power plants (Whitehorse 40 MW, Aishihik 37 MW, and Mayo 15 MW);
- 1.3 MW of Yukon Electrical hydroelectric power plants (Fish Lake 1.3 MW);
- 0.8 MW YEC wind capacity;
- 37 MW YEC diesel capacity (primarily Whitehorse, Faro, and Dawson City); and
- 7.2 MW of Yukon Electrical diesel capacity (back-up power supplies in grid connected communities).

In winter, the capacity at the Whitehorse Rapids Generating Station (WRGS) is reduced to about 24 MW and the overall hydro capacity is reduced to about 72.4 MW. This reduces the overall winter generating capacity to about 116.6 MW (YEC 2012b).

8.1.1 Capital Costs

Currently, the existing WTGS has seven diesel generating units (total nameplate capacity of 25 MW). Two of these units are scheduled for retirement in 2015 (total nameplate capacity of 9.1 MW). In the proposed project, YEC will replace these two units with up to three new natural gas generating units (13.1 MW total capacity), with two of the units (8.8 MW total capacity) anticipated to be in service before

the end of 2014. The Project includes expansion of the current facility for the installation of LNG truck offloading, storage, vapourization, and combustion infrastructure.

YEC provided a capital cost breakdown for 13.4 MW of new diesel generation (two new 6.7 MW Wartsila dual fuel [gas-diesel] engines) and 13.1 MW of new natural gas generation (three new 4.375 MW GE pre-engineered J624 units). This breakdown has been reproduced in Table 14 below (YOR 2013-0115-030-1).

Table 14 Comparison of Project Costs vs. Costs for New Diesel Generating Units (2013\$; in millions \$)

Project Component	Diesel (13.4 MW)	LNG (13.1 MW)
LNG Storage – Equipment and Site Development ¹	\$ - n/a	\$7.9
Generation – Engines and Site Development ²	\$20.8	\$17.9
Engineering Services ³	\$4.2	\$2.1
Grid Connection ⁴	\$0.8	\$2.5
Planning and Owner's Costs Construction Phase ⁵	\$6.2	\$7.0
Balance of Plant – Construction ⁶	\$1.4	\$1.4
Total	\$33.5	\$38.8

Table Notes:

1 LNG storage includes equipment required to build the storage facility in addition to the civil works (e.g., brushing, grubbing, levelling, access roads, etc.). Engineering costs are excluded.

2 Under the Diesel scenario, Generation includes the new engines, freight, new auxiliary equipment, modification to the existing foundations. Under the LNG scenario, Generation includes costs for the new engine and ancillary modules, lube oil and switchgear, freight, assembly, new modules and stack foundation, etc. Engineering costs are excluded under both scenarios.

3 Engineering services for the LNG scenario is less than the for the Diesel scenario as major components (generation and storage) are included in the scope of the EPC contract. For the Diesel scenario, engineering services are required primarily for BOP related components.

4 For the LNG scenario, a new substation is required to increase the voltage from the generator to the 35 kV distribution voltage and connect to the 35 kV bus in the existing S150 substation. Under the Diesel scenario, the new generators would be connected to the existing 6.9/35 kV transformer.

5 Planning costs are estimated at \$2.7M for both LNG and Diesel scenarios. The difference between the owner's costs relates to the acquisition of new land (i.e., the Expended Site Area) to site the new facility.

6 Balance of Plant work includes removal and disposal of the Mirreles units, namely WD1 and WD2. Under the diesel scenario, the Balance of Plant costs would normally be included under Generation – Engines and Site Development as this alternative assumes installation of new generation within the Whitehorse Diesel Plant; however, for comparative purposes, these costs have been removed from Engine and Site Development in Table 1 and shown separately (assuming the same costs for both scenarios).

Included in the estimated cost of \$38.8 million is an estimated capital cost of \$4.4 million for the third natural gas unit, anticipated to be installed a few years after the first two units are in service. YEC has acknowledged that it does not at this time have firm pricing for the third GE natural gas generating unit. The estimate being used is based on currently available pricing (YEC 2013).

During the public comment period, the Executive Committee received comments regarding the capital costs of the proposed LNG facility and diesel generator alternative. Many submissions received (YOR 2013-0115-069-1, 2013-0115-089-1, 2013-0115-159-1, 2013-0115-200-1) suggest that the comparison provided in the proposal is too generalized and that the information did not allow a fair cost comparison. This and the following two sections do not reference the complete list of comments received on the YOR or at the public meeting, but instead provide a representative example. In addition, these sections present quotations from the submissions received to highlight the general expression of the comments.

For example, one comment noted that:

The capital cost breakdowns of the LNG project and alternative diesel project provided in a letter from Mr. Ritchie to Mr. Maguire dated September 17, 2013 (page 4 of 7) do not provide enough detailed information to be helpful. These numbers are far too aggregated...

(YOR 2013-0115-089-1)

Subsequently, the Executive Committee requested a cost breakdown comparison between the proposed natural gas and diesel generators being considered as an alternative to the Project (YOR 2013-0115-217-1). This breakdown is provided above in Table 14 above.

The Executive Committee recognizes uncertainties in the cost estimates developed by YEC based on preliminary quotes and engineering and pertaining to, for example, pricing for the third GE natural gas generating unit. However, the Executive Committee has determined that it has sufficient information to use the cost estimates provided. In addition, these cost estimates have been provided to the YUB (YEC 2013).

8.1.2 Loading Forecasts

YEC provided forecasts for diesel generation on the Yukon grid to 2030, without connecting any new mines or developing other major new sources of generation. The updated 2013 grid load forecast generation is 413.5 GWh. The forecasts are summarized in Table 15 below, reproduced from YEC 2013. Grid load growth is projected to require electrical generation exceeding the existing long-term hydro generation capabilities on the grid, and assumes that no new renewable generation is developed. The forecast applies to both backup and peak loading. YEC notes that it will continue to reduce new thermal generation requirements on the grid each time new renewable generation is developed (YEC 2013).

Table 15 Forecast Base-Case Grid Default Diesel Generation Requirement (2013-2030)

Year	2013	2015	2020	2025	2030
Default Diesel Generation ¹	11 GWh	17 GWh	41 GWh	47 GWh	92 GWh

Table Notes:

1 Default diesel requirement based on long-term average hydro and wind generation, prior to development of any new non-diesel generation supply capacity on the grid (beyond what is permitted in 2013).

YEC updated and corrected forecast figures in the Proposal filed to the Executive Committee (YOR 2013-0115-220-1). These updated forecast figures are reflected in Table 15 above. In this table, Yukon's grid load growth under base-case load conditions is projected to require increases to average default diesel fuel energy generation (based on long-term average hydro and wind generation). YEC also presents other grid load forecast scenarios including potential industrial loads (Alexco and/or Carmacks Copper) in its application to the YUB (YEC 2013). The Project is expected to meet the forecast diesel generation requirements. YEC commits to exploring and developing additional renewable generation supply options to reduce both diesel and LNG requirements wherever possible as the requirement for default diesel generation increases (YEC 2013).

During the public comment period, the Executive Committee received comments regarding YEC's forecasted loading requirements. Comments indicated that the electrical load forecasts are out of date and do not consider various factors, including adding YECL's Fish Lake Unit 1 (hydro generation) to the grid (YOR 2013-0115-181-1, 2013-0115-200-1), and objected to the YEC's analysis of amounts saved based on the projected use as backup and peak power (YOR 2013-0115-137-1, 2013-0115-132-1, 2013-0115-207-1). For example, the following two comments represent the objections:

...the savings projected are based on previous electrical load forecasts that may not accurately represent reality any more

(YOR 2013-0115-181-1)

... in recent years, Yukon Energy has never spent more than a million dollars per year on diesel. In order to achieve the savings that are described in Yukon Energy's public meetings, the LNG generators would have to run continuously

(YOR 2013-0115-194-1)

In its 2012 Annual Report, YEC provides information on energy produced from diesel generators in GWh for the past 10 years, to show an historical use of diesel. This information has been reproduced in Table 16. Note that WAF Diesel is highlighted in bold; this row shows (in GWh) the actual historical diesel generation from 2007-2012 and is the relevant component for the projections.

Table 16 Summary of Utility Operations (adapted from YEC 2012)

Generation (in GWh)	2012	2011	2010	2009	2008	2007
Whitehorse Rapids	230	195	234	224	206	206
Aishihik	143	38	112	119	107	98
Mayo	50	11	32	29	28	27
Wind	0	0	0	0	0	0
WAF Diesel	3	12	3	2	1	0
Other Diesel	0	15	2	1	0	1
Total	427	401	383	375	342	332

YEC notes historical use of diesel reflects various factors each year, while thermal generation forecast requirements include growth and assume long-term average hydro generation with existing facilities and licenses (YOR 2013-0115-220-1). As a result, historical use is less than the forecast load.

The Executive Committee recognizes that uncertainties will always exist in forecasting loading requirements given the unpredictable nature of the economy, weather, and future large-scale projects connecting to the grid.

The Executive Committee has determined that for this assessment it will use the updated loading forecasts provided by YEC (YOR 2013-0115-220-1) and included in YEC's application to the YUB (YEC 2013) (Table 15).

8.1.3 Operational Costs

Considering the loading forecasts above (the base-case grid default generating requirements), annual fuel costs for the Project's natural gas units will be lower than a new diesel option. Fuel cost savings are estimated at 11.1 cents/kWh, assuming natural gas engine fuel costs at 13.5 cents/kWh and diesel engine fuel costs at 24.6 cents/kWh. These estimates are provided by YEC and make several assumptions regarding operations of the new natural gas or diesel generation units (YEC 2013). YEC estimates annual utility fuel cost savings with the Project compared to new diesel generation to be approximately \$3.4 million/year in 2015, increasing to \$4.8 million/year in 2017.

During the public comment period, the Executive Committee received many comments regarding the fuel costs estimated by YEC. Most of the comments disputed the assumption that the cost of LNG will remain lower than diesel for a number of years, arguing that the cost of LNG will increase with global markets and increasing demand Table 17.

Table 17 Comments on Fuel Costs Estimates

YOR Reference Number	Description
2013-0115-109-1	Comments S. Wright, 2013_12_17
2013-0115-157-1	Email P Huber 2014_01_09
2013-0115-170-1	Email D. Roberts 2014_01_09
2013-0115-171-1	Email E Huber 2014_01_09
2013-0115-181-1	Online J Maissan 2014_01_10
2013-0115-189-1	Byhand G Bemis 2014_01_10
2013-0115-191-1	Email a McCorkell 2014_01_10
2013-0115-193-1	Email E E Redlin 2014_01_10
2013-0115-199-1	Email J Gulick, 2014_01_10
2013-0115-200-1	Email J Maissan 2014-01-10
2013-0115-208-1	Email S Jones 2014_01_10
2013-0115-214-2	Email CPAWS 2014_01_09
2013-0115-219-1	Correspondence YESAB-AECOM 2014_01_27

For example, one commenter noted:

Part of the rationale for the LNG plant is saving money. At this moment in time, it might be cheaper to burn LNG than diesel but, given supply and demand principles, this finite resource will rise in price when the easily extracted gas has been used up

(YOR 2013-0115-191-1)

Related comments included criticisms of YEC's cost projections, calculations, and comparisons (Table 18) and urged the Executive Committee to do a cost-benefit analysis (YOR 2013-0115-157-1), although one comment supported the projections (YOR 2013-0115-192-1).

Table 18 Comments on Costs Projections

YOR Reference Number	Description
2013-0115-109-1	Comments S. Wright 2013_12_17
2013-0115-164-1	Online W. Rhein 2014_01_09
2013-0115-170-1	Email D. Roberts 2014_01_09
2013-0115-180-1	Online YCS 2014_01_10
2013-0115-181-1	Online J Maissan 2014_01_10
2013-0115-192-1	Email C. Burke 2014_01_10
2013-0115-211-1	Email T. Russell 2014-01-10

For example, the following comment highlights a common question:

In Yukon Energy's request to YESAB they stated that they would save over \$1 million in the first year of operation. How can that be with the backup costs not even reaching \$1 million for the total year?

(YOR 2013-0115-170-1)

Several comments also noted that YEC should integrate/invest in renewable options in its plan (YOR 2013-0115-211-1, 2013-0115-214-2, 2013-0115-079-1, 2013-0115-156-1, 2013-0115-088-1, 2013-0115-199-1). The following comment relates to both projected costs and renewable energy:

LNG is currently a cheaper resource than diesel. However, with the increasing demand within North America (and other places) the cost of this commodity will increase. In contrast, renewable energy sources such as wind, solar, hydro and biomass will not lock us to the fluctuating market prices of finite fossil fuels and are therefore a more economical choice.

(YOR 2013-0115-199-1)

The Executive Committee recognizes that uncertainties exist with regards to estimates for fuel costs and consumption. YEC's predicted savings are based on increased generation. The Executive Committee acknowledges that historical rates do not necessarily support this trend, however, accepts the prediction to be reasonable.

YEC included a sensitivity analysis in its assessment and determined that the savings projected apply over a wide range of cost differentials between diesel and natural gas prices, including an increase in

natural gas prices (YOR 2013-0115-220-1). This sensitivity analysis is discussed further in Section 8.2 below. The Executive Committee accepts YEC's projections presented in the proposal.

8.2 EFFECTS CHARACTERIZATION

In its proposal, YEC identifies project economics, called "utility ratepayers," as a valued component. In its effects assessment, YEC determined that effects to utility ratepayers are positive and that the Project will not have significant adverse effects to ratepayers. The Executive Committee notes that this determination of positive effects is based on the comparison of diesel and natural gas fuel costs. The Executive Committee recognizes the Project involves a capital cost to replace the existing diesel units. The Executive Committee has considered this capital cost when making its determination of whether the Project will result in significant adverse effects to ratepayers.

YEC estimates annual net savings including both fuel and capital cost impacts combined with forecasted base-case loads at \$1.3 million in the first full year of operation, increasing to \$2.2 million in 2016, \$2.6 million in 2017, and \$3.1 million in 2018 (YEC 2013).

As part of a request for additional project information, the Executive Committee requested a cost comparison including a sensitivity analysis of changes to natural gas and diesel prices, and a sensitivity analysis of actual thermal energy use (YOR 2013-0115-217-1). YEC provided a response (YOR 2013-0115-220-1) making reference to the YEC 2013 application to the YUB, where the Proponent also considered and evaluated various economic risks affecting ratepayers (YEC 2013). YEC concluded that the Project would provide ratepayer cost savings over a wide range of capital cost differentials when comparing new diesel and new natural gas engines. YEC also considered the sensitivity of project effects on ratepayer costs with regard to fuel cost differential increases and annual diesel displacement by natural gas. In YEC 2013, the Proponent considered the sensitivity to forecasted grid loads as part of the sensitivity analysis.

Figure 6 presents a summary of the overall sensitivity analysis performed by YEC. YEC notes that under base-case loads (with diesel displacement at 17 GWh), ratepayers would save under all sensitivities examined other than when the lowest fuel cost savings level is assumed, and assuming at least a 12 percent increase in capital costs.

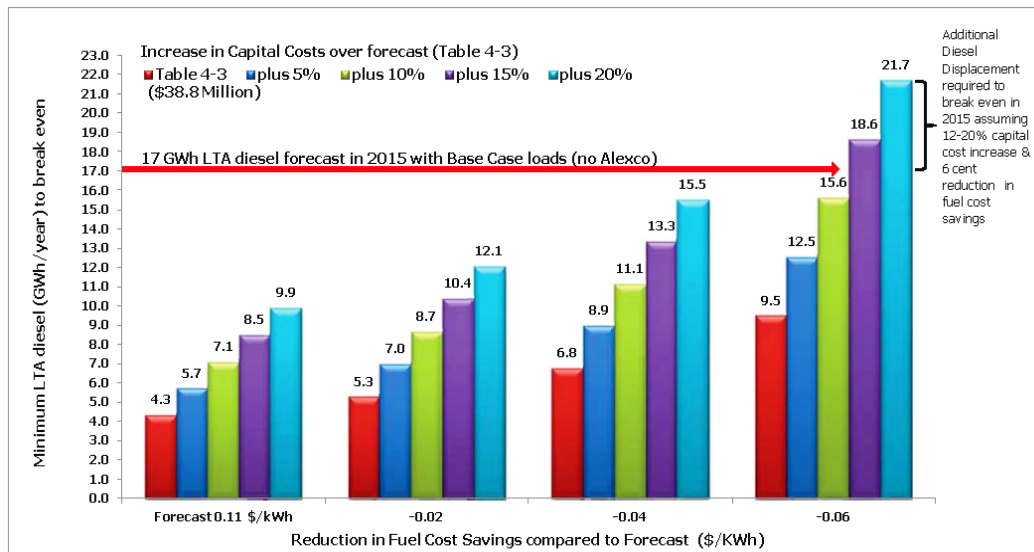


Figure 6 Capital cost and natural gas fuel cost savings sensitivity. Reproduced from YOR 2013-0115-220-1.

8.3 SIGNIFICANCE DETERMINATION

Due to uncertainties in capital costs, loading forecasts, and operations costs, as identified above, the Executive Committee acknowledges that uncertainties exist regarding project costs and/or savings. Further, the Executive Committee acknowledges that an increase in project costs will not necessarily result in an increase to utility ratepayers.

The Executive Committee has also considered the following non-discretionary legislation:

- *Public Utilities Act* and regulations

The *Public Utilities Act* provides the YUB with the mandate to set rates or approve any increase in rates proposed by YEC through a General Rate Application. Furthermore, Government of Yukon may instruct YEC and the YUB on rate and rate setting through an Order-In-Council (OIC). As such, any potential rate increases to YEC customers as a result of to the Project would have to be approved by the YUB and meet requirements of any Order-In-Council by Government of Yukon.

The Executive Committee acknowledges that in December 2013 YEC submitted an application for an energy project certificate and an energy operation certificate, and that Government of Yukon designated, in OIC 2013/200, the Project as a Regulated Project and referred the Project to the YUB for a review and hearing, with terms and references. As a result, the Executive Committee has determined that the Project will not have significant adverse effects on utility ratepayers.

8.4 CUMULATIVE EFFECTS

Residual effects are those effects that remain from project activities after enacting mitigation measures. Cumulative effects are any residual Project effects in combination with the effects of other existing or

proposed projects. The potential for cumulative effects on utility ratepayers has been considered within the City of Whitehorse.

The Executive Committee is not aware of any other projects or activities in Whitehorse that will affect utility ratepayers and therefore a cumulative effects assessment on utility ratepayers has not been conducted.

9.0 WILDLIFE

This section addresses potential effects of the Project on wildlife and wildlife habitat. The assessment uses the project study area (PSA) as defined in the proposal (Figure 2 and Figure 3).

The Executive Committee considered the potential effects of the Project on wildlife, including migratory birds. As the project area is already heavily disturbed, and is a small site (only 1.5 ha), the Executive Committee determined there would be no significant impact on wildlife and wildlife habitat, and focused the assessment on migratory birds.

The Executive Committee considered effects to migratory birds due to:

- habitat loss and alteration; and
- direct injury and/or mortality.

9.1 OVERVIEW

While the PSA provides potential habitat for migratory birds and terrestrial and avian species at risk, the expanded site area (ESA) is a highly disturbed site. The ESA consists of a 1.5 ha fragmented patch of willow/shrub vegetation communities, drainage ditches and infiltration basins, as well as an overgrown railway right-of-way. It is surrounded on all sides by road, and is in proximity to the airport, the Whitehorse Rapids Generating Station (WRGS), a residential area, and various recreational activities, including a motocross track. The Proponent has identified a number of species at risk with potentially overlapping ranges with the PSA. Environment Canada has also noted the possible presence of species at risk (YOR 2013-0115-161-1). However, it is highly unlikely that the ESA provides key habitat for any terrestrial species. Thus, this effects assessment focuses on potential effects of the Project on nesting migratory birds.

9.2 EFFECTS RELATED TO MIGRATORY BIRDS

There is the potential for migratory birds, including birds protected under the *Migratory Birds Convention Act* (MBCA), the *Species at Risk Act* (SARA) or the *Yukon Wildlife Act* to be present in the project area.

The *Migratory Birds Regulations* prohibit the disturbance or destruction of a migratory bird species listed under the MBCA. Land clearing activities that overlap with the nesting period may result in potential effects to migratory birds, including:

- habitat loss or alteration by clearing or disturbing potential nest sites;
- direct bird injury or mortality due to destruction of bird nests or individuals during vegetation clearing.

Project activities that could affect migratory birds include the clearing, grubbing and grading of a 1.5 ha site of potential bird habitat. Vegetation disturbance and removal has the potential to negatively affect migratory birds. However, as discussed, the ESA is a highly disturbed and developed area, due to surrounding buildings and roads, the WRGS, the airport, vehicle traffic, residential areas, and recreational activities.

Although the vegetation structure and composition of the area contains potentially suitable habitat, it is highly unlikely that, due to the degree of disturbance of the site, any migratory birds or species at risk rely on the area for regionally important habitat. Government of Yukon, Department of Environment indicates that the Project does not overlap with any Wildlife Key Areas, known bird breeding locations, rare or endangered species, or other wildlife values and is not likely to result in significant terrestrial effects (YOR 2013-0115-148-1).

The Proponent has committed to following best practices to prevent disturbance or destruction of nests for species protected under the *Migratory Birds Convention Act* (Appendix C). To the extent feasible land clearing will occur outside the bird nesting season (May 1 to July 15). Where clearing is unavoidable during the period from May 1 to July 15, a nest survey will be completed by a qualified avian biologist two days prior to clearing to identify and locate active nests. If nests are observed, an appropriate buffer zone for the species will be marked around the nest and access will be restricted until the fledglings have left the nest.

In addition, the Project includes a single LNG facility flare system to facilitate disposal of excess vapour pressure to the atmosphere in the event of abnormal process conditions or pressure build-up that exceeds fuel gas consumption. The Proponent indicates that “atmospheric venting is considered an abnormal condition and avoided except for emergency conditions to prevent over pressurization in piping systems, tanks and vessels” (YOR 2013-0115-057-1).

Environment Canada raised the flare system as a concern, noting that “under certain circumstances, this flaring could attract birds ... more likely during spring or fall migration” (YOR 2013-0115-161-1). Specifically, Environment Canada referred to an event in 2013 at a Canaport liquefied natural gas receiving and regasification terminal in New Brunswick when an estimated 7 500 songbirds were killed when flying over the 30-metre flare tower. A receiving and regasification terminal is significantly larger in size with a significantly larger flare stack and flare than the proposed project.

However, as there is some uncertainty as to how migratory birds will interact with the flare stack, the Executive Committee agrees with the comment from Environment Canada that Yukon Energy Corporation should consider monitoring the impacts to birds during flaring, and report any incidental kills that may occur. Should the monitoring show impacts, mitigation may be required (YOR 2013-0115-161-1). While it is possible that atmospheric venting could cause injury or mortality to bird species flying close to the flare stack when venting occurs, given that venting is to be avoided except for emergency conditions, it is extremely unlikely that these effects will occur.

Further, the Executive Committee acknowledges uncertainty as to whether birds may be attracted to the flare stack as a potential perch.

9.3 SIGNIFICANCE DETERMINATION

The Executive Committee has considered the requirements of the following non-discretionary legislation:

- *Migratory Birds Convention Act* and the *Migratory Bird Regulations*
- *Species at Risk Act (SARA)*
- *Yukon Wildlife Act*

Further, the Executive Committee recognizes Environment Canada's recommendations that:

- All activities with the risk of disturbing or destroying nests or eggs be conducted outside the migratory bird breeding season.
- If active nests of birds listed under the MBCA are discovered, the Proponent should postpone activities in the nesting area until nesting is completed (i.e. the young have left the vicinity of the nest).

The Executive Committee acknowledges that these recommendations have been committed to by the Proponent (Appendix C). However, the Executive Committee has determined that the Project may still result in significant adverse effects to migratory birds due to project flaring, but that these effects can be eliminated, reduced or controlled through the following mitigations.

9.4 TERMS AND CONDITIONS

The following Terms and Conditions are specified to mitigate significant adverse effects of the Project on wildlife:

4. YEC and appropriate regulators shall identify measures to mitigate effects to birds, including:
 - a) monitoring the impacts to birds during flaring,
 - b) reporting any incidental kills that may occur to the appropriate regulators, and
 - c) any other additional mitigation measures.
5. The Proponent shall give consideration to design features which will prevent raptors or other birds from perching on the flare stack.

9.5 CUMULATIVE EFFECTS ASSESSMENT

Residual effects are those effects that remain from project activities after enacting mitigation measures. There is potential the Project will result in residual effects to migratory birds due to the destruction of habitat and flaring. These effects include disturbance and injury or mortality. Cumulative effects are any residual Project effects in combination with the effects of other existing or proposed projects. The cumulative effects to migratory birds are considered in the spatial and temporal context of their range, and the spatial scope of any residual effects is specific to the bird species considered. The spatial extent boundary has been set to a 500 m radius around the project footprint, based on the PSA.

The Executive Committee is satisfied that the residual effects of the Project, in combination with the effects of other projects or activities will not result in significant adverse cumulative effects to wildlife.

10.0 AESTHETICS

This section addresses potential effects of the Project on aesthetics. The assessment uses the project study area (PSA) (Figure 2) and expanded site area (ESA) (Figure 4) as defined in the proposal.

The Executive Committee considered the following effects to visual aesthetics:

- Land clearing and other construction activities
- The presence of equipment on site
- The view of the new facility and equipment from Robert Service Way and Miles Canyon Road

10.1 OVERVIEW

Currently the ESA consists of a mixture of disturbed areas (drainage ditches, infiltration basins), an overgrown railway right-of-way, and willow/shrub vegetation communities. As shown in Figure 4, the ESA is adjacent to Robert Service Way, the southern road access to downtown Whitehorse, and Miles Canyon Road, a popular recreation route.

The majority of the ESA, which is approximately 1.5 ha in size and runs approximately 270 m along Robert Service Way, will be cleared and graded. Construction activities will take place on the ESA, and the new facility and operations equipment will be seen by travelers along Robert Service Way and recreational users in the area. Thus, effects will occur during both the construction and operations phases of the Project.

10.2 EFFECTS CHARACTERIZATION

The PSA and ESA are part of an area previously disturbed by human activities, including major land alterations due to the construction of Robert Service Way and the WRGS. However, the Project is located along an entry point to downtown Whitehorse and the removal of vegetation and the construction of industrial facilities will affect the natural aesthetics of the area. Additionally, the City of Whitehorse and members of the public have expressed concerns regarding the aesthetic effects of the Project.

While the construction of the Project will cause negative effects on aesthetics, due to the clearing of trees/shrubs and the presence of equipment and building materials on site, the majority of concerns raised were related to the aesthetic effects of project operations.

The City of Whitehorse Zoning Bylaw (2012-20) requires the Project be screened from adjacent streets with a combination of fences, berms, and landscaping. In addition, a specific "Gateway Landscaping" zoning regulation is applicable to this location. The City of Whitehorse Development Review Committee (DRC) recommends that the access roads and vapour barrier be configured to maintain as much of a natural buffer as possible, and that new shrubs/trees be planted amongst the existing vegetation. In addition, the DRC recommends the installation of visibility screening in the fencing (YOR 2013-0115-01-177).

The DRC also stated, regarding proposed overhead power distribution lines connecting the existing substation to the proposed new substation (Figure 4 Project Construction Footprint), that: "installing lines

overhead is not supported in this location, only new underground services are recommended" (YOR 2013-0115-177-01).

To mitigate effects on visual quality, the Proponent has committed to installing a fence and vapour barrier that will partially screen the view of the facility and equipment from Robert Service Way and Miles Canyon Road. The Proponent also commits to maintaining a vegetation buffer approximately 10 m in width along the perimeter of the ESA adjacent to these roads. Landscaping will be undertaken at the end of the construction phase and will comply with relevant City of Whitehorse zoning bylaws (Appendix C).

Throughout their operation, the project facilities will be equipped with lighting for security and safety reasons; these lights may cause additional light pollution in the area. To minimize this effect, the Proponent has committed to designing and installing fully shielded lighting installations for all lights at the ESA. The Proponent commits to directing lighting to minimize any light trespass beyond the perimeter fence, and to turning off any lighting that is not necessary from an operational, safety, or security perspective. This may be achieved through the use of motion controlled lighting and switched lighting that can be controlled at the site or remotely.

While project activities will create noticeable visual changes, visual effects are not expected to extend beyond the PSA.

10.3 SIGNIFICANCE DETERMINATION

The Executive Committee has considered the requirements of:

- *City of Whitehorse Official Community Plan 2010*
- *City of Whitehorse Zoning Bylaw 2012-20*

The Executive Committee has determined that the Project will result in significant adverse effects to visual aesthetic quality in the PSA. However, these effects can be eliminated, reduced or controlled through the mitigations proposed by the Proponent described in the Proposal, compliance with non-discretionary legislation, and the implementation of mitigative measures specified by the Executive Committee.

10.4 TERMS AND CONDITIONS

The following Terms and Conditions are specified to mitigate significant adverse effects of the Project on visual aesthetics:

6. The Proponent shall configure access roads and the vapour barrier to maintain as much of a natural buffer as possible. Where possible, new shrubs/trees shall be planted amongst the existing vegetation.
7. The Proponent shall install visibility screening in fencing.
8. The Proponent shall install underground power distribution lines connecting the existing substation to the proposed new substation.

10.5 CUMULATIVE EFFECTS ASSESSMENT

Residual effects are those effects that remain from project activities after enacting mitigation measures. There is potential the Project will result in residual effects on the visual aesthetics of the area. These effects include the removal of vegetation and the construction of a permanent facility.

Cumulative effects are any residual Project effects in combination with the effects of other existing or proposed projects. The cumulative effects to visual aesthetics are considered in the 500 m radius around the project footprint, based on the PSA.

The Executive Committee is satisfied that the residual effects of the Project, in combination with the effects of other projects or activities will not result in significant adverse cumulative effects to the aesthetics of the area.

PART III ASSESSMENT RECOMMENDATION

11.0 RECOMMENDATION

Pursuant to paragraph 58 (1) (b) of YESAA the Executive Committee recommends to the Decision Body that the be allowed to proceed without a review, subject to the terms and conditions specified below; as the Executive Committee has determined that the Project will have significant adverse environmental and/or socio-economic effects in Yukon that can be mitigated by these terms and conditions.

12.0 TERMS AND CONDITIONS OF RECOMMENDATION

1. The Proponent shall report on the operation and duration of natural gas generators to the appropriate regulator.
2. The Proponent shall work with the appropriate regulators to develop a monitoring program for air emissions. At a minimum, the following constituents should be monitored: CO, VOCs, NO_x, SO_x and PM.
3. The Proponent shall include in the monitoring program GHG emissions identified by the appropriate regulator such as CO₂, CH₄ and N₂O.
4. YEC and appropriate regulators shall identify measures to mitigate effects to birds, including:
 - a) monitoring the impacts to birds during flaring,
 - b) reporting any incidental kills that may occur to the appropriate regulators, and
 - c) any other additional mitigation measures.
5. The Proponent shall give consideration to design features which will prevent raptors or other birds from perching on the flare stack.
6. The Proponent shall configure access roads and the vapour barrier to maintain as much of a natural buffer as possible. Where possible, new shrubs/trees shall be planted amongst the existing vegetation.
7. The Proponent shall install visibility screening in fencing.
8. The Proponent shall install underground power distribution lines connecting the existing substation to the proposed new substation.

Executive Committee Draft Screening Report and Recommendation
Whitehorse Diesel – Natural Gas Conversion Project

13.0 SIGNATORY PAGE



March 19, 2014

Stephen J. Mills
Chair

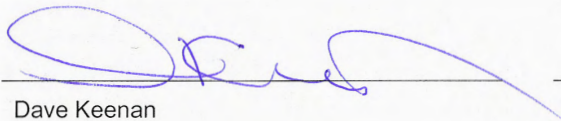
Date



March 19, 2014

Ken McKinnon
Executive Committee Member

Date



March 19, 2014

Dave Keenan
Executive Committee Member

Date

March 19, 2014

YESAB

78

APPENDICES

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Appendix B COMMENTS ON THE PROPOSAL

Period received January 8 to 10, 2014

189-1 Byhand G Bemis 2014_01_10

214-2 Email CPAWS 2014_01_09

213-1 Email B Burns 2014_01_09

215-1 Correction J Vigneux 2014_01_13

211-1 email T. Russell 2014-01-10

210-1 Email T Stad 2014_01_10

209-1 email YCS 2014_01_10

208-1 email S Jones 2014_01_10

207-1 email S Johnston 2014_01_10

206-1 Email R. Gilson 2014_01_10

205-1 email R. Gilson 2 2014_01_10

204-1 email P Becker 2014_01_10

203-1 email M Amerongen 2014_01_10

202-1 email J Vigneux 2014_01_10

201-1 Email J Schou 2014_01_10

200-1 Email J Maissan 2014-01-10

199-1 Email J Gulick 2014_01_10

198-1 email J Frisch 2014_01_10

197-1 Email J Durant 2014_01_10

196-1 email G. Niedermeyer 2014_01_10

195-1 Email G. Lalena 2014_01_10

194-1 Email G Gilgan 2014_01_10

193-1 Email E E Redlin 2014_01_10

192-1 Email C. Burke 2014_01_10

191-1 Email a McCorkell 2014_01_10

190-1 Email A Macaire 2014_01_10

188-1 ByHand A McGuire 2014_01_09

187-1 Online J Pangman 2014_01_11

186-1 Online M Darragh 2014_01_10

185-1 Online G Haase 2014_01_10

184-1 Online S Smith 2014_01_10

183-1 Online JP Pinard 2014_01_10

182-1 Online KDFN 2014_01_10

181-1 Online J Maissan 2014_01_10

180-1 Online YCS 2014_01_10

179-1 Online TKC 2014_01_10

178-1 Online S. Guimond 2014_01_10

177-1 Online CoW 2014_01_10

176-1 supporting docs for CO2e meeting 2014_01_10

175-1 Online L Rifkind 2014_01_10

174-1 Email C. McNutt 2014_01_10

173-1 Email M Berkman 2014_01_09

172-1 Email J Edwards 2014_01_09

171-1 Email E Huber 2014_01_09

170-1 Email D. Roberts 2014_01_09

169-1 Email CA Gringas 2014_01_09

168-1 Email C. McBride 2014_01_09

167-1 email A Belke 2014_01_09

166-1 Online R Lewis 2014_01_09

165-1 Online D Hambly 2014_01_09

164-1 Online W. Rhein 2014_01_09

161_1 Online EC 2014-01-09

160-1 Email M. Lamrock 2014_01_09

159-1 Email J. Maissan 2014_12_09

159-1 2014-01-06 YEC CAT 3616 information

158-1 Email D Homan 2014_01_09

157-1 Email P Huber 2014_01_09

156-1 Email C Ness 2014_01_08

153-1 Online A. Milani 2014_01_09

151-1 Online G Bradshaw 2014_01_08

150-1 Online P LeBlond 2014_01_08

149-1 K. Melton 2014-01-08

148-1 Yukon Government 2014_01_08

148-1 2013-0115_Environment_2013-0115

148-1 2013-0115_EMR-Oil & Gas_2013-0115 OGR

148-1 2013-0115_Community Services_LNG Fire Marshall

148-1 2013-01-08 Letter YG to YESAB 2013-0115 Assessment Input

Period received January 1 to 7, 2014

155-1 Image of tanker E. Stoll 2014_01_06

154-1 Byhand E. Stoll 2014_01_06

152-1 Email S. Wright 2014_01_06

147-1 Online R. Annett 2014_01_07

145-1 Online R Annett 2014_01_07

144-1 Online YCS analysis 2014_01_07

143-1 Online YCS Analysis on Lifecycle Assessments 2014_01_07

138-1 Email R. Jantzen 2014_01_06

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135-1 Email S. Binette 2014_01_02

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Period received December 25 to 31, 2013

126-1 Online R. Annett 2013_12_28

127-1 Online S Wisemyn 2013_12_29

130-1 Comment - Lois Johnston - 2013-12-28

131-1 Email - Kath Selkirk - 2013-12-30

Period received December 18 to 24 2013

115-1 Email J Taggart 2013_12_18

117-1 Email M. Caron 2013_12_18

119-1 Email L. Leon 2013_12_19

120-1 Email J Kerr 2013_12_19

121-1 Email P Cardinal 2013_12_18

124-1 Email C St Vincent 2013_12_20

125-1 Email D Smith 2013_12_23

Period received December 11 to 17, 2013

111-1 byhand A_Weiers 2013_12_17

110-1 email J Maissan 2013_12_17

109-1 Comments S. Wright 2013_12_17

107-1 Request for Extension YCS 2013_12_17

104-1 Request for extension 2013_12_17

103-1 Email D McWhinnie 2013_12_17

102-1 email J Russell 2013_12_17

097-1 email E. Heuer 2013_12_13

096-1 Yukon Legislative Assembly Blues - YEC - December 10 2013

095-1 Email S Wright 2013_12_13

094-1 Email P Davis 2013_12_12-2

093-1 Email P Davis 2013_12_12

092-1 Email N Eady 2013_12_12

091-1 Email K Weekes 2013_12_12

090-1 byhand S. Miller-Wright 2013_12_11

089-1 Maissan questions 2013_12_12

088-1 online J. Plaisonce 2013_12_12

087-1 Online K. Magnusson 2013_12_12

086-1 Online S. Miller-Wright 2013_12_12

085-1 Online C. Stuart Clark 2013_12_11

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083-1 Email Request for Extension TKC 2013_12_11

Period received December 5 to 10, 2013

079-1 Email J. Harwood Dabbs 2013_12_08

Period received November 27 to Dec 4, 2013

077-1 Request for scope change YCS

072-1 Email L. Klauserova 2013_12_02

071-1 Online A Reid 2013_12_01

070-2 TEDxYXY November 27 Nov 2013

069-1 YCS questions re 2013-0115 Nov 27

Period received November 21 to 26, 2013

068-1 Request for Extension JP Pinnard 2013_11_26

067-1 Request for Extension J. Blouin 2013_11_25

066-1 Request for Extension S. Dalley 2013_11_25

064-1 Request for Extension L. Reichenbach 2013_11_26

063-1 YCS Request for Extension 2013_11_22

062-1 Email Request for Extension P Davis 2013_11_21

061-1 Email Request for Extension D. Hedmann 2013_11_21

Period received November 13 to 20, 2013

056-1 email request for extension J. Maissan Nov 15, 2013

Period received November 7 to 12, 2013

052-1 email request for extension J. Maissan Nov 13, 2013

Period received Before November 6, 2013

051-1 email k. MerCs Nov 4, 2013

050-1 email J.P. Pinnard Oct 28, 2013

049-1 email S. Wright Oct 17, 2013

Appendix C PROPONENT COMMITMENTS

March 7, 2014

Keith Maguire – Senior Assessment Officer
Yukon Environmental & Socio-economic Assessment Board
Suite 200-309 Strickland Street
Whitehorse, Yukon Y1A 2J9

(Via email)

Re: Project Assessment 2013.0115 Whitehorse Diesel Natural Gas Conversion Project – List of Yukon Energy Commitments

Dear Mr. Maguire,

On March 3, 2014 you requested that Yukon Energy provide a brief summary of all of the commitments Yukon Energy has made in the Project Proposal for the Whitehorse Diesel-Natural Gas Conversion Project regarding mitigating potential adverse effects of the project and/or best practices.

Yukon Energy has reviewed the Project Proposal as well as subsequent documentation provided to YESAB as responses to requests for further information and provides, as Attachment A to this correspondence, the list of relevant commitments as follows:

1. Table A-1 - Summary of commitments to reduce risk or effects related to accidents and malfunctions.
2. Table A-2 - Summary of commitments to mitigate environmental and socio-economic effects.

Please do not hesitate to contact me at (867) 393-5350 or by email: travis.ritchie@yec.yk.ca should you have any questions, comments, or concerns regarding the above and/or attached.

Sincerely,



Travis Ritchie, P.Biol., EP
Manager – Environment, Assessment, & Licencing

/Attachments: Tables A-1 and A-2.

ATTACHMENT A

Table A-1 Summary of Commitments to reduce risk or effects related to accidents and malfunctions

Section 6.7.1	Fuel & Hazardous Material Management <u>Construction</u> • Risk of spills, containment and response will be addressed by standard environmental protection practices as described in Yukon Energy's EMS. • Yukon Energy will file a spill response plan updated to include new LNG facilities and equipment with Oil and Gas Branch prior to start of construction. • Contractors will be required to have an emergency response plan, including a spill response plan in place that meets, or exceeds, Yukon Energy's EMS and Whitehorse Hydro/ Diesel/ Substation Spill Response Plan. • Spill response materials will be kept onsite. <u>Operation</u> • Activities during the operation phase (to the extent not already addressed by Yukon Energy's existing standard environmental protection practices as included in Yukon Energy's Whitehorse Hydro/ Diesel/ Substation Spill Response Plan) will meet the requirements of CSA - Z276 (LNG) – Production, Storage and Handling (2011) standard, the <i>Yukon Oil and Gas Act</i>, <i>Gas Processing Plant Regulation</i> and any other relevant standards or codes. • Workplace Hazardous Materials Information System, as well as storage and handling requirements, will be applied in compliance with the <i>Transportation of Dangerous Goods Act</i> to ensure workplace safety. <i>Special Waste Regulations</i> will be followed in accordance with the <i>Environment Act</i>.
Section 6.7.2	Oil Spill Prevention and containment • To the extent possible, permanent equipment will be specified to be oil free. Alternatively, equipment will be designed to minimize the volume of oil it contains. • Permanent equipment that must be filled with oil will be equipped with secondary containment, leak detection, and a recovery system.
Section 6.7.4; Chapter 7, page 28; October 25, 2013 letter response to R4, page 8	Emergencies, Accidents & Malfunctions <u>Construction</u> • During construction, the job site will be in compliance with Yukon's <i>Occupational Health and Safety Act</i>, the Yukon's <i>Health and Safety Regulations</i> and any other applicable territorial or federal laws or any other industry-specific

	requirements that may apply. • The A security perimeter (fence) will be installed and maintained during construction and have appropriate signage for comparable construction jobs routinely undertaken in Yukon. <u>Operation</u> • Non-discretionary legislation and standards and codes will apply to mitigate adverse effects on health and safety due to Project-related accidents and malfunctions, including <i>Occupational Health and Safety Act</i> and <i>Occupational Health and Safety Regulations</i>, the <i>Environment Act</i>, <i>Spills Regulations</i> and <i>Storage Tank Regulations</i>. • Workplace Hazardous Materials Information System, as well as storage and handling requirements will also be applied in compliance with the <i>Transportation of Dangerous Goods Act</i> to ensure workplace safety. <i>Special Waste Regulations</i> will be followed in accordance with the <i>Environment Act</i>. • Yukon Energy will adhere to codes and standards set by the industry and regulators regarding LNG storage and transfer, such as CSA Standard Z276-11, applicable fire prevention codes, and any requirements in the <i>Yukon Gas Processing Plant Regulation</i>, and will use equipment that meets the safety and industry standards making a spill or unwanted ignition highly unlikely. • Yukon Energy's use and reliance on the proposed Project facilities will also be constrained by the terms and conditions of pertinent regulatory authorizations, as well as the requirements of relevant legislation that applies to the Project. • Operation and maintenance of the facilities will follow Yukon Energy's well established safe work practices. • Access to the site property will be fenced and gates and safety signage will be posted where necessary. The site property will be completely fenced on all side and access to the site property will be controlled through fencing and controlled gates that will preclude entry to this area by either the public or unauthorized Yukon Energy personnel or contractors. Access to the substation will be controlled through additional fencing within the site property.
Section 6.7.6; January 29, 2014 Response to R9;	Work Force Requirements & Training • All personnel will be required to undertake awareness training focusing on the Health, Safety, and Environmental (HS&E) Work Plans. • Operational HS&E Plans and Procedures will be developed for the Project in advance of taking initial fuel delivery and commissioning of the Project. • Workers will be provided with a list of emergency response plans and reporting protocols, and specific information on waste management practices to be utilized during the construction phase of the Project, including all liquid and solid wastes generated. Special waste regulations will be followed in accordance with the <i>Environment Act</i>. • Contractors will be required to comply with the HS&E Work Plans developed for the Project and ensure that Project

	work is performed in a safe manner, and that it is in compliance with the Yukon's Occupational Health and Safety Act, the Yukon's Health and Safety Regulations and any other applicable territorial and/or federal laws or any other industry-specific requirements that may apply. • Routine auditing of performance against HS&E requirements will be undertaken by contractors and independently by Yukon Energy during the construction phase. • Staff will be trained to ensure practices for the safe handling, transport and storage of LNG are implemented which will further reduce the likelihood of incident. Workers will be trained and supervised and will be provided with a list of emergency response plans and reporting protocols, and specific information on safety and environmental management practices to be utilized during the construction phase of the Project, including all liquid and solid wastes generated. • Employees who are authorized to work in the LNG area will be trained on the hazard of asphyxiation. • Industry standard evacuation zones as per Canadian Transport Emergency Centre (CANUTEC) regulations for the transportation of dangerous goods, including LNG, LPG (propane), gasoline and diesel will be followed.
January 29, 2014 Response to R8, R13, R14	Vapour retention wall & worst probable case high impact radius • In order to address safety requirements related to any vapour cloud, an area classification study will be performed and an area classification drawing prepared as part of detailed design and engineering. Area classifications will be determined per section 18 of the Canadian Electrical Code and CSA Z276, as applicable. If the studies indicate containment of the vapour cloud is required, a vapour barrier will be installed to meet within YEC's property all requirements of CSA Z276-11. • To the extent that the radiant heat zone extends beyond YEC's property, YEC is seeking to secure no-build easements from the adjacent property owners such that this radiant heat zone will not extend beyond a property line that can be built upon. • Per CSA-Z276 requirements, sources of ignition will be at least 15 m from process equipment containing LNG. The site layout will meet these conditions except as allowed by paragraph 13.3.4.4. YEC will have an authorization procedure as detailed in the final clause of 13.3.4.4.
January 29, 2014 Response to R9, R10(b), R10(c); October 10, 2013 letter, page 10; February 4, 2014 Allnorth memorandum.	Safety Engineering • The design of the site will meet CSA standards and setbacks. Yukon Energy's use and reliance on the proposed facilities will be constrained by the terms and conditions of required permits, as well as the requirements of relevant legislation that applies to the Project. Both CSA Z276-11 and the Yukon Gas Processing Plan Regulation prescribe strict requirements and standards related to licencing, construction of an LNG facility, operation and maintenance of an LNG facility, making physical and operational changes to an LNG facility, and records and reporting related to an LNG

	facility. • The design of the site with respect to impoundment of LNG, in the unlikely event of a spill, will be in compliance with section 5.2.1.2 of the code. Specifically, both tanks and tanker unloading area will be constructed with a concrete apron sloped in order to allow LNG to gravity drain from any spill location into the spill impoundment area located away from the tanks and sized to accommodate 110% of the volume of the largest LNG tank. The inner LNG tank will be designed to remain intact in the event of damage to the outer LNG tank, a loss of vacuum and/or damage to the insulation. Rupture of the inner tank due to overpressure (from vapourized LNG) will be prevented using relief devices as required by Section 7.6 of CSA Z276. Foundations and supports upon which the tanks sit will be designed with a two-hour fire resistance rating. • Fire and Gas detectors will be installed in the LNG storage tank areas in specific locations where possibility of LNG spills, gas leaks, flame, excess heat and low temperature indicate unsafe conditions. Emergency manual call points will be provided, as well as sirens and beacons to alert personnel of emergency situations. Logic in fire and gas detection control systems will automatically trigger an emergency shutdown for specific events. • Emergency Shutdown (ESD) valves will be provided in the liquid and vapor lines of the storage tanks and LNG pump outlets and natural gas lines to isolate the system in an emergency. • A control room based surveillance system using CCTV cameras at the LNG tanker unloading area, impounding basin, tankage and process area will be provided to allow constant monitoring of high-risk areas, and be designed as an integrated web-based system with the network and control systems. • Hydrocarbon detectors will be used and will be set to alert personnel should hydrocarbons at a fraction of LFL be detected. • Emergency Shutdown button(s) will be located away from the impoundment area in a location accessible in the event of an impoundment area fire. • Isolation valves for the tanks are connected to an automatic shut-down system, in such a way that there is no possibility of flow. If there is electrical failure, there is automatic shutdown. The manual controls will be appropriately located so they may be accessed.
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Table A-2: Summary of Commitments to mitigate environmental and socio-economic effects (Chapter 7 and Chapter 8)

Chapter 6, Section 6.7.3 Chapter 7, pages 7-7; Chapter 8, page 8-2	Erosion & Sediment • Standard best management practices and mitigation measures to reduce and/or eliminate sedimentation and erosion impacts from surface water on the local landscape from exposed soils, including as applicable, following provisions of Yukon Energy's Environmental Management System Manual (EMS) and any requirements Yukon Government (YG) and/or city of Whitehorse have for storm water conveyance and controls on developed sites. • Fencing will be installed at the perimeter of the construction area to avoid causing excessive damage and disturbance to the vegetative mat. • Excavated material will be stored more than 10 metres from waterways and kept in stable condition until final disposal or use on site. • Stormwater will be managed to address the effect of reduced infiltration on the site; the Project design incorporates a stormwater pond for retention and infiltration that will be constructed early in the Construction phase of the Project to manage runoff during Construction, as well as throughout Operation of the Project and will also provide additional containment for potential contamination related to leaks or spills associated with construction equipment and machinery on site. • Water will be directed to the stormwater pond and/or ditches using methods such as silt fencing and additional ditching. • The final grade within the Project Construction Footprint will be positively graded to direct surface water from impermeable surfaces (asphalt access road, concrete pads, for storage areas and modules, etc) to the stormwater pond. • For construction of the underground piping, pipe burial depth will be above the water table. In the event groundwater is encountered it will be pumped from the excavation site into the stormwater pond or ditches along Robert Service Way and Miles Canyon Road. • Concrete poured on site during construction to establish foundations for the new modular equipment will be undertaken in such a way that contamination of the aquatic environment is avoided. • Standard best management practices and mitigation measures will be followed regarding leaks and spills from equipment, machinery or other sources on site, including following the Whitehorse Hydro/Diesel/ Substation Spill Response plan. All construction contractors will be required to provide spill management plans that meet or exceed the existing plan implemented by Yukon Energy at the Whitehorse Rapids Generating Station or otherwise follow Yukon Energy's plan.
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	During construction and operations standard best practices and mitigation measures will be followed regarding disposal of waste generated on site; all waste generated on site will be classified and handled appropriately as per the Environment Act and Special Waste Regulation, and wastes will be diverted from the landfill to the extent possible.
Chapter 7, pages 7-8 to 7-9; Chapter 8, page 8-2	Vegetation Diversity - Appropriate measures will be undertaken to reduce dust production (e.g., sweeping and spraying access roads with water if dust generation is persistent), which will minimize impacts from dustfall on vegetation - Implementation of standard best practices for introduction of invasive species, including containment of disturbance to the Project Construction footprint, regular washing of construction equipment and prompt re-vegetation (within 1 year) of areas left unpaved will mitigate risks of invasive species introduction associated with project construction. - Re-vegetation and stabilization measures will be completed as soon as feasible (and within one year of cessation of construction activities); including, as applicable, following provisions of Yukon Energy's EMS.
Chapter 7, pages 7-9 to 7-10; Chapter 8, page 8-2	Wildlife Diversity and Habitat Avoidance to the extent feasible of clearing activities during the period from May 1 to July 15; completion of a nesting bird survey by a qualified biologist two days prior to clearing to identify and locate active nests in the event that clearing cannot be avoided during the period from May 1 to July 31. If nests are observed, an appropriate buffer zone for the species will be marked around the nest and access will be restricted until the fledglings have left the nest.
Chapter 7, page 7-13 Chapter 8, page 8-2 to 8-3	Land Use and Heritage All excavation activities will follow standard archeological resources practices as required by the Historic Resources Act and Yukon Energy's Environmental Management System (EMS) with respect to any items uncovered.
Chapter 7, pages 7-14 to 7-17 Chapter 8, page 8-2 to 8-3	Recreation - Construction areas will be delineated with fencing and signage to ensure that during construction any continued recreational uses in the vicinity will occur in a manner that will maintain the safety of the public and the construction staff. - Transport of the LNG to the facility during operations will use existing transportation routes (Alaska Highway and Robert Service Way) and will not disrupt recreational uses in the area. - Movement of equipment on and off-site will be planned such that traffic disruptions re minimized.
Chapter 7, pages 7-14 to 7-16 Chapter 8, page 8-2 to 8-3	Dust Standard best management practices for management of fugitive dust will be implemented as mitigation, such as sweeping or using a water spray on site access roads during construction if dust generation is persistent.

October 25, 2013 response to R2	Emissions Estimates – Water Vapour • If the WTGS is operating and there are ice fog conditions, Yukon Energy, in cooperation with the CoW and/or Yukon Government Public Works departments, will monitor road conditions along Robert Service Way adjacent to the WTGS to determine whether conditions along Robert Service Way are impacted by the operations of the WTGS. Yukon Energy will work with applicable authorities to ensure appropriate response mechanisms are in place.
Chapter 8, page 8-2 to 8-3	Noise • Noise during construction will be minimized through compliance with applicable municipal requirements for construction hours and by ensuring all equipment is equipped with an operational muffler.
Chapter 7, page 7-21 Chapter 8, page 8-2 to 8-3	Aesthetic Quality • The site will be fenced and a vegetation buffer will be maintained post-construction to screen the view of the Project from Robert Service Way or Miles Canyon Road. • Landscaping will commence following construction and will comply with relevant City of Whitehorse zoning bylaws. • Lighting installations at the storage site will be designed and installed to be fully shielded (full cut-off) and lighting levels shall be appropriate for applicable codes and regulations. • Lighting shall be directed so that light trespass beyond the perimeter fence of the site is minimized. Lighting that is not necessary from an operational, safety, or security perspective shall be extinguished when the site is unoccupied.
Chapter 7, page 7-32	Effects of the Environment on the Project • With respect to seismic events, the Project will be developed in accordance with standard and specified engineering practices to address the potential for seismic events to impact the facility and operations. This includes applicable standards and codes such as CSA-Z276-11, ASME B32.3, Process Piping and the National Building Code of Canada which will be reviewed and incorporated into the facility design to ensure the facility is designed to resist seismic events and prevent failure of Project components.
Chapter 8, Page 8-3 to 8-4	Monitoring & Follow up • An environmental compliance monitoring program will be in place to ensure that commitments made to regulatory authorities and others are implemented during construction and operation phases of the Project. • Yukon Energy will designate liaison personnel to manage any concerns that may arise during construction, operation, and maintenance phases. The scope of liaison will include regulatory and environmental affairs, as well as work to maintain close communications with Kwanlin Dün First Nation, Ta'an Kwäch'än Council, the City of Whitehorse, other local and territorial organizations, and citizens as concerns may arise.